Prospective Cost of Service Study

For Fiscal Year Ending

March 31, 2010

Manitoba Hydro

Electric Rates & Regulatory Department

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MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2010

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EXECUTIVE SUMMARY

A Cost of Service Study ("COSS") is a method of allocating a utility's cost to the various classes of customers 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 carried out PCOSS10 incorporating many, but not all, of the Public Utilities Board (PUB) recommendations emerging from the 2006 Cost of Service review and the 2008 General Rate Application (GRA). Below these recommendations are reviewed and the rationale for Manitoba Hydro's approach to the recommendation is set forth.

Export Class

PCOSS10 includes only a single export class that is allocated Generation and Transmission costs on the same basis as to domestic customers.

Load Profile for Allocation of Generation Costs

Twelve SEP time periods have been used in the allocation of generation-related costs, using energy use profiles averaged over six years. Future PCOSS will use the full eight year average as Load Research data becomes available.

Assignment of DSM Costs

In PCOSS10, DSM costs are simply assigned to the customer classes benefiting from the DSM programming, in the same manner as carried out prior to PCOSS08. This process reasonably assigns costs in accordance with the classes which benefit from the expenditures, is relatively simple to carry out, and avoids methodological complications associated with tracking cumulative DSM energy and capacity savings.

The costs of programs that are funded by the Affordable Energy Fund (AEF) have been charged directly to the export class in this study.

Thermal Plant Costs Assigned to the Export Class

Since gas-fired generation is almost never used to support exports, PCOSS10 assigns the cost of gas-fired thermal plants entirely to the domestic classes, as the plants provide dispatchable energy for the benefit of these customers.

Fuel and variable maintenance costs for Brandon Unit 5, other than that related to operation necessary for staff proficiency training and reliability runs, have been assigned to the export class. The remaining costs have been allocated to the domestic classes, as they are the beneficiaries of the reliability benefits provided by the thermal plant.

Assignment of Other Costs to Exports

Purchased power costs and the costs associated with securing US transmission used to make opportunity export sales have been directly assigned to the Export class.

The ‘Trading Desk’, as well as MISO and MAPP memberships provides benefits to domestic customers by facilitating import purchases needed for dependable supply, and during periods of prolonged drought, or in the event of a major generation or transmission failure. Consequently, only the portion of these costs that can be directly attributed to Manitoba Hydro’s export sales activities has been directly assigned to the export class. The remaining 58% of the costs have been assigned to the domestic classes.

Forecast of Export Revenue

PCOSS10 employs Manitoba Hydro’s forecast of export prices for 2009/10 as used in the Integrated Financial Forecast (IFF) that underlies the PCOSS, and which supports Manitoba Hydro’s rate requests to the PUB. If the most recent actual export prices were used as the basis for the IFF in the current year, the rate increase requirements would be increased relative to using Manitoba Hydro’s forecast.

Since the PCOSS is based on median flows, it is incorrect to apply lower average unit prices from a year of above average flows, with predominantly opportunity sales, against sales volumes under median flow conditions.

Net Export Revenue

The assignment and allocation of costs to the Export class results in net export revenue of $126 million to be allocated to domestic customers.

Gross Export Revenue	$546 million
Uniform Rates	$19 million
Affordable Energy Fund Expenditures	$4 million
Trading Desk	$5 million
MISO/MAPP	$2 million
NEB Cost	$2 million
Purchased Power and Transmission	$174 million
Brandon Unit 5 Costs	$14 million
Allocated Generation & Transmission (incl. Water rentals)	$200 million
Net Export Revenue	$126 million

The resulting Revenue Cost Coverage ratios (RCC) of the major classes are outlined below:

CUSTOMER CLASS	**RCC**
Residential	96.4%
GSS Non-Demand	105.7%
GSS Demand	102.8%
GSM	101.3%
GSL 0 – 30 kV	92.3%
GSL 30 – 100 kV	106.8%
GSL > 100 kV	109.2%
Area & Roadway Lighting	100.0%

SECTION A: COST OF SERVICE METHODOLOGY

Cost of Service History

Manitoba Hydro has conducted cost of service studies since the mid 1970s. While significant changes have occurred on an evolutionary basis, cost of service studies filed with previous Rate Applications follow 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 special treatment of items such as DSM or net export revenues. 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 using 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 allocates 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 allocates Customer Service costs in 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 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 in proportion to total allocated costs of all functions. This method was endorsed by the PUB in 2006. Previously the credit was allocated to classes on the same basis as allocated Generation and Transmission costs.

Methodology used in PCOSS10

Manitoba Hydro has carried out PCOSS10 incorporating many, but not all, of the PUB recommendations emerging from the 2006 Cost of Service review and the 2008 GRA. Below these recommendations are reviewed and the rationale for Manitoba Hydro's approach to the recommendation is set forth.

1. **Include only a single export class and allocate costs to that class in a manner comparable to the allocation of costs to domestic classes.**

   PCOSS10 includes only a single export class. After adjusting for energy provided by imports and thermal generation, a share of Manitoba Hydro's Generation and Transmission costs are allocated to the class on the same basis as to domestic customers.

2. **Directly assign the following costs to the export class:**

   a. **50% of fixed costs of thermal plant and 100% of the variable cost of thermal plant.**

      Fuel and variable maintenance costs for Brandon Unit 5, other than that related to operation necessary for staff proficiency training, have been assigned to the export class.

      The remaining operating and maintenance costs, and all fixed costs for the coal plant, have been allocated to the domestic classes, as they are the beneficiaries of the reliability benefits provided by the thermal plant.

      Due to climate change legislation contained in Bill 15, use of the Brandon Unit 5 coal generating station will be limited to emergency use only after December 31st, 2009. Since Manitoba Hydro can then no longer use coal-fired generation to support exports, all the fixed and variable costs will be assigned entirely to the domestic classes in future studies.

      Since gas-fired generation is almost never used to support exports, PCOSS10 assigns the cost of gas-fired thermal plants entirely to the domestic classes, as the plants provide dispatchable energy for the benefit of these customers.

b. Assign DSM costs directly to the export class and add DSM energy savings to domestic load for generation cost-sharing purposes.

PCOSS10 does not incorporate this direction. In PCOSS10, DSM costs are simply assigned to the customer classes benefiting from the DSM programming, in the same manner as carried out prior to PCOSS08. This process reasonably assigns costs in accordance with the classes which benefit from the expenditures, is relatively simple to carry out, and avoids methodological complications associated with tracking cumulative DSM energy and capacity savings. Manitoba Hydro does not have detailed historic data on realized DSM savings by rate class.

The cost of programs that do not pass Manitoba Hydro's screening process for inclusion in the Power Smart plan, but are instead funded by the Affordable Energy Fund (AEF), cannot be directly assigned to the customer classes and still reflect cost causation. These costs have been charged directly to the export class in this study.

c. Assign certain costs directly against the export class; including "trading desk" related costs, MAPP and MISO costs, purchased power costs and the costs associated with accessing US transmission.

PCOSS10 incorporates this recommendation with some modifications. Purchased power costs and the costs associated with securing US transmission used to make opportunity export sales have been directly assigned to the export class.

Although the remaining costs also facilitate export sales, they would largely still be incurred in order to achieve the dependable supply required to serve domestic customers. Manitoba Hydro has designed its system to use imports to meet its dependable energy requirements, as it is more cost effective than building the additional thermal plants that would otherwise be required. The trading desk provides benefits to domestic customers by facilitating these purchases, and energy required during periods of prolonged drought, or in the event of a major generation or transmission failure. Similarly MISO and MAPP memberships would still be required in the absence of export activities in order to gain access to the required import power. Consequently, only the portion of these costs that can be directly attributed to Manitoba Hydro's export sales activities has been directly assigned to the export class.

By comparing the current structure, to the hypothetical organizational structure as it would exist without export sales, it was estimated that 42% of the positions related to the trading desk were purely export related. On this basis 42% of trading desk and MISO/MAPP membership costs are assigned to the export class. The remaining costs, which would likely exist even in the absence of export sales, have been assigned to the domestic customers due to the benefits that domestic customers receive from interconnection.

As noted previously, all import costs are assigned directly to the export class.

3. **Use the most recent actual (not forecast) export prices to establish export revenue in the COSS.**

PCOSS10 employs Manitoba Hydro's forecast of export prices for 2009/10, and not the most recent actual prices, as recommended in 116/08. There are several reasons for this:

a. Manitoba Hydro's forecast, not the most recent actual export prices, is used in the IFF that underlies the PCOSS, and which supports Manitoba Hydro's rate requests to the PUB. It is not appropriate to provide a PCOSS which is inconsistent with the IFF. If the most recent actual export prices were used as the basis for the IFF in the current year, the rate increase requirements would be increased relative to using Manitoba Hydro's forecast.

b. Actual prices are, in some measure, a reflection of actual water flows. Typically high water flows will lead to lower export prices and vice-versa. Since the PCOSS is based on median flows, it should not incorporate export prices which reflect actual flows which are higher (in 2007/08 significantly higher) or lower than median flows.

c. Manitoba Hydro's forecast of export prices already incorporates historical information about pricing.

d. An examination of the actual experience since 2001 does not indicate superiority of using actual previous price data.

4. **Use 12 SEP time periods in the allocation of generation-related costs.**

   This recommendation has been adopted in PCOSS10.

5. **Incorporate Diesel and Export classes in the same fashion as other domestic customer classes.**

   In PCOSS10 the Diesel and Export classes have been added to Revenue Cost Coverage (“RCC”), Customer, Demand and Energy (“CDE”) and Functional Cost Analysis tables included as Schedules B1 to B3.

6. **Use actual (eight year) energy (SEP) prices and energy use profiles in generation energy weighting process.**

   In the version of the PCOSS08 filed during the 2008/09 GRA the energy consumption patterns from the last actual year were used to distribute forecast energy consumption into the twelve time periods, which were then weighted by the relative value of SEP energy in each period. The distribution of export energy among the twelve periods in the actual years previous to the PCOSS06 and PCOSS08 were quite different due to different water conditions in 2003/04 versus 2005/06.

   The season and time of day that export sales are made by Manitoba Hydro are logically affected by changing water conditions. The pattern of domestic energy use does not share the same connection to water conditions, but is likely affected by variations in weather and other factors from year to year. Manitoba Hydro agrees that using averages improves data quality for the export customers, and to a lesser degree for the domestic classes.

   Load Research data is not available to provide domestic consumption profiles over the required twelve periods for years prior to 2002/03. The study has used energy use profiles for the six year period from 2002/03 to the 2007/08 base year of PCOSS10. Future PCOSS will use the full eight year average as data becomes available.

   PCOSS10 uses the same methodology with further refinement to the calculation of estimated class demand. In recent studies the coincident peak (CP) and non-coincident peak (NCP) demand have been estimated for each class by applying CP load factor (CP

LF) and coincidence factors (CF) from the most recent Load Research study against forecast class energy. Although not specifically directed, Manitoba Hydro believes using averaged CP LF and CF from multiple Load Research Studies will provide similar improvement in estimating class CP and NCP allocators. Manitoba Hydro does not have sufficient historical information to provide the full eight years, hence in PCOSS10 the average from five years of Load Research results is used for NCP allocators in Schedule D5, and two years for seasonal CP allocators in Schedule D1. Manitoba Hydro will move towards using average factors from the previous eight years, for consistency with sample used to create the energy use profiles, as Load Research data becomes available.

In PCOSS10 the assignment and allocation of costs to the Export class results in net export revenue of $126 million to be allocated to domestic customers.

Gross Export Revenue	$546 million
Uniform Rates	$19 million
Affordable Energy Fund Expenditures	$4 million
Trading Desk	$5 million
MISO/MAPP	$2 million
NEB Cost	$2 million
Purchased Power and Transmission	$174 million
Brandon Unit 5 Costs	$14 million
Allocated Generation & Transmission (incl. Water rentals)	$200 million
Net Export Revenue	$126 million

Treatment of Diesel Funding Agreement in PCOSS10

Allocation of export revenues in the PCOSS is based on total cost to serve in the diesel rate zone, as provided in the Diesel Funding Agreement between Manitoba Hydro, Indian and Northern Affairs Canada (INAC) and the four First Nations represented by Manitoba Keewatinook Ininew Okimowin (MKO). As such the total unreduced cost is reflected in the RCC Table in PCOSS10, while revenues for the Diesel class in the schedules are based upon variable costs, upon which the revised diesel rates are based. As a result the RCC in the PCOSS does not reflect the true RCC of the Diesel class.

The RCC calculated using the Diesel Cost of Service Study for 2006/07, upon which interim *ex parte* rates from PUB Order 176/06 are based, is 86.3% using revenues of $4,512,711 and variable costs of $5,226,151. Note that revenue does not include allocated net export revenues, which are currently being applied against the accumulated deficit.

SECTION B: SUMMARY RESULTS

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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 IFF08. The level of export sales forecast in this PCOSS reflects this assumption. The PCOSS10 filed herein includes the 2.9 per cent rate increase implemented April 1, 2009 for all customer classes except Area & Roadway Lighting. PCOSS10 does not include the revenue forecast for the Energy Intensive Industrial Rate, which was denied in its proposed form in PUB Order 112/09.

This Section outlines the three primary tables: Revenue Cost Coverage ("RCC"), Customer, Demand and Energy ("CDE"), and Functional Cost Analysis.

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.

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Revenue Cost Coverage Analysis

SUMMARY

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	561,263	486,651	86.7%	54,493	541,144	96.4%
General Service - Small Non Demand	115,977	111,651	96.3%	10,925	122,576	105.7%
General Service - Small Demand	123,375	115,256	93.4%	11,561	126,817	102.8%
General Service - Medium	172,999	158,991	91.9%	16,340	175,331	101.3%
General Service - Large 0 - 30kV	81,925	67,889	82.9%	7,726	75,615	92.3%
General Service - Large 30-100kV*	45,916	44,588	97.1%	4,444	49,033	106.8%
General Service - Large >100kV*	193,762	192,906	99.6%	18,623	211,529	109.2%
*Includes Curtailment Customers						
SEP	1,513	1,315	86.9%	-	1,315	86.9%
Area & Roadway Lighting	20,502	19,837	96.8%	657	20,494	100.0%
Total General Consumers	1,317,232	1,199,084	91.0%	124,770	1,323,853	100.5%
Diesel	12,516	4,665	37.3%	1,229	5,895	47.1%
Export	420,122	546,121	130.0%	(125,999)	420,122	100.0%
Total System	1,749,870	1,749,870	100.0%	-	1,749,870	100.0%

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Customer, Demand, Energy Cost Analysis

SUMMARY

	C U S T O M E R			D E M A N D				E N E R G Y		
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	114,124	466,759	20.38	195,045	0%	n/a	n/a	197,601	6,811,218	5.76 **
GS Small - Non Demand	21,469	52,716	33.94	37,531	0%	n/a	n/a	46,052	1,478,206	5.65 **
GS Small - Demand	6,951	11,260	51.44	44,560	38%	2,203	7.74	60,304	1,983,393	4.43
General Service - Medium	5,523	1,859	247.59	61,751	100%	7,008	8.81	89,384	3,032,155	2.95
General Service - Large <30kV	2,773	259	n/a	27,043	100%	3,452	8.64 *	44,383	1,533,322	2.89
General Service - Large 30-100kV	1,739	30	n/a	9,991	100%	2,455	4.78 *	29,741	1,151,746	2.58
General Service - Large >100kV	2,014	14	n/a	29,355	100%	9,476	3.31 *	143,770	5,626,174	2.56
SEP	356	25	1,187.66	242	0%	n/a	n/a	915	22,550	5.13 **
Area & Roadway Lighting	15,217	153,710	8.25	2,375	0%	n/a	n/a	2,252	99,432	4.65 **
Total General Consumers	170,168	686,631		407,892		24,594		614,402	21,738,196	
Diesel	251	732	28.55	376	0%	n/a	n/a	10,660	12,820	86.08 **
Export	n/a	n/a	n/a	52,345	0%	n/a	n/a	367,777	7,707,000	5.45 ***
Total System	170,419	687,363		460,613		24,594		992,839	29,458,016	

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

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Functional Breakdown

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	506,770	197,601	39.0%	46,764	9.2%	38,994	7.7%	55,248	10.9%	168,163	33.2%
General Service - Small Non Demand	105,052	46,052	43.8%	10,818	10.3%	7,043	6.7%	13,792	13.1%	27,347	26.0%
General Service - Small Demand	111,815	60,304	53.9%	13,291	11.9%	8,223	7.4%	3,051	2.7%	26,946	24.1%
General Service - Medium	156,659	89,384	57.1%	20,069	12.8%	10,961	7.0%	4,559	2.9%	31,685	20.2%
General Service - Large <30kV	74,199	44,383	59.8%	9,865	13.3%	5,126	6.9%	2,553	3.4%	12,272	16.5%
General Service - Large 30-100kV	41,471	29,741	71.7%	6,374	15.4%	3,617	8.7%	1,691	4.1%	49	0.1%
General Service - Large >100kV	175,139	143,770	82.1%	29,355	16.8%	0	0.0%	1,991	1.1%	23	0.0%
SEP	1,513	915	60.5%	242	16.0%	0	0.0%	340	22.5%	16	1.1%
Area & Roadway Lighting	19,844	2,417	12.2%	407	2.0%	563	2.8%	576	2.9%	15,882	80.0%
Total General Consumers	1,192,462	614,567	51.5%	137,185	11.5%	74,528	6.2%	83,800	7.0%	282,383	23.7%
Diesel	11,287	10,660	94.4%	0	0.0%	0	0.0%	0	0.0%	627	5.6%
Export	420,122	367,777	87.5%	52,345	12.5%	0	0.0%	0	0.0%	0	0.0%
Total System	1,623,871	993,004	61.2%	189,530	11.7%	74,528	4.6%	83,800	5.2%	283,010	17.4%

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SECTION C: FUNCTIONALIZATION AND CLASSIFICATION METHODS

Organization and Preparation of Forecast Data

This Section provides a basic review of the approaches taken to organize Manitoba Hydro's 2009/10 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 E. 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:

- 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.

- 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 Open Access 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.

- 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 to load while maintaining reliable operation of the Transmission provider's 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. Although Ancillary Services are functionalized separately, they are included with Transmission for the purpose of presentation.

- 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 specific load centres.

- 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.

- 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 & Regulatory. In addition, it includes a share of administration buildings and general equipment associated with these activities.

Classification – The process of classifying functionalized costs 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]As based on Business Process Synchronization Unit ("BPSU") breakdown in SAP.

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

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.

- *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.

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

- *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.

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 interest expense, capital tax, 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, 2008, is first functionalized.

Functionalized gross plant investment for 2008 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 are functionalized as Generation, with the exception of Dorsey Station which is functionalized as Transmission. AC substations are functionalized as Transmission, Subtransmission or Distribution. An analysis of voltage levels, functions, current use, and related books and records of the company, is used to determine the functionalization of the numerous AC substations. 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.

As noted previously Ancillary Services are items that were formerly 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.

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 from the Transmission provider:

- Scheduling, System Control and Dispatch Service – Required to schedule the movement of power from, to or within a control area;
- Reactive Supply and Voltage Control from Generation Source Service – Required to maintain Transmission voltages within acceptable limits.

The remaining four other Ancillary Services can be procured from the service provider, self supplied, or purchased from a third party:

- 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;
- Energy Imbalance Service – Provided when differences occur between scheduled and actual delivery of energy to a load over a single hour;

- Operating Reserve – Spinning Service – Needed to serve load immediately in the event of a system contingency;
- Operating Reserve – Supplemental Reserve Service – Same as spinning reserve, but able to serve load within a short period of time.

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

Communication facilities and equipment are functionalized as 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"). Depreciation costs for 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 and domestic item additions. The domestic items consist of non-blanket items (facilities specifically identified) and blanket items (facilities broadly identified). Capital items consist of gross additions, salvage material and capital contributions. The functionalization of forecast salvage material and capital contributions follows the same methodology and is treated consistently with the functionalization of gross additions with the exception of the assignment of capital contributions for the Diesel Rate Zone. These contributions are deducted from those functionalized as distribution lines. Contributions in the Diesel Zone are received primarily through work undertaken on district work orders.

Major item additions are functionalized based on the facility being constructed and included in the COS once the new asset is placed in service. Functionalization of domestic items is based on a three-year average of previous domestic item expenditures since the facilities are only broadly defined.

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, 2010.

Schedule C3 shows the functionalization of accumulated depreciation forecast for fiscal year ending March 31, 2010. Accumulated depreciation for diesel generation, street lighting (asset class distribution lines), and HVDC (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 2010.

Depreciation expense, both direct facility depreciation and allocated administrative depreciation, is separated from operating costs. The Corporation periodically undertakes a depreciation study to ensure that amortization of assets is commensurate with the actual life of a particular asset. The last such review was in fiscal year 2004/05, these revised rates are reflected in the PCOSS10. Functionalized depreciation expense is also matched and 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 2008/09 and 2009/10 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, 2010 (gross investment less accumulated depreciation) adjusted to include net deferred expenses which is used to functionalize forecast capital tax assessment. The functionalization of the forecast capital tax assessment for 2009/10 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. 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 include classification of distribution costs into customer and demand components. This approach used to classify distribution facilities is 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.

Class revenue includes an adjustment to offset any revenue reduction that resulted from implementation of the uniform rates legislation that equalized northern, urban and rural rates throughout the province. The adjustment is necessary to ensure that the cost of implementing uniform rates is broadly shared, and not solely borne by the affected classes' former Zone 1 customers through degradation of the class RCC. The class revenue reduction percentages were calculated by dividing the total revenue for each class after uniform rates by that prior to the adoption of uniform rates. The reduction percentages are applied to the forecast revenue in the study to determine the adjusted revenue for the class. While the percentages are based on a one-time calculation and are constant, the forecast revenue will vary resulting in a change of the magnitude of the adjustment between studies. In PCOSS10 the revenue adjustment is $19 million, with the offset charged against net export revenue as per PUB Order 101/04.

The revenue reduction associated with DSM Programs is also assigned to the customer rate classes in the general consumers revenue forecast process. DSM revenue reduction by class is shown below:

CLASS	TOTAL
Residential	$ 2,675,766
General Service Small-Non-Demand	$ 1,397,306
General Service Small-Demand	$ 2,502,471
General Service Medium	$ 2,627,234
General Service Large:	
0 - 30 kV	$1,190,589
30 - 100 kV	$ 132,370
> 100 kV	$ 259,582
Total DSM	**$10,785,318**

The accrual adjustment represents any forecast 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 for street lights and large power customers that 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.

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
MARCH 31, 2008

			Transmission			Distribution			Direct Allocation	
Asset Class	Total	Generation	Domestic	Export	Sub Trans	Plant	Services	Ancillary Services	Lighting	Diesel
GENERATION	4,535,402,877	4,481,742,390	53,660,487							
-Thermal	463,456,864	463,456,864								
DIESEL	42,251,914									42,251,914
SUBSTATION	1,055,398,155		318,602,225	64,406,532	170,509,832	489,833,110		12,046,456		
- HVDC	1,197,291,085	596,591,135	600,699,950							
TRANSMISSION	610,475,203		308,719,716	124,478,617	177,276,870					
- HVDC	188,181,438	188,181,438								
DISTRIBUTION	1,881,810,405					1,742,079,311			136,361,286	3,369,808
SUBTRANSMISSION	249,927,586				239,323,807	10,603,779				
TRANSFORMERS										
- SUBSTATION	15,614,300		4,768,048	963,877	2,551,768	7,330,607				
- DISTRIBUTION	6,924,063					6,924,063				
METERS	49,638,491					49,638,491				
BUILDINGS	188,838,496	79,733,859	20,893,333	8,424,383	12,383,045	43,649,480	18,497,436	-	4,634,481	622,477
COMMUNICATION	402,810,408	81,422,862	37,742,116	11,763,308	75,867,353	100,667,365		95,347,404		
GENERAL EQUIPMENT	306,624,071	71,351,024	44,592,780	17,921,345	26,530,406	98,808,830	37,993,218		9,426,468	
SUBTOTAL	11,194,645,356	5,962,479,572	1,389,678,655	227,958,062	704,443,081	2,549,535,036	56,490,654	107,393,860	150,422,235	46,244,199
MOTOR VEHICLES	146,479,644									
TOTAL FIXED ASSETS	11,341,125,000	5,962,479,572	1,389,678,655	227,958,062	704,443,081	2,549,535,036	56,490,654	107,393,860	150,422,235	46,244,199

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2010

			Transmission		Sub-	Distribution		Ancillary	DIRECT ALLOCATIONS	
Asset Class	Total	Generation	Domestic	Export	Transmission	Plant	Services	Services	Lighting	Diesel
GENERATION	4,813,421,749	4,754,725,310	58,696,439	-	-	-	-	-	-	-
-Thermal	480,770,015	480,770,015	-	-	-	-	-	-	-	-
DIESEL	42,536,849	-	-	-	-	-	-	-	-	42,536,849
SUBSTATION	1,134,806,393	-	332,168,949	64,486,209	182,318,119	543,771,758	-	12,061,359	-	-
- HVDC	1,279,385,402	640,345,826	639,039,576	-	-	-	-	-	-	-
TRANSMISSION	630,232,541	-	321,220,257	127,815,329	181,196,955	-	-	-	-	-
- HVDC	188,462,438	188,462,438	-	-	-	-	-	-	-	-
DISTRIBUTION	2,106,151,860	-	-	-	-	1,963,136,729	-	-	139,645,323	3,369,808
SUBTRANSMISSION	267,449,903	-	-	-	256,946,587	10,503,316	-	-	-	-
TRANSFORMERS										
- SUBSTATION	15,614,300	-	4,768,048	963,877	2,551,768	7,330,607	-	-	-	-
- DISTRIBUTION	6,924,063	-	-	-	-	6,924,063	-	-	-	-
METERS	58,367,127	-	-	-	-	58,367,127	-	-	-	-
BUILDINGS	464,091,024	197,703,163	59,531,450	20,784,885	27,306,228	84,858,017	64,275,007	-	9,009,796	622,477
COMMUNICATION	479,997,025	121,971,702	43,034,798	13,897,377	85,152,173	118,930,065	-	97,010,910	-	-
GENERAL EQUIPMENT	406,308,873	102,524,363	58,544,494	23,448,619	34,555,970	123,694,678	51,653,616	-	11,887,133	-
SUBTOTAL	12,374,519,562	6,486,502,817	1,517,004,011	251,396,296	770,027,801	2,917,516,360	115,928,623	109,072,268	160,542,252	46,529,134
MOTOR VEHICLES	170,363,678									
TOTAL FIXED ASSETS	12,544,883,240	6,486,502,817	1,517,004,011	251,396,296	770,027,801	2,917,516,360	115,928,623	109,072,268	160,542,252	46,529,134

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF ACCUMULATED DEPRECIATION
FORECAST YEAR ENDING MARCH 31, 2010

Asset Class	Accum Depn by Asset Class	Generation	Transmission		Sub Trans	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	1,575,811,878	1,555,968,674	19,843,204	-	-	-	-	-	-	-
-Thermal	247,484,099	247,484,099	-	-	-	-	-	-	-	-
DIESEL	32,586,169	-	-	-	-	-	-	-	-	32,586,169
SUBSTATION	433,841,039	-	122,489,542	22,045,437	87,338,110	191,021,790	-	10,946,160	-	-
- HVDC	671,507,673	363,089,254	308,418,418	-	-	-	-	-	-	-
TRANSMISSION	206,223,497	-	109,984,747	48,305,033	47,933,716	-	-	-	-	-
- HVDC	73,830,445	73,830,445	-	-	-	-	-	-	-	-
DISTRIBUTION	889,503,137	-	-	-	-	811,545,515	-	-	75,970,831	1,986,791
SUBTRANSMISSION	97,615,056	-	-	-	93,520,415	4,094,641	-	-	-	-
TRANSFORMERS										
- SUBSTATION	10,927,680	-	3,148,878	560,743	2,276,585	4,941,474	-	-	-	-
- DISTRIBUTION	2,523,462	-	-	-	-	2,523,462	-	-	-	-
METERS	20,165,398	-	-	-	-	20,165,398	-	-	-	-
BUILDINGS	51,987,065	20,381,593	6,103,603	2,446,501	3,581,465	12,425,815	5,564,113		1,319,309	164,667
COMMUNICATION	185,835,497	47,906,403	15,100,548	4,133,801	33,528,360	35,375,939	-	49,790,447	-	-
GENERAL EQUIPMENT	186,707,471	52,714,884	26,485,347	10,661,041	15,722,180	56,872,363	18,818,759		5,432,897	-
SUBTOTAL	4,686,549,567	2,361,375,352	611,574,286	88,152,556	283,900,832	1,138,966,397	24,382,872	60,736,607	82,723,038	34,737,627
MOTOR VEHICLES	68,388,183									
TOTAL ACCUM DEPRECIATION	4,754,937,750	2,361,375,352	611,574,286	88,152,556	283,900,832	1,138,966,397	24,382,872	60,736,607	82,723,038	34,737,627

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
UNAMORTIZED BALANCE
FORECAST YEAR ENDING MARCH 31, 2010

			Transmission			Distribution			DIRECT ALLOCATIONS	
Asset Class	Unamortized Capital Contribution	Generation	Domestic	Export	Sub-Transmission	Plant	Services	Ancillary Services	Lighting	Diesel
GENERATION	26,965	26,965	-	-	-	-	-	-	-	-
-Thermal	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-
SUBSTATION	27,935,042	-	4,617,441	-	2,080,426	21,237,176	-	-	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
TRANSMISSION	67,784,175	-	1,829,812	94,630	65,859,732	-	-	-	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
DISTRIBUTION	174,337,131	-	-	-	-	147,783,823	-	-	26,089,135	464,172
SUBTRANSMISSION	7,449,116	-	-	-	7,152,932	296,184	-	-	-	-
TRANSFORMERS										
- SUBSTATION	-	-	-	-	-	-	-	-	-	-
- DISTRIBUTION	-	-	-	-	-	-	-	-	-	-
METERS	12,127	-	-	-	-	12,127	-	-	-	-
BUILDINGS	-	-	-	-	-	-	-	-	-	-
COMMUNICATION	272,175	37,144	146,313	42,127	7,999	38,593	-	-	-	-
GENERAL EQUIPMENT	-	-	-	-	-	-	-	-	-	-
SUBTOTAL	277,816,731	64,109	6,593,566	136,757	75,101,089	169,367,903	-	-	26,089,135	464,172
MOTOR VEHICLES	-									
TOTAL UNAMORTIZED CONTRIBS	277,816,731	64,109	6,593,566	136,757	75,101,089	169,367,903	-	-	26,089,135	464,172

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
ANNUAL AMORTIZATION
FORECAST YEAR ENDING MARCH 31, 2010

Asset Class	Annual Amortization Contribution	Generation	Transmission		Sub - Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	6,780	6,780								
-Thermal	-									
DIESEL	-									
SUBSTATION	1,461,619		227,164		81,797	1,152,658				
- HVDC	-									
TRANSMISSION	1,639,850		18,855	2,774	1,618,221					
- HVDC	-									
DISTRIBUTION	9,966,097					8,179,644			1,751,858	34,595
SUBTRANSMISSION	120,759				120,759					
TRANSFORMERS										
- SUBSTATION	-									
- DISTRIBUTION	-									
METERS	-									
BUILDINGS	-									
COMMUNICATION	34,932	7,524	4,390	1,646	6,008	15,364				
GENERAL EQUIPMENT	-									
SUBTOTAL	13,230,038	14,304	250,409	4,420	1,826,785	9,347,667	-	-	1,751,858	34,595
MOTOR VEHICLES	-									
TOTAL ANNUAL AMORT.	13,230,038	14,304	250,409	4,420	1,826,785	9,347,667	-	-	1,751,858	34,595

SCHEDULE C6
Functionalization of Depreciation Costs

2010 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2010
Functionalization of Depreciation Costs

SCC Description	Depreciation	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancillary Services	Diesel	Street Lighting	Exports
Research & Development	132,774	132,774								
Generation External Marketing	277,753	162,023								115,730
Common Generation Costs	33,517,747	33,190,640					-			327,108
Generating Station Costs	18,028,240	18,028,240					-			-
Other Generation Related Costs	170,026	170,026								
Dedicated Gen. Facilities	18,198,265	18,198,265					-	-	-	-
Hydraulic Generating Stations	48,931,178	48,931,178					-			
Other Hydraulic Generation Related Costs	16,334,081	16,334,081					-			
Hydraulic Generation Costs	65,265,259	65,265,259					-			
Thermal Generating Station	19,162,354	19,162,354					-	-	-	-
Non-Dedicated Gen. Facilities	84,427,612	84,427,612					-			-
Generation Facilities Costs	102,625,877	102,625,877					-			-
Purchased Power/Export Costs	-	-								-
Generation Facilities & Costs	***136,143,625***	***135,816,517***					***-***			***327,108***
Research & Development	199,625	39,652	129,654	30,319						
Transmission External Marketing	-	-	-	-						-
Common Trans. Costs/Revenues	4,205,160	39,652	3,376,044	789,463			-			-
Generation Switching Stations	2,052,142	-	2,052,142							
HVDC & Collector Facilities	52,482,256	26,758,779	25,723,477							
Networked AC Facilities	9,457,161	-	9,457,161							
Generation Access Transmission	63,991,559	26,758,779	37,232,780							
Regional Networked Trans.	8,962,716	-	8,962,716				-			
Future Transmission Line ROW	12,984	-	12,984							
Transmission Common	585,328	-	733,583	-	-	-	58,137			
Transmission Facilities/Costs	***77,757,747***	***26,798,431***	***50,318,108***	***789,463***			***58,137***			***-***
Common Subtransmission Costs	1,020,931	-	-	1,020,931						
Subtrans. Facilities & Costs	***20,848,856***	***-***	***-***	***18,239,198***	***2,403,266***	***-***	***-***	***-***	***-***	***-***
Dist. Facilities & Costs	***95,305,814***	***-***	***-***	***-***	***92,473,934***	***288,084***		***-***	***2,543,797***	***-***
Customer Service Costs	***10,393,103***	***-***	***-***	***-***	***-***	***10,393,103***		***-***	***-***	***-***
Isolated Diesel Facilities	***6,974,105***	***1,677,000***	***-***	***-***	***1,301,712***	***-***	***-***	***3,995,393***		
System Control	6,548,514	2,357,465	-	2,357,465	-	-	1,833,584	-		
Communication & Control System	***19,911,317***	***6,977,683***	***872,315***	***3,334,762***	***5,026,850***	***-***	***3,699,707***	***-***	***-***	***-***
Planned Grants In Lieu Taxes	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***		
	367,334,567	**171,269,631**	**51,190,423**	**22,363,424**	**101,205,762**	**10,681,187**	**3,757,844**	**3,995,393**	**2,543,797**	**327,108**

SCHEDULE C7
Functionalization of Net Investment

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF NET INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2010

Asset Class	Net Investment	Generation	Transmission Domestic	Transmission Export	Sub-Transmission	Distribution Plant	Distribution Services	Ancillary Services	DIRECT ALLOCATIONS Lighting	DIRECT ALLOCATIONS Diesel
GENERATION	3,237,582,906	3,198,729,671	38,853,235	-	-	-	-	-	-	-
-Thermal	233,285,916	233,285,916	-	-	-	-	-	-	-	-
DIESEL	9,950,680	-	-	-	-	-	-	-	-	9,950,680
SUBSTATION	673,030,311	-	205,061,966	42,440,772	92,899,583	331,512,792	-	1,115,199	-	-
- HVDC	607,877,730	277,256,572	330,621,158	-	-	-	-	-	-	-
TRANSMISSION	356,224,869	-	209,405,698	79,415,665	67,403,507	-	-	-	-	-
- HVDC	114,631,993	114,631,993	-	-						
DISTRIBUTION	1,042,311,592	-	-	-	-	1,003,807,391	-	-	37,585,357	918,845
SUBTRANSMISSION	162,385,731	-	-	-	156,273,240	6,112,491	-	-	-	-
TRANSFORMERS										
- SUBSTATION	4,686,620	-	1,619,170	403,134	275,183	2,389,133	-	-	-	-
- DISTRIBUTION	4,400,601	-	-	-	-	4,400,601	-	-	-	-
METERS	38,189,601	-	-	-	-	38,189,601	-	-	-	-
BUILDINGS	412,103,959	177,321,570	53,427,847	18,338,385	23,724,763	72,432,203	58,710,894	-	7,690,487	457,810
COMMUNICATION	293,889,352	74,028,154	27,787,938	9,721,449	51,615,814	83,515,534	-	47,220,463	-	-
GENERAL EQUIPMENT	219,601,402	49,809,479	32,059,147	12,787,578	18,833,790	66,822,315	32,834,857	-	6,454,236	-
SUBTOTAL	7,410,153,265	4,125,063,355	898,836,159	163,106,983	411,025,880	1,609,182,060	91,545,751	48,335,662	51,730,079	11,327,335
MOTOR VEHICLES	101,975,495									
TOTAL NET INVESTMENT	7,512,128,760	4,125,063,355	898,836,159	163,106,983	411,025,880	1,609,182,060	91,545,751	48,335,662	51,730,079	11,327,335

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2010

			Transmission			Distribution			DIRECT ALLOCATIONS	
Asset Class	Rate Base Investment	Generation	Domestic	Export	Sub-Transmission	Plant	Services	Ancillary Services	Lighting	Diesel
GENERATION	3,414,693,075	3,375,061,034	39,632,041	-	-	-	-	-	-	-
-Thermal	238,265,992	238,265,992	-	-	-	-	-	-	-	-
DIESEL	13,492,798	-	-	-	-	-	-	-	-	13,492,798
SUBSTATION	668,048,793	-	205,085,983	43,509,430	92,130,218	326,043,961	-	1,279,201	-	-
- HVDC	607,005,356	275,105,784	331,899,572	-	-	-	-	-	-	-
TRANSMISSION	360,153,622	-	211,182,341	79,819,031	69,152,251	-	-	-	-	-
- HVDC	117,632,158	117,632,158	-	-	-	-	-	-	-	-
DISTRIBUTION	1,022,198,281	-	-	-	-	983,507,371	-	-	37,701,850	989,060
SUBTRANSMISSION	163,609,465	-	-	-	157,211,652	6,397,814	-	-	-	-
TRANSFORMERS										
- SUBSTATION	5,977,489	-	2,013,356	482,819	486,143	2,995,171	-	-	-	-
- DISTRIBUTION	5,060,457	-	-	-	-	5,060,457	-	-	-	-
METERS	35,849,127	-	-	-	-	35,849,127	-	-	-	-
BUILDINGS	400,094,519	172,683,450	46,825,053	17,278,184	23,781,836	72,706,489	58,636,769	-	7,719,609	463,129
COMMUNICATION	285,716,867	69,034,975	27,064,149	9,356,377	50,831,674	80,390,698	-	49,038,995	-	-
GENERAL EQUIPMENT	243,362,211	54,454,251	35,453,910	14,198,331	20,976,612	75,197,357	35,823,527	-	7,258,223	-
SUBTOTAL	7,581,160,211	4,302,237,643	899,156,405	164,644,173	414,570,386	1,588,148,444	94,460,296	50,318,196	52,679,681	14,944,986
MOTOR VEHICLES	99,921,843									
Total Rate Base Investment	7,681,082,054	4,302,237,643	899,156,405	164,644,173	414,570,386	1,588,148,444	94,460,296	50,318,196	52,679,681	14,944,986

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF INTEREST EXPENSE & RESERVE CONTRIBUTION
FORECAST YEAR ENDING MARCH 31, 2010

Asset Class	Interest & Reserve Expense	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	279,876,319	276,627,983	3,248,336	-	-	-	-	-	-	-
-THERMAL	19,528,844	19,528,844	-	-	-	-	-	-	-	-
DIESEL	1,105,902	-	-	-	-	-	-	-	-	1,105,902
SUBSTATION	54,754,859	-	16,809,332	3,566,136	7,551,211	26,723,334	-	104,846	-	-
- HVDC	49,751,594	22,548,321	27,203,274	-	-	-	-	-	-	-
TRANSMISSION	29,519,043	-	17,309,004	6,542,157	5,667,882	-	-	-	-	-
- HVDC	9,641,410	9,641,410	-	-	-	-	-	-	-	-
DISTRIBUTION	83,781,788	-	-	-	-	80,610,590	-	-	3,090,133	81,066
SUBTRANSMISSION	13,409,819	-	-	-	12,885,439	524,380	-	-	-	-
TRANSFORMERS										
- SUBSTATION	489,929	-	165,019	39,573	39,845	245,491	-	-	-	-
- DISTRIBUTION	414,767	-	-	-	-	414,767	-	-	-	-
METERS	2,938,279	-	-	-	-	2,938,279	-	-	-	-
BUILDINGS	10,292,468	4,442,298	1,204,579	444,483	611,790	1,870,381	1,508,436	-	198,588	11,914
COMMUNICATION	23,418,030	5,658,270	2,218,242	766,871	4,166,284	6,589,012	-	4,019,352	-	-
GENERAL EQUIPMENT	6,260,515	1,400,841	912,055	365,253	539,625	1,934,459	921,564	-	186,718	-
SUBTOTAL	585,183,566	339,847,966	69,069,841	11,724,472	31,462,076	121,850,693	2,430,000	4,124,198	3,475,439	1,198,881
MOTOR VEHICLES	-									
Total Interest Exp Allocated	585,183,566	339,847,966	69,069,841	11,724,472	31,462,076	121,850,693	2,430,000	4,124,198	3,475,439	1,198,881

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE FOR CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2010

Asset Class	Rate Based for Capital Tax	Generation	Transmission		Sub- Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	3,446,798,498	3,407,945,263	38,853,235	-	-	-	-	-	-	-
-THERMAL	234,859,751	234,859,751	-	-	-	-	-	-	-	-
DIESEL	11,803,104	-	-	-	-	-	-	-	-	11,803,104
SUBSTATION	673,747,508	-	205,280,972	42,485,045	93,016,791	331,849,501	-	1,115,199	-	-
- HVDC	607,877,730	277,256,572	330,621,158	-	-	-	-	-	-	-
TRANSMISSION	359,809,757	-	211,206,282	79,462,877	69,140,598	-	-	-	-	-
- HVDC	115,791,206	115,791,206	-	-	-	-	-	-	-	-
DISTRIBUTION	1,042,311,592	-	-	-	-	1,003,807,391	-	-	37,585,357	918,845
SUBTRANSMISSION	162,385,731	-	-	-	156,273,240	6,112,491	-	-	-	-
TRANSFORMERS										
- SUBSTATION	5,370,145	-	1,827,894	445,328	386,888	2,710,034	-	-	-	-
- DISTRIBUTION	4,703,706	-	-	-	-	4,703,706	-	-	-	-
METERS	38,189,601	-	-	-	-	38,189,601	-	-	-	-
BUILDINGS	412,629,096	177,544,034	53,486,141	18,361,889	23,759,313	72,553,988	58,762,504	-	7,703,417	457,810
COMMUNICATION	293,889,352	74,028,154	27,787,938	9,721,449	51,615,814	83,515,534	-	47,220,463	-	-
GENERAL EQUIPMENT	234,092,716	53,181,589	34,166,640	13,634,556	20,087,639	71,492,104	34,630,449	-	6,899,739	-
SUBTOTAL	7,644,259,494	4,340,606,569	903,230,261	164,111,144	414,280,283	1,614,934,351	93,392,952	48,335,662	52,188,513	13,179,759
MOTOR VEHICLES	-									
Rate Base for Capital Tax	7,644,259,494	4,340,606,569	903,230,261	164,111,144	414,280,283	1,614,934,351	93,392,952	48,335,662	52,188,513	13,179,759

2010 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2010

			Transmission		Sub-	Distribution		Ancillary	DIRECT ALLOCATIONS	
Asset Class	Capital Tax	Generation	Domestic	Export	Transmission	Plant	Services	Services	Lighting	Diesel
GENERATION	20,265,419	20,036,982	228,437	-	-	-	-	-	-	-
-Thermal	1,380,856	1,380,856	-	-	-	-	-	-	-	-
DIESEL	69,396	-	-	-	-	-	-	-	-	69,396
SUBSTATION	3,961,292	-	1,206,948	249,790	546,891	1,951,106	-	6,557	-	-
- HVDC	3,574,011	1,630,127	1,943,884	-	-	-	-	-	-	-
TRANSMISSION	2,115,498	-	1,241,785	467,201	406,511	-	-	-	-	-
- HVDC	680,793	680,793	-	-	-	-	-	-	-	-
DISTRIBUTION	6,128,261	-	-	-	-	5,901,876	-	-	220,983	5,402
SUBTRANSMISSION	954,745	-	-	-	918,807	35,938	-	-	-	-
TRANSFORMERS										
- SUBSTATION	31,574	-	10,747	2,618	2,275	15,934	-	-	-	-
- DISTRIBUTION	27,655	-	-	-	-	27,655	-	-	-	-
METERS	224,535	-	-	-	-	224,535	-	-	-	-
BUILDINGS	2,426,049	1,043,868	314,471	107,959	139,693	426,580	345,494	-	45,292	2,692
COMMUNICATION	1,727,920	435,248	163,379	57,157	303,475	491,029	-	277,632	-	-
GENERAL EQUIPMENT	1,376,346	312,681	200,882	80,164	118,105	420,337	203,609	-	40,567	-
SUBTOTAL	44,944,351	25,520,555	5,310,534	964,890	2,435,757	9,494,991	549,103	284,189	306,842	77,490
MOTOR VEHICLES	-									
Capital Tax Allocation	44,944,351	25,520,555	5,310,534	964,890	2,435,757	9,494,991	549,103	284,189	306,842	77,490

2010 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2010
Functionalization of Operating Costs

SCC Description	Operating	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancillary Services	Diesel	Street Lighting	Exports
Research & Development	1,893,393	1,893,393								
Generation External Marketing	3,960,830	2,310,484								1,650,346
Common Generation Costs	30,261,004	25,596,363					-			4,664,641
Generating Station Costs	41,624,128	41,624,128					-			-
Other Generation Related Costs	264,879	264,879	-	-	-	-	-	-	-	
Dedicated Gen. Facilities	41,889,007	41,889,007					-	-	-	-
Hydraulic Generating Stations	147,957,998	147,957,998					-			
Other Hydraulic Generation Related Costs	20,335,095	20,335,095								
Hydraulic Generation Costs	168,293,094	168,293,094					-			
Thermal Generating Station	43,916,031	30,053,171					-			13,862,860
Non-Dedicated Gen. Facilities	212,209,125	198,346,264					-			13,862,860
Generation Facilities Costs	254,098,131	240,235,271					-	-	-	13,862,860
Purchased Power/Export Costs	175,802,000	-								175,802,000
Generation Facilities & Costs	***460,161,135***	***265,831,635***					-	-	-	***194,329,501***
Research & Development	1,498,647	565,447	789,633	143,567						
Transmission External Marketing	4,747,000	3,105,750	-	-						1,641,250
Common Trans. Costs/Revenues	23,051,461	3,671,197	14,814,281	2,924,734			-			1,641,250
Generation Switching Stations	2,266,261	-	2,266,261							
HVDC & Collector Facilities	37,099,076	22,707,366	14,391,709							
Networked AC Facilities	3,343,330	-	3,343,330							
Generation Access Transmission	42,708,666	22,707,366	20,001,300							
Regional Networked Trans.	1,001,490	-	1,001,490							
Future Transmission Line ROW	-	-	-							
Transmission Common	14,864,464	-	14,168,495	655,819			40,150			
Transmission Facilities/Costs	***81,626,081***	***26,378,563***	***49,985,566***	***3,580,552***			***40,150***			***1,641,250***
Common Subtransmission Costs	5,955,577	-	-	5,955,577						
Subtrans. Facilities & Costs	***25,266,232***	-	-	***19,334,408***	***5,931,824***	-	-	-	-	-
Dist. Facilities & Costs	***62,216,740***	-	-	-	***54,739,926***	-	-	-	***7,476,814***	-
Customer Service Costs	***79,475,185***					***79,475,185***	-	-	-	-
Isolated Diesel Facilities	***7,244,324***	-	-	-	-	-	-	***7,244,324***		
System Control	5,427,674	1,953,963	-	1,953,963	-	-	1,519,749			
Communication & Control System	***10,633,539***	***5,248,829***	-	***2,192,250***	***747,750***		***2,445,437***	-	-	-
Planned Grants In Lieu Taxes	***13,165,468***	***4,175,728***	***3,877,700***	***1,235,208***	***3,876,106***		-			
	739,788,704	**301,634,755**	**53,863,266**	**26,342,418**	**65,295,605**	**79,475,185**	**2,485,587**	**7,244,324**	**7,476,814**	**195,970,751**

Adjusted Revenue including DSM Reduction at Approved Rates

2010 PROSPECTIVE COST OF SERVICE STUDY
ADJUSTED REVENUE INCLUDING DSM REDUCTION @ APPROVED RATES
For Year Ended March 31, 2010

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								
Residential	458,232,333			1,207,076	2,414,601	461,854,010	16,127,942	477,981,952
Seasonal	6,144,601				32,378	6,176,979	1,210,070	7,387,049
Water Heating	1,271,754			3,350	6,701	1,281,805		1,281,805
	465,648,688	-		1,210,426	2,453,680	469,312,794	17,338,012	486,650,807
General Service - Small								
Non Demand	108,304,195			285,295	570,696	109,160,186	1,439,823	110,600,009
Seasonal	477,112				2,514	479,626	34,288	513,915
Water Heating	532,935			1,404	2,808	537,147		537,147
Total Non Demand	109,314,242	-		286,699	576,018	110,176,959	1,474,111	111,651,071
Demand	113,988,539			300,269	600,649	114,889,456	366,497	115,255,954
	113,988,539	-	-	300,269	600,649	114,889,456	366,497	115,255,954
SEP								
GSM	1,133,081			2985	5970.635484	1,142,036.40		1,142,036
GSL	173,221					173,221		173,221
	1,306,302			2,985	5,971	1,315,257	-	1,315,257
General Service - Medium	157,709,549			415,439	831,032	158,956,019	34,970	158,990,990
	157,709,549	-		415,439	831,032	158,956,019	34,970	158,990,990

General Service - Large								
0 - 30 Kv	67,356,567			177,431	354,927	67,888,925		67,888,925
30 - 100 Kv	36,939,131					36,939,131		36,939,131
31 - 100 Kv Curtailable	7,649,087					7,649,087		7,649,087
Over - 100 Kv	100,466,502					100,466,502		100,466,502
Over - 100 Kv Curtailable	92,439,305					92,439,305		92,439,305
	304,850,593	-		177,431	354,927	305,382,951	-	305,382,951
Area & Roadway Lighting								
Street Lighting	16,930,519					16,930,519	223,977	17,154,496
Sentinel Lighting	2,672,046	(10,922)		7,010	14,022	2,682,157		2,682,157
	19,602,565	(10,922)	-	7,010	14,022	19,612,676	223,977	19,836,652
Diesel								
Residential	$612,718					612,718		612,718
General Service		-				-		-
Street Lighting		10,922				10,922		10,922
Full Cost	4,041,434					4,041,434		4,041,434
	4,654,152	10,922		-	-	4,665,074	-	4,665,074
Construction Power	-					-	-	-
Gen. Consumers Before Adj	1,177,074,629	-	-	2,400,258	4,836,300	1,184,311,187	19,437,568	1,203,748,755
Accrual - Other	2,400,258			(2,400,258)				
Seasonal Adjustment	-							
Miscellaneous - Non-Energy	565,950		(565,950)		-	-		
Customer Acctg. Adjustment	-				-	-		
Late Pmt Charges & Cust Adj	4,836,300				(4,836,300)	-		
Total General Consumers	1,184,877,137	-	(565,950)	-	-	1,184,311,187	19,437,568	1,203,748,755
Extra-Provincial	545,555,000		565,950			546,120,950		546,120,950
Other (Non Energy net of Subs)	6,819,000		(6,819,000)			-		
Total Revenue	1,737,251,137	-	(6,819,000)	-	-	1,730,432,137	19,437,568	1,749,869,705

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2010

RECONCILIATION TO FINANCIAL FORECAST
(In Millions of Dollars)

Reconciliation of Revenue

As per Financial Forecast:	
General Consumers Revenue	1,159.0
Additional GCR	45.0
Extra Provincial Revenue	545.6
Other Revenue (non-energy)	6.8
Total Revenue Per Financial Forecast	$ 1,756.4
Cost of Service Adjustments	
a. Transfer of Other Revenue (non-energy) to Miscellaneous Revenue	(6.8)
b. Correction to GCR; Additional GCR of 2.8% vs 4% in IFF	(6.0)
c. Remove Energy Intensive Industrial Rate Revenue	(13.2)
d. Uniform Rates Adjustment	19.4
Total Revenue Per Cost of Service Study	$ 1,749.8

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2010

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 2009 and 2010 adjusted for net deferred items and net major capital additions forecast to come into service during fiscal year 2009/10 which are included on an in-service date basis. This calculation is summarized below:

	2009	2010
Net Investment (Excluding Motor Vehicles)	$ 7,240.8	$ 7,410.2
Add: Total Net Deferred Items	277.3	234.1
Less: Major Capital Item Additions 2010		(166.3)
	$ 7,518.1	$ 7,478.0
Average Investment (2009 + 2010) ÷ 2		$ 7,498.0
Add: Major Capital Item Additions 2010 on an in-service date basis		83.1
		$ 7,581.2

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SECTION D: LOAD INFORMATION

Load data used in the preparation of the PCOSS for 2009/10 has been estimated using forecast energy and peak demand from the System Load Forecast and available class load information.

In PCOSS10 Manitoba Hydro introduced the use of averaged results from multiple Load Research studies to minimize year-to-year variation in the factors used to estimate class demands. The average will be based on the past eight Load Research studies, and will be phased in as data becomes available.

Load research data is used to estimate the average top 50 hourly peaks during both the summer and winter. Class data for 2005/06 and 2007/08 is used in the PCOSS to estimate this average seasonal class demand. Load research data used to estimate non-coincident peaks are based on the five year average of 2002/03 to 2005/06 and 2007/08 data.

Also included is a forecast of energy and capacity savings to be achieved through DSM Programs. For 2009/10 the DSM savings are forecast to be 205.3 GW.h and 57.7 MW at Generation, or 181.3 and 50.8 measured at the meter.

Schedule D1 outlines Manitoba Hydro's calculation of forecast demand for the 2009/10 fiscal year. Forecast consumption by rate class is shown seasonally; 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 Transmission related costs.

Generation costs are allocated based on energies weighted by relative value of SEP energy in each of the twelve time of use periods: Winter Peak/Off-Peak/Shoulder, Spring Peak/Off-Peak/Shoulder, Summer Peak/Off-Peak/Shoulder and Fall Peak/Off-Peak/Shoulder. The development of these allocators is outlined in Schedule D2.

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 2,183,018 MW.h and 343.3 MW respectively have been taken from the 2008 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 D4 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 PCOSS10 from the system peak forecasted in the 2008 System Load Forecast for the 2010 fiscal year. This difference of 154 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.

<u>Assignment of Losses</u>

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 (1.5%). Customers receiving service at supply voltage less than 30 kV share in the residual losses. A differential percentage has been assigned depending upon whether 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 the Distribution energy loss differential and Schedule D6 shows the results of this assignment based upon sales at the meter for both energy and capacity.

Residual Losses Assigned on a Differential Percentage Basis	
Secondary	+1.6%
Primary – Utility-owned transformation	-0.1%
Primary – Customer-owned transformation	-1.0%

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 twelve 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 1,260 customers was selected from Manitoba Hydro's various customer classes. All General Service Large 30 - 100 kV and >100 kV customers are sampled.

Development of Class Loads

1. Residential Class

The 2009/10 forecast kW.h sales to the Residential Class and the forecast number of customers are taken from the 2008 System Load Forecast. Load Forecasting provides separate information for Flat Rate Water Heating and Seasonal customers.

In Schedule D5, energy sales have been reduced by the forecast savings of 42 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 data from the last two load research studies, and are based on the average top 50 hourly peaks during the winter and summer seasons.

The Flat Rate Water Heating Class coincident demand is estimated on the basis of 1 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%.

The estimated coincident peaks at the meter have been adjusted by 123.4 MW to incorporate Residential's share of the total calibration factor derived in Schedule D3. The applicable share of each class's contribution to the calibration factor is provided by the error margin in the Load Research sample.

These loads have been reduced by the forecast capacity savings of 8.4 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 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 2008 data. Also shown are loads for small subgroups: Water Heating and Seasonal.

As with the Residential Class, General Service Small kW.h sales and customer counts are taken from the 2008 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 61.2 GW.h and 21.7 MW before being grossed up to include Distribution and Transmission losses.

For the General Service Small classes the coincident peak load factors were determined using load research information, with the same load factors 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 23.1 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 have been applied to derive class non-coincident peaks.

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

General Service Medium includes 1,841 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 there are 265 pulse metered customers included in the Load Research sample.

Customer and kW.h sales data are derived from the load forecast and apportioned among service voltages on the basis of recent past experience. DSM savings of 43.8 GW.h and 12.8 MW have been assigned to this class.

General Service Medium estimated coincident peaks at the meter have been adjusted by 7.6 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.

4. General Service Large

For customers in this class load information has been historically available. Sixty-two percent of the customers in the 0 - 30 kV subclass, 100% 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 0.2 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 33.8 GW.h and 8.0 MW.

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.

5. Surplus Energy Program

Surplus Energy Program (SEP) energy sales are taken from the 2008 System Load Forecast. Customers and forecast energy have been separated into service voltage levels and into utility or customer owned transformation.

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 2008 System Load Forecast. 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 2009/10 is based on the inventory wattage multiplied by 4,252 hours of use per year, a figure based on Load Research results. The customer count is based on June 2008 actual billing data plus forecast additions to the system of 3,040 lights to year end 2010. 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.

2010 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report
Seasonal Coincident Peaks (2 CP) at Generation Peak

			Winter				*SUMMER*			**D14**
	Forcast Total Energy @ Generation	**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										
Residential	7,882,119,564	62.6%	4,934,206,847	81.5%	1,393,702	37.4%	2,947,912,717	83.0%	804,280	1,098,991
Seasonal	84,495,444	36.4%	30,777,897	162.5%	4,360	63.6%	53,717,547	162.5%	7,486	5,923
Water Heating	20,019,300	49.6%	9,938,381	126.0%	1,816	50.4%	8,809,416	126.0%	1,583	1,699
Total Residential	7,986,634,308		4,974,923,125		1,399,878		3,010,439,680		813,349	1,106,614
GS Small										
Non-Demand	1,710,865,468	57.8%	988,880,240	79.6%	285,983	42.2%	721,985,227	73.0%	223,963	254,973
Demand	2,295,968,181	56.2%	1,290,334,118	84.8%	350,281	43.8%	1,005,634,063	81.7%	278,733	314,507
Subtotal	4,006,833,649		2,279,214,358		636,264		1,727,619,291		502,696	569,480
Seasonal	5,417,275	20.6%	1,118,234	162.5%	158	79.4%	3,781,000	162.5%	527	343
Water Heating	6,344,779	49.8%	3,161,540	106.0%	687	50.2%	3,183,239	106.0%	680	683
Total GSS	4,018,595,704		2,283,494,132		637,109		1,734,583,530		503,903	570,506
General Service - Medium	3,498,920,113	53.1%	1,857,926,580	87.1%	491,044	46.9%	1,640,993,533	81.0%	458,768	474,906
General Service - Large										
0 - 30 Kv	1,754,234,868	50.3%	882,380,139	88.8%	228,746	49.7%	871,854,729	82.9%	238,155	233,451
30 - 100 Kv	1,037,040,995	53.9%	558,965,096	90.4%	142,340	46.1%	478,075,898	101.7%	106,450	124,395
30 - 100 Kv - Curtailed Cust	244,220,956	50.6%	123,575,804	104.4%	27,249	49.4%	120,645,152	106.6%	25,629	26,439
Over 100 Kv	3,156,106,669	52.4%	1,653,799,894	98.4%	386,899	47.6%	1,502,306,774	108.6%	313,256	350,078
Over 100 Kv - Curtailed Cust	3,010,243,409	50.5%	1,520,172,921	99.5%	351,706	49.5%	1,490,070,487	100.0%	337,425	344,566
Total G.S.- Large	9,201,846,896		4,738,893,854		1,136,940		4,462,953,042		1,020,916	1,078,928
								81.6%		
Street Lighting	116,590,542	57.9%	67,476,148	86.7%	17,926	42.1%	49,114,394	0.0%	-	8,963
Total - General Consumers	24,822,587,563		13,922,713,839		3,682,897		10,898,084,179		2,796,936	3,239,917
Extra Provincial	8,575,000,000	39.9%	3,421,425,000	88.9%	885,963	60.1%	5,153,575,000	88.2%	1,323,156	1,104,559
Integrated System	33,397,587,563		17,344,138,839		4,568,860		16,051,659,179		4,120,092	4,344,476

2010 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report

Energy (MW.h) Weighted by Marginal Cost (Hydraulic for Domestic and Export Classes)

	2009/10 Forecast		Spring Peak	Spring Shoulder	Spring Off Peak	Summer Peak	Summer Shoulder	Summer Off Peak	Fall Peak	Fall Shoulder	Fall Off Peak	Winter Peak	Winter Shoulder	Winter Off Peak	Total	Weighted Energy/1000
Residential	7,831,948,530	Residential	252,136,339	479,694,560	307,643,591	485,872,434	908,179,538	460,964,880	332,979,991	604,043,107	377,993,173	888,009,681	1,627,361,716	1,107,069,520	7,831,948,530	19,536,101
Res FRWH	19,891,874	Residential FRWH	804,167	1,529,944	981,202	1,736,716	3,246,223	1,647,686	839,482	1,522,864	952,966	1,625,440	2,978,772	2,026,413	19,891,874	48,423
Res Seasonal	83,957,616	Residential Seasonal	3,854,883	7,333,995	4,703,527	9,320,219	17,421,100	8,842,431	3,062,230	5,555,045	3,476,191	4,997,938	9,159,194	6,230,861	83,957,616	201,202
GS Small Non Demand	1,699,975,517	GS Small Non-Demand	63,169,675	113,139,517	65,546,470	146,108,969	213,161,587	119,242,216	74,882,670	129,202,012	77,800,874	178,737,740	315,750,229	203,233,558	1,699,975,517	4,247,235
GSS FRWH	6,304,394	GS Small Non-Demand FRWH	274,438	491,530	284,764	641,661	936,133	523,671	279,126	481,602	290,004	538,339	951,007	612,118	6,304,394	15,525
GSS Seasonal	5,382,794	GS Small Non-Demand Seasonal	303,111	542,885	314,516	869,542	1,268,594	709,649	168,356	290,480	174,917	189,759	335,220	215,765	5,382,794	12,839
GS Small Demand	2,281,353,953	GS Small Demand	83,696,379	146,991,056	89,302,491	178,266,239	291,346,879	169,911,019	102,245,928	175,932,915	109,787,832	237,144,144	419,771,724	276,957,347	2,281,353,953	5,655,564
GS Medium	3,476,648,890	GS Medium	134,938,050	236,401,141	144,503,448	299,209,167	488,425,641	290,457,394	151,794,756	261,316,524	161,893,687	335,856,518	588,768,733	383,083,834	3,476,648,890	8,566,269
GS Large <30KV	1,743,068,864	GS Large 750-30kV	72,793,420	121,835,898	79,369,038	158,098,820	250,217,035	163,029,274	77,257,665	127,092,422	84,510,777	160,622,548	267,725,792	180,516,176	1,743,068,864	4,256,626
GS Large 30-100kV	1,030,440,052	GS Large 30-100kV	36,014,278	70,371,417	54,785,569	72,849,372	137,393,514	107,295,480	40,343,284	76,440,296	60,481,821	85,437,291	162,800,908	126,226,822	1,030,440,052	2,437,875
GS Large 30-100kV Curtail	242,666,448	GS Large 30-100kV Curtailable	8,832,789	17,502,414	13,231,349	17,677,043	34,343,935	26,157,653	9,245,286	18,009,863	13,671,209	18,916,414	36,979,088	28,099,404	242,666,448	572,157
GS Large > 100kV	3,136,017,512	GS Large > 100kV	120,097,255	230,388,001	179,079,534	218,539,949	408,120,391	319,486,835	123,161,343	233,179,627	181,811,562	256,720,419	487,396,415	378,036,182	3,136,017,512	7,412,217
GS Large > 100kV Curtail	2,991,082,697	GS >100kV Curtailable	108,157,981	211,855,092	162,298,696	217,935,677	427,598,356	329,943,486	112,870,159	218,683,496	167,898,520	232,764,416	453,985,199	347,091,620	2,991,082,697	7,042,243
Streetlights	115,848,424	Street Lights	-	4,402,240	10,831,828	463,394	8,225,238	21,721,579	3,359,604	6,603,360	13,206,720	7,877,693	13,264,645	25,892,123	115,848,424	232,378
Total	24,664,587,563	Totals	885,072,765	1,642,479,689	1,112,876,023	1,807,589,201	3,189,884,162	2,019,933,252	1,032,489,881	1,858,353,614	1,253,950,253	2,409,438,340	4,387,228,642	3,065,291,741	24,664,587,563	60,236,653
Exports	6,424,000,000	Exports	374,082,464	599,973,034	266,694,981	821,308,537	1,336,495,478	648,409,340	247,670,381	422,821,900	231,537,059	416,739,624	697,752,991	360,514,212	6,424,000,000	15,786,874
		Weighting Factor	2.712	2.344	1.380	3.435	2.484	1.000	2.793	2.305	1.440	3.845	2.652	2.096		

Energy (MW.h) Weighted by Marginal Cost (Thermal for Domestic Classes)

Thermal Generation	2009/10 Forecast		Spring Peak	Spring Shoulder	Spring Off Peak	Summer Peak	Summer Shoulder	Summer Off Peak	Fall Peak	Fall Shoulder	Fall Off Peak	Winter Peak	Winter Shoulder	Winter Off Peak	Total	Weighted Energy/1000
Residential	50,171,034	Residential	1,615,172	3,072,897	1,970,748	3,112,472	5,817,748	2,952,916	2,133,052	3,869,467	2,421,404	5,688,541	10,424,790	7,091,827	50,171,034	125,147
Res FRWH	127,426	Residential FRWH	5,151	9,801	6,286	11,125	20,795	10,555	5,378	9,755	6,105	10,412	19,082	12,981	127,426	310
Res Seasonal	537,828	Residential Seasonal	24,694	46,981	30,131	59,705	111,599	56,644	19,616	35,585	22,268	32,017	58,673	39,915	537,828	1,289
GS Small Non Demand	10,889,950	GS Small Non-Demand	404,661	724,766	419,887	935,966	1,365,501	763,859	479,694	827,661	498,388	1,144,984	2,022,679	1,301,903	10,889,950	27,208
GSS FRWH	40,386	GS Small Non-Demand FRWH	1,758	3,149	1,824	4,110	5,997	3,355	1,788	3,085	1,858	3,449	6,092	3,921	40,386	99
GSS Seasonal	34,482	GS Small Non-Demand Seasonal	1,942	3,478	2,015	5,570	8,127	4,546	1,078	1,861	1,121	1,216	2,147	1,382	34,482	82
GS Small Demand	14,614,229	GS Small Demand	536,154	941,617	572,067	1,141,964	1,866,352	1,088,441	654,982	1,127,017	703,295	1,519,132	2,689,035	1,774,174	14,614,229	36,229
GS Medium	22,271,223	GS Medium	864,406	1,514,373	925,681	1,916,718	3,128,828	1,860,654	972,389	1,673,979	1,037,082	2,151,478	3,771,620	2,454,014	22,271,223	54,875
GS Large <30KV	11,166,004	GS Large 750-30kV	466,311	780,474	508,434	1,012,772	1,602,877	1,044,357	494,908	814,147	541,371	1,028,939	1,715,037	1,156,377	11,166,004	27,268
GS Large 30-100kV	6,600,943	GS Large 30-100kV	230,705	450,795	350,953	466,669	880,135	687,329	258,437	489,672	387,443	547,307	1,042,894	808,602	6,600,943	15,617
GS Large 30-100kV Curtail	1,554,508	GS Large 30-100kV Curtailable	56,582	112,120	84,759	113,238	220,005	167,564	59,225	115,370	87,577	121,178	236,886	180,003	1,554,508	3,665
GS Large > 100kV	20,089,157	GS Large > 100kV	769,336	1,475,853	1,147,174	1,399,955	2,614,397	2,046,615	788,965	1,493,736	1,164,675	1,644,537	3,122,235	2,421,679	20,089,157	47,482
GS Large > 100kV Curtail	19,160,712	GS >100kV Curtailable	692,854	1,357,132	1,039,677	1,396,084	2,739,172	2,113,600	723,040	1,400,875	1,075,549	1,491,076	2,908,204	2,223,450	19,160,712	45,112
Streetlights	742,119	Street Lights	-	28,201	69,388	2,968	52,690	139,147	21,521	42,301	84,602	50,464	84,973	165,864	742,119	1,489
Thermal Generation	158,000,000	Totals	5,669,728	10,521,635	7,129,023	11,579,318	20,434,224	12,939,582	6,614,074	11,904,512	8,032,737	15,434,730	28,104,347	19,636,091	158,000,000	385,873
Exports	-	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Weighting Factor	2.712	2.344	1.380	3.435	2.484	1.000	2.793	2.305	1.440	3.845	2.652	2.096		

Definition of Periods
Spring (April 1 to May 31)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Summer (June 1 to Sept 30)
Peak = 12:00 noon to 8:00 pm weekdays
Shoulder = 7:00 am to 12:00 noon weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Fall (Oct 1 to Nov 30)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

Winter (December 1 to March 31)
Peak = 7:00 am to 11:00 am and 4:00 pm to 8:00 pm weekdays
Shoulder = 11:00 am to 4:00 pm weekdays; 8:00 pm to 11:00 pm weekdays; 7:00 am to 11:00 pm weekends & Holidays
Off-Peak = 11:00 pm to 7:00 am everyday

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
March 31, 2010

CALCULATION OF LOSSES

ENERGY (in MWh)	*MANITOBA HYDRO*
Firm Energy at Generation (After DSM)	24,920,125,444
Common Bus Losses (After DSM)	2,183,017,784
Deliveries From Common Bus	22,737,107,660
Sales at Meter	21,800,196,244
Distribution Losses	936,911,416

DEMAND (in MW)	*MANITOBA HYDRO*
Firm Peak Capacity At Generation (After DSM)	4,427.8
Common Bus Losses (After DSM)	343.3
Deliveries From Common Bus	4,084.5
Calculated Distribution Losses	274.9
Calculated Demand at Meter (CP Load Factors)	3,654.4
Less: Adj made for curtailable load added back	(0.9)
Adjustment To Reconcile	154.3

MANITOBA HYDRO
2010 PROSPECTIVE COST OF SERVICE STUDY
March 31, 2010
DETERMINATION OF COINCIDENT PEAK DISTRIBUTION LOSSES

1) ENERGY SALES AND TOTAL LOSSES ON DISTRIBUTION SYSTEM

	Sales	**Losses**	**Energy @ Common Bus**
RESIDENTIAL	6,811,217,752	475,782,649	7,287,000,401
G.S.S. SINGLE PHASE	1,294,700,733	90,438,475	1,385,139,208
G.S.S. THREE PHASE	2,166,898,469	114,526,657	2,281,425,126
* G.S.M.	3,051,904,757	161,301,720	3,213,206,477
* G.S.L. O - 30	1,536,122,369	67,363,271	1,603,485,640
G.S.L. 30 - 100	1,151,746,446	17,276,197	1,169,022,643
LIGHTING	99,431,568	6,945,574	106,377,142
MAN. HYDRO CONSTRUCTION	62,000,000	3,276,874	65,276,874
	16,174,022,094	936,911,416	17,110,933,510

* (includes SEP sales)

2) COINCIDENT PEAK AT COMMON BUS

C.P. AT GENERATION	4,427.77
LESS SALES AT CB LEVEL :	
- EXPORTS	0.00
- * G.S.L. >100	(364.21)
C.B. LOSSES	(343.28)
EXPORT LOSSES	0.00
COINCIDENT PEAK AT COMMON BUS	3,720.28

3) LOAD FACTOR AT COMMON BUS 52.5%
(Hours per Year = 8,760)

4) EQUIVALENT HOURS LOSS FACTOR

EQF = (0.08 x 52.5%) + (0.92 x (52.5%)²)
= 0.295618

5) NO LOAD LOSS FACTOR AS A PERCENTAGE OF DISTRIBUTION ENERGY LOSSES 18.00%

a) 936,911 x 0.1800 = 168,644 MW.H

b) $\frac{936{,}911 \times 0.1800}{8{,}760}$ = 19.3 MW @ PEAK

6) CO-EFFICIENT OF SYSTEM LOSSES

$$= \frac{936{,}911. - 168{,}644}{8{,}760 \times (3{,}720.28)^2 \times 0.29562}$$
$$= 0.000021$$

7) SYSTEM DISTRIBUTION LOSSES AT PEAK

$$= 19.25 + 0.000021 \times (3{,}720.28)^2$$
$$= 315.92$$

8) ADJUSTMENT FACTOR FOR TEMPERATURE -13.0%

9) SYSTEM DISTRIBUTION LOSSES AT PEAK ASSIGNED IN COSS 274.854 MW

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

AVERAGE (KW.h)	936,911	/ 16,174,022	= 5.79%
PEAK (MW)	274.85	/ 3,445.430	= 7.98%

Prospective Peak Load Report - Using Top 50 Peak Hours

2010 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	Forecast DSM KW.h Savings	Total KW.h Sales After DSM **E20**	Distribution Losses	Common Bus Losses	KW.h Generated Adjusted **E10**
Residential							
Residential	440,315	6,764,557,231	(42,472,480)	6,722,084,751	469,556,459	690,478,353	7,882,119,564
Seasonal	21,642	72,060,000	-	72,060,000	5,033,593	7,401,851	84,495,444
Water Heating	4,802	17,073,001	-	17,073,001	1,192,597	1,753,703	20,019,300
Total Residential	466,759	6,853,690,232	(42,472,480)	6,811,217,752	475,782,649	699,633,907	7,986,634,308
GS Small - Single Phase							
Non-Demand	39,985	909,674,198	(14,371,987)	895,302,211	62,539,369	91,963,553	1,049,805,132
Demand	3,972	396,750,322	(7,382,798)	389,367,524	27,198,413	39,995,010	456,560,947
Subtotal	43,957	1,306,424,520	(21,754,785)	1,284,669,735	89,737,781	131,958,563	1,506,366,079
Seasonal	816	4,619,999	-	4,619,999	322,720	474,557	5,417,275
Water Heating	447	5,410,999	-	5,410,999	377,973	555,806	6,344,779
Total Single Phase	45,220	1,316,455,518	(21,754,785)	1,294,700,733	90,438,475	132,988,926	1,518,128,134
GS Small - Three Phase							
Non-Demand	11,468	582,069,249	(9,196,141)	572,873,108	30,277,949	57,909,278	661,060,336
Demand	7,288	1,624,249,677	(30,224,316)	1,594,025,361	84,248,708	161,133,166	1,839,407,235
Total Three Phase	18,756	2,206,318,926	(39,420,457)	2,166,898,469	114,526,657	219,042,444	2,500,467,570
Total G.S.Small							
Non-Demand	51,453	1,491,743,447	(23,568,128)	1,468,175,319	92,817,318	149,872,831	1,710,865,468
Demand	11,260	2,020,999,999	(37,607,114)	1,983,392,885	111,447,121	201,128,176	2,295,968,181
Sub-Total G.S. Small	62,713	3,512,743,446	(61,175,242)	3,451,568,204	204,264,439	351,001,006	4,006,833,649
Seasonal	816	4,619,999	-	4,619,999	322,720	474,557	5,417,275
Water Heating	447	5,410,999	-	5,410,999	377,973	555,806	6,344,779
Total GS Small	63,976	3,522,774,444	(61,175,242)	3,461,599,202	204,965,132	352,031,369	4,018,595,704
General Service - Medium	1,859	3,076,000,000	(43,845,243)	3,032,154,757	160,257,877	306,507,479	3,498,920,113
General Service - Large							
0 - 30 Kv	259	1,557,556,000	(24,233,631)	1,533,322,369	67,240,483	153,672,016	1,754,234,868
30 - 100 kV	29	934,191,000	(1,978,598)	932,212,402	13,983,186	90,845,407	1,037,040,995
30 - 100 kV - Curtailment Cust's	1	220,000,000	(465,956)	219,534,044	3,293,011	21,393,901	244,220,956
Over 100 Kv	11	2,883,253,000	(3,623,149)	2,879,629,851	-	276,476,818	3,156,106,669
Over 100 Kv - Curtailment Cust's	3	2,750,000,000	(3,455,701)	2,746,544,299	-	263,699,110	3,010,243,409
Total G.S.- Large	303	8,345,000,000	(33,757,035)	8,311,242,965	84,516,680	806,087,251	9,201,846,896
SEP							
GSM	20	19,750,000		19,750,000	1,043,843	1,996,443	22,790,285
GSL 0 - 30 Kv	5	2,800,000		2,800,000	122,788	280,620	3,203,408
Total SEP	25	22,550,000	-	22,550,000	1,166,631	2,277,063	25,993,694
Street Lighting	127,540	88,661,568	-	88,661,568	6,193,259	9,107,129	103,961,956
Sentinel Lighting	26,165	10,770,000	-	10,770,000	752,315	1,106,272	12,628,586
Total - Lighting	153,705	99,431,568	-	99,431,568	6,945,574	10,213,401	116,590,542
Total - General Consumers	686,627	21,919,446,244	(181,250,000)	21,738,196,244	933,634,543	2,176,750,470	24,848,581,257
Extra Provincial		-	-	-		-	-
Man Hydro - Construction		62,000,000		62,000,000	3,276,874	6,267,313	71,544,187
Integrated System	686,627	21,981,446,244	(181,250,000)	21,800,196,244	936,911,416	2,183,017,784	24,920,125,444

2010 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	Forecast 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	CP @ Gen. MW	Class Coinc. Factor	Class Demand NCP MW @ Meter **D50**	Class Demand NCP MW @ Gen. **D20**
Residential													
Residential	51.5%	1,498.9	(8.4)	1,490.5	80.0%	123.4	1,613.9	162.5	149.3	1,925.7	90.9%	1,775.4	2,118.4
Seasonal	157.8%	5.2		5.2		-	5.2	0.5	0.5	6.2	8.0%	65.2	77.8
Water Heating	67.6%	2.9		2.9		-	2.9	0.3	0.3	3.4	80.0%	3.6	4.3
Total Residential	51.9%	1,506.9	(8.4)	1,498.6	80.0%	123.4	1,622.0	163.3	150.1	1,935.3	87.9%	1,844.2	2,200.5
GS Small - Single Phase													
Non-Demand	62.0%	167.5	(5.1)	162.3	7.3%	11.2	173.6	17.5	16.1	207.1	86.1%	201.6	240.6
Demand	64.8%	69.9	(2.6)	67.3	0.6%	0.9	68.2	6.9	6.3	81.4	87.8%	77.7	92.7
Subtotal	62.8%	237.3	(7.7)	229.6	7.9%	12.2	241.8	24.3	22.4	288.5	86.6%	279.3	333.2
Seasonal	162.5%	0.3		0.3			0.3	0.0	0.0	0.4	8.0%	4.1	4.8
Water Heating	69.7%	0.9		0.9			0.9	0.1	0.1	1.1	75.0%	1.2	1.4
Total Single Phase	63.0%	238.6	(7.7)	230.8	7.9%	12.2	243.0	24.5	22.5	289.9	85.4%	284.5	339.5
GS Small - Three Phase													
Non-Demand	62.0%	107.2	(3.3)	103.9	4.7%	7.2	111.1	8.6	10.1	129.7	86.1%	129.0	150.6
Demand	64.8%	286.1	(10.6)	275.4	2.4%	3.8	279.2	21.6	25.3	326.0	87.8%	318.0	371.4
Total Three Phase	64.0%	393.2	(13.9)	379.3	7.1%	11.0	390.3	30.1	35.3	455.8	87.3%	447.0	522.0
Total G.S.Small													
Non-Demand	61.0%	274.6	(8.4)	266.2	12.0%	18.4	284.7	26.1	26.1	336.8	86.1%	330.6	391.2
Demand	63.6%	356.0	(13.2)	342.7	3.0%	4.7	347.4	28.4	31.6	407.4	87.8%	395.7	464.0
Sub-Total G.S. Small	63.6%	630.6	(21.7)	608.9	15.0%	23.1	632.1	54.5	57.7	744.3	87.0%	726.3	855.2
Seasonal	162.3%	0.3	-	0.3	0.0%	-	0.3	0.0	0.0	0.4	8.0%	4.1	4.8
Water Heating	69.7%	0.9	-	0.9	0.0%	-	0.9	0.1	0.1	1.1	75.0%	1.2	1.4
Total GS Small	63.7%	631.8	(21.7)	610.2	15.0%	23.1	633.3	54.6	57.8	745.7	86.6%	731.5	861.5
General Service - Medium	71.3%	492.5	(12.8)	479.7	4.9%	7.6	487.3	37.6	44.1	569.1	92.0%	529.7	618.6
General Service - Large													
0 - 30 Kv	78.4%	226.7	(5.9)	220.8	0.1%	0.2	221.0	14.3	19.8	255.1	88.2%	250.6	289.3
30 - 100 kV	90.1%	118.4	(0.7)	117.6		-	117.6	2.4	10.1	130.2	75.3%	156.2	172.8
30 - 100 kV - Curtailment Cust's	101.0%	24.9	(0.2)	24.7		-	24.7	0.5	2.1 †	27.3	87.5%	28.2	31.3
Over 100 Kv	90.4%	364.2	(0.6)	363.6		-	363.6	-	30.6	394.1	89.9%	404.4	438.4
Over 100 Kv - Curtailment Cust's	99.4%	315.9	(0.5)	315.4		-	315.4	-	26.5 †	341.9	88.6%	355.9	385.9
Total G.S.- Large	90.7%	1,050.1	(8.0)	1,042.1	0.1%	0.2	1,042.3	17.3	89.1	1,148.7	87.2%	1,195.4	1,317.7
SEP													
GSM	54.4%	4.1		4.1		-	4.1	0.3	0.4	4.8	66.2%	6.3	7.3
GSL 0 - 30 Kv	103.9%	0.3		0.3		-	0.3	0.0	0.0	0.4	17.1%	1.8	2.1
Total SEP	57.8%	4.5	-	4.5		-	4.5	0.3	0.4	5.2	55.2%	8.1	9.4
Street Lighting	119.7%	8.5	-	8.5		-	8.5	0.9	0.8	10.1	38.2%	22.1	26.4
Sentinel Lighting	119.7%	1.0	-	1.0		-	1.0	0.1	0.1	1.2	38.2%	2.7	3.2
Total - Lighting	119.7%	9.5	-	9.5	0.0%	-	9.5	1.0	0.9	11.3	38.2%	24.8	29.6
Total - General Consumers	67.7%	3,695.3	(50.8)	3,644.5	100.0%	154.3	3,798.8	274.1	342.4	4,415.3	87.7%	4,333.7	5,037.2
Extra Provincial	0.0%	0.0		0.0		-	-		-	0.0			
Man Hydro - Construction	71.3%	9.9		9.9		-	9.9	0.8	0.9	11.6			
Integrated System	67.7%	3,705.2	(50.8)	3,654.4	100.0%	154.3	3,808.7	274.9	343.3	4,426.9			

† Demand for curtailable customers is forecast as if customers are not curtailed at time of system peak.

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2010

Distribution Energy Losses Expressed as a %'age of Kwh @ meter

	Class Avg
Export Sales	n/a
GS Large	
< 30	4.4%
30-100	1.5%
> 100	n/a
GS Medium	5.3%
GS Small	
3 Phase	5.3%
1 Phase	7.0%
Residential	7.0%
Area & Roadway Lighting	7.0%

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2010

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

	Class Avg
Export Sales	n/a
GS Large	
< 30	6.5%
30-100	2.1%
> 100	n/a
GS Medium	7.7%
GS Small	
3 Phase	7.7%
1 Phase	10.1%
Residential	10.1%
Area & Roadway Lighting	10.1%

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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 unweighted count of the 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:

- Schedule E1 summarizes the classified costs by allocation table.
- Schedules E2 – E19 represent some of the main tables used to allocate classified costs.

Prospective Cost Of Service Study
March 31, 2010
Classified Costs by Allocation Table

Allocation Table	Function		Interest	Depreciation	Operating	Misc. Rev	Total
E12	Generation - Dom & Export		329,366.6	124,123.8	264,727.5	(424.0)	717,793.8
E13	Generation - Domestic		20,910	19,620	36,584	-	77,113.7
			350,276.3	143,744.1	301,311.1	(424.0)	794,907.5
D13	Transmission - 2CP Domestic				3,105.8		3,105.8
D14	Transmission - 2CP Dom & Export		91,369.1	54,882.9	53,176.0		199,427.9
			91,369.1	54,882.9	56,281.7	-	202,533.7
D21	Subtrans		5,879	22,363.4	26,342.4		54,584.7
D22	Subtrans	Stations	8,140	-			8,140.2
D23	Subtrans	Line	19,879	-			19,878.6
			33,897.8	22,363.4	26,342.4	-	82,603.6
D32	Dist. Plant Stn		28,936	22,539.3	31,185.9		82,661.1
D36	Dist. Plant	Lines	48,340	37,968.8	15,739.0		102,047.7
D40	Dist. Plant	S/E	14,115	13,740.7	5,058.3		32,914.3
			91,391.0	74,248.8	51,983.2	-	217,623.0
C23	Dist. Plant	Lines	32,227	25,312.5	10,492.7		68,031.8
C27	Dist. Plant	Services	4,565				4,565.3
C40	Dist. Plant	Meter Investment	3,163	1,932.5			5,095.3
C41	Dist. Plant	Meter Mtce.	-		2,819.7		2,819.7
			39,954.7	27,245.0	13,312.4	-	80,512.1
C10	Dist Serv	Cust Service - General	1,091	4,098.8	29,436.2	-	34,626.2
C11	Dist Serv	Cust Acct - Billings	907	3,214.7	24,076.4		28,198.5
C12	Dist Serv	Cust Acct - Collections	418	1,398.4	12,956.2		14,772.9
C13	Dist Serv	Marketing - R & D	50	140.3	1,300.3		1,490.1
C14	Dist Serv	Inspection	116	349.6	3,238.7		3,703.8
C15	Dist Serv	Meter Read	397	913.9	8,467.4		9,778.3
C30	Dist Serv	Hot Water Tank Program		277.5	0.0		277.5
			2,979.1	10,393.1	79,475.2	-	92,847.4
	Total Allocated Costs		609,868.0	332,877.3	528,706.1	(424.0)	1,471,027.3

DIRECTS

C02	Generation	Diesel	1,175	3,729.4	6,916.4		11,821.1
E01	Generation	Export	19,437.6	4,194.3	194,329.5		217,961.4
			19,437.6	4,194.3	194,329.5	-	217,961.4
E01	Generation	SEP - GSM	354.4	156.5	279.4		790.3
E01	Generation	SEP - GSL 0-30kV	56.0	24.7	44.2		125.0
E01	Generation	DSM Direct Assignment - Energy					
E01	Generation	Residential	2,565.50	3,958.85			6,524.3
E01	Generation	GSS ND	1,913.03	2,847.82			4,760.9
E02	Generation	GSS Demand	2,173.92	3,512.65			5,686.6
E01	Generation	GSM	2,657.20	4,000.16			6,657.4
E01	Generation	GSL 0-30kV	1,305.51	1,970.09			3,275.6
E02	Generation	GSL 30-100kV excl Curt.	144.76	262.40			407.2
E01	Generation	GSL >100kV excl Curt.	419.42	845.22			1,264.6
E01	Generation	Street Lights	1.79	6.25			8.0
E00	Generation	Curtailment (GSL 30-100)	310.33	530.77		(576.0)	265.1
E01	Generation	Curtailment (GSL > 100)	3,190.34	5,542.93		(5,819.0)	2,914.3
			15,092.2	23,658.4	323.6	(6,395.0)	32,679.2
E02	Transmission	Export	-	-	1,641.3		1,641.3
D04	Transmission	SEP - GSM	94.1	56.5	58.0		208.6
D04	Transmission	SEP - GSL 0-30kV	14.9	8.9	9.2		33.0
			109.0	65.5	67.1	-	241.6
C01	Distribution	Lighting	3,782	2,543.8	7,476.8		13,802.9
C01	Distribution	Diesel	101	266.0	327.9		695.0
			3,883.4	2,809.8	7,804.7	-	14,497.9
	Total Directs		39,697.5	34,457.3	211,082.6	(6,395.0)	278,842.4
	Total		649,565.5	367,334.6	739,788.7	(6,819.0)	1,749,869.8
	Generation		385,981.4	175,326.1	502,880.6	(6,819.0)	1,057,369.2
	Transmission		91,478.1	54,948.3	57,990.1	-	204,416.6
	Subtransmission		33,897.8	22,363.4	26,342.4	-	82,603.6
	Distribution Plant		135,229.0	104,303.7	73,100.4	-	312,633.1
	Distribution Services		2,979.1	10,393.1	79,475.2	-	92,847.4
			649,565.5	367,334.6	739,788.7	(6,819.0)	1,749,869.8
	Energy		384,806.1	171,596.8	495,964.3	(6,819.0)	1,045,548.1
	Demand		216,767.0	151,560.5	136,315.8	-	504,643.2
	Customer		47,992.4	44,177.3	107,508.7	-	199,678.5
			649,565.5	367,334.6	739,788.7	(6,819.0)	1,749,869.8

12 PERIOD WEIGHTED ENERGY TABLE

(E12 Generation)

PURPOSE

This table is used to allocate costs associated with the energy component within the Generation function that are shared by the Domestic and Export classes.

METHOD

Table represents marginal cost ratios multiplied by twelve-period seasonal kW.h sales as measured at Generation (On-Peak, Off-Peak and Shoulder periods for each of the four seasons).

JUSTIFICATION

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

12 PERIOD WEIGHTED ENERGY TABLE

(E13 Generation)

PURPOSE

This table is used to allocate costs associated with the energy component within the Generation function that are shared by the Domestic classes.

METHOD

Table represents marginal cost ratios multiplied by twelve-period seasonal kW.h sales as measured at Generation (On-Peak, Off-Peak and Shoulder periods for each of the four seasons).

JUSTIFICATION

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

AVERAGE WINTER AND SUMMER COINCIDENT PEAK DEMAND TABLE (MW)

(D13 Transmission)

PURPOSE

This table is used to allocate costs associated with the demand component of the Transmission function that are among the Domestic classes.

METHOD

Class contributions to the seasonal system peaks in both summer and winter have been averaged to develop the allocators (2CP) using average of load research data for 2006/07 and 2007/08.

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.

AVERAGE WINTER AND SUMMER COINCIDENT PEAK DEMAND TABLE (MW)

(D14 Transmission)

PURPOSE

This table is used to allocate costs associated with the demand component of the Transmission function that are share by the Export and Domestic classes.

METHOD

Class contributions to the seasonal system peaks in both summer and winter have been averaged to develop the allocators (2CP) using average of load research data for 2006/07 and 2007/08.

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)

(D21/D22/D23 - Subtransmission)

PURPOSE

This table is used to allocate costs associated with buildings, communication and general equipment of 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 the average of load research data available from fiscal years 2003-2006 and 2008.

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)

(D32 - Distribution Plant)

PURPOSE

This table is used to allocate costs associated with the demand component of Distribution stations and station transformers 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.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D36 - Distribution Plant)

PURPOSE

These tables are used to allocate costs associated with the demand component of Distribution lines, farm lines and associated Distribution infrastructure 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.

CLASS NON-COINCIDENT PEAK DEMAND TABLE (MW)

(D40 - Distribution Plant)

PURPOSE

This table is used to allocate costs associated with the demand component of Distribution transformation. Classes receiving service at greater than 30 kV or with customer-owned transformation are excluded from the table.

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 - Distribution Service)

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. An analysis was undertaken to estimate the efforts various departments devote to each customer class, which was weighted by the budget for each department. 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.

WEIGHTED CUSTOMER COUNT TABLE - BILLING

(C11 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of billing costs.

METHOD

The allocation table represents the percentage of billing costs assignable to each rate class. 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 forecast customer numbers.

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

WEIGHTED CUSTOMER COUNT TABLE - COLLECTIONS

(C12 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of collection costs.

METHOD

The allocation table represents the percentage of collection costs assignable to each rate class. 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 forecast customer numbers.

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

CUSTOMER COUNT TABLE - RESEARCH AND DEVELOPMENT

(C13 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of marketing - research and development costs.

METHOD

Number of customers adjusted for water heating and street/sentinel lighting

JUSTIFICATION

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.

WEIGHTED CUSTOMER COUNT TABLE - ELECTRICAL INSPECTIONS

(C14 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of electrical inspection costs.

METHOD

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.

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

WEIGHTED CUSTOMER COUNT TABLE - METER READING

(C15 - Distribution Service)

PURPOSE

This table is used to allocate the customer portion of meter reading costs.

METHOD

The allocation table represents customers weighted by the relative frequency in which a meter is read by the utility. The results of this analysis are used to weight the forecast number of customers.

The relative frequency of meter readings by rate class is shown in the following table.

RATE CLASS	
Residential	
Standard	5
Seasonal	1
General Service - Small	
Demand	12
Non-Demand	5
Seasonal	1
General Service Medium	12
General Service Large	
<30 kV	12
30 - 100 kV	12
>100 kV	12

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

CUSTOMER COUNT TABLE - DISTRIBUTION POLE AND WIRE

(C23 - Distribution Plant)

PURPOSE

This table is used to allocate the customer portion associated with Distribution lines. Classes receiving service at greater than 30 kV are excluded from this table.

METHOD

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.

JUSTIFICATION

Customer component costs are incurred in Distribution plant dependent upon the number of customers being served.

WEIGHTED CUSTOMER COUNT TABLE - SERVICES

(C27 - Distribution Plant)

PURPOSE

This table is used to allocate the customer portion associated with service drops. Classes receiving service at greater than 30 kV, Flat Rate Water Heating, Street and Sentinel Lighting are excluded from this table.

METHOD

Number of customers are weighted 5 x for General Service Small - 3 Phase, General Service Medium and General Service Large customers.

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

WEIGHTED CUSTOMER COUNT TABLE - METER INVESTMENT

(C40- Distribution Plant)

PURPOSE

This table is used to allocate the customer portion associated with meters and metering transformers. Flat Rate Water Heating, Street and Sentinel Lighting are excluded from this table.

METHOD

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 forecast number of customers.

This table represents the number of customers weighted by the relative cost of 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
Residential	1
General Service Small	
Single Phase - Non-Demand	1
- Demand	14
Three Phase - Non-Demand	5
- Demand	23
General Service Medium	36
General Service Large	
0 - 30 kV	49
30 - 100 kV	224
>100 kV	233

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.

WEIGHTED CUSTOMER COUNT TABLE - METER MAINTENANCE

(C41- Distribution Plant)

PURPOSE

This table is used to allocate the customer portion relating to meter maintenance costs. Flat Rate Water Heating, Street and Sentinel Lighting are excluded from this table.

METHOD

An analysis of meter maintenance costs was undertaken to determine the relative costs for meter maintenance by customer class. The results of this analysis are used to weight the forecast number of customers.

This table represents the number of customers weighted by the relative 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
Residential	1
General Service Small	
Single Phase - Non-Demand	1
- Demand	155
Three Phase - Non-Demand	50
- Demand	105
General Service Medium	215
General Service Large	
0 - 30 kV	530
30 - 100 kV	530
>100 kV	530

JUSTIFICATION

Weighted customer recognizes cost differential to serve different customer classes.