CHAPTER 4
INITIAL UNBUNDLED RATES - CALCULATIONS

4.1 INTRODUCTION

As discussed in Chapter 3, initial rates are the unbundled rates adjusted for a move towards a MBRR, if the electricity distribution utility chooses to do so. Implementation details on the specific calculation process that has been adopted by the Board to set initial rates are provided in this chapter. An electricity distribution utility may either use the model provided in this chapter or its own load profile and cost allocation data. If an electricity distribution utility is using its own data, justification for the procedures must be included in filing for initial rates.

The following steps are involved in developing initial rates:

- Unbundling of class revenue requirement ("RR") into distribution and COP revenue requirement.
- Designing of two-part distribution rates.
- Rate impact analysis related to change in rate design.
- Adjusting of rates for selected ROE.
- Rate impact analysis related to adjustment of return level.

In this section procedures and guidelines are provided for deriving initial rates going in to first generation PBR. An illustrative example is used in this chapter to demonstrate the procedures.

As a default, in the absence of utility-specific cost allocation information, the initial unbundled rates will be based on the existing rates which were derived using the average Municipal Electrical Utility cost allocation model used by Ontario Hydro in establishing rates. These rates were adopted by the Board in Transitional Rate Orders. Electricity distribution utilities that are setting rates based on their own cost allocation circumstances should provide their cost allocation studies as evidence filed in support of their initial rates.

A RUD Model has been developed to be used by electricity distribution utilities to develop initial rates and is available on the Board's Web site (*www.oeb.gov.on.ca*). Documentation for the Model is provided in Appendix C. The completed Model, both in electronic form and hard copy must be filed as part of the evidence in support of an electricity distribution utility's initial unbundled rates.

As noted earlier, the change in rate structure and the move towards MBRR may result in significant rate impact. The electricity distribution utilities should use the RUD Model in assessing rate impact and in considering rate impact mitigation options.

4.1.1 Distribution Customer Classes

Use of the RUD Model will result in the continuation of the existing distribution customer groups for the first generation PBR plan: residential, sentinel lights, general service (including intermediate use), street lighting and large use. The definitions of these distribution rate groups will remain, where pertinent, as they were described in Ontario Hydro's document, entitled Standard Application of Rates ("SAR"). These definitions are continued in Chapter 9. To mitigate rate impact resulting from the change in rate design, the RUD Model further divides the general service class into three groups: <50 kW, >50 kW, and intermediate use (where appropriate) customers. Therefore rate schedules for initial unbundled rates will incorporate rates for these new groups.

Electricity distribution utilities that have other rate classes that are not included in the RUD Model should use the same approach used in the RUD Model to derive unbundled rates for their customer classes.

4.1.2 COP Rates - Pre-Market Opening

Prior to market opening the COP rates will cover both transmission and electricity commodity costs, since these are both currently included in the wholesale COP rates. The pre-market opening COP rates resulting from the unbundling of existing rates include the following rates:

Residential Non-Time-of-Use
Residential Time-of-Use
Sentinel Lighting Non-Time-of-Use
Sentinel Lighting Time-of-Use
General Service <50 kW Non-Time-of-Use
General Service <50 kW Time-of-Use
General Service >50 kW Non-Time-of-Use
General Service >50 kW Time-of-Use

Intermediate Service
Street Lighting Non-Time-of-Use
Street Lighting Time-of-Use
Large Use

Upon market opening these pre-market opening COP rates will no longer be in effect.

4.1.3 COP Rates - Post-Market Opening

Following market opening, separate transmission and commodity charges will replace the pre-market opening COP rates. Guidance on billing of transmission, commodity, and IMO charges are provided as updates to Chapter 11.

4.2 UNBUNDLING OF CLASS RR

In order to unbundle existing rates into distribution and COP rates a customer class' RR must first be separated into distribution and COP revenue requirements. To ensure revenue neutrality at the class level in unbundling the distribution and COP revenue streams, the class COP is first determined and subtracted from the class RR, with the remaining RR allocated to distribution.

Upon market opening distribution system losses ("DSL") will be collected in accordance with the RSC.

4.2.1 Determination of COP Revenue Requirement

This section describes the procedure for determining COP by customer class.

At the wholesale level, electricity distribution utilities are currently billed on time-of-use ("TOU") rates and demand is billed on the basis of an electricity distribution utility's monthly peak demand. Therefore, in allocating COP to each customer class it is necessary to know the class' monthly demand that is coincident with the utility's monthly peak demand, and the class' energy consumption by TOU period. To accomplish this a load profile model developed by Ontario Hydro and the MEUs in the 1980's is used.

The load profile model's coincident demand factors and energy weighting factors for the various customer classes are provided in Tables 4-1 and 4-2, respectively. The Model provides data for the total general service class and the <50 kW non-TOU customers. The Model does not provide data for the >50 kW non-TOU customers. Therefore, to derive the factors for the >50 kW non-TOU customers, the Model subtracts the calculated data for <50 kW non-TOU and the actual data for >50 kW TOU and intermediate use customers from the total general service values.

The Model is used to determine COP for the residential, sentinel lighting, general service and street lighting classes. Since coincidence factors and TOU sales data are available for intermediate use and large use customers, actual data can be used to determine the COP for these customers.

Table 4-1
Coincident Load (Demand) Factor
Ontario Hydro - MEU Load Data (1980's Data)

Month	**Hours in Month**	**Residential**	**Sentinel Lighting**	**General Service**		**Street Lighting**
				Total	<50 kW	
January	730	68.12%	62.08%	86.54%	92.80%	62.16%
February	730	57.09%	51.93%	78.83%	66.83%	51.99%
March	730	69.26%	51.60%	86.46%	68.89%	51.67%
April	730	71.07%	43.88%	75.73%	66.51%	43.94%
May	730	67.39%	0.00%	77.53%	76.06%	0.00%
June	730	60.76%	0.00%	59.90%	69.11%	0.00%
July	730	68.56%	0.00%	65.68%	56.18%	0.00%
August	730	71.55%	0.00%	63.12%	69.72%	0.00%
September	730	65.54%	0.00%	74.08%	63.38%	0.00%
October	730	66.88%	61.55%	83.20%	65.00%	61.63%
November	730	62.10%	58.74%	82.51%	89.96%	58.82%
December	730	61.67%	63.53%	79.53%	82.67%	63.61%

Table 4-2
Energy (kWh) Weighting
Ontario Hydro – MEU Load Data (1980's Data)

Month	**Residential**			**Sentinel Lighting**			**General Service**						**Street Lighting**		
							Total			**<50 kW**					
	%	%	%	%	%	%	%	%	%	%	%	%	%	%	%
	Peak	**Off-peak**	**Total**	**Peak**	**Off-peak**	**Total**	**Peak**	**Off-peak**	**Total**	**Peak**	**Off-peak**	**Total**	**Peak**	**Off-peak**	**Total**
Jan	5.52	5.53	11.05	3.27	7.23	10.50	4.78	4.60	9.38	5.67	5.59	11.26	3.27	7.23	10.50
Feb	4.85	4.57	9.42	2.62	6.16	8.78	4.47	3.99	8.46	5.14	4.55	9.69	2.62	6.16	8.78
Mar	4.97	4.25	9.22	2.46	6.27	8.73	4.83	3.85	8.68	5.45	4.31	9.75	2.46	6.27	8.73
Apr	3.70	4.36	8.06	1.34	6.08	7.42	3.92	3.82	7.74	3.81	3.67	7.48	1.34	6.08	7.42
May	3.72	3.35	7.07	1.26	5.48	6.74	4.45	3.38	7.83	3.93	3.04	6.98	1.26	5.48	6.74
Jun	4.00	3.12	7.12	1.04	5.00	6.04	4.46	3.23	7.69	4.07	2.92	6.98	1.04	5.00	6.04
Jul	3.94	4.20	8.14	0.98	5.48	6.46	4.14	3.76	7.90	3.42	3.02	6.44	0.98	5.48	6.46
Aug	4.12	3.67	7.79	1.38	5.88	7.26	4.64	3.59	8.23	3.64	2.67	6.33	1.38	5.88	7.26
Sept	3.25	3.46	6.71	1.73	6.30	8.03	4.23	3.57	7.80	3.52	2.86	6.39	1.73	6.30	8.03
Oct	3.52	3.48	7.00	2.51	6.84	9.35	4.36	3.78	8.14	3.84	3.24	7.08	2.51	6.84	9.35
Nov	4.53	3.87	8.40	3.27	6.67	9.94	4.93	3.83	8.76	5.04	3.90	8.94	3.27	6.67	9.94
Dec	4.62	5.40	10.02	3.12	7.63	10.75	4.38	5.01	9.39	5.81	6.87	12.68	3.12	7.63	10.75

The COP for the customer class is derived by calculating wholesale demand and energy volumes that the residential, general service, and street lighting classes are responsible for, according to the load profile model. This provides calculated coincident demand ("kW") and energy ("kWh") volumes to be allocated to the customer class.

Since a load profile model, rather than a utility's specific load profile, is used to determine the COP for each class, the sum of the classes' calculated COP may not add up to the utility's actual COP. To ensure that the electricity distribution utility collects the proper RR to cover its total COP bill, the COP determined for each class needs to be reconciled with the utility's actual total COP (before any diversity adjustment for large use customers). If there is a short-fall or excess, each of the estimated class' COP should be adjusted proportionately to cover the difference. No adjustments are needed for the general service TOU, intermediate use, and large use groups as actual data was used to determine the COP for these groups. In making this adjustment, the difference in the sum of the calculated class COP amounts and the actual electricity distribution utility's total COP is allocated to each rate class proportionately based on the ratio of the class' calculated COP to the calculated total system COP.

For those electricity distribution utilities with local generation, there is an additional step to the COP calculations. First, the cost of local generation is determined. Second, the amount of purchased and locally generated electricity in kWh is used to obtain a weighted average COP. Third, the weighted average COP is used to adjust the purchased COP proportionately across rate classes and TOU periods.

4.3 DETERMINATION OF DISTRIBUTION RR

The distribution RR for a customer class is established as follows:

- The total customer class revenue at existing rates is determined using the 1999 year-end kW and kWh amounts times the appropriate existing approved rates.

- The class' base distribution RR is obtained by subtracting the customer class' COP from the class RR at current rates determined above. This approach ensures class revenue neutrality at existing rates in the unbundling of the distribution and COP revenue streams.

4.4 DEVELOPMENT OF DISTRIBUTION AND COP RATES

The distribution and COP revenue requirements are used in the development of the distribution and pre-market opening COP rates.

4.4.1 Distribution Rate Structure

The new distribution rates for each of the rate classes has a two-part structure consisting of:

- A monthly service charge; and
- A distribution volumetric rate in kWh for customers without a demand meter and kW for customers with a demand meter.

The monthly service charge is designed to recover the distribution fixed costs. The distribution volumetric rate is intended to reflect the difference in system usage by customers within the same customer class and is designed based on the IDC.

The IDC used in the volumetric rate derivation presented in this chapter is $0.0062/kWh (see Section 3.3).

4.4.2 Assessment of Rate Impact Resulting from Change of Rate Design

In moving to a two-part distribution rate structure, small volume customers may see a significant rate impact. The impact increases with the size of the monthly service charge. The rate impact resulting from the change in rate structure should not exceed 10 per cent for the small volume customers in a rate class. In order to assist a utility in assessing rate impact on low volume customers, the RUD Model provides a rate impact analysis for customers at different consumption levels. In mitigating the rate impact, the monthly service charge should be lowered and the volumetric charge raised to a point where the rate impact on the small volume customer groups within a rate class is less than 10 per cent. Class RR neutrality must be maintained in meeting the rate impact mitigation requirement.

4.4.3 COP Rates - Pre-Market Opening

The pre-market opening COP rates are developed by dividing the COP revenue requirement by the retail kWh for the non-demand metered customers (residential class and general service class customers <50 kW) and by the retail kW for the demand metered customers. For customers on TOU rates (e.g. residential TOU, general service TOU, intermediate, street lighting and large use customers) the COP for each time period is divided by the corresponding retail kWh or kW for the time period.

4.5 ADJUSTMENT OF BASE RR FOR MARKET BASED RATE OF RETURN

The base distribution RR derived in 4.2.1.1 is next adjusted for the rate of return level that the electricity distribution utility chooses to earn up to the allowed MBRR, in order to establish its RR for 2000. To accomplish this, the difference in RR between 1999 and 2000 is determined (section 3.4.1.4, formula [3-3]), and the class base distribution RR is proportionately adjusted by this amount.

4.6 RESIDENTIAL RATES

As noted above, the rate structure for the collection of distribution revenue from residential customers for the first generation PBR plan is a monthly service charge plus a volumetric $/kWh distribution rate based on IDC.

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

4.6.1 Determination of Residential Class RR

The residential class RR is based on 1999 year-end residential kWh sales and existing residential rates. It is determined by multiplying the annual energy (kWh) sales within a rate block by the relevant existing energy block rates and summing the products (Table 4-3).

Table 4-3
Residential Class Revenue at Existing Rates

Block	Sales in Block kWh	Block Rate $/kWh	RR at Existing Rates $
First 250 kWh	2,185,549	0.0938	205,005
Additional kWh	129,267,800	0.0808	10,444,838
Total			**10,649,843**

4.6.1.1 Determination of the Pre-Market Opening Residential COP

To derive the annual COP for the residential class, the wholesale demand cost, as well as the wholesale energy cost attributable to this class, is first determined. Assuming that an electricity distribution utility does not have information on class system peak coincident demand and energy consumption by TOU periods, this information is derived using the load data research factors provided in Table 4-1 for class system peak coincident demand, and Table 4-2 for class TOU energy weighting.

In calculating the residential class' demand that is coincident with the electricity distribution utility's system peak, the residential class' 1999 monthly kWh (energy) sales, adjusted for system losses, is first restated in kW (demand) by dividing the kWh amount by the product of the coincident factor (Table 4-1) times the number of hours in a month (e.g. 730 hours). The coincident demand for the TOU periods are then summed (Table 4-4).

Table 4-4
Calculated Wholesale Demand (kW) Quantities

	Residential	**Sentinel Lighting**	**General Service**		**Street Lighting**
Coincident Peak Demand					
			Total	**<50 kW**	
January	30,405	225	54,905	8,764	605
February	30,928	225	54,364	10,473	605
March	24,952	225	50,855	10,223	605
April	21,257	225	51,773	8,123	605
May	19,664	0	51,159	6,629	0
June	21,964	0	65,032	7,295	0
July	22,254	0	60,929	8,280	0
August	20,407	0	66,048	6,558	0
September	19,190	0	53,336	7,282	0
October	19,618	202	49,560	7,868	544
November	25,354	225	53,781	7,178	605
December	30,455	225	59,809	11,079	605
Winter Peak	161,712	1,328	323,273	55,585	3,570
Summer Peak	124,738	225	348,277	44,168	605

The first step in determining the residential wholesale energy cost is to adjust the residential class kWh monthly 1999 sales amount upward for the DSL (Table 4-5).

This adjustment is necessary to account for system losses between the wholesale delivery point and retail delivery point that result in the need to purchase a larger amount of kWh than is sold. The DSL to be applied is the most recent 5-year average loss factor (this is based on going from the retail level to the wholesale level, not wholesale to retail basis).

For utilities with large use customers, the kWh associated with this class should be removed in the determination of the DSL. A default line loss value of 1 per cent is applied to the kWh for large use customers in the absence of utility-specific line losses data. Large use customers generally have little requirement for distribution facilities and their purchases are therefore subject to minimal distribution line losses.

Table 4-5
Calculated Monthly Wholesale Energy (kWh) Quantities

Month	Residential		Sentinel Lighting		General Service				Street Lighting	
					Total		<50 kW			
	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak	Peak	Off-peak
Energy including losses – Wholesale purchase amount										
Jan	7,553,004	7,566,687	31,784	70,275	17,675,834	17,010,217	2,989,728	2,947,544	85,517	189,079
Feb	6,636,245	6,253,121	25,466	59,875	16,529,493	14,754,514	2,710,264	2,399,164	68,518	161,096
Mar	6,800,441	5,815,266	23,911	60,944	17,860,727	14,236,812	2,873,724	2,272,615	64,334	163,973
Apr	5,062,702	5,965,779	13,025	59,097	14,495,663	14,125,875	2,008,970	1,935,150	35,044	159,004
May	5,090,068	4,583,798	12,247	53,265	16,455,536	12,498,811	2,072,245	1,602,958	32,952	143,313
Jun	5,473,192	4,269,089	10,109	48,600	16,492,514	11,944,130	2,146,065	1,539,683	27,198	130,760
Jul	5,391,094	5,746,851	9,526	53,265	15,309,195	13,904,003	1,803,328	1,592,412	25,629	143,313
Aug	5,637,387	5,021,653	13,413	57,153	17,158,131	13,275,365	1,919,331	1,418,407	36,090	153,774
Sept	4,446,968	4,734,311	16,815	61,236	15,642,003	13,201,407	1,856,057	1,508,046	45,243	164,758
Oct	4,816,409	4,761,677	24,397	66,484	16,122,727	13,977,961	2,024,789	1,708,416	65,641	178,880
Nov	6,198,390	5,295,313	31,784	64,832	18,230,515	14,162,854	2,657,536	2,056,426	85,517	174,434
Dec	6,321,536	7,388,809	30,326	74,163	16,196,684	18,526,344	3,063,548	3,622,474	81,594	199,540

The retail kWh amounts adjusted for system losses represent the wholesale kWh amounts (Table 4-5). The energy weighting factors (Table 4-2) are then applied to the wholesale kWh amounts for the time of use period. (Table 4-6).

Table 4-6
Calculated TOU Wholesale Energy (kWh) Quantities

	Residential	**Sentinel Lighting**	**General Service**		**Street Lighting**	**Total**
Energy including system losses – wholesale purchase amounts						
			Total	**<50 kW**		
Winter peak kWh	38,326,024	167,669	102,615,980	16,319,589	451,122	141,560,795
Winter off-peak kWh	37,080,873	396,573	92,668,701	15,006,639	1,067,001	131,213,148
Summer peak kWh	31,101,411	75,135	95,553,042	11,805,996	202,155	126,931,743
Summer off-peak kWh	30,321,482	332,616	78,949,592	9,596,656	894,921	110,498,611
Total	136,829,791	971,992	369,787,315	52,728,881	2,615,199	510,204,297

The residential kW amounts (Table 4-4) are multiplied by the appropriate wholesale demand rates (e.g. power taken at < 115 kV, or at 115 kV) to obtain the residential wholesale demand cost (Table 4- 7) for the non-TOU customers. The residential kWh amounts (Table 4-6) are multiplied by the appropriate wholesale energy rates to obtain the residential wholesale energy cost. The residential demand and energy wholesale costs are then summed to obtain the calculated total residential class COP (Table 4-7).

Table 4-7
Residential Class COP

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak	Total
Purchased at < **115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(a) Volume	129,369	99,790	30,660,820	29,664,699	24,881,129	24,257,185	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(b) Wholesale Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(c) COP=**(a)*(b)**	1,558,899	900,106	1,867,244	993,767	1,251,521	557,915	7,129,452
Purchased at **>115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(d) Volume	32,342	24,948	7,665,205	7,416,175	6,220,282	6,064,296	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(e) Wholesale Rates	11.02	7.99	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(f) COP=**(d)*(e)**	356,412	199,331	466,811	248,442	312,880	139,479	1,723,355
	$	**$**	**$**	**$**	**$**	**$**	**$**
(g) Total Calculated Residential COP=**(c)**+**(f)**	1,915,311	1,099,437	2,334,055	1,242,209	1,564,401	697,394	8,852,807
	$	**$**	**$**	**$**	**$**	**$**	**$**
Reconciled COP	1,863,089	1,069,459	2,270,415	1,208,339	1,521,746	678,379	8,611,427

4.6.1.2 Reconciliation of Actual and Calculated Residential Class COP

To ensure that the electricity distribution utility's actual COP is recovered, the sum of the calculated COP for the customer classes needs to be reconciled with the actual COP. Therefore, in applying this unbundling model, the calculated COP for all classes needs to be derived first and then reconciled with the utility's actual COP before any of the classes' base distribution RR can be determined.

In reconciling the calculated COP with the actual COP, the difference between the sum of the calculated class' COP and the electricity distribution utility's actual total COP for 1999 is determined. This difference is allocated to the individual customer class in proportion to, in the ratio of the class' calculated COP to the calculated total system COP (before any diversity adjustment for large use customers), and the residential class calculated COP is adjusted accordingly (Table 4-7).

4.6.1.3 Determination of Base Residential Distribution RR

The base residential class distribution RR is determined by subtracting the residential COP from the residential class base RR (Table 4-8).

Table 4-8
Residential Distribution RR

	Total Annual Revenue $	COP $	Distribution Revenue $
	(a)	**(b)**	**(c) =(a)-(b)**
Residential	10,649,843	8,611,427	2,038,416

4.6.2 Designing the Residential Rates

In designing the residential rates, the distribution volumetric kWh rate is developed first. The distribution kWh rate is designed to cover the residential IDC. Once the residential distribution kWh rate has been derived, a monthly distribution service charge is designed to generate the remaining residential class distribution RR.

4.6.2.1 Residential Distribution Volumetric kWh Rate

To determine the volumetric kWh revenue, the IDC is multiplied by the residential retail kWh. The distribution volumetric kWh rate is designed to recover the IDC set at $0.0062/kWh.

Table 4-9
Residential Distribution Energy (kWh) Rate

	IDC per $/kWh	**Retail kWh**	**Volumetric Revenue** $
	Default Value **(a)**	**(b)**	**(c) =(a)*(b)**
Distribution kWh Rate	0.0062	131,453,349	815,011

4.6.2.2 Residential Monthly Distribution Service Charge

To determine the residential monthly distribution service charge, the revenue generated through the distribution kWh rate is subtracted from the total residential class RR. The remaining amount is divided by the number of residential customers (1999 year end number of customers) and then by 12 to obtain the per customer residential monthly service charge (Table 4-10).

For customers on TOU cost of power rates that do not own their own meter, and that are currently charged an additional $5.50 for this meter, this charge will need to be continued. Electricity distribution utilities that have their own value for the incremental cost of TOU metering should use their own value and provide justification for the value in their evidence filed in support of initial rates.

Table 4-10
Residential Distribution Monthly Service Charge and COP kWh Rate

	Distribution Revenue **$** **(a)**	**Volumetric Revenue** **$** **(b)**	**Service Charge Revenue** **$** **(c)**	**Number of Customers** **(d)**	**Distribution Service Charge per Month** $/Month/Customer **(e) = [(c)/(d)]/12**
Distribution Monthly Service Charge	2,038,416	815,011	1,223,405	9,115	11.1849
	COP $ **(f)**	**Annual Residential** kWh **(g)**			**COP Rate** $/kWh **(h)= (f)/(g)**
COP kWh Rate	8,611,427	131,453,349			0.0655

4.6.2.3 Residential Non-TOU COP Energy (kWh) Rate

To derive the pre-market opening energy rate, the residential class annual COP is divided by the 1999 annual retail residential energy (kWh) sales (Table 4-10).

Upon market opening, the customer's non-distribution charges will be based on the RSC.

4.6.2.4 Residential TOU COP Energy (kWh) 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 determined. The demand and energy costs for the winter peak and summer peak periods are summed to obtain the total wholesale COP for these two periods. Only energy costs apply to the off-peak periods; therefore, energy costs make up the total COP for the off-peak periods. The total wholesale COP within each of the TOU periods are divided by the respective residential kWh sales to obtain the residential TOU rates (Table 4-11).

Table 4-11
Residential Class TOU Rates

	Winter Peak kW	**Summer Peak kW**	**Winter Peak kWh**	**Winter Off-peak kWh**	**Summer Peak kWh**	**Summer Off-peak kWh**
COP $	1,863,089	1,069,459	2,270,415	1,208,339	1,521,746	678,379
(a) Total COP TOU Period $			4,133,503	1,208,339	2,591,206	678,379
(b) kWh Sales			36,820,083	35,623,858	29,879,346	29,130,062
(c) TOU Rates (a)/(b) $/kWh			0.1123	0.0339	0.0867	0.0233

4.7 SENTINEL LIGHTING

The rate structure for the collection of distribution revenue from sentinel lighting customers for the first generation PBR plan is also a monthly service charge plus a volumetric $/kW distribution rate charge. The monthly service charge and the volumetric distribution rate are determined by splitting the sentinel lighting distribution RR using the ratio of the distribution monthly service charge RR to volumetric charge RR for the residential class.

For the recovery of COP prior to market opening, a flat demand ($/kW) charge is used.

4.7.1 Sentinel Lighting Class RR

The base RR for sentinel lighting is determined by multiplying the 1999 year-end winter and summer kW retail sales by the appropriate existing rates (Table 4-12).

Table 4-12
Sentinel Lighting Revenue (Time of Use) Requirement at Existing Rates

	Sales in Block	Block Rate	RR at Existing Rates
	kW	**$/Connected kW**	**$**
Winter Demand	1,297	29.00	37,613
Summer Demand	1,297	17.60	22,827
Total			**60,440**

4.7.1.1 Pre-Market opening Sentinel Lighting COP

To calculate the sentinel lighting COP the wholesale demand and energy costs associated with this class are determined. Assuming that an electricity distribution utility does not have information on the sentinel lighting class' system peak coincident demand and energy consumption by TOU periods, this information is estimated using the weighting factors provided in Tables 4-1 and 4-2, respectively. The calculated quantities are shown in Tables 4-4 and 4-5.

The calculated coincident demands are then summed for the winter and summer periods and these amounts are multiplied by the appropriate wholesale rates to determine the wholesale demand cost for sentinel lighting (Table 4-13).

Table 4-13
Sentinel lighting Class COP

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak	Total
Purchased at **< 115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(a) Volume	1,063	180	134,135	317,258	60,108	266,093	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(b)Wholesale Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(c) COP=**(a)*(b)**	12,807	1,625	8,169	10,628	3,023	6,120	42,372
Purchased at **> 115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(d) Volume	266	45	33,534	79,315	15,027	66,523	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(e)Wholesale Rates	11.02	7.99	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(f) COP=**(d)*(e)**	2,928	360	2,042	2,657	756	1,530	10,273
	$	**$**	**$**	**$**	**$**	**$**	**$**
(g)Total calculated Sentinel lighting COP=**(c)+(f)**	15,735	1,984	10,211	13,285	3,779	7,650	52,645
Reconciled COP	15,306	1,930	9,933	12,923	3,676	7,442	51,209

Sentinel lighting energy usage is un-metered and to determine the retail kWh for this class, the peak kW amounts are multiplied by the number of hours in a month. The sentinel lighting kWh amounts are then summed for the TOU periods and multiplied by the appropriate wholesale rate (Table 4-13).

The demand and energy costs for the TOU periods are then added to obtain the total sentinel lighting class COP.

4.7.1.2 Reconciliation of Actual and Calculated COP

To ensure that the utility's actual total utility system COP is recovered, the sentinel lighting COP is adjusted for the differential between the actual and calculated utility system COP as described in Section 4.5.1.2 (Table 4-13).

4.7.1.3 Base Sentinel Lighting Distribution RR

The base sentinel lighting distribution RR is derived by subtracting the adjusted class COP from the total class RR (Table 4-14).

Table 4-14
Sentinel Lighting Distribution RR

	Total Annual Revenue $	COP $	Distribution Revenue $
	(a)	(b)	(c) = (a)-(b)
Sentinel Lighting	60,440	51,209	9,231

4.7.2 Designing the Sentinel Lighting Distribution Rates

The distribution volumetric $/kW rate and the monthly service charge for sentinel lighting are determined by applying the residential distribution proportions of monthly service charge and volumetric charge revenues to the distribution revenue requirements for sentinel lighting
(Table 4-15). The volumetric revenue is then divided by the kW sales to determine the distribution rate. The service charge revenue is divided by the number of connections and then by 12 to obtain a per connection monthly service charge (Table 4-16).

Table 4-15
Sentinel Lighting (Time of Use) Distribution Demand (kW) Rate

Volumetric Revenue $	Retail kW	Distribution kW Rate $
(a)	(b)	(c)=(a)/(b)
3,691	2,594	1.4228

Table 4-16
Sentinel Lighting Monthly Service Charge

	Distribution Revenue $	Volumetric Revenue $	Service Charge Revenue $	# of Connections	Monthly Service Charge per Connection $
	(a)	(b)	(c)	(d)	[(c)/(d)]/12
Monthly Service Charge	9,231	3,691	5,540	500	0.9234

4.7.2.1 Sentinel Lighting COP Rates

To determine the COP demand (kW) rates, the wholesale volumes are allocated to the sentinel lighting class using the weights provided earlier to determine the demand and energy wholesale costs. The demand wholesale cost is then divided by the kW sales to derive the COP $/kW rate. An illustration for time of use COP rates is presented in Table 4-17.

Table 4-17
Sentinel Lighting COP Rates

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak
	(1)	(2)	(3)	(4)	(5)	(6)
COP	$ 15,306	$ 1,930	$ 9,933	$ 12,923	$ 3,676	$ 7,442

	(1)+(3)+(4)	(2)+(5)+(6)
(a) Winter/Summer COP $	38,161	13,048
(b) Retail kW	1,297	1,297
(c) kW Rate (a)/(b) $	29.42	10.06

4.8 GENERAL SERVICE RATES

The rate structure for the collection of distribution revenue from general service customers for the first generation PBR plan is also a monthly service charge plus a volumetric $/kWh distribution rate charge for non-demand metered general service customers (<50 kW). For demand-metered general service customers (>50 kW), the rate structure consists of a monthly service charge plus a volumetric $/kW distribution rate. The monthly service charge and the volumetric distribution rate are determined by applying the residential class distribution revenue proportions for these components to the distribution revenue for each general service sub-group.

For the recovery of COP prior to market opening, a flat energy rate ($/kWh) is used for general service customers without demand meters, and a flat demand ($/kW) charge plus a flat energy ($/kWh) charge is used for demand metered general service customers.

Customers who own their own transformation facilities are entitled to a transformation allowance credit. The amount of this credit should be deducted from the bills of customers that own the transformation facilities after the volumetric distribution rate and monthly service charge are determined. The transformation allowance credit for service < 115 kV will remain at the current level of $0.60/kW or at the level that is on the utility's current approved rate schedule if that amount differs from the $0.60/kW.

4.8.1 Determination of the General Service Class RR

The base RR for the general service class is determined by multiplying the 1999 year-end annual energy (kWh) sales for the class by the existing appropriate energy block rates and multiplying the 1999 year-end annual demand (kW) sales by the appropriate demand block rate for each of the following groups of customers: general service < 50 kW (Table 4-18); general service >50 kW non-TOU (Table 4-19); general service >50 kW TOU (Table 4-20); and intermediate use >3,000 kW (Table 4-21).

Table 4-18
General Service RR at Existing Rates
For Non Time of Use < 50 kW

Block	Sales in Block	Block Rate	RR at Existing Rates
Energy	**kWh**	**$/kWh**	**$**
First 250 kWh	1,050,732	0.0834	87,631
Next 12,250 kWh	38,813,155	0.0760	2,949,800
All Additional kWh	10,793,122	0.0650	701,553
Total			**3,738,984**

Table 4-19
General Service RR at Existing Rates
For Non Time of Use > 50 kW

Block	Sales in Block	Block Rate	RR at Existing Rates
Energy	**kWh**	**$/kWh**	**$**
First 250 kWh	5,026,918	0.0834	419,245
Next 12,250 kWh	175,327,710	0.0760	13,324,906
All Additional kWh	50,636,575	0.0650	3,291,377
Demand	**kW**	**$/kW**	**$**
First 50 kW	78,411	0	0
All Additional kW	478,200	6.00	2,869,200
Total			**19,904,728**

Table 4-20 General Service RR at Existing Rates for Time of Use >50 kW			
Block	**Sales in Block**	**Block Rate**	**RR at Existing Rates**
Energy	**kWh**	**$/kWh**	**$**
Winter Peak First Block	2,000	0.1700	340
Winter Peak Next Block	53,000	0.1425	7,553
Winter Peak Next Block	7,699,610	0.1000	769,961
Winter Peak Balance Block	519,490	0.0550	28,572
Winter Off-peak All	9,802,600	0.0500	490,130
Summer Peak First Block	3,000	0.2405	722
Summer Peak Next Block	79,500	0.1550	12,323
Summer Peak Next Block	11,331,150	0.0828	938,219
Summer Peak Balance Block	969,250	0.0502	48,656
Summer Off-peak All	14,069,900	0.0305	429,132
Demand	**kWh**	**$/kWh**	**$**
Winter Peak First 50 kW	50	0	0
Winter Peak Second Block	28,550	0.5700	16,274
Winter Peak Balance Block	0	0.1475	0
Summer Peak First 50 kW	50	0	0
Summer Peak Second Block	41,650	0.0430	1,791
Summer Peak Balance Block	0	0.1070	0
Total			**2,743,671**

Table 4-21
General Service RR at Existing Rates for Intermediate Use

Block	Sales in Block	Block Rate	RR at Existing Rates
Energy	**kWh**	**$/kWh**	**$**
Winter Peak	7,186,230	0.0794	570,587
Winter Off-peak	8,200,430	0.0442	362,459
Summer Peak	6,544,100	0.0963	630,197
Summer Off-peak	7,148,820	0.0253	180,865
Demand	**kW**	**$/kW**	**$**
Winter Peak	23,750	6.25	148,438
Summer Peak	22,050	4.60	101,430
Total			**1,993,975**

4.8.1.1 Determination of the Pre-market Opening General Service COP

To determine the general service class COP, the COP for the following general service customer groups are determined separately: general service <50 kW, general service non-TOU >50 kW, general service TOU >50 kW, intermediate use. Where a utility does not have system peak coincident demand information and energy consumption by TOU periods, this information is derived using the load data research factors provided in Tables 4-1 and 4-2. Where actual data is available, such as for general service TOU and intermediate use customers, the actual load data should be used in the determination of the COP.

For each of the group of general service customers, the demand coincident with the system peak is calculated. In determining this for the non-demand metered general service customers, the monthly energy sales for 1999 are restated in kW by dividing the kWh amount by the product of the coincident factor (Table 4-1) times the number of hours in a month (e.g. 730 hours). The coincident demands are then summed for the winter and summer periods
(Table 4-4).

The wholesale kWh purchase amount for the various general service customer groups is determined by taking the kWh retail sales for each group and adjusting it for utility system losses (Table 4-5). This adjustment is necessary to account for line losses between the wholesale delivery point and retail delivery point that results in the need to purchase a larger amount of kWh than is sold. The DSL to be applied is the most recent 5-year average loss rate. For utilities with large use customers, the kWh sales associated with these customers should be removed in the determination of the DSL since the actual line losses associated with the large use customers or the default line loss rate of 1 per cent will be used for the large use customers. This factor is based on going from the retail level to the wholesale level, rather than wholesale to retail level.

For each of the general service customer groups, the appropriate energy weighting factors (Table 4-2) are applied to the wholesale kWh amounts and the amounts are summed for the TOU periods (Table 4-6).

The coincident kW amounts for each of the general service customer groups are multiplied by the appropriate wholesale demand rates (e.g. power taken at <115 kV, or at 115 kV) to obtain the general service demand wholesale cost. The wholesale kWh amounts are multiplied by the appropriate wholesale energy rates to obtain the general service energy wholesale cost (Tables 4-22 to 4-25). The wholesale demand and energy costs are then summed to obtain the calculated COP for each general service sub-groups.

Table 4-22
General Service Non Time of Use >50 kW

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak	Total
Purchased at **< 115 kV**	**kW**	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(a) Volume	173,066	192,747	56,162,987	47,138,166	51,236,745	37,813,096	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$kWh**	
(b) **Wholesale Rates**	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(c) COP=**(a)*(b)**	2,085,448	1,738,576	3,420,326	1,579,129	2,577,208	869,701	12,270,388
Purchased at **> 115 kV**	**kW**	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(d) Volume	43,267	48,187	14,040,747	11,784,542	12,809,186	9,453,274	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$kWh**	
(e) Wholesale Rates	11.02	7.99	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(f) COP=**(d)*(e)**	476,797	385,012	855,081	394,782	644,302	217,425	2,973,400
	$	$	$	$	$	$	$
(g) Total Calculated General Service Non Time of Use >50 kW COP=**(c)+(f)**	2,562,245	2,123,588	4,275,407	1,973,911	3,221,510	1,087,127	15,243,788
Reconciled COP	2,492,383	2,065,686	4,158,835	1,920,090	3,133,673	1,057,485	14,828,152

Table 4-23
General Service Non Time of Use <50 kW

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak	Total
Purchased at **< 115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(a) Volume	44,468	35,334	13,055,671	12,005,312	9,444,797	7,677,325	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(b) Wholesale Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(c) COP=**(a)*(b)**	535,840	318,714	795,090	402,178	475,073	176,578	2,703,475
Purchased at **> 115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(d) Volume	11,117	8,834	3,263,918	3,001,328	2,361,199	1,919,331	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(e) Wholesale Rates	11.02	7.99	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(f) COP=**(d)*(e)**	122,510	70,580	198,773	100,544	118,768	44,145	655,320
	$	**$**	**$**	**$**	**$**	**$**	**$**
(g) Total Calculated General Service Non Time of Use <50 kW COP=**(c)+(f)**	658,350	389,294	993,863	502,722	593,842	220,723	3,358,794
Reconciled COP	640,399	378,680	966,764	489,015	577,650	214,705	3,627,214

Table 4-24
General Service Time of Use >50 kW

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak	Total
Purchased at **< 115 kV**	**kW**	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(a) Volume	22,445	33,060	6,890,009	8,162,821	10,311,488	11,716,287	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(b) Wholesale Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(c) COP=**(a)*(b)**	270,466	298,199	419,602	273,455	518,668	269,475	2,049,863
Purchased at **> 115 kV**	**kW**	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(d) Volume	5,611	8,265	1,722,502	2,040,705	2,577,872	2,929,072	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(e) Wholesale Rates	11.02	7.99	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(f) COP=**(d)*(e)**	61,837	66,037	104,900	68,364	129,667	67,369	498,173
	$	**$**	**$**	**$**	**$**	**$**	**$**
(g) Total Calculated General Serv-ice Non Time of Use >50 kW COP=**(c)**+**(f)**	332,302	364,236	524,502	341,818	648,335	336,843	2,548,036

Table 4-25
Intermediate Use

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak	Total
Purchased at **< 115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(a) Volume	18,639	17,481	5,984,117	6,828,662	5,449,403	5,952,965	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(b) Wholesale Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(c) COP=**(a)*(b)**	224,600	157,681	364,433	228,760	274,105	136,918	1,386,497
Purchased at **> 115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(d) Volume	4,660	4,370	1,496,029	1,707,166	1,362,351	1,488,241	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(e) Wholesale Rates	11.02	7.99	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(f) COP=**(d)*(e)**	51,350	34,919	91,108	57,190	68,526	34,230	337,323
	$	**$**	**$**	**$**	**$**	**$**	**$**
(g) Total Calculated Intermediate Use COP=**(c)+(f)**	275,950	192,600	455,541	285,950	342,631	171,148	1,723,820

Subtracting each sub-group COP from the associated sub-group RR provides the base distribution RR for each sub-group.

4.8.1.2 Reconciliation of Actual and Calculated General Service COP

To ensure that the utility's actual COP is recovered, the general service sub-group COPs are adjusted for the differential between the actual and calculated COP as described in Section 4.5.1.2.

4.8.1.3 Determination of the Base General Service Distribution RR

The base general service sub-group distribution RR is determined for each sub-group by subtracting the relevant sub-group COP from the sub-group base RR (Tables 4-26 to 4-29).

Table 4-26
General Service Distribution RR For Non Time of Use <50 kW

General Service	Total Annual Revenue $	COP $	Distribution Revenue $
	(a) 3,738,984	**(b)** 3,267,214	**(c) =(a)-(b)** 471,770

Table 4-27
General Service Distribution RR For Non Time of Use >50 kW

General Service	Total Annual Revenue $	COP $	Distribution Revenue $
	(a) 19,904,728	**(b)** 14,828,152	**(c) =(a)-(b)** 5,076,576

Table 4-28
General Service Distribution RR For Time of Use >50 kW

General Service	Total Annual Revenue $	COP $	Distribution Revenue $
	(a) 2,743,671	**(b)** 2,548,036	**(c) =(a)-(b)** 195,635

Table 4-29
General Service Distribution RR For Intermediate Use

General Service	Total Annual Revenue $	COP $	Distribution Revenue $
	(a)	(b)	(c) = (a)-(b)
	1,993,975	1,723,820	270,155

4.8.2 Designing the General Service Rates

The distribution volumetric kWh or kW rate and the monthly service charge for each sub-group are determined by applying the residential distribution proportions of monthly service charge and volumetric charge revenue to the distribution revenue requirements for each general service sub-group. The volumetric revenue is then divided by the kWh or kW sales as appropriate to determine the distribution rate (Tables 4-30 to 4-33). Service charge revenue for each sub-group is divided by the number of customers in that sub-group and then by 12 to obtain a per customer monthly service charge (Tables 4-34 to 4-37).

For a utility that has not included the incremental cost of TOU metering in its TOU rates, and where the customers do not own their own TOU meter, an additional $5.50 is added to the monthly distribution service charge to cover the incremental cost of TOU metering. Utilities that have their own value for the incremental cost of TOU metering should use their own value and provide justification for the value in their evidence filed in support of initial rates.

Table 4-30
General Service Non-Time of Use
<50 kW Distribution Demand (kWh) Rate

Volumetric Revenue $	Retail kWh	Distribution kWh Rate $
(a)	(b)	(c)=(a)/(b)
188,626	50,657,009	0.0037

Table 4-31
General Service Non-Time of Use
>50 kW Distribution Demand (kW) Rate

Volumetric Revenue $	Retail kWh	Distribution kWh Rate $
(a)	(b)	(c)=(a)/(b)
2,029,745	556,611	3.65

Table 4-32 General Service Non-Time of Use >50 kW Distribution Demand (kW) Rate		
Volumetric Revenue $	**Retail kW**	**Distribution kW Rate $**
(a)	**(b)**	**(c)=(a)/(b)**
78,220	70,300	1.11

Table 4-33 Intermediate Use Distribution Demand (kW) Rate		
Volumetric Revenue $	**Retail kW**	**Distribution kW Rate $**
(a)	**(b)**	**(c)=(a)/(b)**
108,015	45,800	2.36

Table 4-34 General Service Monthly Service Charge For <50 kW					
	Distribution Revenue	**Volumetric Revenue**	**Service Charge Revenue**	**# of Customers**	**Monthly Service Charge per Customers $**
	(a)	**(b)**	**(c) = (a)-(b)**	**(d)**	**[(c)/(d)]/12**
Monthly Service Charge	471,770	188,626	283,144	1,744	13.53
COP kWh Rate	**COP** **(f)** 3,267,214	**Annual kWh** **(g)** 50,657,009			**COP Rate $/kWh** **(h)=(f)/(g)** 0.0645

Table 4-35
General Service Monthly Service Charge For Non-Time of Use >50 kW

	Distribution Revenue	Volumetric Revenue	Service Charge Revenue	# of Customers	Monthly Service Charge per Customers $
	(a)	(b)	(c)=(a)-(b)	(d)	[(c)/(d)]/12
Monthly Service Charge	5,076,576	2,029,745	3,046,831	497	510.87

Table 4-36
General Service Monthly Service Charge For Time of Use >50 kW

	Distribution Revenue	Volumetric Revenue	Service Charge Revenue	# of Customers	Monthly Service Charge per Customers $
	(a)	(b)	(c)=(a)-(b)	(d)	[(c)/(d)]/12
Monthly Service Charge	195,635	78,220	117,415	1	9,784.59

Table 4-37
General Service Monthly Service Charge and For Intermediate Use

	Distribution Revenue	Volumetric Revenue	Service Charge Revenue	# of Customers	Monthly Service Charge per Customers $
	(a)	(b)	(c)=(a)-(b)	(d)	[(c)/(d)]/12
Monthly Service Charge	270,155	108,015	162,140	1	13,511.68

To derive the pre-market opening COP energy rate, for general service customers <50 kW the energy COP for this group of customers is divided by the retail kWh sales associated with these customers (Table 4-34).

4.8.2.1 General Service Non-Time of Use >50 kW COP Rates

To determine the pre-market opening COP demand and energy rates for general service >50 kW non-TOU customers the wholesale demand and energy costs are divided by these customers' retail kW and kWh sales, respectively (Table 4-38).

Table 4-38
General Service Class COP Rates For Non-Time of Use >50 kW

	Winter Peak	**Summer Peak**	**Winter Peak**	**Winter Off-peak**	**Summer Peak**	**Summer Off-peak**
	(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**
COP	**$** 2,492,383	**$** 2,065,686	**$** 4,158,835	**$** 1,920,090	**$** 3,133,673	**$** 1,057,485
(a) Total Demand Cost **(1)+(2) $**	4,558,070					
(b) Total Energy Cost **(3)+(4)+(5)+(6)** $	10,270,083					
(c) Total kW Sales	556,611					
(d) Total kWh Sales	230,991,203					
(e) COP kW Rate **(a)/(c) $**	8.18					
(f) COP kWh Rate **(b)/(d)** $	0.0445					

4.8.2.2 General Service > 50 kWh TOU COP Rates

Given that retail TOU rates are related to the wholesale price signal, TOU rates only apply to the COP and not to distribution.

To determine the TOU cost of power demand rates, the demand cost within each of the winter and summer peak periods for these customers are divided by their respective kW demand sales (Table 4-39). Likewise, to derive the TOU cost of power energy rates, the energy costs associated with these customers within each TOU are divided by the respective energy sales.

Table 4-39
General Service Class >50 kW TOU Rates

	Winter Peak	**Summer Peak**	**Winter Peak**	**Winter Off-peak**	**Summer Peak**	**Summer Off-peak**
(a) COP $	332,302	364,236	524,502	341,818	648,335	336,843
(b) kW Sales	28,600	41,700				
(c) kWh Sales			8,274,100	9,802,600	12,382,900	14,069,900
(d) kW Rate **(a)/(b)** $	11.62	8.73				
(e) kWh Rate **(a)/(c)** $			0.0634	0.0349	0.0524	0.0239

4.9 INTERMEDIATE USE COP RATES

To determine the intermediate use COP demand rates, the demand cost within each of the winter and summer peak periods for the intermediate use customers are divided by their respective kW demand sales (Table 4-40). Likewise, to derive the intermediate use COP energy rates, the energy costs associated with these customers within each TOU period are divided by the respective energy sales.

Table 4-40
General Service Class TOU Rates For Intermediate Use

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak
(a) COP $	275,950	192,600	455,541	285,950	342,631	171,148
(b) kW Sales	23,750	22,050				
(c) kWh Sales			7,186,230	8,200,430	6,544,100	7,148,820
(d) kW Rate **(a)/(b)** $	11.62	8.73				
(e) kWh Rate **(a)/(c)** $			0.0634	0.0349	0.0524	0.0239

4.10 STREET LIGHTING RATES

The rate structure for the collection of the distribution RR from street lighting customers is similar to the rate structure for demand metered general service customers, with a monthly distribution service charge plus a distribution volumetric kW rate.

Prior to market opening, the COP will be recovered through a flat demand rate ($/kW).

4.10.1 Street Lighting Class RR

The base RR for the street lighting class is determined by multiplying the 1999 year winter and summer kW retail sales by the appropriate existing rates (Table 4-41).

Table 4-41
Street Lighting Revenue (Time of Use) Requirement at Existing Rates

	Sales in Block	Block Rate	RR at Existing Rates
	kW	**$/Connected kW**	**$**
Winter Demand	3624	26.22	95,021
Summer Demand	3,624	16.00	57,984
Total			**153,005**

4.10.1.1 Pre-Market Opening Street Lighting COP

To calculate the street lighting COP the wholesale demand and energy costs associated with this class are determined. Assuming that a utility does not have the street lighting class' system peak coincident demand information and energy consumption by TOU periods, this information is determined by using the weighting factors provided in Tables 4-1 and 4-2 respectively.

The calculated coincident demands are then summed for the winter and summer periods and these amounts are multiplied by the appropriate wholesale rates to determine the wholesale demand cost for street lighting (Table 4-42).

Table 4-42
Street Lighting Class COP

	Winter Peak	**Summer Peak**	**Winter Peak**	**Winter Off-peak**	**Summer Peak**	**Summer Off-peak**	**Total**
Purchased at **< 115 kV**	**kW**	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(a) Volume	2,856	484	360,897	853,601	161,724	715,937	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(b) wholesale Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(c) COP=**(a)*(b)**	34,413	4,365	21,979	28,596	8,135	16,467	113,953
Purchased at **> 115 kV**	**kW**	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(d) Volume	714	121	90,224	213,400	40,431	178,984	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(e) Wholesale Rates	11.02	7.99	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(f) COP=(d)*(e)	7,868	967	5,495	7,149	2,034	4,117	27,629
	$	**$**	**$**	**$**	**$**	**$**	**$**
(g) Total Calculated Street Lighting COP=**(c)+(f)**	42,280	5,332	27,473	35,745	10,168	20,583	141,582
Reconciled COP	41,127	5,187	26,724	34,770	9,891	20,022	137,721

The demand and energy costs for the TOU periods are then added to obtain the total street lighting class COP.

4.10.1.2 Reconciliation of Actual and Calculated COP

To ensure that the utility's actual total utility system COP is recovered, the street lighting COP is adjusted for the differential between the actual and calculated utility system COP as described in Section 4.5.1.2.

4.10.1.3 Base Street Lighting Distribution RR

The base street lighting distribution RR is derived by subtracting the adjusted class COP from the total class RR (Table 4-43).

Table 4-43
Street Lighting Distribution RR

	Total Annual Revenue $	COP $	Distribution Revenue $
	(a)	(b)	(c) =(a)-(b)
Street Lighting	153,005	137,721	15,284

4.10.2 Designing the Street Lighting Distribution Rates

The distribution volumetric kW rate and the monthly service charge for street lighting are determined by applying the residential distribution proportions of monthly service charge to volumetric charge revenue to the distribution revenue requirement for street lighting (Table 4-44). The volumetric revenue is then divided by the kW sales to determine the distribution rate. The service charge revenue is divided by the number of connections and then by 12 to obtain a per connection monthly service charge (Table 4-45).

Table 4-44
Street Lighting (Time 0f Use) Distribution Demand (kW) Rate

Volumetric Revenue $	Retail kW	Distribution kW Rate $
(a)	(b)	(c)=(a)/(b)
6,111	7,248	0.8431

Table 4-45
Street Lighting Monthly Service Charge

	Distribution Revenue	Variable Revenue	Service Charge Revenue	# of Connections	Monthly Service Charge per Connection $
	(a)	(b)	(c)	(d)	[(c)/(d)]/12
Monthly Service Charge	15,284	6,111	9,173	5,000	0.1529

4.10.3 Street Lighting COP Rates

To determine the COP demand (kW) rates, the wholesale volumes are allocated to the street lighting class using the weights provided earlier to determine the demand and energy wholesale costs. The demand wholesale cost is then divided by the kW sales to derive the COP $/kW rate. An illustration for TOU rates is presented in Table 4-46.

Table 4-46
Street Lighting COP Rates

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak
	(1)	**(2)**	**(3)**	**(4)**	**(5)**	**(6)**
COP $	41,127	5,187	26,724	34,770	9,891	20,022
	(1)+(3)+(4)			**(2)+(5)+(6)**		
(a) Winter/Summer COP $	102,622			35,100		
(b) Retail kW	3,624			3,624		
(c) kW Rate (a)/(b) $	28.32			9.69		

4.11 LARGE USE RATES

The rate structure for the collection of distribution revenue from large use customers for the first generation PBR plan is a monthly service charge plus a volumetric kW distribution rate.

Customers who own their own transformation facilities are entitled to a transformation allowance credit. The amount of this credit should be deducted from the bills of customers that own the transformation facilities, after the volumetric distribution rate and monthly service charge are determined. The transformation allowance credit for service <115 kV will remain at the current level of $0.60/kW or at a level that is on the utility's current approved rate schedule if that amount differs from the $0.60/kW.

For the recovery of COP prior to market opening, a flat demand ($/kW) and a flat energy ($/kWh) charge is used.

4.11.1 Large Use Class RR

The large use class RR is based on 1999 year-end large use kW and kWh sales and existing large use rates. It is determined by multiplying the annual kW and kWh sales within each TOU period by the applicable rates and then totalling the individual amounts (Table 4-47).

Table 4-47 Large Use RR at Existing Rates			
	Sales in Block	**Rate**	**RR at Existing Rates**
	kW	**$/kW**	**$**
Winter Peak	51,435	17.74	912,457
Summer Peak	51,342	13.00	667,446
	kWh	**$/kW**	**$**
Winter Peak	12,337,530	0.0543	669,928
Winter Off-peak	12,203,038	0.0432	527,171
Summer Peak	12,235,439	0.0452	553,042
Summer Off-peak	11,902,231	0.0335	398,725
Total			**3,728,769**

4.11.1.1 Large Use Class COP

In determining the large use demand COP the actual coincident demand amounts for year-end 1999 are used. The large use demands are multiplied by the actual large use class coincident factors to obtain the coincident demands (Table 4-48).

Table 4-48
Large Use Class COP

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak	Total
Purchased at **< 115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(a) Volume	0	0	0	0	0	0	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(b) Rates	12.05	9.02	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(c) COP=**(a)*(b)**	0	0	0	0	0	0	
Purchased at **> 115 kV**							
	kW	**kW**	**kWh**	**kWh**	**kWh**	**kWh**	
(d) Volume	50,458	50,880	12,460,905	12,325,068	12,357,793	12,021,253	
	$/kW	**$/kW**	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**	
(e) Wholesale Rates	11.02	7.99	0.0609	0.0335	0.0503	0.023	
	$	**$**	**$**	**$**	**$**	**$**	**$**
(f) COP=**(d)*(e)**	556,044	406,531	758,869	412,890	621,597	276,489	3,032,420
(g) Total COP =(c)+(f)							3,032,420

In the illustration presented in Table 4-48, the large use customer class only takes power at >115 kW.

The large use wholesale energy cost is determined by taking the actual large use kWh sales for year-end 1999 and adjusting for utility system losses. In the absence of electricity distribution utility specific loss data the default DSL to be used for the large use class is 1 per cent.

The kW amounts are multiplied by the appropriate wholesale demand rates to obtain the large use wholesale demand cost and the energy amounts are multiplied by the appropriate wholesale energy rates to obtain the large use wholesale energy cost (Table 4-48). The demand and energy wholesale costs are added to obtain the total large use class COP.

No adjustment to the COP for the reconciliation of actual to estimated utility COP is required because actual rather than estimated data are used in the determination of the large use COP.

4.11.1.2 Large Use Base Distribution RR

Subtracting the large use COP from the class RR provides the base distribution RR (Table 4-49).

Table 4-49
Large Use Distribution RR

Large Use	Total Annual Revenue $	COP $	Distribution Revenue $
	(a)	**(b)**	**(c) =(a)-(b)**
	3,728,769	3,032,420	696,349

4.11.2 Designing the Large Use Distribution Rates

The distribution volumetric kW rate and the monthly service charge for large use customers are determined by applying the residential distribution proportions of monthly service charge to volumetric charge revenue to the distribution revenue requirements for large use customers. The volumetric revenue is then divided by the kW sales to determine the distribution volumetric rate (Table 4-50). The monthly service charge revenue is divided by the number of customers and then by 12 to obtain a per customer monthly service charge (Table 4-51).

Table 4-50
Large Use Distribution Demand (kW) Rate

Volumetric Revenue $	Retail kW	Distribution kW Rate $
(a)	**(b)**	**(c)=(a)/(b)**
278,418	102,777	2.70

Table 4-51
Large Use Monthly Service Charge

	Distribution Revenue $	Volumetric Revenue $	Service Charge Revenue $	# of Customers	Monthly Service Charge per Customers $
	(a)	(b)	(c)=(a)-(b)	(d)	[(c)/(d)]/12
Monthly Service Charge	696,349	278,418	417,931	1	34,827.57

4.11.2.1 Large Use COP Rates

To determine the pre-market opening large use COP demand (kW) and energy (kWh) rates, the wholesale demand and energy costs are divided by the year-end large use retail kW and kWh amounts for each TOU period (Table 4-52).

Table 4-52
Large Use COP Rates

	Winter Peak	Summer Peak	Winter Peak	Winter Off-peak	Summer Peak	Summer Off-peak
(a) COP $	556,044	406,531	758,869	412,890	621,597	276,489
(b) kW Sales $	51,435	51,342				
(c) kWh Sales (adjusted for line losses) $			12,337,530	12,203,038	12,235,439	11,902,231
(d) kW Rate (a)/(b) $	10.81	7.92				
(e) kWh Rate (a)/(c) $			0.0615	0.0338	0.0508	0.0232

4.11.2.2 Diversity Adjustment

While the diversity adjustment is still in effect, it should be included on the rate schedule as a separate line item. Since the diversity adjustment will only continue to stay in effect for a relatively short period, and to simplify the rate setting process, electricity distribution utilities will continue with their current approved diversity adjustment rates until market opening. The diversity adjustment credit rates must be removed when the market opens.

4.12 RATE IMPACT ANALYSIS

A change in rate design generally results in rate impacts within a class. To assess the impact of rate unbundling and the move from the existing declining block rate structure to a distribution monthly service charge and distribution volumetric rate, and a COP volumetric rate, rate impact analysis should be conducted.

In carrying out rate impact analysis for each customer class, the existing bill amounts are compared to the new bill amounts at various levels of consumption. The rate impact analyses are included in the RUD model and should be filed as evidence in support of the electricity distribution utility’s initial rates.

Where the total impact is significant (limit of total bill impact of 10 per cent), a utility will need to explore rate impact mitigation options. From the electricity distribution utility’s perspective, the application of rate mitigation options is limited to the distribution rates. In moving to a service charge and volumetric rate the highest bill increases are generally experienced by the group of low-use consumers. The degree of impact is related to the level of the monthly service charge and a higher impact is experienced as the monthly service charge increases. Therefore rate impact should be mitigated by lowering the level of the monthly service charge and setting the volumetric charge to pickup the class revenue shortfall.

In addressing the rate impact mitigation related to change in rate structure, the class must be held revenue neutral at the 1999 revenue level. If the electricity distribution utility cannot limit the impact to 10 per cent for low-end users, it must highlight this in its evidence provided to the Board.

4.13 MARKET-BASED RATE OF RETURN

As noted earlier, electricity distribution utilities have the option of earning a rate of return on common equity (ROE) up to the Board allowed ROE ceiling. The ROE ceiling for 2000 is 9.88 per cent (see Chapter 3). If the electricity distribution utility chooses to change its 2000 return level from the 1999 level, an adjustment will be required to its RR to accommodate the change in ROE. The RUD model is used to make this adjustment.

In making this adjustment the following steps are taken:

1. Determination of return at utility's selected ROE level for 2000.

2. Determination of difference between utility's 1999 return (use actual 1999 return) and 2000 return (1).

3. Allocation of the difference in 1999 and 2000 returns (2) to the customer classes relative to the proportion of the class' RR to total utility RR.

4. Proportional allocation of class RR between the service charge and volumetric rate RR's.

5. Adjustment of service charge and volumetric rates based on RR for 2000.

To determine the electricity distribution utility's return at the selected ROE level, the MBRR formula presented in Chapter 3 is used. The details provided in Appendix D should be used in determining the distribution wires-only rate base for 2000.

The mitigation option provided by the Board is the use of a deferral account to spread an increase over future years. As an example if a utility's desired increase in return is $600,000 it could adjust initial rates by $300,000 and place the remaining amount in a deferral account. In year 2, rates would be adjusted for the deferred amount. The use of a deferral account to address rate impact must be highlighted in the evidence filed in support of initial rates.