Prospective Cost of Service Study

For Fiscal Year Ending

March 31, 2011

Manitoba Hydro

Cost of Service Department
May 25, 2010

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2011

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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 only provides an approximation of the actual cost of serving a particular customer or group of customers within a customer class. 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. Because of the inexactness of a Cost of Service Study, a Zone of Reasonableness (ZOR) is usually established within which Revenue to Cost Coverage (RCC) ratios are targeted. At Manitoba Hydro the target Zone of Reasonableness is for RCC's to be within the range of 95 to 105 percent.

Manitoba Hydro has carried out PCOSS11 using the same methodology employed for PCOSS10. This methodology incorporates many of the Public Utilities Board (PUB) recommendations emerging from the 2006 Cost of Service review and the 2008 General Rate Application (GRA).

Manitoba Hydro's approach to PCOSS11 is outlined as follows:

Export Class

PCOSS11 includes 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 seven years. Future PCOSS will use the full eight year average as Load Research data becomes available.

Assignment of DSM Costs

DSM costs are 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

As gas-fired generation is almost never used to support exports and the plants provide dispatchable energy for the benefit of domestic customers, PCOSS11 assigns the cost of gas-fired thermal plants entirely to the domestic classes.

In accordance with climate change legislation, use of the Brandon Unit 5 coal generating station is limited to emergency use only. As Manitoba Hydro can no longer use coal-fired generation to support exports, all the fixed and variable costs have been assigned entirely to the domestic classes in this study.

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

Manitoba Hydro’s forecast of export prices for 2010/11 used in PCOSS11 is consistent with the Integrated Financial Forecast (IFF09).

Net Export Revenue

The assignment and allocation of costs to the Export class results in net export revenue of $47 million to be allocated to domestic customers as indicated in the following table:

	(million $)
Gross Export Revenue	$384
Uniform Rates	$20
Affordable Energy Fund Expenditures	$12
Trading Desk	$5
MISO/MAPP	$2
NEB Cost	$1
Purchased Power and Transmission	$120
Allocated Water Rentals	$21
Allocated Generation & Transmission	$156
Net Export Revenue	$47

PCOSS Results

Revenues in PCOSS11 are based upon the rates approved on an interim basis in Board Order 33/10. The resulting Revenue Cost Coverage ratios (RCC) of the major classes are as follows:

CUSTOMER CLASS	RCC (April 1, 2009 Rates)	RCC (Interim April 1, 2010 Rates)
Residential	95.8%	95.9%
GSS Non-Demand	104.6%	104.8%
GSS Demand	103.3%	103.8%
GSM	101.4%	101.1%
GSL 0 – 30 kV	91.8%	91.9%
GSL 30 – 100 kV	104.2%	104.2%
GSL > 100 kV	112.7%	112.6%
Area & Roadway Lighting	107.8%	105.2%

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 (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 PCOSS11

Manitoba Hydro has carried out PCOSS11 using the same methodology employed for PCOSS10. This methodology incorporates many of the PUB recommendations emerging from the 2006 Cost of Service review and the 2008 GRA. Below are the PUB's recommendations and Manitoba Hydro's approach in PCOSS11:

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.**

   PCOSS11 includes only a single export class. After adjusting for energy provided by imports, 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.**

      As gas-fired generation is almost never used to support exports and the plants provide dispatchable energy for the benefit of domestic customers, PCOSS11 assigns the cost of gas-fired thermal plants entirely to the domestic classes.

      When Brandon Coal Generation is restricted to emergency use only (in accordance with the government's direction), the allocation of costs to the export class will decrease. (PUB Order 116/08, page 270)

      In accordance with climate change legislation, use of the Brandon Unit 5 coal generating station is limited to emergency use only. As Manitoba Hydro can no longer use coal-fired generation to support exports, all the fixed and variable costs have been assigned entirely to the domestic classes in this study.

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

In PCOSS11, DSM costs are assigned to the customer classes benefiting from the DSM programming, in the same manner as carried out prior to PCOSS08, and again in PCOSS10. 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.

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.

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.

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

PCOSS11 employs Manitoba Hydro's forecast of export prices for 2010/11. 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 application to the PUB. It is not appropriate to provide a PCOSS which is inconsistent with the IFF.

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 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 incorporated into PCOSS11.

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

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.**

   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 seven year period from 2002/03 to the 2008/09 base year of PCOSS11. Future PCOSS will use the full eight year average as data becomes available.

   PCOSS11 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 PCOSS11 the average from six years of Load Research results is used for NCP allocators in Schedule D5, and three 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.

The assignment and allocation of costs to the Export class results in net export revenue of $47 million to be allocated to domestic customers as indicated in the following table:

	(million $)
Gross Export Revenue	$384
Uniform Rates	$20
Affordable Energy Fund Expenditures	$12
Trading Desk	$5
MISO/MAPP	$2
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Purchased Power and Transmission	$120
Allocated Water Rentals	$21
Allocated Generation & Transmission	$156

Net Export Revenue	$47

Treatment of Diesel Funding Agreement in PCOSS11

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 PCOSS11, while revenues for the Diesel class in the schedules are based upon variable costs, upon which the revised diesel rates are based.

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.

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SECTION B: SUMMARY RESULTS

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 IFF09. The level of export sales forecast in this PCOSS reflects this assumption.

PCOSS11 includes the 2.9 per cent rate increase for all customer classes except Area & Roadway Lighting, as approved on an interim basis in Board Order 33/10. PCOSS11 does not include the revenue from the revised Energy Intensive Industrial Rate as included in the revenue forecast in IFF09.

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

S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	540,365	497,455	20,535	517,990	95.9%
General Service - Small Non Demand	118,628	119,914	4,383	124,297	104.8%
General Service - Small Demand	114,981	115,086	4,217	119,303	103.8%
General Service - Medium	168,455	164,114	6,237	170,352	101.1%
General Service - Large 0 - 30kV	80,204	70,730	2,964	73,694	91.9%
General Service - Large 30-100kV*	32,915	33,070	1,241	34,311	104.2%
General Service - Large >100kV*	173,341	188,679	6,499	195,178	112.6%
*Includes Curtailment Customers					
SEP	1,006	852	-	852	84.7%
Area & Roadway Lighting	19,574	20,339	259	20,598	105.2%
Total General Consumers	1,249,469	1,210,239	46,336	1,256,574	100.6%
Diesel	12,375	4,793	477	5,270	42.6%
Export	337,251	384,064	(46,813)	337,251	100.0%
Total System	1,599,096	1,599,096	-	1,599,096	100.0%

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Customer, Demand, Energy Cost Analysis

SUMMARY

Class	CUSTOMER Cost ($000)	CUSTOMER Number of Customers	CUSTOMER Unit Cost $/Month	DEMAND Cost ($000)	DEMAND % Recovery	DEMAND Billable Demand MVA	DEMAND Unit Cost $/KVA	ENERGY Cost ($000)	ENERGY Metered Energy mWh	ENERGY Unit Cost ¢/kWh
Residential	121,464	470,975	21.49	201,202	0%	n/a	n/a	197,163	6,771,781	5.88 **
GS Small - Non Demand	23,721	53,170	37.18	41,769	0%	n/a	n/a	48,756	1,571,227	5.76 **
GS Small - Demand	7,335	11,451	53.38	46,112	38%	2,100	8.34	57,316	1,883,200	4.56
General Service - Medium	6,325	1,867	282.36	67,099	87%	6,978	8.40	88,794	3,015,078	3.23
General Service - Large <30kV	3,153	259	n/a	29,553	100%	3,646	8.97 *	44,535	1,538,688	2.89
General Service - Large 30-100kV	2,156	30	n/a	7,597	100%	1,681	5.80 *	21,921	846,683	2.59
General Service - Large >100kV	2,231	14	n/a	29,035	100%	8,969	3.49 *	135,576	5,310,790	2.55
SEP	261	23	946.48	159	0%	n/a	n/a	587	15,200	4.90 **
Area & Roadway Lighting	14,342	154,961	7.71	2,664	0%	n/a	n/a	2,309	101,099	4.92 **
Total General Consumers	180,988	692,750		425,189		23,374		596,956	21,053,746	
Diesel	273	760	29.91	409	0%	n/a	n/a	11,217	13,664	85.08 **
Export	n/a	n/a	n/a	46,327	0%	n/a	n/a	290,925	7,122,000	4.74 ***
Total System	181,261	693,510		471,925		23,374		899,098	28,189,411	

* - 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	519,830	197,163	37.9%	49,565	9.5%	37,259	7.2%	60,599	11.7%	175,243	33.7%
General Service - Small Non Demand	114,246	48,756	42.7%	12,186	10.7%	7,288	6.4%	15,902	13.9%	30,114	26.4%
General Service - Small Demand	110,763	57,316	51.7%	13,460	12.2%	8,023	7.2%	3,538	3.2%	28,426	25.7%
General Service - Medium	162,218	88,794	54.7%	21,331	13.1%	11,246	6.9%	5,411	3.3%	35,437	21.8%
General Service - Large <30kV	77,240	44,535	57.7%	10,610	13.7%	5,317	6.9%	2,945	3.8%	13,833	17.9%
General Service - Large 30-100kV	31,674	21,921	69.2%	4,927	15.6%	2,670	8.4%	2,111	6.7%	44	0.1%
General Service - Large >100kV	166,842	135,576	81.3%	29,035	17.4%	0	0.0%	2,209	1.3%	21	0.0%
SEP	1,006	587	58.3%	159	15.8%	0	0.0%	248	24.6%	13	1.3%
Area & Roadway Lighting	19,315	2,369	12.3%	415	2.1%	570	3.0%	608	3.1%	15,353	79.5%
Total General Consumers	1,203,134	597,017	49.6%	141,688	11.8%	72,373	6.0%	93,572	7.8%	298,484	24.8%
Diesel	11,898	11,217	94.3%	0	0.0%	0	0.0%	0	0.0%	682	5.7%
Export	337,251	290,925	86.3%	46,327	13.7%	0	0.0%	0	0.0%	0	0.0%
Total System	1,552,283	899,158	57.9%	188,014	12.1%	72,373	4.7%	93,572	6.0%	299,166	19.3%

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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 2010/11 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 costs 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, 2009, is first functionalized.

Functionalized gross plant investment for 2009 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, 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 nets salvage labour and expense together by facility. 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, 2011.

Schedule C3 shows the functionalization of accumulated depreciation forecast for fiscal year ending March 31, 2011. 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 2011.

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 PCOSS11. 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 2009/10 and 2010/11 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, 2011 (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 2010/11 is shown on Schedule C11.

<u>Functionalization and Classification of Operating and Administrative Costs</u>

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%

<u>Adjusted Revenue</u>

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 PCOSS11 the revenue adjustment is $20 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	$ 10,434,733
General Service Small-Non-Demand	$ 2,162,080
General Service Small-Demand	$ 1,808,078
General Service Medium	$ 2,293,619
General Service Large:	
0 - 30 kV	$1,132,669
30 - 100 kV	$ 165,852
> 100 kV	$ 458,702
Total DSM	**$18,455,733**

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.

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
MARCH 31, 2009

ASSET CLASS	TOTAL GROSS INVESTMENT	Generation	Transmission		Sub Trans	Distribution		Ancillary Services	Direct Allocation	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	4,642,582,152	4,584,860,925	57,721,227							
-Thermal	472,619,840	472,619,840								
DIESEL	43,158,192									43,158,192
SUBSTATION	1,066,964,314		317,565,478	64,718,863	159,916,953	512,306,214		12,456,806		
- HVDC	1,223,991,773	601,833,219	622,158,554							
TRANSMISSION	616,558,712		312,604,290	125,425,922	178,528,500					
- HVDC	188,427,061	188,427,061								
DISTRIBUTION	2,035,359,061					1,889,768,252			141,524,635	4,066,174
SUBTRANSMISSION	256,153,257				245,151,216	11,002,041				
TRANSFORMERS										
- SUBSTATION	17,253,857		5,346,375	1,045,725	2,583,932	8,277,825				
- DISTRIBUTION	8,245,155					8,245,155				
METERS	49,862,080					49,862,080				
BUILDINGS	452,557,675	197,812,563	46,139,584	18,512,541	29,073,830	82,497,362	68,454,071		9,445,548	622,176
COMMUNICATION	427,964,103	97,938,987	36,222,195	11,031,093	76,991,541	103,345,053		102,435,234		
GENERAL EQUIPMENT	307,178,748	87,027,636	41,104,067	16,433,006	25,998,111	85,136,020	42,364,147		9,115,761	
SUBTOTAL	11,808,875,980	6,230,520,231	1,438,861,770	237,167,150	718,244,083	2,750,440,002	110,818,218	114,892,040	160,085,944	47,846,542
MOTOR VEHICLES	157,025,109									
TOTAL FIXED ASSETS	11,965,901,089	6,230,520,231	1,438,861,770	237,167,150	718,244,083	2,750,440,002	110,818,218	114,892,040	160,085,944	47,846,542

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF GROSS INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2011

			Transmission		Sub-	Distribution		Ancillary	DIRECT ALLOCATIONS	
Asset Class	Total	Generation	Domestic	Export	Transmission	Plant	Services	Services	Lighting	Diesel
GENERATION	4,926,296,424	4,865,406,452	60,889,972	-	-	-	-	-	-	-
-Thermal	496,636,131	496,636,131	-	-	-	-	-	-	-	-
DIESEL	50,913,184	-	-	-	-	-	-	-	-	50,913,184
SUBSTATION	1,216,282,371	-	353,856,408	67,807,869	174,889,480	606,233,002	-	13,495,612	-	-
- HVDC	1,289,389,976	637,527,193	651,862,783	-	-	-	-	-	-	-
TRANSMISSION	631,920,604	-	323,544,042	127,422,261	180,954,301	-	-	-	-	-
- HVDC	188,427,061	188,427,061	-	-	-	-	-	-	-	-
DISTRIBUTION	2,318,935,453	-	-	-	-	2,162,613,896	-	-	152,255,383	4,066,174
SUBTRANSMISSION	278,405,968	-	-	-	267,403,927	11,002,041	-	-	-	-
TRANSFORMERS										
- SUBSTATION	17,253,857	-	5,346,375	1,045,725	2,583,932	8,277,825	-	-	-	-
- DISTRIBUTION	8,245,155	-	-	-	-	8,245,155	-	-	-	-
METERS	58,221,471	-	-	-	-	58,221,471	-	-	-	-
BUILDINGS	489,587,428	218,313,499	49,793,140	19,978,473	30,036,071	87,184,880	73,676,997	-	9,982,192	622,176
COMMUNICATION	488,200,409	121,700,812	41,340,226	13,056,471	86,173,836	121,658,683	-	104,270,381	-	-
GENERAL EQUIPMENT	393,455,398	113,244,653	50,411,041	20,182,197	31,589,919	105,490,544	61,602,817	-	10,934,227	-
SUBTOTAL	12,852,170,890	6,641,255,801	1,537,043,987	249,492,996	773,631,466	3,168,927,497	135,279,814	117,765,993	173,171,802	55,601,534
MOTOR VEHICLES	181,381,059									
TOTAL FIXED ASSETS	13,033,551,949	6,641,255,801	1,537,043,987	249,492,996	773,631,466	3,168,927,497	135,279,814	117,765,993	173,171,802	55,601,534

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF ACCUMULATED DEPRECIATION
FORECAST YEAR ENDING MARCH 31, 2011

Asset Class	Accum Depn by Asset Class	Generation	Transmission		Sub Trans	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	1,642,878,533	1,621,910,093	20,968,440	-	-	-	-	-	-	-
-Thermal	264,001,500	264,001,500	-	-	-	-	-	-	-	-
DIESEL	36,212,221	-	-	-	-	-	-	-	-	36,212,221
SUBSTATION	454,822,936	-	129,778,211	23,745,128	90,126,361	199,609,514	-	11,563,723	-	-
- HVDC	707,531,102	379,548,491	327,982,611	-	-	-	-	-	-	-
TRANSMISSION	216,888,110	-	115,193,255	50,590,619	51,104,236	-	-	-	-	-
- HVDC	77,565,698	77,565,698	-	-	-	-	-	-	-	-
DISTRIBUTION	962,267,297	-	-	-	-	880,603,277	-	-	79,513,967	2,150,054
SUBTRANSMISSION	106,528,986	-	-	-	102,018,621	4,510,365	-	-	-	-
TRANSFORMERS										
- SUBSTATION	8,981,252	-	2,612,705	474,620	1,821,468	4,072,459	-	-	-	-
- DISTRIBUTION	2,862,154	-	-	-	-	2,862,154	-	-	-	-
METERS	20,016,290	-	-	-	-	20,016,290	-	-	-	-
BUILDINGS	56,677,900	22,619,696	6,539,624	2,624,322	4,093,482	12,906,783	6,237,448		1,477,968	178,578
COMMUNICATION	208,326,818	52,736,917	16,263,055	4,442,314	37,128,544	41,586,573	-	56,169,414	-	-
GENERAL EQUIPMENT	178,785,129	55,597,258	23,134,097	9,266,789	14,549,546	46,165,307	25,099,003		4,973,129	-
SUBTOTAL	4,944,345,927	2,473,979,653	642,471,998	91,143,791	300,842,258	1,212,332,722	31,336,451	67,733,137	85,965,064	38,540,853
MOTOR VEHICLES	74,227,269									
TOTAL ACCUM DEPRECIATION	5,018,573,196	2,473,979,653	642,471,998	91,143,791	300,842,258	1,212,332,722	31,336,451	67,733,137	85,965,064	38,540,853

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
UNAMORTIZED BALANCE
FORECAST YEAR ENDING MARCH 31, 2011

Asset Class	Unamortized Capital Contribution	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	20,184	20,184	-	-	-	-	-	-	-	-
-Thermal	-	-	-	-	-	-	-	-	-	-
DIESEL	-	-	-	-	-	-	-	-	-	-
SUBSTATION	26,473,421	-	4,390,276	-	1,998,629	20,084,517	-	-	-	-
- HVDC	-	-	-	-	-	-	-	-	-	-
TRANSMISSION	66,468,925	-	1,900,242	-	64,568,683	-	-	-	-	-
- HVDC	7,388	7,388	-	-	-	-	-	-	-	-
DISTRIBUTION	169,968,475	-	-	-	-	149,083,828	-	-	20,436,737	447,910
SUBTRANSMISSION	1,821,011	-	-	-	1,821,011	-	-	-	-	-
TRANSFORMERS										
- SUBSTATION	-	-	-	-	-	-	-	-	-	-
- DISTRIBUTION	-	-	-	-	-	-	-	-	-	-
METERS	-	-	-	-	-	-	-	-	-	-
BUILDINGS	-	-	-	-	-	-	-	-	-	-
COMMUNICATION	215,729	22,196	131,993	34,251	4,183	23,106	-	-	-	-
GENERAL EQUIPMENT	223,137	223,137	-	-	-	-	-	-	-	-
SUBTOTAL	265,198,270	272,905	6,422,510	34,251	68,392,506	169,191,450	-	-	20,436,737	447,910
MOTOR VEHICLES	-									
TOTAL UNAMORTIZED CONTRIBS	265,198,270	272,905	6,422,510	34,251	68,392,506	169,191,450	-	-	20,436,737	447,910

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL CONTRIBUTIONS
ANNUAL AMORITIZATION
FORECAST YEAR ENDING MARCH 31, 2011

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	1,677,798		59,586		1,618,211					
- HVDC	139	139								
DISTRIBUTION	10,708,436					9,427,777			1,245,507	35,153
SUBTRANSMISSION	120,327				120,327					
TRANSFORMERS										
- SUBSTATION	-									
- DISTRIBUTION	-									
METERS	-									
BUILDINGS	-									
COMMUNICATION	28,943	7,524	3,427	1,285	4,712	11,995				
GENERAL EQUIPMENT	18,226	18,226								
SUBTOTAL	14,022,269	32,669	290,177	1,285	1,825,048	10,592,430	-	-	1,245,507	35,153
MOTOR VEHICLES	-									
TOTAL ANNUAL AMORT.	14,022,269	32,669	290,177	1,285	1,825,048	10,592,430	-	-	1,245,507	35,153

2011 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2011
Functionalization of Depreciation Costs

SCC Description	Depreciation	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancillary Services	Diesel	Street Lighting	Exports
Research & Development	90,196	90,196								
Generation External Marketing	192,906	112,529								80,378
Common Generation Costs	40,418,396	40,159,066					-			259,331
Generating Station Costs	18,920,817	18,920,817					-			-
Other Generation Related Costs	138,363	138,363								
Dedicated Gen. Facilities	19,059,181	19,059,181					-	-	-	-
Hydraulic Generating Stations	49,220,217	49,220,217					-			
Other Hydraulic Generation Related Costs	16,252,927	16,252,927					-			
Hydraulic Generation Costs	65,473,144	65,473,144					-			
Thermal Generating Station	19,198,229	19,198,229					-	-	-	-
Non-Dedicated Gen. Facilities	84,671,374	84,671,374					-			-
Generation Facilities Costs	103,730,554	103,730,554					-			-
Purchased Power/Export Costs	-	-								-
Generation Facilities & Costs	***144,148,951***	***143,889,620***					***-***			***259,331***
Research & Development	171,797	24,625	118,386	28,786						
Transmission External Marketing	87,334	-	87,334	-						-
Common Trans. Costs/Revenues	4,062,055	24,625	3,264,813	772,617			-			-
Generation Switching Stations	1,999,556	-	1,999,556							
HVDC & Collector Facilities	54,350,126	28,072,266	26,277,861							
Networked AC Facilities	9,309,309	-	9,309,309							
Generation Access Transmission	65,658,991	28,072,266	37,586,726							
Regional Networked Trans.	9,018,769	-	9,018,769				-			
Future Transmission Line ROW	-	-	-							
Transmission Common	2,137,226	-	1,961,811	303,753.0	-	-	78,054			
Transmission Facilities/Costs	***80,877,041***	***28,096,891***	***51,832,118***	***1,076,370***			***78,054***			***-***
Common Subtransmission Costs	790,248	-	-	790,248						
Subtrans. Facilities & Costs	***20,576,933***	***-***	***-***	***18,082,498***	***2,288,044***	***-***	***-***	***-***	***-***	***-***
Dist. Facilities & Costs	***98,061,241***	***-***	***-***	***-***	***94,685,878***	***288,084***		***-***	***3,087,279***	***-***
Customer Service Costs	***10,346,143***	***-***	***-***	***-***	***-***	***10,346,143***		***-***	***-***	***-***
Isolated Diesel Facilities	***7,036,796***	***1,428,522***	***-***	***-***	***1,360,399***	***-***	***-***	***4,247,876***		
System Control	6,195,852	2,230,507	-	2,230,507	-	-	1,734,838	-		
Communication & Control System	***20,730,208***	***7,180,561***	***1,016,358***	***3,271,226***	***5,518,251***	***-***	***3,743,812***	***-***	***-***	***-***
Planned Grants In Lieu Taxes	***-***	***-***	***-***	***-***	***-***	***-***	***-***	***-***		
	381,777,314	**180,595,594**	**52,848,476**	**22,430,094**	**103,852,571**	**10,634,227**	**3,821,865**	**4,247,876**	**3,087,279**	**259,331**

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF NET INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2011

			Transmission		Sub-	Distribution		Ancillary	DIRECT ALLOCATIONS	
Asset Class	Net Investment	Generation	Domestic	Export	Transmission	Plant	Services	Services	Lighting	Diesel
GENERATION	3,283,397,707	3,243,476,175	39,921,532	-	-	-	-	-	-	-
-Thermal	232,634,631	232,634,631	-	-	-	-	-	-	-	-
DIESEL	14,700,963	-	-	-	-	-	-	-	-	14,700,963
SUBSTATION	734,986,014	-	219,687,922	44,062,741	82,764,490	386,538,971	-	1,931,889	-	-
- HVDC	581,858,874	257,978,702	323,880,172	-	-	-	-	-	-	-
TRANSMISSION	348,563,570	-	206,450,545	76,831,642	65,281,382	-	-	-	-	-
- HVDC	110,853,975	110,853,975	-	-						
DISTRIBUTION	1,186,699,680	-	-	-	-	1,132,926,792	-	-	52,304,679	1,468,210
SUBTRANSMISSION	170,055,970	-	-	-	163,564,294	6,491,676	-	-	-	-
TRANSFORMERS										
- SUBSTATION	8,272,605	-	2,733,670	571,105	762,464	4,205,366	-	-	-	-
- DISTRIBUTION	5,383,001	-	-	-	-	5,383,001	-	-	-	-
METERS	38,205,181	-	-	-	-	38,205,181	-	-	-	-
BUILDINGS	432,909,528	195,693,803	43,253,516	17,354,151	25,942,589	74,278,097	67,439,549	-	8,504,224	443,598
COMMUNICATION	279,657,863	68,941,698	24,945,178	8,579,906	49,041,109	80,049,004	-	48,100,967	-	-
GENERAL EQUIPMENT	214,447,132	57,424,259	27,276,943	10,915,408	17,040,373	59,325,237	36,503,814	-	5,961,098	-
SUBTOTAL	7,642,626,694	4,167,003,243	888,149,478	158,314,954	404,396,702	1,787,403,325	103,943,363	50,032,856	66,770,001	16,612,771
MOTOR VEHICLES	107,153,790									
TOTAL NET INVESTMENT	7,749,780,484	4,167,003,243	888,149,478	158,314,954	404,396,702	1,787,403,325	103,943,363	50,032,856	66,770,001	16,612,771

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE INVESTMENT
FORECAST YEAR ENDING MARCH 31, 2011

Asset Class	Rate Base Investment	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	3,482,007,404	3,442,158,988	39,848,416	-	-	-	-	-	-	-
-Thermal	236,515,795	236,515,795	-	-	-	-	-	-	-	-
DIESEL	19,975,429	-	-	-	-	-	-	-	-	19,975,429
SUBSTATION	706,752,737	-	211,736,684	44,745,307	81,494,951	367,051,245	-	1,724,550	-	-
- HVDC	592,304,803	263,217,835	329,086,968	-	-	-	-	-	-	-
TRANSMISSION	351,485,886	-	206,571,727	77,579,364	67,334,795	-	-	-	-	-
- HVDC	112,723,705	112,723,705	-	-	-	-	-	-	-	-
DISTRIBUTION	1,164,113,567	-	-	-	-	1,110,827,356	-	-	51,746,638	1,539,572
SUBTRANSMISSION	169,960,371	-	-	-	163,265,567	6,694,804	-	-	-	-
TRANSFORMERS										
- SUBSTATION	9,145,067	-	3,004,016	623,984	893,123	4,623,944	-	-	-	-
- DISTRIBUTION	5,894,430	-	-	-	-	5,894,430	-	-	-	-
METERS	36,012,090	-	-	-	-	36,012,090	-	-	-	-
BUILDINGS	430,643,421	193,014,264	42,923,908	17,221,898	26,056,253	74,671,305	67,757,598	-	8,549,280	448,914
COMMUNICATION	280,369,902	66,160,753	25,189,548	8,618,973	49,626,172	80,570,401	-	50,204,056	-	-
GENERAL EQUIPMENT	241,155,073	65,670,907	31,134,791	12,453,680	19,523,918	66,494,416	39,001,717	-	6,875,644	-
SUBTOTAL	7,839,059,681	4,379,462,247	889,496,058	161,243,207	408,194,780	1,752,839,989	106,759,315	51,928,606	67,171,563	21,963,916
MOTOR VEHICLES	105,774,394									
Total Rate Base Investment	7,944,834,075	4,379,462,247	889,496,058	161,243,207	408,194,780	1,752,839,989	106,759,315	51,928,606	67,171,563	21,963,916

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF INTEREST EXPENSE & RESERVE CONTRIBUTION
FORECAST YEAR ENDING MARCH 31, 2011

Asset Class	Interest & Reserve Expense	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	221,464,233	218,929,776	2,534,457	-	-	-	-	-	-	-
-THERMAL	15,042,986	15,042,986	-	-	-	-	-	-	-	-
DIESEL	1,270,486	-	-	-	-	-	-	-	-	1,270,486
SUBSTATION	44,951,212	-	13,466,974	2,845,912	5,183,279	23,345,362	-	109,686	-	-
- HVDC	37,672,042	16,741,302	20,930,740	-	-	-	-	-	-	-
TRANSMISSION	22,355,367	-	13,138,470	4,934,238	4,282,659	-	-	-	-	-
- HVDC	7,169,505	7,169,505	-	-	-	-	-	-	-	-
DISTRIBUTION	74,040,486	-	-	-	-	70,651,351	-	-	3,291,213	97,921
SUBTRANSMISSION	10,809,898	-	-	-	10,384,092	425,806	-	-	-	-
TRANSFORMERS										
- SUBSTATION	581,649	-	191,063	39,687	56,805	294,094	-	-	-	-
- DISTRIBUTION	374,900	-	-	-	-	374,900	-	-	-	-
METERS	2,290,457	-	-	-	-	2,290,457	-	-	-	-
BUILDINGS	4,625,262	2,073,041	461,018	184,969	279,853	801,996	727,740	-	91,822	4,821
COMMUNICATION	17,832,215	4,207,987	1,602,117	548,188	3,156,347	5,124,476	-	3,193,101	-	-
GENERAL EQUIPMENT	2,590,090	705,329	334,399	133,757	209,694	714,173	418,892	-	73,847	-
SUBTOTAL	463,070,788	264,869,925	52,659,238	8,686,751	23,552,728	104,022,616	1,146,633	3,302,787	3,456,883	1,373,229
MOTOR VEHICLES	-									
Total Interest Exp Allocated	463,070,788	264,869,925	52,659,238	8,686,751	23,552,728	104,022,616	1,146,633	3,302,787	3,456,883	1,373,229

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF RATE BASE FOR CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2011

Asset Class	Rate Based for Capital Tax	Generation	Transmission		Sub-Transmission	Distribution		Ancillary Services	DIRECT ALLOCATIONS	
			Domestic	Export		Plant	Services		Lighting	Diesel
GENERATION	3,517,021,693	3,477,100,161	39,921,532	-	-	-	-	-	-	-
-THERMAL	233,516,303	233,516,303	-	-	-	-	-	-	-	-
DIESEL	27,688,088	-	-	-	-	-	-	-	-	27,688,088
SUBSTATION	740,484,398	-	219,687,922	44,062,741	84,072,515	390,729,330	-	1,931,889	-	-
- HVDC	581,874,142	257,993,970	323,880,172	-	-	-	-	-	-	-
TRANSMISSION	350,361,050	-	206,571,859	76,880,317	66,908,875	-	-	-	-	-
- HVDC	110,853,974	110,853,974	-	-	-	-	-	-	-	-
DISTRIBUTION	1,186,699,680	-	-	-	-	1,132,926,792	-	-	52,304,679	1,468,210
SUBTRANSMISSION	170,055,970	-	-	-	163,564,294	6,491,676	-	-	-	-
TRANSFORMERS										
- SUBSTATION	8,652,067	-	2,851,252	594,104	819,292	4,387,419	-	-	-	-
- DISTRIBUTION	5,564,336	-	-	-	-	5,564,336	-	-	-	-
METERS	38,205,181	-	-	-	-	38,205,181	-	-	-	-
BUILDINGS	433,647,481	196,016,806	43,328,856	17,384,380	25,990,063	74,412,805	67,551,326	-	8,519,648	443,598
COMMUNICATION	279,657,863	68,941,698	24,945,178	8,579,906	49,041,109	80,049,004	-	48,100,967	-	-
GENERAL EQUIPMENT	244,870,762	66,043,659	31,347,977	12,542,967	19,615,281	67,757,288	40,699,648	-	6,863,942	-
SUBTOTAL	7,929,152,989	4,410,466,572	892,534,748	160,044,416	410,011,429	1,800,523,831	108,250,974	50,032,856	67,688,269	29,599,896
MOTOR VEHICLES	-									
Rate Base for Capital Tax	7,929,152,989	4,410,466,572	892,534,748	160,044,416	410,011,429	1,800,523,831	108,250,974	50,032,856	67,688,269	29,599,896

2011 PROSPECTIVE COST OF SERVICE STUDY
FUNCTIONALIZATION OF CAPITAL TAX
FORECAST YEAR ENDING MARCH 31, 2011

			Transmission		Sub-	Distribution		Ancillary	DIRECT ALLOCATIONS	
Asset Class	Capital Tax	Generation	Domestic	Export	Transmission	Plant	Services	Services	Lighting	Diesel
GENERATION	20,967,109	20,729,113	237,997	-	-	-	-	-	-	-
-Thermal	1,392,133	1,392,133	-	-	-	-	-	-	-	-
DIESEL	165,066	-	-	-	-	-	-	-	-	165,066
SUBSTATION	4,414,479	-	1,309,694	262,685	501,207	2,329,376	-	11,517	-	-
- HVDC	3,468,906	1,538,059	1,930,847	-	-	-	-	-	-	-
TRANSMISSION	2,088,716	-	1,231,501	458,330	398,885	-	-	-	-	-
- HVDC	660,868	660,868	-	-	-	-	-	-	-	-
DISTRIBUTION	7,074,640	-	-	-	-	6,754,067	-	-	311,820	8,753
SUBTRANSMISSION	1,013,807	-	-	-	975,106	38,701	-	-	-	-
TRANSFORMERS										
- SUBSTATION	51,580	-	16,998	3,542	4,884	26,156	-	-	-	-
- DISTRIBUTION	33,172	-	-	-	-	33,172	-	-	-	-
METERS	227,764	-	-	-	-	227,764	-	-	-	-
BUILDINGS	2,585,237	1,168,576	258,310	103,639	154,943	443,620	402,715	-	50,791	2,645
COMMUNICATION	1,667,211	411,003	148,713	51,150	292,364	477,221	-	286,759	-	-
GENERAL EQUIPMENT	1,459,824	393,726	186,884	74,776	116,939	403,942	242,635	-	40,920	-
SUBTOTAL	47,270,512	26,293,478	5,320,943	954,122	2,444,328	10,734,020	645,350	298,276	403,531	176,463
MOTOR VEHICLES	-									
Capital Tax Allocation	47,270,512	26,293,478	5,320,943	954,122	2,444,328	10,734,020	645,350	298,276	403,531	176,463

2011 PROSPECTIVE COST OF SERVICE
Fiscal Year Ending March 31, 2011
Functionalization of Operating Costs

SCC Description	Operating	Generation	Transmission	Subtransmission	Distribution Plant	Customer Service	Ancillary Services	Diesel	Street Lighting	Exports
Research & Development	1,730,739	1,730,739								
Generation External Marketing	3,701,633	2,159,286								1,542,347
Common Generation Costs	31,531,140	26,554,910					-			4,976,229
Generating Station Costs	45,740,990	45,740,990					-			-
Other Generation Related Costs	290,119	290,119	-	-	-	-	-	-	-	
Dedicated Gen. Facilities	46,031,110	46,031,110					-	-	-	-
Hydraulic Generating Stations	145,996,999	145,996,999					-			
Other Hydraulic Generation Related Costs	17,919,439	17,919,439								
Hydraulic Generation Costs	163,916,438	163,916,438					-			
Thermal Generating Station	32,616,259	32,616,259					-			-
Non-Dedicated Gen. Facilities	196,532,697	196,532,697					-			-
Generation Facilities Costs	242,563,807	242,563,807					-	-	-	-
Purchased Power/Export Costs	120,922,210	-								120,922,210
Generation Facilities & Costs	***395,017,157***	***269,118,718***					-	-	-	***125,898,439***
Research & Development	1,559,048	472,523	922,555	163,970						
Transmission External Marketing	6,240,759	-	4,321,593	-						1,919,167
Common Trans. Costs/Revenues	26,318,215	472,523	20,786,798	3,139,728			-			1,919,167
Generation Switching Stations	2,392,278	-	2,392,278							
HVDC & Collector Facilities	41,028,073	22,723,368	18,304,705							
Networked AC Facilities	3,723,661	-	3,723,661							
Generation Access Transmission	47,144,012	22,723,368	24,420,644							
Regional Networked Trans.	1,014,465	-	1,014,465							
Future Transmission Line ROW	-	-	-							
Transmission Common	14,002,537	-	13,648,683	295,020			58,834			
Transmission Facilities/Costs	***88,479,230***	***23,195,891***	***59,870,590***	***3,434,748***			***58,834***			***1,919,167***
Common Subtransmission Costs	5,834,148	-	-	5,834,148						
Subtrans. Facilities & Costs	***29,437,897***	-	-	***20,829,787***	***8,608,110***	-	-	-	-	-
Dist. Facilities & Costs	***72,962,868***	-	-	-	***67,078,407***	-	-	-	***5,884,461***	-
Customer Service Costs	***85,157,781***					***85,157,781***	-	-	-	-
Isolated Diesel Facilities	***6,577,723***	-	-	-	-	-	-	***6,577,723***		
System Control	5,125,025	1,845,009	-	1,845,009	-	-	1,435,007			
Communication & Control System	***10,849,110***	***5,332,131***	-	***2,114,762***	***980,167***		***2,422,050***	-	-	-
Planned Grants In Lieu Taxes	***5,828,620***	***2,225,970***	***1,511,787***	***451,242***	***1,639,621***		-			
	694,310,386	**299,872,710**	**61,382,377**	**26,830,539**	**78,306,305**	**85,157,781**	**2,480,884**	**6,577,723**	**5,884,461**	**127,817,606**

Adjusted Revenue including DSM Reduction at Approved Rates

2011 PROSPECTIVE COST OF SERVICE STUDY
ADJUSTED REVENUE INCLUDING DSM REDUCTION @ INTERIM APRIL 1, 2010 RATES
For Year Ended March 31, 2011

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	468,857,508			449,659	2,194,032	471,501,199	16,464,822	487,966,021
Seasonal	6,836,916				31,994	6,868,910	1,345,619	8,214,529
Water Heating	1,266,919			1,215	5,929	1,274,063		1,274,063
	476,961,343	-		450,874	2,231,954	479,644,171	17,810,441	497,454,613
General Service - Small								
Non Demand	116,639,845			111,864	545,820	117,297,528	1,547,154	118,844,683
Seasonal	498,675				2,334	501,009	35,817	536,826
Water Heating	529,707			508	2,479	532,694		532,694
Total Non Demand	117,668,227	-		112,372	550,632	118,331,231	1,582,971	119,914,202
Demand	114,076,794			109,406	533,826	114,720,025	365,957	115,085,982
	114,076,794	-	-	109,406	533,826	114,720,025	365,957	115,085,982
SEP								
GSM	683,400			655	3,198	687,253		687,253
GSL	165,053					165,053		165,053
	848,453			655	3,198	852,306	-	852,306
General Service - Medium	163,158,360			156,477	763,504	164,078,342	36,097	164,114,439
	163,158,360	-		156,477	763,504	164,078,342	36,097	164,114,439

General Service - Large								
0 - 30 Kv	70,333,119			67,453	329,126	70,729,698		70,729,698
30 - 100 Kv	25,204,327					25,204,327		25,204,327
31 - 100 Kv Curtailable	7,865,581					7,865,581		7,865,581
Over - 100 Kv	94,437,136					94,437,136		94,437,136
Over - 100 Kv Curtailable	94,241,555					94,241,555		94,241,555
	292,081,718	-		67,453	329,126	292,478,297	-	292,478,297
Area & Roadway Lighting								
Street Lighting	17,376,349					17,376,349	229,646	17,605,995
Sentinel Lighting	2,732,275	(14,813)		2,606	12,716	2,732,785		2,732,785
	20,108,624	(14,813)	-	2,606	12,716	20,109,134	229,646	20,338,780
Diesel								
Residential	636,600					636,600		636,600
General Service		-				-		-
Street Lighting		14,813				14,813		14,813
Full Cost	4,141,931					4,141,931		4,141,931
	4,778,531	14,813		-	-	4,793,344	-	4,793,344
Construction Power	-					-	-	-
Gen. Consumers Before Adj	1,189,682,050	-	-	899,844	4,424,956	1,195,006,850	20,025,113	1,215,031,963
Accrual - Other	899,844			(899,844)				
Seasonal Adjustment	-							
Miscellaneous - Non-Energy	597,000		(597,000)		-	-		
Customer Acctg. Adjustment	-				-	-		
Late Pmt Charges & Cust Adj	4,424,956				(4,424,956)	-		
Total General Consumers	1,195,603,850	-	(597,000)	-	-	1,195,006,850	20,025,113	1,215,031,963
Extra-Provincial	383,467,000		597,000			384,064,000		384,064,000
Other (Non Energy net of Subs)	7,358,000		(7,358,000)			-		
Total Revenue	1,586,428,850	-	(7,358,000)	-	-	1,579,070,850	20,025,113	1,599,095,963

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2011

RECONCILIATION TO FINANCIAL FORECAST
(In Millions of Dollars)

Reconciliation of Revenue

As per Financial Forecast:	
General Consumers Revenue	1,159.3
Additional GCR	33.5
Extra Provincial Revenue	383.5
Other Revenue (non-energy)	7.4
Total Revenue Per Financial Forecast	$ 1,583.6
Cost of Service Adjustments	
a. Transfer of Other Revenue (non-energy) to Miscellaneous Revenue	(7.4)
b. Revenue Adjustment/GCR from Order 33/10 vs IFF	7.8
c. Remove Energy Intensive Industrial Rate Revenue	(4.9)
d. Uniform Rates Adjustment	20.0
Total Revenue Per Cost of Service Study	$ 1,599.1

MANITOBA HYDRO
PROSPECTIVE COST OF SERVICE STUDY
FOR FISCAL YEAR ENDING
MARCH 31, 2011

RATE BASE CALCULATION AND DEFERRED ITEMS
(In Millions of Dollars)

Allocation of net interest expense and reserve contribution is based upon average net plant in-service forecast for fiscal years 2010 and 2011 adjusted for net deferred items and net major capital additions forecast to come into service during fiscal year 2010/11 which are included on an in-service date basis. This calculation is summarized below:

	2010	2011
Net Investment (Excluding Motor Vehicles)	$ 7,493.2	$ 7,642.6
Add: Total Net Deferred Items	255.8	286.5
Less: Major Capital Item Additions 2011		(279.1)
	$ 7,749.0	$ 7,650.0
Average Investment (2010 + 2011) ÷ 2		$ 7,699.5
Add: Major Capital Item Additions 2011 on an in-service date basis		139.6
		$ 7,839.1

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SECTION D: LOAD INFORMATION

Load data used in the preparation of the PCOSS for 2010/11 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, 2007/08 and 2008/09 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 six year average of 2002/03 to 2005/06 and 2007/08 to 2008/09 data.

Also included is a forecast of energy and capacity savings to be achieved through DSM Programs. For 2010/11 the DSM savings are forecast to be 428.3 GW.h and 93.3 MW at generation, or 389.4 and 84.8 measured at the meter.

Schedule D1 outlines Manitoba Hydro's calculation of forecast demand for the 2010/11 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 2,141,030 MW.h and 322.9 MW respectively have been taken from the 2009 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 PCOSS11 from the system peak forecasted in the 2009 System Load Forecast for the 2011 fiscal year. This difference of 16 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 1,367 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 2010/11 forecast kW.h sales to the Residential Class and the forecast number of customers are taken from the 2009 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 160 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 three 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 11.7 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 36.0 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 2009 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 2009 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 77.2 GW.h and 19.8 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 3.2 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 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 307 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 64.0 GW.h and 12.9 MW have been assigned to this class.

General Service Medium estimated coincident peaks at the meter have been adjusted by 0.8 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 0.0 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 88.5 GW.h and 16.1 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 2009 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 2009 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 2010/11 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 July 2009 actual billing data plus forecast additions to the system of 2,351 lights to year end 2011. 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.

7. Export Class

Forecast Export energy in PCOSS11 includes 7,122 GWh in sales, which equals 7,757 GWh at Generation after adding back transmission losses of 635 GWh

Export energy sales used to determine 'Seasonal 2CP Demand' in Schedule D1 has been reduced by the forecast 155 GWh of US On Peak purchases. These purchases are assumed to serve On Peak US sales in a median flow year, and would not physically use Manitoba Hydro's Transmission system.

Export energy sales in Schedule D2 ‘12 Period Marginal Cost Weighted Energy’ has been reduced for 1,508 GWh in Imports deemed to serve export markets.

2011 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	7,891,770,782	63.3%	4,995,490,905	80.2%	1,433,884	36.7%	2,896,279,877	83.0%	790,193	1,112,039
Seasonal	95,915,334	42.8%	41,093,484	162.5%	5,821	57.2%	54,821,850	162.5%	7,640	6,731
Water Heating	19,015,637	49.4%	9,391,253	126.0%	1,716	50.6%	9,624,384	126.0%	1,730	1,723
Total Residential	8,006,701,754		5,045,975,642		1,441,421		2,960,726,112		799,563	1,120,492
GS Small										
Non-Demand	1,834,645,275	58.2%	1,067,763,550	78.8%	311,931	41.8%	766,881,725	73.3%	236,917	274,424
Demand	2,198,420,433	56.6%	1,244,305,965	83.4%	343,456	43.4%	954,114,468	81.5%	265,102	304,279
Subtotal	4,033,065,709		2,312,069,515		655,388		1,720,996,193		502,019	578,703
Seasonal	5,497,987	20.0%	1,099,597	162.5%	156	80.0%	4,398,389	162.5%	613	384
Water Heating	6,240,510	49.7%	3,103,905	106.0%	674	50.3%	3,136,605	106.0%	670	672
Total GSS	4,044,804,205		2,316,273,018		656,217		1,728,531,187		503,302	579,760
General Service - Medium	3,508,716,078	53.4%	1,873,654,386	85.5%	504,468	46.6%	1,635,061,692	80.5%	459,948	482,208
General Service - Large										
0 - 30 Kv	1,775,423,530	50.4%	894,813,459	87.2%	236,225	49.6%	880,610,071	81.9%	243,484	239,855
30 - 100 Kv	699,372,489	53.0%	370,667,419	90.6%	94,182	47.0%	328,705,070	100.4%	74,138	84,160
30 - 100 Kv - Curtailed Cust	242,893,597	49.0%	119,017,863	100.6%	27,235	51.0%	123,875,735	103.1%	27,208	27,221
Over 100 Kv	2,873,900,186	52.0%	1,494,428,096	98.2%	350,327	48.0%	1,379,472,089	107.3%	291,128	320,728
Over 100 Kv - Curtailed Cust	2,949,088,904	49.8%	1,468,646,274	100.5%	336,404	50.2%	1,480,442,630	100.1%	334,910	335,657
Total G.S.- Large	8,540,678,705		4,347,573,111		1,044,373		4,193,105,594		970,869	1,007,621
Street Lighting	119,535,813	57.5%	68,764,362	86.7%	18,269	42.5%	50,771,451	0.0%	-	9,134
Total - General Consumers	24,220,436,555		13,652,240,519		3,664,748		10,568,196,036		2,733,682	3,199,215
Extra Provincial	7,602,000,000	38.2%	2,903,964,000	88.8%	752,815	61.8%	4,698,036,000	86.7%	1,227,067	989,941
Integrated System	31,822,436,555		16,556,204,519		4,417,563		15,266,232,036		3,960,749	4,189,156

2011 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report

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

			Spring			Summer			Fall			Winter				
	2010/11 Forecast		**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Total**	**Weighted Energy/1000**
Residential	7,839,963,642	Residential	254,543,015	479,464,375	308,388,409	482,579,062	899,637,649	456,081,764	331,228,237	605,003,204	375,190,537	895,447,916	1,637,157,776	1,115,241,697	7,839,963,642	19,078,157
Res FRWH	18,890,805	Residential FRWH	768,825	1,448,181	931,461	1,653,034	3,081,632	1,562,269	795,214	1,452,494	900,759	1,545,727	2,826,071	1,925,137	18,890,805	44,955
Res Seasonal	95,285,678	Residential Seasonal	4,155,501	7,827,419	5,034,546	9,531,351	17,768,616	9,008,007	3,724,027	6,802,101	4,218,298	6,680,746	12,214,485	8,320,580	95,285,678	225,027
GS Small Non Demand	1,822,601,372	GS Small Non-Demand	68,201,964	120,935,054	70,535,051	155,067,974	226,915,732	127,106,823	80,128,001	138,240,957	82,770,729	193,471,797	340,057,368	219,169,921	1,822,601,372	4,445,282
GSS FRWH	6,199,543	GS Small Non-Demand FRWH	271,381	481,211	280,665	629,456	921,103	515,955	274,932	474,326	283,999	531,171	933,618	601,725	6,199,543	14,928
GSS Seasonal	5,461,894	GS Small Non-Demand Seasonal	310,819	551,141	321,451	887,297	1,298,409	727,304	169,553	292,522	175,145	187,188	329,013	212,052	5,461,894	12,771
GS Small Demand	2,183,988,454	GS Small Demand	80,769,431	140,878,105	86,474,395	170,424,052	278,685,700	162,793,997	97,050,209	168,248,193	104,820,521	226,903,393	401,525,727	265,414,731	2,183,988,454	5,280,892
GS Medium	3,485,682,395	GS Medium	136,634,391	237,024,225	145,860,177	299,837,156	488,164,953	291,335,295	151,483,595	261,954,741	162,279,376	337,200,997	589,619,570	384,287,919	3,485,682,395	8,382,540
GS Large <30KV	1,763,768,400	GS Large 750-30kV	74,162,319	123,262,361	80,671,404	160,432,508	253,723,144	165,277,415	77,841,085	128,669,778	85,426,997	161,946,503	270,094,309	182,260,576	1,763,768,400	4,206,270
GS Large 30-100kV	694,781,315	GS Large 30-100kV	24,215,246	46,929,502	36,571,365	49,449,609	93,638,789	72,876,374	27,384,485	52,388,532	41,177,903	57,070,613	108,809,388	84,269,510	694,781,315	1,607,356
GS Large 30-100kV Curtail	241,299,073	GS Large 30-100kV Curtailable	8,951,075	17,584,341	13,352,252	17,911,356	34,800,217	26,455,613	9,317,770	18,193,111	13,799,067	18,281,869	35,590,162	27,062,240	241,299,073	555,734
GS Large > 100kV	2,855,033,881	GS Large > 100kV	110,360,316	210,236,016	163,912,706	200,094,746	374,886,171	293,673,000	111,937,146	213,191,881	165,893,740	231,592,607	438,577,013	340,678,539	2,855,033,881	6,602,477
GS Large > 100kV Curtail	2,929,729,007	GS >100kV Curtailable	107,999,261	208,658,021	160,773,777	215,072,494	422,402,971	325,726,291	110,561,163	215,678,012	165,354,961	225,154,512	437,302,399	335,045,145	2,929,729,007	6,743,976
Streetlights	118,751,095	Street Lights	-	4,512,542	11,103,227	475,004	8,431,328	22,265,830	3,443,782	6,768,812	13,537,625	8,075,074	13,597,000	26,540,870	118,751,095	234,480
Total	24,061,436,555	Totals	871,343,546	1,599,792,494	1,084,210,886	1,764,045,099	3,104,356,414	1,955,405,938	1,005,339,198	1,817,358,666	1,215,829,657	2,364,090,115	4,288,633,901	2,991,030,641	24,061,436,555	57,434,846
Exports	6,249,000,000	Exports	355,690,472	576,057,701	256,186,458	784,120,718	1,299,188,940	663,161,249	245,147,639	430,232,635	250,184,588	396,180,400	660,806,969	332,042,231	6,249,000,000	14,927,427
		Weighting Factor	2.813	2.433	1.424	3.409	2.310	1.000	2.718	2.297	1.467	3.478	2.607	2.111		

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

			Spring			Summer			Fall			Winter				
Thermal Generation	2010/11 Forecast		**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Total**	**Weighted Energy/1000**
Residential	51,807,140	Residential	1,682,042	3,168,341	2,037,857	3,188,923	5,944,881	3,013,827	2,188,784	3,997,912	2,479,291	5,917,195	10,818,477	7,369,611	51,807,140	126,070
Res FRWH	124,832	Residential FRWH	5,080	9,570	6,155	10,923	20,364	10,324	5,255	9,598	5,952	10,214	18,675	12,721	124,832	297
Res Seasonal	629,656	Residential Seasonal	27,460	51,724	33,269	62,984	117,417	59,526	24,609	44,949	27,875	44,147	80,714	54,983	629,656	1,487
GS Small Non Demand	12,043,903	GS Small Non-Demand	450,684	799,149	466,102	1,024,702	1,499,478	839,933	529,493	913,508	546,956	1,278,478	2,247,128	1,448,293	12,043,903	29,375
GSS FRWH	40,967	GS Small Non-Demand FRWH	1,793	3,180	1,855	4,159	6,087	3,409	1,817	3,134	1,877	3,510	6,169	3,976	40,967	99
GSS Seasonal	36,093	GS Small Non-Demand Seasonal	2,054	3,642	2,124	5,863	8,580	4,806	1,120	1,933	1,157	1,237	2,174	1,401	36,093	84
GS Small Demand	14,431,980	GS Small Demand	533,731	930,934	571,430	1,126,176	1,841,579	1,075,756	641,316	1,111,798	692,663	1,499,397	2,653,316	1,753,883	14,431,980	34,897
GS Medium	23,033,683	GS Medium	902,892	1,566,276	963,856	1,981,349	3,225,835	1,925,168	1,001,016	1,731,019	1,072,356	2,228,253	3,896,256	2,539,407	23,033,683	55,393
GS Large <30KV	11,655,130	GS Large 750-30kV	490,071	814,528	533,083	1,060,152	1,676,624	1,092,167	514,380	850,261	564,509	1,070,156	1,784,806	1,204,393	11,655,130	27,795
GS Large 30-100kV	4,591,173	GS Large 30-100kV	160,016	310,114	241,667	326,767	618,773	481,573	180,959	346,188	272,107	377,127	719,022	556,860	4,591,173	10,622
GS Large 30-100kV Curtail	1,594,525	GS Large 30-100kV Curtailable	59,149	116,199	88,233	118,360	229,963	174,821	61,573	120,222	91,185	120,808	235,183	178,830	1,594,525	3,672
GS Large > 100kV	18,866,304	GS Large > 100kV	729,270	1,389,257	1,083,149	1,322,243	2,477,279	1,940,616	739,690	1,408,790	1,096,240	1,530,383	2,898,154	2,251,232	18,866,304	43,630
GS Large > 100kV Curtail	19,359,896	GS >100kV Curtailable	713,668	1,378,830	1,062,407	1,421,217	2,791,274	2,152,427	730,597	1,425,218	1,092,680	1,487,840	2,889,731	2,214,007	19,359,896	44,565
Streetlights	784,717	Street Lights	-	29,819	73,371	3,139	55,715	147,134	22,757	44,729	89,458	53,361	89,850	175,384	784,717	1,549
Thermal Generation	159,000,000	Totals	5,757,912	10,571,564	7,164,557	11,656,959	20,513,849	12,921,487	6,643,366	12,009,259	8,034,305	15,622,107	28,339,654	19,764,982	159,000,000	379,534
Exports	-	Exports	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		Weighting Factor	2.813	2.433	1.424	3.409	2.310	1.000	2.718	2.297	1.467	3.478	2.607	2.111		

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, 2011

CALCULATION OF LOSSES

ENERGY (in MWh)	*MANITOBA HYDRO*
Firm Energy at Generation (After DSM)	24,340,506,142
Common Bus Losses (After DSM)	2,141,030,312
Deliveries From Common Bus	22,199,475,829
Sales at Meter	21,141,746,329
Distribution Losses	1,057,729,501

DEMAND (in MW)	*MANITOBA HYDRO*
Firm Peak Capacity At Generation (After DSM)	4,164.78
Common Bus Losses (After DSM)	322.93
Deliveries From Common Bus	3,841.85
Calculated Distribution Losses	287.00
Calculated Demand at Meter (CP Load Factors)	3,570.63
Less: Adj made for curtailable load added back	-
Adjustment To Reconcile	(15.78)

MANITOBA HYDRO
2011 PROSPECTIVE COST OF SERVICE STUDY
March 31, 2011
DETERMINATION OF COINCIDENT PEAK DISTRIBUTION LOSSES

1) ENERGY SALES AND TOTAL LOSSES ON DISTRIBUTION SYSTEM

	Sales	Losses	Energy @ Common Bus
RESIDENTIAL	6,771,781,233	530,638,076	7,302,419,310
G.S.S. SINGLE PHASE	1,330,873,709	104,287,519	1,435,161,228
G.S.S. THREE PHASE	2,123,553,785	130,301,668	2,253,855,453
* G.S.M.	3,027,577,971	185,772,765	3,213,350,736
* G.S.L. O - 30	1,541,388,384	80,707,391	1,622,095,775
G.S.L. 30 - 100	846,682,597	12,700,239	859,382,836
LIGHTING	101,099,104	7,922,145	109,021,249
MAN. HYDRO CONSTRUCTION	88,000,000	5,399,697	93,399,697
	15,830,956,784	1,057,729,501	16,888,686,284

* (includes SEP sales)

2) COINCIDENT PEAK AT COMMON BUS

C.P. AT GENERATION	4,164.78
LESS SALES AT CB LEVEL :	
- EXPORTS	0.00
- * G.S.L. >100	(330.70)
C.B. LOSSES	(322.93)
EXPORT LOSSES	0.00
COINCIDENT PEAK AT COMMON BUS	3,511.15

3) LOAD FACTOR AT COMMON BUS 54.9%
(Hours per Year = 8,760)

4) EQUIVALENT HOURS LOSS FACTOR

EQF = (0.08 x 54.91%) + (0.92 x $(54.91\%)^2$)
= 0.321305

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

a) 1,057,730 x 0.1800 = 190,391 MW.H

b) $\frac{1,057,730 \times 0.1800}{8,760}$ = 21.7 MW @ PEAK

6) CO-EFFICIENT OF SYSTEM LOSSES

$$= \frac{1,057,730. - 190,391}{8,760 \times (3,511.15)^2 \times 0.32131}$$
= 0.000025

7) SYSTEM DISTRIBUTION LOSSES AT PEAK

= 21.73 + 0.000025 X $(3,511.15)^2$
= 329.89

8) ADJUSTMENT FACTOR FOR TEMPERATURE -13.0%

9) SYSTEM DISTRIBUTION LOSSES AT PEAK ASSIGNED IN COSS 287.002 MW

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

AVERAGE (KW.h)	1,057,730 / 15,830,957	=	6.68%
PEAK (MW)	287.00 / 3,224.148	=	8.90%

Prospective Peak Load Report - Using Top 50 Peak Hours

2011 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	445,517	6,834,275,747	(159,699,008)	6,674,576,739	523,021,114	694,172,930	7,891,770,782
Seasonal	20,855	81,121,750	-	81,121,750	6,356,716	8,436,868	95,915,334
Water Heating	4,603	16,082,744	-	16,082,744	1,260,247	1,672,646	19,015,637
Total Residential	470,975	6,931,480,241	(159,699,008)	6,771,781,233	530,638,076	704,282,444	8,006,701,754
GS Small - Single Phase							
Non-Demand	40,497	975,242,117	(24,311,107)	950,931,010	74,515,136	98,899,240	1,124,345,387
Demand	4,035	377,330,717	(7,316,017)	370,014,700	28,994,423	38,482,468	437,491,591
Subtotal	44,532	1,352,572,834	(31,627,124)	1,320,945,710	103,509,559	137,381,708	1,561,836,977
Seasonal	830	4,650,000	-	4,650,000	364,375	483,612	5,497,987
Water Heating	435	5,277,999	-	5,277,999	413,585	548,925	6,240,510
Total Single Phase	45,797	1,362,500,833	(31,627,124)	1,330,873,709	104,287,519	138,414,245	1,573,575,474
GS Small - Three Phase							
Non-Demand	11,408	625,972,862	(15,604,425)	610,368,437	37,452,324	62,479,128	710,299,889
Demand	7,416	1,543,104,404	(29,919,056)	1,513,185,348	92,849,343	154,894,151	1,760,928,842
Total Three Phase	18,824	2,169,077,266	(45,523,481)	2,123,553,785	130,301,668	217,373,279	2,471,228,731
Total G.S.Small							
Non-Demand	51,905	1,601,214,979	(39,915,532)	1,561,299,447	111,967,461	161,378,368	1,834,645,275
Demand	11,451	1,920,435,121	(37,235,073)	1,883,200,048	121,843,766	193,376,619	2,198,420,433
Sub-Total G.S. Small	63,356	3,521,650,100	(77,150,605)	3,444,499,495	233,811,227	354,754,987	4,033,065,709
Seasonal	830	4,650,000	-	4,650,000	364,375	483,612	5,497,987
Water Heating	435	5,277,999	-	5,277,999	413,585	548,925	6,240,510
Total GS Small	64,621	3,531,578,099	(77,150,605)	3,454,427,494	234,589,187	355,787,524	4,044,804,205
General Service - Medium	1,867	3,079,120,765	(64,042,794)	3,015,077,971	185,005,763	308,632,345	3,508,716,078
General Service - Large							
0 - 30 Kv	259	1,576,359,879	(37,671,495)	1,538,688,384	80,566,019	156,169,127	1,775,423,530
30 - 100 kV	29	633,454,110	(5,025,979)	628,428,131	9,426,422	61,517,936	699,372,489
30 - 100 kV - Curtailment Cust's	1	220,000,000	(1,745,534)	218,254,466	3,273,817	21,365,314	242,893,597
Over 100 Kv	11	2,642,856,000	(21,748,726)	2,621,107,274	-	252,792,911	2,873,900,186
Over 100 Kv - Curtailment Cust's	3	2,712,000,000	(22,317,729)	2,689,682,271	-	259,406,633	2,949,088,904
Total G.S.- Large	303	7,784,669,989	(88,509,463)	7,696,160,526	93,266,258	751,251,921	8,540,678,705
SEP							
GSM	18	12,500,000		12,500,000	767,002	1,279,537	14,546,540
GSL 0 - 30 Kv	5	2,700,000		2,700,000	141,373	274,036	3,115,409
Total SEP	23	15,200,000	-	15,200,000	908,375	1,553,574	17,661,948
Street Lighting	128,396	89,780,370	-	89,780,370	7,035,207	9,337,386	106,152,963
Sentinel Lighting	26,565	11,318,734	-	11,318,734	886,938	1,177,177	13,382,849
Total - Lighting	154,961	101,099,104	-	101,099,104	7,922,145	10,514,564	119,535,813
Total - General Consumers	692,749	21,443,148,199	(389,401,870)	21,053,746,329	1,052,329,804	2,132,022,371	24,238,098,503
Extra Provincial		-	-	-		-	-
Man Hydro - Construction		88,000,000		88,000,000	5,399,697	9,007,942	102,407,638
Integrated System	692,749	21,531,148,199	(389,401,870)	21,141,746,329	1,057,729,501	2,141,030,312	24,340,506,142

2011 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	51.3%	1,520.8	(36.0)	1,484.8	74.4%	(11.7)	1,473.0	163.2	137.5	1,773.8	91.1%	1,616.8	1,946.9
Seasonal	157.8%	5.9		5.9		-	5.9	0.7	0.5	7.1	8.0%	73.4	88.3
Water Heating	66.5%	2.8		2.8		-	2.8	0.3	0.3	3.3	80.0%	3.5	4.2
Total Residential	51.7%	1,529.4	(36.0)	1,493.4	74.4%	(11.7)	1,481.7	164.2	138.3	1,784.2	87.5%	1,693.6	2,039.4
GS Small - Single Phase													
Non-Demand	62.0%	179.7	(6.1)	173.6	10.5%	(1.7)	171.9	19.1	16.1	207.0	85.9%	200.2	241.0
Demand	65.1%	66.2	(1.9)	64.3	0.7%	(0.1)	64.2	7.1	6.0	77.3	88.1%	72.8	87.7
Subtotal	62.8%	245.9	(8.0)	237.8	11.2%	(1.8)	236.1	26.2	22.0	284.3	86.5%	273.0	328.8
Seasonal	162.5%	0.3		0.3			0.3	0.0	0.0	0.4	8.0%	4.1	4.9
Water Heating	69.9%	0.9		0.9			0.9	0.1	0.1	1.0	75.0%	1.1	1.4
Total Single Phase	63.0%	247.1	(8.0)	239.0	11.2%	(1.8)	237.3	26.3	22.2	285.7	85.3%	278.3	335.1
GS Small - Three Phase													
Non-Demand	62.0%	115.3	(3.9)	111.4	6.8%	(1.1)	110.3	9.7	10.1	130.2	85.9%	128.5	151.6
Demand	65.1%	270.7	(7.8)	262.8	2.7%	(0.4)	262.4	23.1	24.0	309.6	88.1%	297.9	351.4
Total Three Phase	64.1%	386.0	(11.7)	374.3	9.4%	(1.5)	372.8	32.9	34.1	439.7	87.4%	426.4	503.0
Total G.S.Small													
Non-Demand	60.4%	295.0	(10.0)	285.0	17.3%	(2.7)	282.2	28.8	26.1	337.2	85.9%	328.7	392.6
Demand	63.8%	336.9	(9.7)	327.1	3.3%	(0.5)	326.6	30.2	30.0	386.8	88.1%	370.8	439.1
Sub-Total G.S. Small	63.6%	631.9	(19.8)	612.1	20.6%	(3.2)	608.8	59.0	56.1	724.0	87.1%	699.4	831.7
Seasonal	162.3%	0.3	-	0.3	0.0%	-	0.3	0.0	0.0	0.4	8.0%	4.1	4.9
Water Heating	69.9%	0.9	-	0.9	0.0%	-	0.9	0.1	0.1	1.0	75.0%	1.1	1.4
Total GS Small	63.7%	633.1	(19.8)	613.3	20.6%	(3.2)	610.0	59.2	56.3	725.4	86.6%	704.6	838.1
General Service - Medium	71.5%	491.8	(12.9)	478.9	4.8%	(0.8)	478.1	42.2	43.7	564.0	91.6%	521.8	615.5
General Service - Large													
0 - 30 Kv	78.7%	228.6	(7.6)	221.0	0.2%	(0.0)	221.0	16.8	20.0	257.8	88.6%	249.5	291.0
30 - 100 kV	89.4%	80.9	(1.1)	79.7		-	79.7	1.6	6.8	88.2	76.6%	104.1	115.1
30 - 100 kV - Curtailment Cust's	100.3%	25.0	(0.4)	24.7		-	24.7	0.5	2.1 †	27.3	88.0%	28.1	31.0
Over 100 Kv	91.2%	330.7	(3.6)	327.1		-	327.1	-	27.5	354.6	88.8%	368.4	399.4
Over 100 Kv - Curtailment Cust's	100.1%	309.2	(3.4)	305.8		-	305.8	-	25.7 †	331.5	87.7%	348.6	377.9
Total G.S.- Large	91.2%	974.4	(16.1)	958.4	0.2%	(0.0)	958.3	18.9	82.1	1,059.4	87.2%	1,098.6	1,214.4
SEP													
GSM	53.1%	2.7		2.7		-	2.7	0.2	0.2	3.2	68.8%	3.9	4.6
GSL 0 - 30 Kv	104.2%	0.3		0.3		-	0.3	0.0	0.0	0.3	16.4%	1.8	2.1
Total SEP	58.1%	3.0	-	3.0		-	3.0	0.3	0.3	3.5	52.2%	5.7	6.7
Street Lighting	119.7%	8.6	-	8.6		-	8.6	0.9	0.8	10.3	38.2%	22.4	27.0
Sentinel Lighting	119.7%	1.1	-	1.1		-	1.1	0.1	0.1	1.3	38.2%	2.8	3.4
Total - Lighting	119.7%	9.6	-	9.6	0.0%	-	9.6	1.1	0.9	11.6	38.2%	25.2	30.4
Total - General Consumers	67.2%	3,641.4	(84.8)	3,556.6	100.0%	(15.8)	3,540.8	285.8	321.6	4,148.2	87.4%	4,049.6	4,744.5
Extra Provincial	0.0%	0.0		0.0		-	-		-	0.0			
Man Hydro - Construction	71.5%	14.1		14.1		-	14.1	1.2	1.3	16.6			
Integrated System	67.2%	3,655.4	(84.8)	3,570.6	100.0%	(15.8)	3,554.8	287.0	322.9	4,164.8			

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2011

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

	Class Avg
Export Sales	n/a
GS Large	
< 30	5.2%
30-100	1.5%
> 100	n/a
GS Medium	6.1%
GS Small	
3 Phase	6.1%
1 Phase	7.8%
Residential	7.8%
Area & Roadway Lighting	7.8%

PROSPECTIVE COST OF SERVICE STUDY
March 31, 2011

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

	Class Avg
Export Sales	n/a
GS Large	
< 30	7.6%
30-100	2.0%
> 100	n/a
GS Medium	8.8%
GS Small	
3 Phase	8.8%
1 Phase	11.1%
Residential	11.1%
Area & Roadway Lighting	11.1%

SECTION E: ALLOCATION METHODS

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

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

The allocation process uses class characteristics that comport with the classification of the cost: customer costs are allocated based on a weighted or 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, 2011
Classified Costs by Allocation Table

Allocation Table	Function		Interest	Depreciation	Operating	Misc. Rev	Total
E12	Generation - Domestic & Export		262,358	121,475	260,070	(913)	642,990
E13	Generation - Domestic		16,435	19,561	39,583	-	75,579
			278,793	141,036	299,653	(913)	718,569
D13	Transmission - 2CP Domestic			-	3,677		3,677
D14	Transmission - 2CP Domestic & Export		71,162	56,623	60,136		187,920
			71,162	56,623	63,813	-	191,597
D21	Subtrans		4,210	22,430	26,831		53,471
D22	Subtrans	Stations	5,746	-			5,746
D23	Subtrans	Line	16,041	-			16,041
			25,997	22,430	26,831	-	75,258
D32	Dist. Plant Stn		25,995	24,820	34,625		85,440
D36	Dist. Plant	Lines	41,721	37,595	20,914		100,231
D40	Dist. Plant	S/E	12,795	14,834	6,316		33,944
			80,511	77,250	61,855	-	219,615
C23	Dist. Plant	Lines	27,814	25,063	13,943		66,821
C27	Dist. Plant	Services	3,913				3,913
C40	Dist. Plant	Meter Investment	2,518	1,828			4,346
C41	Dist. Plant	Meter Mtce.	-		2,509		2,509
			34,246	26,891	16,452	-	77,588
C10	Dist Serv	Cust Service - General	676	4,472	32,101	-	37,248
C11	Dist Serv	Cust Acct - Billings	507	2,826	24,072		27,405
C12	Dist Serv	Cust Acct - Collections	320	1,446	15,226		16,992
C13	Dist Serv	Marketing - R & D	27	121	1,276		1,424
C14	Dist Serv	Inspection	82	371	3,908		4,362
C15	Dist Serv	Meter Read	180	814	8,574		9,568
C30	Dist Serv	Hot Water Tank Program		297	-		297
			1,792	10,346	85,158	-	97,296
	Total Allocated Costs		492,501	334,576	553,760	(913)	1,379,924

Prospective Cost Of Service Study
March 31, 2011
Classified Costs by Allocation Table

Allocation Table	Function		Interest	Depreciation	Operating	Misc. Rev	Total
DIRECTS							
C02	Generation	Diesel	1,436	3,990	6,241		11,666
E01	Generation	Export	20,025	12,360	125,898		158,284
			20,025	12,360	125,898	-	158,284
E01	Generation	SEP - GSM	185	108	175		469
E01	Generation	SEP - GSL 0-30kV	47	27	44		118
E01	Generation	DSM Direct Assignment - Energy					
E01	Generation	Residential	2,433	4,953			7,386
E01	Generation	GSS ND	1,553	3,329			4,882
E01	Generation	GSS Demand	1,638	3,880			5,518
E01	Generation	GSM	2,035	4,538			6,573
E01	Generation	GSL 0-30kV	1,011	2,267			3,277
E01	Generation	GSL 30-100kV excl Curt.	122	276			398
E01	Generation	GSL >100kV excl Curt.	439	1,030			1,469
E01	Generation	Street Lights	2	7			9
E01	Generation	Curtailment (GSL 30-100)	260	628		(582)	306
E01	Generation	Curtailment (GSL > 100)	2,645	6,415		(5,863)	3,197
			12,370	27,458	219	(6,445)	33,603
D04	Transmission	Export	-	-	1,919		1,919
D04	Transmission	SEP - GSM	48	38	41		127
D04	Transmission	SEP - GSL 0-30kV	12	10	10		32
			60	48	51	-	159
C01	Distribution	Lighting	3,860	3,087	5,884		12,832
C01	Distribution	Diesel	114	258	337		709
			3,975	3,346	6,221	-	13,541
	Total Directs		37,866	47,202	140,550	(6,445)	219,172
	Total		530,366	381,777	694,310	(7,358)	1,599,096
	Generation		312,624	184,844	432,012	(7,358)	922,123
	Transmission		71,222	56,670	65,782	-	193,675
	Subtransmission		25,997	22,430	26,831	-	75,258
	Distribution Plant		118,731	107,486	84,527	-	310,745
	Distribution Services		1,792	10,346	85,158	-	97,296
			530,366	381,777	694,310	(7,358)	1,599,096
	Energy		311,188	180,855	425,771	(7,358)	910,456
	Demand		177,730	156,350	154,468	-	488,548
	Customer		41,448	44,572	114,072	-	200,091
			530,366	381,777	694,310	(7,358)	1,599,096

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 shared 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 2005/06, 2007/08 and 2008/09.

JUSTIFICATION

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 shared 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 2005/06, 2007/08 and 2008/09.

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 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 2008-2009.

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 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.