APPENDIX A

ESTABLISHING INITIAL RATES

Cost of Service Requirements

Initial rates for the first generation PBR plan can be set based on:

    (1)   A utility's individual cost of service study; or

    (2)   The average Municipal Electric Utility (MEU) cost of service model that was used by Ontario Hydro in establishing the existing MEU rates adopted by the Board.

Guidance is provided here on the establishment of distribution rates based on the average cost of service model for the first generation PBR plan.

Requirement for Unbundled Rates

Given that retail open access is expected to start during the first generation PBR plan term, the distribution (wires only) rates must be separated (unbundled) from the cost of power (COP) rates for this plan. The COP rates prior to retail access will cover both the transmission and commodity costs, since these are currently both included in Ontario Hydro's wholesale rates. Following the introduction of retail access, a transmission charge and a commodity charge will replace the COP charge.

In order to unbundle existing rates into distribution and COP rates a customer class's revenue requirement must first be separated into distribution and cost of power revenue requirements. The rate unbundling process described in this handbook starts off with the separation of the revenue requirements followed by the rate design process.

In unbundling the rates, the cost of distribution system losses (DSL) must be separated as well. Prior to retail access, the DSL can be included in the COP since there will still only be one supplier. However, upon the introduction of retail access, the DSL will be recovered through a separate charge since the rate applied to the DSL volumes will not necessarily be the competitive commodity rate.

Methods for developing the following rates are provided:

1. Residential Customer Class

    1.1 Distribution Monthly Service Charge

    1.2 Non-Time-of-Use (N-TOU) COP Energy (kWh) Rate

    1.3 Time-of-Use (TOU) COP Energy (kWh) Rate

2. General Service (GS) Customer Class (<5,000 kW)

    2.1 Distribution Monthly Service Charge

    2.2 Distribution Demand Rate for GS Customers with Demand Meters

    2.3 Distribution Energy Rate for GS Customers without Demand Meters

    2.4 COP N-TOU Energy (kWh) Rate

    2.5 COP N-TOU Demand (kW) Rate

    2.6 COP TOU Energy (kWh) Rate

    2.7 COP TOU Demand (kW) Rate

3. Street Lighting Class Rates

    3.1 Distribution Monthly Service Charge

    3.2 Distribution Demand(kW) Rate

    3.3 COP Energy (kWh) Rate

    3.4 COP Demand (kWh) Rate

4. Large Use Class Rates (> 5,000 kW)

    4.1 Distribution Monthly Service Charge

    4.2 Distribution Demand(kW) Rate

    4.3 COP TOU Energy (kWh) Rate

    4.4 COP TOU Demand (kW) Rate

5. Intermediate Use Rates

6. Water Heater Load Control Discount

7. Rental Rates

8. Miscellaneous Charges

Guidance on billing for transmission, commodity, Independent Market Operator and any Competition Transition charges that may be imposed will be provided in an addendum to the rate handbook that will be distributed when settlement issues have been resolved.

1. Class Base Distribution Revenue Requirement

The class base distribution revenue requirement is the revenue requirement that is derived when the cost of power is backed out of the class revenue requirement that is determined using existing rates. This approach ensures class distribution revenue neutrality at existing rates. The base distribution revenue requirement can then be adjusted to meet the forecast year's revenue requirement.

At the wholesale level, a utility is currently billed on wholesale TOU rates and demand is billed on the basis of the utility's monthly peak demand. Therefore, in allocating the COP to the class it is necessary to know a class's monthly demands that are coincident with the utility's monthly peaks and the class energy consumption by TOU period. To do this a load profile model developed by Onario Hydro and the MEU's in the 1980's is used. While the load profile model is based on 1980's load data research, it has not been updated, and is therefore the most recent available. The load data research coincident demand factors and energy weighting factors are provided in Tables 2-1 and 2-2 for the various customer classes. These factors should be used in the determination of COP for the customer classes unless a utility has actual data available.

Table 2-1

COINCIDENT LOAD (DEMAND) FACTOR
ONTARIO HYDRO-MEU LOAD DATA (1980'S DATA)

	Hours in Month	Residential	Sentinel Lighting	General Service	Street Lighting
Jan	730	68.12%	62.08%	86.54%	62.16%
Feb	730	57.09%	51.93%	78.83%	51.99%
Mar	730	69.26%	51.60%	86.46%	51.67%
Apr	730	71.07%	43.88%	75.73%	43.94%
May	730	92.32%	0.00%	77.53%	0.00%
Jun	730	60.76%	0.00%	59.90%	0.00%
Jul	730	68.56%	0.00%	65.68%	0.00%
Aug	730	71.55%	0.00%	63.12%	0.00%
Sept	730	67.54%	0.00%	74.08%	0.00%
Oct	730	66.88%	61.55%	83.20%	61.63%
Nov	730	62.10%	58.74%	82.51%	58.82%
Dec	730	61.67%	63.53%	79.53%	63.61%

Table 2-2

CALCULATED MONTHLY WHOLESALE ENERGY (kWh) QUANTITIES

	Residential			Sentinel Lighting			General Service			Street Lighting		
	Peak	Off-Peak	TOTAL	Peak	Off-Peak	TOTAL	Peak	Off-Peak	TOTAL	Peak	Off-Peak	TOTAL
Energy Including Losses- Wholesal Purchase Amount												
Jan	7,552,815	7,569,875	15,122,690	0	0	0	14,017,381	13,481,742	27,499,123	85,519	189,078	274,597
Feb	6,634,276	6,252,180	12,886,456	0	0	0	13,087,833	11,699,425	24,787,258	68,627	161,072	229,699
Mar	6,796,287	5,820,313	12,616,600	0	0	0	14,170,765	11,276,140	25,446,905	64,392	163,877	228,269
Apr	5,059,453	5,968,026	11,027,479	0	0	0	11,507,509	11,186,814	22,694,323	35,165	158,963	194,128
May	5,093,455	4,574,740	9,668,195	0	0	0	13,022,142	9,921,441	22,943,583	32,948	143,440	176,388
Jun	5,474,629	4,270,934	9,745,563	0	0	0	13,094,359	9,462,339	22,556,699	27,270	130,789	158,059
Jul	5,385,846	5,753,052	11,138,899	0	0	0	12,131,923	11,022,448	23,154,370	25,655	143,245	168,900
Aug	5,642,994	5,017,073	10,660,067	0	0	0	13,603,763	10,519,749	24,123,511	36,090	153,836	189,926
Sept	4,448,647	4,730,168	9,178,815	0	0	0	12,392,685	10,473,608	22,866,294	45,114	164,716	209,830
Oct	4,821,691	4,760,996	9,582,687	0	0	0	12,789,916	11,073,329	23,863,245	65,455	179,001	244,457
Nov	6,194,433	5,288,910	11,483,343	0	0	0	14,459,719	11,234,699	25,694,417	85,521	174,333	259,854
Dec	6,320,251	7,395,460	13,715,711	0	0	0	12,850,863	14,679,991	27,530,854	81,450	199,578	281,028

Approach to Establishing Class Base Distribution Revenue Requirement

The approach presented here is for utilities that do not have load data for their residential, general service and street lighting customer classes. Utilities that have load information for these classes should use their actual data and include their load data analysis in the evidence to be filed for the first year of the PBR plan.

The base distribution revenue requirement for a customer class is established as follows:

(1)   The class revenue at existing rates is determined using the most recent calendar year actual kW and kWh amounts.

(2)   The COP for the customer class is derived by calculating wholesale volumes for the residential, general service and street lighting classes according to the load profile model. This provides calculated demand (kW) and energy (kWh) volumes to be allocated to the customer class. Actual demand data (most recent calendar year kW, kWh and coincidence factor) should be used to determine the large use cost of power.

(3)   The class's base distribution revenue requirement is obtained by subtracting the customer class's COP determined in (2) from the class revenue at current rates determined in (1). This ensures class revenue neutrality at existing rates in the unbundling of the distribution and COP revenue streams.

(4)   Adjusting the class's base distribution revenue requirement (3) to meet the revenue requirement (e.g. for rate of return and transition costs) derives the forecast year's revenue requirement. The rate of return should be uniformly applied to each customer class. The adjusted revenue requirement of all the utilities' customer classes should add up to the total utility distribution revenue requirement as determined by PBR.

(5)   The forecast year's distribution revenue requirement (4) is then used to set t he customer class's unbundled distribution rates.

The distribution rate structure for each of the rate classes consists of a monthly service charge plus a distribution energy (kWh) or demand (kW) rate. The distribution kWh or kW charge reflects the difference in system usage by customers within the same customer class and is designed based on the incremental distribution cost (IDC).

The IDC used in the rate derivations presented in this chapter is $0.00620/kWh. It is intended to represent the cost of providing the next kWh and includes incremental operating and maintenance expenses, incremental capital investment, incremental financing charges, and system losses. The value was derived in a 1980's joint Ontario Hydro-MEU study. It is the only value currently available and is recommended for use in developing the distribution kWh or kW rate.

2.   Residential Rates

Residential service is all service supplied to single-family dwelling units for domestic or household purposes. A distributor may apply residential rates to apartment buildings supplied through one service if there are six or less residential units in the building.

Residential Rate Structure for First Generation PBR Plan

The recommended rate structure for the collection of distribution revenue from residential customers for the first generation PBR plan is a monthly service charge plus a distribution kWh (energy) charge.

For the recovery of cost of power, a flat energy charge ($/kWh) is recommended prior to market opening.

Determining the Residential Class Base Revenue Requirement

The base revenue requirement for the residential class is determined by multiplying the annual energy (kWh) sales for the class by the existing energy block rates (Table 2-3).

Table 2-3

RESIDENTIAL CLASS REVENUE REQUIREMENT AT EXISTING RATES

Block	Sales in Block kWh	Block Rate $/kWh	Revenue Requirement at Existing Rates $
Fist 250 kWh	2,185,549	0.0938	205,088
Additional kWh	129,044,752	0.0808	10,429,407
Total			10,634,495

Determining the Residential Cost of Power

To derive the annual cost of power for the residential class the wholesale demand cost as well as the wholesale energy cost attributable to this class need to be determined. Assuming that utilities do not have class coincident demand information and energy consumption by TOU periods, this is derived using the load data research factors provided in Table 2-1 for class coincident demand and Table 2-2 for class energy weightings.

In calculating the residential demand coincident with the utility peak the residential class monthly energy sales for the most recent calendar year are first restated in kW by dividing the kWh amount by the product of the coincident factor (Table 2-1) times the number of hours in a month (730 hours). The coincident demand (kW) for the TOU periods are then summed (Table 2-4).

Table 2-4

CALCULATED WHOLESALE DEMAND (kW) QUANTITIES

	Residential	Sentinel Lighting	General Service	Street Lighting
Coincident Peak Demand				
Jan	30,409	0	43,528	605
Feb	30,921	0	43,075	605
Mar	24,952	0	40,317	605
Apr	21,255	0	41,050	605
May	14,347	0	40,540	0
Jun	21,972	0	51,584	0
Jul	22,257	0	48,295	0
Aug	20,410	0	52,353	0
Sept	18,616	0	42,284	0
Oct	19,628	0	39,289	543
Nov	25,331	0	42,658	605
Dec	30,467	0	47,418	605
Winter Peak	161,709	0	256,284	3,569
Summer Peak	118,857	0	276,106	605

The residential wholesale energy cost is determined first by taking the residential class kWh sales for the most recent calendar year and adjusting it for the utility distribution system losses (DSL). The DSL to be applied is the most recent 5-year average loss factor. For utilities with large use and/or intermediate use customers, the kWh associated with these classes should be removed in the determination of the DSL.

The energy weighting factors (Table 2-2) are then applied to the kWh amounts that have been adjusted for system losses (Table 2-5) and the amounts are summed for the TOU periods (Table 2-6).

The kW amounts are multiplied by the appropriate wholesale demand rates to obtain the residential demand wholesale cost and the energy amounts are multiplied by the appropriate wholesale energy rates to obtain the residential energy wholesale   cost .

Table 2-5

CALCULATED MONTHLY WHOLESALE ENERGY (kWh) QUANTITIES

	Residential			Sentinel Lighting			General Service			Street Lighting		
	Peak	Off-Peak	TOTAL	Peak	Off-Peak	TOTAL	Peak	Off-Peak	TOTAL	Peak	Off-Peak	TOTAL
Energy Including Losses- Wholesale Purchase Amount												
Jan	7,552,815	7,569,875	15,122,690	0	0	0	14,017,381	13,481,742	27,499,123	85,519	189,078	274,597
Feb	6,634,276	6,252,180	12,886,456	0	0	0	13,087,833	11,699,425	24,787,258	68,627	161,072	229,699
Mar	6,796,287	5,820,313	12,616,600	0	0	0	14,170,765	11,276,140	25,446,905	64,392	163,877	228,269
Apr	5,059,453	5,968,026	11,027,479	0	0	0	11,507,509	11,186,814	22,694,323	35,165	158,963	194,128
May	5,093,455	4,574,740	9,668,195	0	0	0	13,022,142	9,921,441	22,943,583	32,948	143,440	176,388
Jun	5,474,629	4,270,934	9,745,563	0	0	0	13,094,359	9,462,339	22,556,699	27,270	130,789	158,059
Jul	5,385,846	5,753,052	11,138,899	0	0	0	12,131,923	11,022,448	23,154,370	25,655	143,245	168,900
Aug	5,642,994	5,017,073	10,660,067	0	0	0	13,603,763	10,519,749	24,123,511	36,090	153,836	189,926
Sept	4,448,647	4,730,168	9,178,815	0	0	0	12,392,685	10,473,608	22,866,294	45,114	164,716	209,830
Oct	4,821,691	4,760,996	9,582,687	0	0	0	12,789,916	11,073,329	23,863,245	65,455	179,001	244,457
Nov	6,194,433	5,288,910	11,483,343	0	0	0	14,459,719	11,234,699	25,694,417	85,521	174,333	259,854
Dec	6,320,251	7,395,460	13,715,711	0	0	0	12,850,863	14,679,991	27,530,854	81,450	199,578	281,028

(Table 2-7). The demand and energy wholesale costs are summed to obtain the total residential class COP.

Determining the Residential Distribution Revenue Requirement

Subtracting the class COP from the total residential class revenue requirement (Table 2-8) provides the residential base distribution revenue requirement. At this point the base revenue requirement can be adjusted to meet the residential revenue requirement if needed.

Table 2-6

CALCULATED TOU WHOLESALE ENERGY (kWh) QUANTITIES

	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Total
	kWh	kWh	kWh	kWh	kWh
Energy including system losses - wholesale purchase amounts					
Residential	38,319,753	37,087,735	31,105,023	30,313,993	136,826,505
Sentinel Lighting	0	0	0	0	0
General Service	81,376,477	73,445,326	75,752,381	62,586,400	293,160,583
Street Lighting	450,965	1,066,939	202,242	894,990	2,615,136

Table 2-7

RESIDENTIAL CLASS COST OF POWER

	Winter Peak	Summer Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Total
	kW	kW	kWh	kwh	kWh	kWh	
(a) Volume	161,709	118,857	38,319,753	37,087,735	31,105,023	30,313,993	
	$/kW	$/kW	$/kWh	$/kWh	$/kWh	$/kWh	
(b) Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	$	$	$	$	$	$
(c) COP=(a)*(b)	1,948,593	1,072,090	2,333,673	1,242,439	1,564,583	697,222	8,858,600

Table 2-8

RESIDENTIAL DISTRIBUTION REVENUE REQUIREMENT

	Total Annual Revenue	Cost of Power	Distribution Revenue
	$	$	$
	(a)	(b)	(c) = (a) - (b)
Residential	10,634,495	8,858,598	1,775,897

Designing the Residential Rates

In designing the residential rates the distribution kWh rate is developed first. The distribution kWh rate is intended to cover the residential incremental distribution cost (IDC). Once the residential distribution kWh rate has been derived, a monthly distribution service charge is designed that will generate the remaining residential distribution revenue requirement.

Residential Distribution Energy (kWh) Rate

Because the distribution kWh rate is intended to recover the IDC, this amount must first be determined. The IDC was determined to be $0.00620/kWh in a 1980's study conducted by Ontario Hydro-MEU. This is the only value currently available and is the value recommended for use in developing the residential distribution kWh rate.

This value includes system losses. Since system losses are included in the COP energy charge, this component of the IDC needs to be removed in order to develop distribution rates net of system losses. To do this, the utility's 5-year average loss factor should be applied to the IDC. This provides the residential distribution kWh rate.

An example of the distribution demand rate derivation is provided in Table 2-9.

Table 2-9

RESIDENTIAL DISTRIBUTION ENERGY (kWh) RATE

	Incremental Distribution Cost per kWh	Utility's System Loss Rate	Variable Distribution Rate ($/kWh)	Retail kWh	Variable Revenue $
	(a) Default Value	(b) Default Value	(c)=(a)-(b)	(d)	(e)=(c)*(d)
Distribution kWh Rate	0.0062	0.0025	0.00366	136,826,505	500,785

Residential Monthly Distribution Service Charge

To determine the monthly distribution service charge, the revenue generated from the distribution kWh rate is subtracted from the residential revenue requirement. The remaining amount is divided by the number of residential customers and then by 12 to obtain the per customer monthly service charge (Table 2-10).

Residential COP Energy (kWh) Rate

To derive the energy rate, the residential class annual COP is divided by the most recent calendar year annual residential energy (kWh) consumption (Table 2-10).

Table 2-10

RESIDENTIAL DISTRIBUTION MONTHLY SERVICE CHARGE AND COP KWH RATE AND

	Distribution Revenue	Variable Revenue	Service Charge Revene	Number of Customers	Distribution Service Charge per Month $/Month/Customer
	(a)	(b)	(c)=(a)-(b)	(d)	(e) = ((c)/(d))/12
Distribution Monthly Service Charge	1,775,897	500,785	1,275,112	9,115	11.66
	Cost of Power	**Annual Residential kWh**			**Cost of Power Rate $/kWh**
	(f)	(g)			(h)=(f)/(g)
COP kWh Rate	8,858,600	131,230,301			0.068

Upon retail access, the customers new energy bill will be based on the new settlement system. The DSL charge will be the customers' energy usage times the utility's most recent five-year average annual DSL (adjusted for large use DSL) multiplied by the appropriate rate as determined by the new settlement system.

Residential TOU Rates

Given that retail TOU rates are related to wholesale price signals, the residential TOU rates will only apply to the COP.

To derive the TOU energy rates, the COP for each TOU period is first determined. The demand and energy costs for the winter peak and summer peak periods are summed to obtain the total wholesale costs for these two periods. Only energy costs apply to the off-peak periods; therefore, these costs make up the total costs for the off-peak periods. The total wholesale costs within each of the TOU periods are then divided by the respective energy sales to obtain the residential TOU rates (Table 2-11).

Table 2-11

RESIDENTIAL CLASS TOU RATES

	Winter Peak	Summer Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
	kW	kW	kWh	kwh	kWh	kWh
(a) Wholesale Volume	161,709	118,857	38,319,753	37,087,735	31,105,023	30,313,993
	$/kW	$/kW	$/kWh	$/kWh	$/kWh	$/kWh
(b) Rates	12.05	9.02	0.0609	0.0335	0.0503	0.0235
	$	$	$	$	$	$
(c) COP=(a)*(b)	1,948,593	1,072,090	2,333,673	1,242,439	1,564,583	697,222
(d) Total COP/TOU period			4,282,266	1,242,439	2,636,673	697,222
(e) kWh Sales			36,752,475	35,570,847	29,832,828	29,074,151
(f) TOU Rates (d)/(e)			0.1165	0.0349	0.0884	0.0240

3. General Service Rates

All services supplied to premises other than those classified as residential, sentinel lighting   , street lighting, large use or intermediate use are classified as general service.

General Service Rate Structure for First Generation PBR Plan

General Service Customers with Demand Meters

The recommended rate structure for the collection of the distribution revenue requirement from general service customer class with demand meters is a monthly service charge plus a distribution demand (kW) rate. The distribution kW rate is designed to recover the incremental distribution cost.

The transformation allowance for customers who own their own transformation facilities for service < 115 kV will remain at the current level of $0.60/kW.

For the recovery of cost of power, a flat demand ($/kW) and a flat energy rate ($/kWh) are recommended.

General Service Customers without Demand Meters

For general service customers without demand meters, the recommended rate structure is a monthly service charge plus a distribution kWh rate with the distribution kWh rate designed to collect the incremental distribution cost.

Determining the General Service Class Base Revenue Requirement

The base revenue requirement for the general service class is determined by multiplying the annual energy (kWh) sales for the class by the existing appropriate energy block rates (Table 3-1).

Table 3-1

GENERAL SERVICE REVENUE REQUIREMENT AT EXISTING RATES

Block	Sales in Block	Block Rate	Revenue Requirement at Existing Rates
Energy	kWh	$/kWh	$
First 250 kWh	5,682,668	0.0834	474,000
Next 12500 kWh	215,797,500	0.0630	13,590,353
All Additional kWh	59,690,148	0.0551	3,287,283
Demand	kW	$/kW	$
First 50 kW	75,000	0	0
All Additional kW	457,390	6.00	2,744,340
Total			20,095,977

Determining the Cost of Power

To determine the general service COP the same procedure used to determine the residential COP is followed.

To derive the annual COP for the general service class the wholesale demand cost as well as the wholesale energy cost attributable to this class need to be determined. Assuming that utilities do not have class coincident demand information and energy consumption by TOU periods, this is derived using the load data research factors provided in Table 2-1 for class coincident demand and Table 2-2 for class energy weightings.

In calculating the general service demand coincident with the utility peak the general service monthly energy sales for the last calendar year are restated in kW by dividing the kWh amount by the product of the coincident factor (Table 2-1) times the number of hours in a month (730 hours). The coincident demands (kW) are then summed for the TOU periods (Table 2-4).

The general service wholesale energy cost is determined by taking the general service kWh sales and adjusting it for utility system losses (Table 2-5). The DSL to be applied is the most recent 5-year average loss factor. For utilities with large use and/or intermediate use customers, the kWh associated with these classes should be removed in the determination of the DSL.

The energy weighting factors (Table 2-2) are then applied to the wholesale kWh amounts, and these amounts are summed for the TOU periods (Table 2-6).

The kW amounts are multiplied by the appropriate wholesale demand rates (e.g. <115 kV, at 115 kV) to obtain the general service demand wholesale cost and the energy amounts are multiplied by the appropriate wholesale energy rates to obtain the general service energy wholesale cost (Table 3-2). The demand and energy wholesale costs are added to obtain the total general service class COP.

Table 3-2

GENERAL SERVICE CLASS COST OF POWER

	Winter Peak	Summer Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Total
	kW	kW	kWh	kwh	kWh	kWh	
(a) Volume	256,284	276,106	81,376,477	73,445,326	75,752,381	62,586,400	
	$/kW	$/kW	$/kWh	$/kWh	$/kWh	$/kWh	
(b) Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	$	$	$	$	$	$
(c) COP=(a)*(b)	3,088,222	2,490,476	4,955,827	2,460,418	3,810,345	1,439,487	18,244,776

Subtracting the class cost of power from the general service revenue requirement (Table 3-3) provides the base distribution revenue requirement. At this point, the base distribution revenue requirement can be adjusted to meet the forecast year's general service revenue requirement if needed.

Table 3-3

GENERAL SERVICE DISTRIBUTION REVENUE REQUIREMENT

	Total Annual Revenue	Cost of Power	Distribution Revenue
	$ (a)	$ (b)	$ (c) = (a) - (b)
General Service	20,095,977	18,244,776	1,851,201

Designing the General Service Rates

In designing the general service rates the distribution demand (kW) rate is developed first. The distribution kW rate is intended to cover the general service incremental distribution costs (IDC). Once the general service distribution kW rate has been derived, a monthly distribution service charge is designed that will generate the remaining distribution revenue requirement.

General Service Distribution Demand (kW) Rate

Because the distribution demand rate is intended to recover the IDC, this amount must first be determined. The incremental distribution cost was determined to be 0.00620/kWh in a 1980's study conducted by Ontario Hydro-MEU. This is the only value currently available and is the value recommended for use in developing the distribution demand rate.

This value includes system losses. Since system losses are included in the COP energy charge, this component of the IDC needs to be removed in order to develop distribution rates net of system losses. To do this, the utility's 5-year average loss factor should be applied to the IDC. This provides a $/kWh IDC rate. However, a $/kW rate is required.

To convert the kWh rate to a kW rate, the adjusted IDC is first multiplied by the utility's kWh general service class sales for the most recent calendar year to obtain the IDC revenue requirement. The IDC revenue requirement is then divided by the general service kW sales to obtain a kW rate.

An example of the distribution demand rate derivation is provided in Table 3-4.

Table 3-4

GENERAL SERVICE DISTRIBUTION DEMAND (kW) RATE

	Incremental Distribution Cost per kWh*	Loss Rate*	Variable Distribution Rate	Retail kWh	Variable Revenue $	Retail kW	Distribution kW Rate $
	(a)*Default Value	(b)*Default Value	(c) = (a)-(b)	(d)	(e) = (c)*(d)	(f)	(g)=(e)/(f)
Distribution kW Rate	0.0062	0.0025	0.00366	281,170,316	1,029,083	532,390	1.9330

For general service customers without a demand meter, the variable distribution rate ($/kWh) is the distribution energy rate.

General Service Monthly Distribution Service Charge

To determine the monthly distribution service charge the revenue generated from the distribution kW rate is subtracted from the general service revenue requirement (Table 3-5). The remaining amount is divided by the number of general service customers and then by 12 to obtain a per customer monthly service charge.

Table 3-5

GENERAL SERVICE MONTHLY SERVICE CHARGE

	Distribution Revenue	Variable Revenue	Service Charge Revenue	# of Customers	Monthly Service Charge per Customer $
	(a)	(b)	(c) = (a)-(b)	(d)	((c)/(d))/12
Monthly Service Charge	1,851,195	1,029,083	822,112	1975	34.69

General Service Cost of Power Rates

To determine the cost of power demand (kW) and energy (kWh) rates the wholesale volumes are allocated to the general service class using the weightings provided earlier to determine the demand and energy wholesale costs. The demand wholesale cost is then divided by the kW sales to derive a COP $/kW rate. The energy cost is divided by the class's energy sales to derive a COP $/kWh rate. An illustration is presented in Table 3-6.

Table 3-6

GENERAL SERVICE CLASS COST OF POWER RATES

	Winter Peak	Summer Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
	kW	kW	kWh	kwh	kWh	kWh
(a) Volume	256,284	276,106	81,376,477	73,445,326	75,752,381	62,586,400
	$/kW	$/kW	$/kWh	$/kWh	$/kWh	$/kWh
(b) Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023
	(1)	(2)	(3)	(4)	(5)	(6)
	$	$	$	$	$	$
(c) COP=(a)*(b)	3,088,222	2,490,476	4,955,827	2,460,418	3,810,345	1,439,487

(d) Total Demand Cost (1)+(2)	$	5,578,698
(e) Total Energy Cost (3)+(4)+(5)+(6)	$	12,666,078
(f) Total kW Sales	kW	532,390
(g) Total kWh Sales	kWh	281,170,316
(h) COP kW Rate (d)/(f)	$/kW	10.48
(i) COP kWh Rate (e)/(g)	$/kWh	0.0450

Upon retail access, the customers new energy bill will be based on the new settlement system. The DSL charge will be the customer's energy usage times the utility's most recent five-year average annual system loss (adjusted for large use DSL) multiplied by the applicable rate as determined by the new settlements system.

General Service TOU Rates

Given that retail TOU rates are related to wholesale price signals, the general service TOU rates will only apply to the COP.

To determine the TOU demand rates, the demand cost within each of the winter and summer peak periods are divided by the respective demand sales (Table 3-7).

Likewise to derive the TOU energy rates, the energy costs within each of the TOU periods are divided by the respective energy sales (Table 3-7).

Table 3-7

GENERAL SERVICE CLASS TOU RATES

	Winter Peak	Summer Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
	kW	kW	kWh	kwh	kWh	kWh
(a) Sales	256,284	276,106	81,376,477	73,445,326	75,752,381	62,586,400
	$/kW	$/kW	$/kWh	$/kWh	$/kWh	$/kWh
(b) Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023
	(1)	(2)	(3)	(4)	(5)	(6)
	$	$	$	$	$	$
(c) COP=(a)*(b)	3,088,222	2,490,476	4,955,827	2,460,418	3,810,345	1,439,487
(d) kW Sales	256,284	276,106				
(e) kWh Sales			78,048,179	70,441,412	72,654,109	60,026,616
(f) kW Rate (c)/(d)	12.05	9.02				
(g) kWh Rate (c)/(e)			0.0635	0.0349	0.0524	0.0240

4.   STREET LIGHTING RATES

Street Lighting Rate Structure for First Generation PBR Plan

The recommended rate structure for the collection of distribution revenue requirement from street lighting is similar to the general service rate structure with a monthly distribution service charge plus a distribution demand (kW) rate. The distribution kW rate is designed to recover the incremental distribution cost.

Prior to retail access the COP will be recovered through a flat demand rate ($/kW) and a flat energy rate ($/kWh).

Determining the Street Lighting Class Revenue Requirement

The base revenue requirement for the street lighting class is determined by multiplying the most recent calendar year's annual kW amounts by the existing demand rates (Table 4-1).

Table 4-1

STREET LIGHTING REVENUE REQUIREMENT AT EXISTING RATES

	Sales in Block	Block Rate	Revenue Requirement at Existing Rates
	kW	$/Connected kW	$
Winter Demand	3,624	26.22	95,021
Summer Demand	3,624	14.00	50,747
Total			145,768

Determining the Street Lighting Cost of Power

To determine the street lighting COP the same procedure used to determine the residential and general service COP is followed.

To derive the annual COP for the street lighting class the wholesale demand cost as well as the wholesale energy cost attributable to this class need to be determined. Assuming that utilities do not have class coincident demand information and energy consumption by TOU periods, this is derived using the load data research factors provided in Table 2-1 for class coincident demand and Table 2-2 for class energy weightings.

In calculating the street lighting demand coincident with the utility peak the street lighting monthly energy sales are restated in kW by dividing the kWh amount by the product of the coincident factor times the number of hours in a month (730 hours). The kW amounts are then summed for the TOU periods (Table 2-4).

The street lighting wholesale energy cost is determined by taking the street lighting kWh sales and adjusting it for utility system losses (Table 2-5). The DSL to be applied is the most recent 5-year average loss factor. For utilities with large use and/or intermediate use customers, the kWh associated with these classes should be removed in the determination of the DSL.

The energy weighting factors (Table 2-2) are then applied to the wholesale kWh amounts, and these amounts are summed for the TOU periods (Table 2-6).

The kW amounts are multiplied by the appropriate wholesale demand rates to obtain the street lighting demand wholesale cost, and the energy amounts are multiplied by the appropriate

wholesale energy rates to obtain the street lighting energy wholesale cost (Table 4-2). The demand and energy wholesale costs are added to obtain the total general service class COP.

Table 4-2

STREET LIGHTING CLASS COST OF POWER

	Winter Peak	Summer Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Total
	kW	kW	kWh	kwh	kWh	kWh	
(a) Volume	3,569	605	450,965	1,066,939	202,242	894,990	
	$/kW	$/kW	$/kWh	$/kWh	$/kWh	$/kWh	
(b) Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	(1) $	(2) $	(3) $	(4) $	(5) $	(6) $	
(c) COP=(a)*(b)	43,006	5,457	27,464	35,742	10,173	20,585	142,427

Subtracting the class cost of power from the street lighting class revenue requirement provides the base distribution revenue requirement (Table 4-3). At this point, the base distribution revenue requirement can be adjusted to meet the forecast year's street lighting requirement if needed.

Table 4-3
STREET LIGHTING DISTRIBUTION REVENUE REQUIREMENT

	Total Annual Revenue	Cost of Power	Distribution Revenue
	$ (a)	$ (b)	$ (c) = (a) - (b)
Streetlighting	145,768	142,433	3,335

Designing the Street Lighting Rates

In designing the street lighting rates the distribution demand (kW) rate is developed first. The distribution kW rate is intended to cover the street lighting incremental distribution costs (IDC). Once the street lighting distribution kW rate has been derived, a monthly distribution service charge is designed that will generate the remaining distribution revenue requirement.

Street Lighting Distribution Demand (kW) Rate

Because the distribution demand rate is intended to recover the IDC, this amount must first be determined. The incremental distribution cost was determined to be 0.00620/kWh in a 1980's study conducted by Ontario Hydro-MEU. Since it is the only value currently available, it is recommended for use in developing the distribution demand rate.

This value includes system losses. Since system losses are included in the energy charge, this component of the IDC needs to be removed in order to develop distribution rates net of system losses. To do this, the utility's loss factor (adjusted for large use DSL) should be applied to the IDC. This provides a $/kWh IDC rate. However, a $/kW rate is required.

To convert the kWh rate to a kW rate, the adjusted IDC is first multiplied by the utility's kWh for the street lighting class to obtain the IDC revenue requirement. Since street lighting is not metered the assumed hours-use for the TOU periods is used to restate the connected load into kWh (Table 4-4). The IDC revenue requirement is then divided by the kW sales to obtain a kW rate.

Table 4-4

STREET LIGHTING CALCULATED kWh

	Winter Peak	Summer Peak	Total
(a) kW Sales	4,656	1,335	
(b) Hours -Use	126	57	
kWh (a)*(b)	586,656	76,095	662,751

An example of the distribution demand rate derivation is provided in Table 4-5.

Table 4-5

STREETLIGHT DISTRIBUTION DEMAND (kW) RATE

	Incremental Distribution Cost per kWh*	Loss Rate*	Variable Distribution Rate	Retail kWh	Variable Revenue $	Retail kW	Distribution kW Rate $
	(a)*Default Value	(b)*Default Value	(c) = (a)-(b)	(d)	(e) = (c)*(d)	(f)	(g)=(e)/(f)
Distribution kW Rate	0.0062	0.0025	0.00366	662,751	2,426	5,991	0.4049

Street Lighting Monthly Distribution Service Charge

To determine the monthly distribution service charge the revenue generated from the distribution kW rate is subtracted from the street lighting revenue requirement (Table 4-6). The remaining amount is divided by the number of street lighting customers and then by 12 to obtain a per customer monthly service charge.

Table 4-6

STREET LIGHTING MONTHLY SERVICE CHARGE

	Distribution Revenue	Variable Revenue	Service Charge Revenue	# of Customers	Monthly Service Charge per Customer $
	(a)	(b)	(c) = (a)-(b)	(d)	((c)/(d))/12
Monthly Service Charge	3,335	2,426	909	1	75.78

Street Lighting Cost of Power Rates

To determine the cost of power demand (kW) rates the wholesale volumes are allocated to the street lighting class using the weightings provided earlier to determine the demand and energy

wholesale costs. The demand wholesale cost is then divided by the kW sales to derive a COP $/kW rate. The energy cost is divided by the class's energy sales to derive a COP $/kWh rate. An illustration is presented for TOU rates in Table 4-7.

Upon retail access, the customers new energy bill will be based on the new settlement system. The DSL charge will be the customer's energy usage times the utility's five-year average annual DSL multiplied by the appropriate rate as determined by the new settlements system.

5.   LARGE USE RATES

Derivation of Existing Large Use Rates

Large use rates apply to customers with average monthly load in excess of 5,000 kW. The existing rates were derived by first determining the cost of power for the class. The existing large use energy rates for the TOU periods are then set at Ontario   Hydro's direct industrial customer class TOU energy rates. The revenues generated by the winter and summer energy rates are netted from the class's winter and summer cost of power, respectively and the large use demand rates are then developed to generate sufficient revenue to meet the residual cost of power. The demand rates derived based on the cost of power are adjusted for (a) the diversity adjustment and (b) a transformation adjustment.

Table 4-7
STREET LIGHTING COST OF POWER RATES

	Winter Peak	Summer Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
	kW	kW	kWh	kwh	kWh	kWh
(a) Wholesale Volume	3,569	605	450,965	1,066,939	202,242	894,990
	$/kW	$/kW	$/kWh	$/kWh	$/kWh	$/kWh
(b) Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023
	(1)	(2)	(3)	(4)	(5)	(6)
	$	$	$	$	$	$
(c) COP=(a)*(b)	43,006	5,457	27,464	35,742	10,173	20,585
	(1)+(3)+(4)	(2)+((5)+(6)				
(d) Winter/Summer COP	106,213	36,215				
(e) Retail kW	4,656	1,335				
(f) kW Rate (d)/(e)	22.81	27.13				

Ontario Hydro applied direct industrial energy rates to the large use class in an attempt to minimize the difference between the direct industrial and large use rates. The direct industrial

customers are Ontario Hydro's customers with average monthly demand > 5,000 kW. In addition, the diversity adjustment for MEU large use customers was introduced by Ontario Hydro in 1989, to further reduce the differential between utility large use rates and Ontario Hydro direct industrial rates. While referred to as a "diversity" adjustment, the adjustment is not related to peak demand diversity between these customer classes but is an adjustment made to the large use demand rates to minimize the differential between the direct industrial and large use demand rates. The adjustment is credited by Ontario Hydro to the MEU's with large use customers on their wholesale bills while the cost associated with the adjustment is allocated to Ontario Hydro's direct industrial class.

The transformation adjustment recovers the cost of transformation losses estimated to be at 1% of the demand component of the cost of power.

The distribution revenue requirement is generated through a local cost component incorporated into the demand rate through a local cost adjustment. This adjustment adds a percentage of the total large use COP to the demand rate for the recovery of distribution costs and line losses.

Large Use Rate Structure for First Generation PBR Plan

The recommended rate structure for the recovery of large use distribution costs is a monthly service charge plus a distribution kW ($/kW) rate. The distribution demand rate will be based on the system IDC.

The transformation allowance for customers who own their own transformation facilities for service < 115 kV will remain at the current level of $0.60/kW.

Prior to retail access, the COP will be recovered through TOU demand ($/kW) and energy ($/kWh) rates and the diversity adjustment will apply.

Determining the Large Use Class Revenue Requirement

The class revenue requirement at existing rates is determined by multiplying the most recent calendar year annual demand (kW) sales and energy (kWh) sales within each TOU period by the appropriate existing large use rates (Table 5-1).

Table 5-1

LARGE USE REVENUE REQUIREMENT AT EXISTING RATES

	Forecast Sales	Rate	Revenue Requirement at Existing Rates
	kW	$/kW	$
Winter Peak	51,435	18.66	959,777
Summer Peak	51,342	11.31	580,543
	kWh	$/kWh	$
Winter Peak	13,846,203	0.0463	641,079
Winter Off-Peak	13,695,265	0.0342	468,378
Summer Peak	13,731,628	0.0402	552,011
Summer Off-Peak	13,357,675	0.0235	313,905
Total			3,515,694

Determining the Large Use Cost of Power

In determining the large use demand COP the actual coincident demand amounts for the most recent calendar year are used. The large use demands are multiplied by the actual coincident factors to obtain the coincident demands (Table 5-2).

The large use wholesale energy cost is determined by taking the actual large use kWh sales for the most recent calendar year and adjusting it for utility system losses (Table 5-2). The DSL to be applied to the large use kWh is 1%.

The kW amounts are multiplied by the appropriate wholesale demand rates to obtain the large use demand wholesale cost and the energy amounts are multiplied by the appropriate wholesale energy rates to obtain the large use energy wholesale cost (Table 5-2). The demand and energy wholesale costs are added to obtain the total large use class COP.

Table 5-2

LARGE USE CLASS COST OF POWER

	Winter Peak	Summer Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Total
	kW	kW	kWh	kWh	kWh	kWh	
(a) Retail Volume	51,435	51,342	13,846,203	13,695,265	13,731,628	13,357,675	
(b) Coincidence Factor	0.981	0.991					
(c) System Loss Adjust			1.01	1.01	1.01	1.01	
(d) Wholesale Volume	50,458	50,880	13,984,665	13,832,218	13,868,944	13,491,252	
	$/kW	$/kW	$/kWh	$/kWh	$/kWh	$/kWh	
(b) Rates	11.02	7.99	0.0609	0.0335	0.0503	0.023	
	$	$	$	$	$	$	$
(c) COP=(a)*(b)	556,044	406,531	851,666	463,379	697,608	310,299	3,285,527

Subtracting the class cost of power from the large use class revenue requirement (Table 5-3) provides the base distribution revenue requirement. At this point, the base distribution revenue requirement can be adjusted to meet the forecast year's large use revenue requirement if needed.

Table 5-3

LARGE USE DISTRIBUTION REVENUE REQUIREMENT

	Total Annual Revenue	Cost of Power	Distribution Revenue
	$	$	$
	(a)	(b)	(c) = (a) - (b)
Large Use	3,515,694	3,285,527	230,167

Designing the Large Use Rates

In designing the large use rates the distribution demand (kW) rate is developed first. The distribution kW rate is intended to cover the large use IDC. Once the large use distribution kW rate has been derived, a monthly distribution service charge is designed that will generate the remaining distribution revenue requirement.

Large Distribution Demand (kW) Rate

Because the distribution demand rate is intended to recover the IDC, this amount must first be determined. The incremental distribution cost was determined to be 0.00620/kWh in a 1980's study conducted by Ontario Hydro-MEU. This is the only value currently available and is the value recommended for use in developing the distribution demand rate.

The IDC value includes system losses. Since system losses are included in the energy charge, this component of the IDC needs to be removed in order to develop distribution rates net of DSL. To do this, the utility's loss factor should be applied to the IDC. This provides a $/kWh IDC rate. However, a $/kW rate is required.

To convert the kWh rate to a kW rate, the adjusted IDC is first multiplied by the utility's kWh sales for the large use class to obtain the IDC revenue requirement. The IDC revenue requirement is then divided by the large use kW sales to obtain a kW rate.

An example of the distribution demand rate derivation is provided in Table 5-4.

Table 5-4

LARGE USE DISTRIBUTION DEMAND (kW) RATE

	Incremental Distribution Cost per kWh*	Loss Rate*	Variable Distribution Rate	Retail kWh	Variable Revenue $	Retail kW	Distribution kW Rate $
	(a)*Default Value	(b)*Default Value	(c) = (a)-(b)	(d)	(e) = (c)*(d)	(f)	(g)=(e)/(f)
Distribution kW Rate	0.0062	0.0025	0.00366	54,630,771	199,949	102,777	1.95

Large Use Monthly Distribution Service Charge

To determine the monthly large use distribution service charge the revenue generated from the distribution kW rate is subtracted from the large use revenue requirement (Table 5-5). The remaining amount is divided by the number of large use customers and then by 12 to obtain a per customer monthly service charge.

Table 5-5

LARGE USE MONTHLY SERVICE CHARGE

	Distribution Revenue	Variable Revenue	Service Charge Revenue	# of Customers	Monthly Service Charge per Customer $
	(a)	(b)	(c) = (a)-(b)	(d)	((c)/(d))/12
Monthly Service Charge	230,167	199,949	30,218	1	2,518

Large Use Cost of Power Rates

To determine the large use cost of power demand (kW) and energy (kWh) rates the wholesale volumes are allocated to the large use class using the weightings provided earlier to determine the demand and energy wholesale costs. The demand wholesale cost is then divided by the kW sales to derive a COP $/kW rate. The energy cost is divided by the class's energy sales to derive a COP $/kWh rate. An illustration is presented in Table 5-6.

Table 5-6
LARGE USE COST OF POWER RATES

	Winter Peak	Summer Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
	kW	kW	kWh	kwh	kWh	kWh
(a) Wholesale Volume	50,458	50,880	13,984,665	13,832,218	13,868,944	13,491,252
	$/kW	$/kW	$/kWh	$/kWh	$/kWh	$/kWh
(b) Rates	11.02	7.99	0.0609	0.0335	0.0503	0.0235
	$	$	$	$	$	$
(c) COP=(a)*(b)	556,047	406,531	851,666	463,379	697,608	317,044
(d) kW Sales	51,435	51,342				
(e) kWh Sales (adjusted for line losses)			13,846,203	13,695,265	13,731,628	13,357,675
(f) kW Rate (c)/(d)	10.81	7.92				
(g) kWh Rate (c)/(e)			0.0615	0.0338	0.0508	0.0237

While the diversity adjustment is still in effect the demand rates derived in Table 5-6 are subjected to this adjustment. Since the diversity adjustment will only continue to be in effect for a relatively short period, and to simplify the rate setting process, it is recommended that the utilities apply their current diversity adjustment rates. The diversity adjustment rates must be removed when retail access is introduced.

Upon retail access, the customers' new energy bill will be based on the new settlement system. The DSL charge will be the customer's energy usage times 1% multiplied by the weighted average market spot price. The transformation adjustment should be recalculated based on the new demand COP.

6.   Intermediate Use Rates

Derivation of Existing Intermediate Use Rates

The intermediate use customers are a subset of the general service class with an average monthly demand > 3,000 kW and load factors that significantly affect the rates of the remaining general service class customers. These customers are removed from the general service class and have rates fashioned after the large use rate design. The difference from the large use rates is that the energy rates are not set at the direct industrial energy rates and the diversity adjustment does not apply to their demand rates. As such there is no attempt at equalizing the intermediate rates with the direct industrial rates.

Derivation of Unbundled Intermediate Use Rates

For those distributors that currently have intermediate use customers, with the exception of the diversity adjustment, the method described for the large use determination of the distribution revenue requirement and the distribution and COP rates should be used to develop the unbundled rates.

7.   Rental Rates

Some distributors currently have rental programs that are to date, considered to be regulated services within the monopoly business (e.g. water heater, sentinel lights) as per Ontario   Hydro's regulatory oversight. The Board has yet to determine whether these services will be considered to be the distributors' business or a competitive business. If the affiliate code allows the distributors to carry on with this activity, then distribution utilities that currently have water heater and/or sentinel light rental rates must provide justification of the level of the rental rates in the context of overall earnings. The justification must demonstrate that the program revenue, at minimum, covers all costs associated with the program.

Pole rental rates will remain at the existing level.

8.   Load Control Discount

The load control discount currently offered by utilities is based on a utility's wholesale bill savings resulting from load control. The savings are a result of shifting demand off the utility's peak thus reducing the utility's wholesale demand cost.   The distributors load control is generally limited to water heater load control.   Part of the utility's savings resulting from water heater load control is given to the customer participating in the load control program through discount on the water heater rental charge.

Since existing distributors' load control programs are related to the COP rather than demand on the distribution systems, upon retail access, load control discount will no longer apply to the distributors' business.   However, upon retail access a distributor could sell load control service to a customer that has a load control contract with a retailer. In justifying the load control rates the utility would have to demonstrate full cost recovery on the program.

9.   Miscellaneous/Specific Service Charges

Miscellaneous, or, specific service charges are charges for services that are not included in a distributor's standard of service. While all utilities must at minimum include all services related to the distributor's core function in maintaining and operating the distribution system, there are some extra services it may or may not choose to include in its standard of service. Some of the services for which the distributors are currently recovering costs through specific services are arrears certificates, account setup, remote metering, and non-payment of account charges.

The level of these charges will be held at their current levels. If a change in the level of a specific service charge is sought, the distributor will need to provide cost justification for the adjustment.

10.   Rural or Remote Rate Protection

Rural or remote rate protection will be administered according to the regulation made under the Ontario Energy Board Act, 1998.