<u>Order 116/08 Directive 19 Revisions to PCOSS08</u>

The attached Electric Cost of Service schedules are filed to comply with Directive 19 in PUB Order 116/08 requiring Manitoba Hydro to re-file the results of the 2007/08 Prospective Cost of Service Study ("PCOSS08") with modifications as directed in that Order. Order 116/08 was issued subsequent to PUB Order 90/08 which dealt with Manitoba Hydro's 2008/09 General Rate Application. Order 116/08 provided further direction on a number significant matters including directing Manitoba Hydro to make some specific modifications to the Corporation's Cost of Service Study ("COSS") that had been filed as part of the 2008/09 GRA as compliant with earlier Cost of Service Order 117/06. Directed modifications are discussed below.

a) Manitoba Hydro was directed to re-file the study using the methodology as defined by Order 117/06 (Directive 19(a)).

Manitoba Hydro has revised PCOSS08 to reflect the intention of the PUB as clarified in Order 116/08. Differences from the methodology used by Manitoba Hydro in preparing PCOSS08 as per order 117/06 and PCOSS08 as revised pursuant to the clarifications issued in Order 116/08 are discussed in the remainder of the document.

b) The PCOSS should incorporate diesel and exports in the same fashion as other domestic customer classes (Directive 19(b)).

As directed the Export and Diesel classes have been incorporated, and disclosed, in the study in the same fashion as other customer classes as shown in Schedules 5 and 6.

c) Fifty percent of fixed and 100% variable thermal plant costs are to be directly assigned to the Export class. (Directive 19(c)).

In Order 117/06 Manitoba Hydro was directed to allocate costs to the export customer class in a manner that reflected cost causation, and in particular, costs assigned to the Export class were to include thermal plant costs.

In PCOSS08 filed to support the 2008/09 GRA, Manitoba Hydro assigned the thermal fuel costs to the export customers, while the remaining operating and maintenance, interest and depreciation expense were allocated as part of the generation pool. Manitoba Hydro believed this treatment was the closest cost-causal interpretation consistent with the directive. MIPUG provided support for Manitoba Hydro's interpretation and agreed that the treatment did not appear unreasonable.

In Order 116/08 the Board stated that while it understood the rationale that "thermal plants provide dispatchable energy, increase dependable energy for export, and enhance the reliability of domestic energy and, as such, all non-variable costs should be shared by both domestic and export classes", the approach "would reject the principles of cost causation and would be avoiding a proper allocation of costs" (Order 116/08, pp 270). The Directive from

Order 117/06 was modified in 116/08 to assign all fuel costs and 50% of the fixed costs to the Export class.

Manitoba Hydro continues to believe that it is inconsistent with cost causation, and therefore inappropriate to directly assign fixed thermal plant costs to the Export class, or to assign any fixed cost at all to opportunity export sales. However, as directed, 100% of the fuel costs of $23.2 million have been directly assigned to the Export class in the revised study. The remaining fixed operating and maintenance costs ($20.5M), interest ($20.3M) and depreciation ($17.5) are split evenly between exports and the generation pool. The $52.4 million in thermal plant fixed and variable costs assigned to exports implies a cost of 8.92¢/kWh for the 587 GW.h of thermal energy forecast in PCOSS08. The remaining costs are assigned to the generation pool for allocation to the domestic and Export classes, with the export share reduced for sales deemed served by thermal generation and power purchases.

d) Assign DSM cost directly to export class and add DSM energy savings to domestic load for Generation cost-sharing purposes (Directive 19(d)).

Order 117/06 directed Manitoba Hydro to directly assign the cost of domestic DSM to export customers, but did not provide a specific treatment for DSM energy. In PCOSS08 Manitoba Hydro interpreted the directive to mean that the associated DSM energy savings should also be assumed to serve the export market. The PUB clarified their intent in 116/08, and stated that while the costs of DSM are to be directly assigned to the export class, exports should not to be deemed to receive the benefit from the associated energy savings.

As directed Manitoba Hydro has assigned the costs of domestic DSM programs to the Export class, and added the DSM energy and capacity savings into the domestic load in this revised PCOSS. No reduction was made to the Export class energy or demand for cumulative DSM savings.

Energy savings from DSM programs are included in the PCOSS in two ways. Energy savings from programs undertaken in the past are implicitly and inextricably included in the forecast energy consumption for the class. Additional energy savings from new DSM planned for the two forecast years included in the PCOSS are then explicitly assigned to reduce forecast consumption for each class. This treatment of the DSM energy savings is consistent with PCOSS prepared prior to the issuance of 117/06.

In this revision to PCOSS08, once forecast class loads (including savings from DSM undertaken in the two forecast years) are calculated, the forecast cumulative DSM savings of 1,350 GW.h (actual to 2005/06 plus forecast for 2006/07 and 2007/08) are added back to the domestic classes in accordance with Directive 19(d). The determination of class energy including cumulative DSM is illustrated in Schedule 1. The DSM savings are assumed to have the same distribution between the twelve time periods as the forecast class energy when determining the weighted energy allocator for Generation cost-sharing purposes. The determination of marginal cost weighted class energy including cumulative DSM is illustrated in Schedule 2.

While forecast DSM savings are allocated to individual classes for rate design and use in the PCOSS, the DSM cumulative savings have only been tracked on an aggregate basis by sector, and are not available broken down by customer class. The sector aggregations can be directly matched to a specific class in the case of Residential programs, but in the cases of Industrial and Commercial programs participants belong to multiple classes. To estimate the savings on a class level, cumulative DSM savings aggregated by sector have been split using the forecast for DSM as used in the PCOSS (See Table 1). For example, if General Service Medium class was expected to provide 36% of the forecast savings from the Commercial DSM programs, then 36% of the 539 GW.h savings projected from Commercial programs to the end of 2007/08 would be added to the GSM load.

The class share of forecast sector savings from a sample of past studies (PCOSS from 1995, 1999, 2004 and 2008) has been averaged to recognize the evolution in the Power Smart programs as technologies change, existing opportunities are exhausted and new ones identified. Table 2 shows the average class share of forecast savings for the Commercial and Industrial sector programs in the sampled studies. As a PCOSS is not prepared each year, and due to the considerable effort required to produce the data, a complete analysis incorporating all years is neither practical nor even possible.

Unlike other classes that benefit from ongoing DSM programs, the Streetlighting and Sentinel conversion was completed in a single program spanning several years in the early 1990's and accordingly are not represented in Power Smart program forecasts since that time. The programs were significant, but would not be recognized in the revised PCOSS without a specific adjustment to the methodology used to estimate class share of DSM savings. A post-conversion review of the Streetlighting and Sentinel programs identified the savings realized from the conversion. As these savings are directly attributable to the lighting class, they are removed from the Commercial sector savings before allocating the remaining savings between classes.

While Manitoba Hydro believes this method of estimating class share of DSM savings is the most reasonable given the lack of historical data at the detailed level, it should be stressed that these results may vary considerably from actual class-by-class savings had they been tracked in that manner since the Power Smart program's inception.

Table 1 – Cumulative DSM Energy Savings Forecast to 2007/08 (GW.h @ Generation)

Sector	**Program Savings by Sector**	**Codes & Standards Savings Attributed to Sectors**	**Total Savings by Sector**
Residential (including Customer Service Initiatives)	113.0	279.9	392.9
Industrial	349.0	27.5	376.6
Commercial (less A&R Lighting)	386.5	151.4	538.0
A&R Lighting	42.6	-	42.6
Total Energy Savings	891.1	458.9	1,350.0

Table 2 – Average Class Share of Forecast Sector Savings in PCOSS

Sector	Res	A&R Lighting	GSS ND	GSS Demand	GSM	GSL 0-30	GSL 30-100	GSL >100	Total
Industrial	0.0%	0.0%	2.5%	2.5%	17.3%	17.7%	6.3%	53.8%	100%
Commercial	0.5%	0.0%	25.8%	27.4%	36.0%	8.4%	1.1%	0.7%	100%

Table 3 – Sector Energy Savings Assigned to Classes (GW.h @ Gen)

Sector	Res	A&R Lighting	GSS ND	GSS Demand	GSM	GSL 0-30	GSL 30-100	GSL >100	Total
Residential	392.9								392.9
Industrial	-		9.4	9.4	65.0	66.7	23.5	202.5	376.6
Commercial	2.9		138.6	147.4	193.9	45.4	6.1	3.6	538.0
A&R Lighting		42.6							42.6
Total Savings	395.8	42.6	148.0	156.8	258.9	112.1	29.6	206.1	1,350.0

Both Coincident Peak (CP) and class Non-Coincident Peak (NCP) demand allocators for Transmission, Subtransmission and Distribution incorporate the cumulative DSM capacity savings into the forecast class demand in a similar manner. Cumulative winter and summer demand savings by sector, excluding rate programs, have been broken down to the class level on the same basis as energy savings and added to the forecast seasonal demands used to calculate the seasonal demand (2 CP) allocator for Transmission. The determination of the seasonal demand allocator is illustrated in Schedule 3. Cumulative savings forecast to 2007/08 are 294.5 MW at Generation at winter peak, and 249.5 MW at summer peak, excluding rate programs

Demand for curtailable customers was calculated in previous PCOSS as if the customers were not curtailed at the time of the system peak. There were no curtailments in the top fifty hours, summer or winter, in the 2005/06 Load Research results used in PCOSS08 so the adjustment did not change calculated demand in the study. This adjustment to customer demand allocators, and the possible resulting increase in demand allocated costs, was offset in prior studies by crediting the affected classes with a cost reduction equal to the value of the curtailable load. However, as the demand allocators for all customer classes have now been increased by the amount of their cumulative DSM demand savings, this trade-off for the curtailable incentive is no longer applicable. As such, there is no assignment of a curtailable credit to the curtailable classes in this revised version.

The increase in class Non-Coincident Peak is estimated using the increase in winter CP and the class diversity factor, and results in an increase to total NCP load of 340.6 MW at Generation. The determination of the NCP demand allocator is illustrated in Schedule 1.

Manitoba Hydro is of the view that the treatment of DSM savings and costs, as described above, is unnecessarily cumbersome, requires significant analytical effort, provides only a rough allocation of DSM energy and demand to classes, and does not improve the results of the PCOSS. Manitoba Hydro recommends that DSM be incorporated into the PCOSS by allocating ongoing costs and benefits both to the domestic classes.

e) Use the most recent actual [not forecast] export prices to establish export revenue in the COSS (Directive 19(e)).

The 7,707 GWh of forecast export sales in PCOSS08 had an average price 6.362¢/kWh, while the actual average price for Market and Bilateral sales in 2005/06 (the most recent actual year at the time PCOSS08 was prepared) was 5.194¢/kWh. The actual average sales price has been adjusted for forecast CPI in 2006/07 and 2007/08 (2.0% per year) to calculate the inflation adjusted price used in the PCOSS of 5.404¢/kWh. For comparison purposes the actual average price received for export sales for the first three quarters of 2007/08 was 4.942¢/kWh.

Export revenue in the study also included $42.5 million in Merchant or Off System sales that are made only when there are arbitrage opportunities to allow such sales to be made profitably. These price-sensitive sales are directly linked to an offsetting import purchase, the cost of which ($35.2 million) is directly assigned to the export class as part of power purchases. There is no energy associated with these transactions in the PCOSS.

As a proxy for restating using actual export prices, total merchant sales revenue has been adjusted while purchases are held constant, to yield the same ratio of sales to purchases as realized in 2005/06. In 2005/06 the ratio of actual sales revenue to purchases was 114.4% for these transactions, compared to the 120.8% forecast for 2007/08.

<u>Table 4 – Calculation of Revised System Merchant Sales Revenue</u>

2005/06 System Merchant Sales ($/MWh)	68.49
2005/06 System Merchant Purchase ($/MWh)	59.87
Ratio of Sales:Purchase	114.4%
Forecast System Merchant Purchases in PCOSS08 (000$)	35,213
Adjusted System Merchant Sales in PCOSS08 (000$)	40,283

Export revenue includes items such as MISO Transmission Credits and other export related revenues that are not related to energy sales. These items have not been adjusted in the revised PCOSS. Revised export revenue of $475.4 million is $76 million less than in the prior version of PCOSS08.

Table 5 – Calculation of Revised Export Revenue

	(000 $)
Export Sales at Forecast Price (7,707 GW.h @ 6.362¢/kWh)	490,314
Adjust Export Sales to use Actual Price (5.404¢/kWh vs 6.362¢/kWh)	(73,840)
Merchant Sales at Forecast Price	42,538
Adjust Merchant Sales to 114.4% of Forecast Merchant Purchases	(2,255)
Miscellaneous Revenue	18,662
Revised Export Revenue	475,419

Adjusting the revenue side of the transaction requires a corresponding adjustment to the cost of the supply that is subject to many of the same market forces and conditions. The 2,028 GW.h in forecast Power Purchases included in the PCOSS have been restated to use the CPI adjusted actual price of purchased power for 2005/06 of 3.939¢/kWh, resulting in the power purchase costs directly assigned to the Export class increasing by $5.8 million. Power Purchases also include Merchant Purchases, PSO Transmission Charges and Financial Transmission Rights. These items have not been adjusted in the revised PCOSS.

Table 6 – Calculation of Revised Power Purchases

	(000 $)
Power Purchases at Forecast Price (2,028 GW.h @ 3.652¢/kWh)	74,065
Adjust Power Purchases to use Actual Price (3.939¢/kWh vs. 3.652¢/kWh)	5,817
Merchant Purchases at Forecast Price	35,213
PSO Transmission and FTR Charges	25,181
Revised Power Purchases	140,276

The net change in Manitoba Hydro revenue due to the $76.1 million reduction in export revenue and $5.8 million increase in Purchased Power costs is matched on the cost side by making a $81.9 million reduction in Contribution to Reserves (a component of Interest costs included in the PCOSS) so costs continue to equal revenue in the study.

The intervenor, COALITION, has raised concerns that this would result in revenues and net costs in the PCOSS that will not match Manitoba Hydro's projected revenue requirement as per the Integrated Financial Forecast (IFF). Manitoba Hydro does not believe that the fact that PCOSS revenues do not match Manitoba Hydro's projected revenue requirement necessarily reduces the usefulness of the PCOSS results. There is already a precedent for a mismatch between the PCOSS and the IFF revenue requirement with the addition of the Uniform Rate Adjustment (URA) which increased revenue in the PCOSS without, by definition, a similar increase to the revenue requirement.

The purpose of the COSS is to determine a fair sharing of revenue requirement among the customer classes and with minor changes in export revenue the apportionment of the revenue requirement is still valid, regardless of the precise amount of revenue required. The risk is that a dramatic reduction in export revenue requires adjustments to the PCOSS that imply a considerably lower cost for Manitoba Hydro's plant, even though the Corporation's revenue requirement as identified in the IFF does not change.

Revenue Cost Coverage (RCC) ratios for the domestic classes are utilized post allocation of net export credit and the change will not be material for most classes as a result of the change in gross export revenues. There are some classes that are more sensitive to these changes than others, and could see significant changes in their RCC with dramatic changes to export revenues. The accompanying change in interest costs has the greatest impact on plant-intensive functions such as Generation and Transmission, while the reduction in net export has a uniform effect on the net cost of all functions. As a result the net cost of Generation and Transmission after allocation of exports is reduced more than other functions due to this change. Similarly, directly assigned interest costs will change, but are not offset by net export revenues in the approved methodology. Classes with a relatively higher proportion of direct costs or Generation and Transmission related costs are liable to see greater changes than average with the directed change to export revenue.

f) Use actual [eight year] energy [SEP] prices and energy use profiles in Generation energy weighting process (Directive 19(f)).

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

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

Load Research data is not available to provide domestic consumption profiles over the required twelve periods for years prior to 2002/03. The revised study has used energy use profiles for the four year period from 2002/03 to the 2005/06 base year of PCOSS08. Future PCOSS will use the full eight year average as data becomes available. As expected the use of average weightings from a number of years affects the Export class distribution more than any domestic class.

Table 7 – Energy Profile Using Average of 2002/03 to 2005/06 Actual Consumptions

	Spring			Summer			Fall			Winter		
	On	Shoulder	Off	On	Shoulder	Off	On	Shoulder	Off	On	Shoulder	Off
Residential	3.3%	6.2%	3.9%	6.2%	11.6%	5.9%	4.2%	7.8%	4.9%	11.4%	20.6%	14.1%
GSS	3.7%	6.5%	3.9%	8.3%	12.6%	7.2%	4.4%	7.7%	4.7%	10.5%	18.4%	12.0%
GSM	3.9%	6.7%	4.1%	8.6%	14.0%	8.3%	4.3%	7.6%	4.7%	9.8%	16.9%	11.0%
GSL	3.8%	7.1%	5.3%	7.5%	13.8%	10.3%	3.9%	7.4%	5.6%	8.4%	15.4%	11.6%
Exports	6.3%	9.2%	3.4%	13.7%	20.6%	7.9%	3.9%	7.0%	3.7%	6.7%	11.2%	6.5%

Table 8 – Energy Profile Using 2005/06 Actual Consumption

	Spring			Summer			Fall			Winter		
	On	Shoulder	Off	On	Shoulder	Off	On	Shoulder	Off	On	Shoulder	Off
Residential	3.2%	5.9%	4.1%	6.4%	12.0%	6.4%	4.2%	7.6%	5.2%	11.2%	20.3%	13.4%
GSS	3.9%	6.7%	4.0%	8.5%	12.8%	7.5%	4.4%	7.6%	4.6%	10.4%	17.9%	11.5%
GSM	4.0%	7.0%	4.2%	8.7%	14.3%	8.4%	4.3%	7.7%	4.6%	9.6%	16.5%	10.7%
GSL	3.9%	7.1%	5.4%	7.7%	13.8%	10.5%	3.9%	7.3%	5.5%	8.3%	15.2%	11.5%
Exports	4.0%	7.8%	5.6%	9.2%	17.3%	11.7%	3.6%	7.6%	5.5%	6.5%	12.8%	8.4%

Table 9 compares the ratio of class weighted energy to their un-weighted energy under both consumption profiles, and illustrates the effect of using an averaged consumption profile versus a single year. The use of a multi-year consumption profile instead of just a single year has essentially no effect on the aggregate weighting applied to the domestic classes energy consumption, and only moderately increases the weighting applied to the export energy sales. While it is reasonable to assume that the aggregate weighting for the domestic class will not change significantly once the full eight year sample is available, it is difficult to predict the impact the additional data will have on the export aggregate weighting.

Table 9 – Comparison of Aggregate Weightings of Single vs. Multi-Year Energy Profile

	Aggregate Weight using 2002/03 to 2005/06 Profiles	**Aggregate Weight using 2005/06 Profile**	**Increase Due to Multi-Year Profile**
Residential	2.25	2.25	0.3%
GSS	2.26	2.26	0.1%
GSM	2.25	2.25	0.1%
GSL	2.17	2.17	0.0%
Exports	2.32	2.16	7.1%

Revised Results of PCOSS08

Manitoba Hydro has modeled the results of the Prospective Cost of Service Study for 2007/08 to reflect the modifications directed in Order 116/08 as discussed above. Other than the changes previously mentioned, costs and revenues in PCOSS08 have not been updated or changed in order to allow comparison between versions, and allow the effects of Order 116/08 revisions to be studied in isolation. A variance analysis illustrating the effect of incorporating these directions is included as Schedule 7. The changes were implemented on a cumulative basis in the variance analysis, and it should be noted that the impact attributed to any individual modification may be different if they had been implemented in a different sequence.

The assignment and allocation of costs as directed in Order 116/08 results in net export revenue of $48.7 million remaining to be allocated to domestic customers, considerably lower than the $165 million in the study prior to incorporating the 116/08 directives.

Table 10 – Comparison of Net Export Revenue under Order 116/08 vs. 117/06

	PCOSS08 116/08[i] **($ Million)**	**PCOSS08 117/06**[ii] **($ Million)**
Gross Export Revenue	475	552
Less:		
Uniform Rates	17	17
DSM	23	25
Trading Desk	13	13
MAPP/MISO/NEB	7	7
Purchased Power	140	134
Thermal Costs	52	23
Allocated Generation	129	116
Allocated Transmission	45	51
Net Export Revenue	49	165

Table 11 – Comparison of Class Share of Export Revenue

Customer Class	**PCOSS08 116/08**[i]	**PCOSS08 117/06**[ii]	**PCOSS06 Previous**[iii]	**PCOSS06 Recommended**[iv]
Residential	42.6%	42.4%	34.2%	42.6%
GSS Non-Demand	8.6%	8.3%	8.4%	9.6%
GSS Demand	9.8%	9.7%	8.6%	8.3%
GSM	13.6%	13.4%	14.8%	13.6%
GSL 0-30 kV	7.0%	7.0%	7.3%	6.5%
GSL 30-100 kV	3.1%	3.2%	3.5%	2.6%
GSL >100kV	13.8%	14.5%	22.8%	15.4%
A&R Lighting	0.7%	0.5%	0.4%	0.5%
Diesel	1.0%	0.9%	0.0%	0.8%

As shown in Table 12, application of Order 116/08 directives yields results similar to those from studies before the review and revision of Manitoba Hydro's Cost of Service methodology began. With the reduction of net export to only $49 million, the distorting effects of exports on class RCC's remain. Although the study no longer explicitly allocates net export credits as an offset to Generation and Transmission costs, the assignment of sufficient Generation and Transmission expenses to the Export class to largely eliminate the net export credit has simply shifted the appearance of the allocation but not its results.

The changes perpetuate the distorting effects of export revenues that caused concern for Manitoba Hydro and some of the parties in the first place. Using the methodology from 116/08 results in four classes falling within the 0.95 - 1.05 zone of reasonableness (ZOR), three classes above the ZOR, and one below the ZOR.

The greatest impact on class RCC is from the assignment of DSM costs directly to the Export class, and the addition of DSM savings back to the domestic class load. Unfortunately the lack of detailed historic data on realized savings requires a number of assumptions and allocations to disaggregate savings to the class level, and yields an estimate for which the level of confidence is disproportionate to its impact on the results of the study.

Table 12 – Comparison of Class RCC

Customer Class	**PCOSS08 116/08**[i]	**PCOSS08 117/06**[ii]	**PCOSS06 Previous**[iii]	**PCOSS06 Recommended**[iv]
Residential	96.2%	96.4%	92.2%	97.0%
GSS Non-Demand	101.4%	104.3%	103.1%	107.4%
GSS Demand	107.8%	107.2%	106.0%	105.4%
GSM	100.2%	101.1%	102.9%	100.6%
GSL 0-30 kV	89.9%	90.4%	94.0%	90.1%
GSL 30-100 kV	108.4%	103.7%	109.4%	101.5%
GSL >100kV	112.0%	108.7%	114.7%	103.2%
A&R Lighting	102.4%	105.8%	105.2%	107.1%

i Version of PCOSS described herein with changes as directed in PUB Order 116/08
[ii] Version of PCOSS submitted during the 2008/09 GRA with changes as directed in PUB Order 117/06
[iii] Version of PCOSS submitted during the 2005 Cost of Service Review using Manitoba Hydro's then current methodology
[iv] Version of PCOSS submitted during the 2005 Cost of Service Review using Manitoba Hydro's preferred methodology

2008 Prospective Cost of Service Study
Prospective Peak Load Report
Using Top 50 Peak Hours

Energy Data

	Forecast # Cust. **C90**	Forecast Total KW.h Sales Before DSM	Forecast DSM KW.h Savings	Total KW.h Sales After DSM **E20**	Distribution Losses	Common Bus Losses	Forecast Cummulative DSM KW.h Savings to 07/08	KW.h Generated Adjusted **E10**	CP Load Factor
Residential									
Residential	430,295	6,538,090,000	(42,040,000)	6,496,050,000	420,132,337	677,948,495	395,799,888	7,989,930,721	53.6%
Seasonal	20,118	61,960,000	-	61,960,000	4,007,266	6,466,343	-	72,433,609	157.8%
Water Heating	5,490	19,516,000	-	19,516,000	1,262,198	2,036,752	-	22,814,950	67.4%
Total Residential	455,903	6,619,566,000	(42,040,000)	6,577,526,000	425,401,801	686,451,591	395,799,888	8,085,179,280	54.0%
GS Small - Single Phase									
Non-Demand	39,843	937,201,579	(19,818,120)	917,383,459	59,331,818	95,741,064	103,021,792	1,175,478,133	61.6%
Demand	3,371	489,087,449	(6,996,907)	482,090,542	31,179,228	50,312,506	37,086,499	600,668,777	68.1%
Subtotal	43,214	1,426,289,028	(26,815,027)	1,399,474,001	90,511,046	146,053,570	140,108,292	1,776,146,909	63.7%
Seasonal	779	4,760,000	-	4,760,000	307,853	496,769		5,564,622	162.5%
Water Heating	509	6,104,000	-	6,104,000	394,776	637,033		7,135,809	68.9%
Total Single Phase	44,502	1,437,153,028	(26,815,027)	1,410,338,001	91,213,676	147,187,372	140,108,292	1,788,847,341	63.8%
GS Small - Three Phase									
Non-Demand	10,911	409,238,420	(8,653,780)	400,584,640	19,097,891	41,138,756	44,985,493	505,806,781	61.6%
Demand	5,877	1,578,912,552	(22,587,993)	1,556,324,559	74,197,846	159,829,536	119,725,705	1,910,077,645	68.1%
Total Three Phase	16,788	1,988,150,972	(31,241,773)	1,956,909,199	93,295,737	200,968,292	164,711,198	2,415,884,427	66.7%
Total G.S.Small									
Non-Demand	50,754	1,346,439,999	(28,471,900)	1,317,968,099	78,429,709	136,879,820	148,007,286	1,681,284,914	60.3%
Demand	9,248	2,068,000,001	(29,584,900)	2,038,415,101	105,377,074	210,142,042	156,812,204	2,510,746,422	67.1%
Sub-Total G.S. Small	60,002	3,414,440,000	(58,056,800)	3,356,383,200	183,806,784	347,021,862	304,819,490	4,192,031,336	65.4%
Seasonal	779	4,760,000	-	4,760,000	307,853	496,769	-	5,564,622	162.7%
Water Heating	509	6,104,000	-	6,104,000	394,776	637,033	-	7,135,809	68.9%
Total GS Small	61,290	3,425,304,000	(58,056,800)	3,367,247,200	184,509,414	348,155,664	304,819,490	4,204,731,767	65.4%
General Service - Medium	1,801	2,987,000,000	(38,282,780)	2,948,717,220	140,580,231	302,823,792	258,898,845	3,651,020,088	73.6%
General Service - Large									
0 - 30 Kv	252	1,636,326,000	(24,523,120)	1,611,802,880	62,336,552	164,105,030	112,129,996	1,950,374,458	81.2%
30 - 100 kV	27	769,958,000	(1,810,474)	768,147,526	8,961,613	76,174,968	23,053,906	876,338,013	83.2%
30 - 100 kV - Curtailment Cust's	1	220,000,000	(517,306)	219,482,694	2,560,600	21,765,464	6,587,189	250,395,947	98.0%
Over 100 Kv	11	2,662,716,000	(5,347,953)	2,657,368,047	-	260,484,554	105,292,717	3,023,145,318	87.0%
Over 100 Kv - Curtailment Cust's	3	2,550,000,000	(5,121,567)	2,544,878,433	-	249,457,926	100,835,548	2,895,171,908	97.3%
Total G.S.- Large	294	7,839,000,000	(37,320,420)	7,801,679,580	73,858,765	771,987,942	347,899,357	8,995,425,644	88.6%
SEP									
GSM	22	21,000,000		21,000,000	1,001,176	2,156,633		24,157,809	44.8%
GSL 0 - 30 Kv	6	2,700,000		2,700,000	104,423	274,899		3,079,322	88.8%
Total SEP	28	23,700,000	-	23,700,000	1,105,599	2,431,532	-	27,237,131	47.5%
Street Lighting	12,424	85,666,830	-	85,666,830	5,540,506	8,940,464	34,032,420	134,180,220	119.7%
Sentinel Lighting	2,576	10,330,000	-	10,330,000	668,093	1,078,072	8,550,000	20,626,165	119.7%
Total - Lighting	15,000	95,996,830	-	95,996,830	6,208,599	10,018,535	42,582,420	154,806,385	119.7%
Total - General Consumers	534,316	20,990,566,830	(175,700,000)	20,814,866,830	831,664,409	2,121,869,056	1,350,000,000	25,118,400,295	68.7%
Extra Provincial		-	-	-		-	-	-	0.0%
Man Hydro - Construction		52,000,000		52,000,000	2,479,102	5,340,233		59,819,335	73.6%
Integrated System	534,316	21,042,566,830	(175,700,000)	20,866,866,830	834,143,511	2,127,209,289	1,350,000,000	25,178,219,630	68.8%

Demand Data

	CP @ Meter Before DSM Non-Recon MW	Forecast DSM MW Savings	CP @ Meter After DSM Non-Recon. MW	Adjust %'age	Adjust To Recon.	CP @ Meter Reconciled MW	Distrib Losses MW	Common Bus Losses MW	Forecast Cummulative DSM MW Savings to 2007/08	CP @ Gen. MW	Class Coinc. Factor	Class Demand NCP MW @ Meter **D50**	Class Demand NCP MW @ Gen. **D20**
Residential													
Residential	1,388.65	(3.81)	1,384.84	55.1%	(72.65)	1,312.19	115.97	165.09	88.07	1,681.32	87.8%	1,494.53	1,914.94
Seasonal	4.47		4.47		-	4.47	0.40	0.56	0.00	5.43	8.0%	55.89	67.86
Water Heating	3.29		3.29		-	3.29	0.29	0.41	0.00	4.00	80.0%	4.12	5.00
Total Residential	1,396.42	(3.81)	1,392.61	55.1%	(72.65)	1,319.96	116.65	166.07	88.07	1,690.75	84.9%	1,554.53	1,987.80
GS Small - Single Phase													
Non-Demand	173.21	(3.94)	169.26	10.4%	(13.70)	155.56	13.75	19.57	22.32	211.20	83.0%	187.42	254.46
Demand	81.76	(1.39)	80.38	4.1%	(5.35)	75.03	6.63	9.44	8.03	99.13	87.2%	86.04	113.68
Subtotal	254.97	(5.33)	249.64	14.4%	(19.05)	230.58	20.38	29.01	30.35	310.33	84.3%	273.46	368.13
Seasonal	0.33		0.33			0.33	0.03	0.04	0.00	0.40	8.0%	4.16	5.05
Water Heating	1.01		1.01			1.01	0.09	0.13	0.00	1.22	75.0%	1.34	1.63
Total Single Phase	256.31	(5.33)	250.98	14.4%	(19.05)	231.92	20.50	29.18	30.35	311.95	83.1%	278.96	374.82
GS Small - Three Phase													
Non-Demand	75.63	(1.72)	73.91	4.5%	(5.98)	67.93	4.54	8.38	9.75	90.59	83.0%	81.84	109.15
Demand	263.95	(4.47)	259.47	13.1%	(17.27)	242.21	16.19	29.87	25.93	314.20	87.2%	277.76	360.32
Total Three Phase	339.58	(6.20)	333.38	17.6%	(23.25)	310.13	20.73	38.25	35.68	404.79	86.2%	359.60	469.46
Total G.S.Small													
Non-Demand	248.84	(5.67)	243.17	14.9%	(19.69)	223.48	18.29	27.95	32.07	301.79	83.0%	269.26	363.60
Demand	345.71	(5.86)	339.85	17.1%	(22.61)	317.23	22.82	39.31	33.96	413.32	87.2%	363.80	473.99
Sub-Total G.S. Small	594.55	(11.53)	583.02	32.1%	(42.30)	540.72	41.11	67.26	66.03	715.11	85.4%	633.06	837.59
Seasonal	0.33	-	0.33	0.0%	-	0.33	0.03	0.04	0.00	0.40	8.0%	4.16	5.05
Water Heating	1.01	-	1.01	0.0%	-	1.01	0.09	0.13	0.00	1.22	75.0%	1.34	1.63
Total GS Small	595.89	(11.53)	584.36	32.1%	(42.30)	542.06	41.23	67.43	66.03	716.74	84.9%	638.56	844.28
General Service - Medium	462.03	(7.21)	454.81	12.6%	(16.67)	438.14	29.29	54.03	56.95	578.40	90.6%	483.59	638.42
General Service - Large													
0 - 30 Kv	229.42	(4.26)	225.16	0.2%	(0.27)	224.88	12.47	27.44	25.34	290.13	84.2%	267.08	344.57
30 - 100 kV	105.35	(0.47)	104.89		-	104.89	1.60	12.31	5.47	124.27	77.7%	134.99	159.94
30 - 100 kV - Curtailment Cust's	25.56	(0.11)	25.44		-	25.44	0.39	2.99	1.33 †	30.15	94.1%	27.04	32.04
Over 100 Kv	348.43	(0.83)	347.60		-	347.60	-	40.18	25.85	413.63	91.8%	378.65	450.58
Over 100 Kv - Curtailment Cust's	298.36	(0.71)	297.65		-	297.65	-	34.41	22.14 †	354.19	95.8%	310.70	369.72
Total G.S.- Large	1,007.11	(6.38)	1,000.73	0.2%	(0.27)	1,000.46	14.46	117.32	80.13	1,212.37	89.5%	1,118.45	1,356.84
SEP													
GSM	5.34		5.34		-	5.34	0.36	0.66		6.35	78.7%	6.78	8.07
GSL 0 - 30 Kv	0.35		0.35		-	0.35	0.02	0.04		0.41	18.0%	1.92	2.26
Total SEP	5.68	-	5.68		-	5.68	0.38	0.70	0.00	6.76	65.3%	8.70	10.33
Street Lighting	8.15	-	8.15		-	8.15	0.72	1.03	3.03	12.93	38.2%	21.33	33.84
Sentinel Lighting	0.98	-	0.98		-	0.98	0.09	0.12	0.78	1.97	38.2%	2.57	5.15
Total - Lighting	9.13	-	9.13	0.0%	-	9.13	0.81	1.15	3.81	14.89	38.2%	23.90	38.99
Total - General Consumers	3,476.25	(28.93)	3,447.32	100.0%	(131.90)	3,315.42	202.81	406.69	294.99	4,219.91	86.6%	3,827.75	4,876.66
Extra Provincial	-		-		-	0.00		0.00		0.00			
Man Hydro - Construction	8.04		8.04		-	8.04	0.54	0.99		9.57			
Integrated System	3,484.30	(28.93)	3,455.37	100.0%	(131.90)	3,323.47	203.34	407.69		4,229.49			

2008 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report
Energy (MW.h) Weighted by Marginal Cost

	Spring			Summer			Fall			Winter				
	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total	Weighted Energy/1000
Residential	260,215,668	491,708,977	311,526,521	495,985,920	927,184,012	472,795,945	335,498,650	623,540,968	391,257,440	909,479,875	1,646,211,365	1,124,525,380	7,989,930,721	18,010,482
Residential FRWH	930,431	1,758,162	1,113,899	1,989,469	3,719,064	1,896,450	944,778	1,755,917	1,101,797	1,879,395	3,401,813	2,323,775	22,814,950	50,826
Residential Seasonal	3,425,956	6,473,758	4,101,506	8,334,687	15,580,661	7,944,996	2,520,237	4,683,986	2,939,092	4,059,978	7,348,795	5,019,955	72,433,609	160,183
GS Small Non-Demand	62,844,245	111,722,522	64,596,402	146,123,313	210,944,436	118,819,101	73,513,433	129,314,537	77,675,964	177,130,903	309,384,838	199,215,219	1,681,284,914	3,817,507
GS Small Non-Demand FRWH	312,509	555,570	321,223	730,361	1,054,354	593,888	311,688	548,277	329,336	614,416	1,073,167	691,020	7,135,809	16,088
GS Small Non-Demand Seasonal	316,323	562,348	325,142	908,998	1,312,235	739,145	170,628	300,144	180,289	193,569	338,097	217,703	5,564,622	12,401
GS Small Demand	92,573,922	161,090,331	98,014,160	196,384,238	319,037,872	185,454,789	112,048,121	195,964,779	121,278,023	263,960,116	460,565,323	304,374,748	2,510,746,422	5,660,405
GS Medium	141,211,522	245,898,382	149,823,196	315,113,424	511,972,152	302,765,618	158,215,234	277,528,164	170,711,983	356,718,215	618,339,374	402,722,824	3,651,020,088	8,209,245
GS Large 750-30kV	81,095,211	135,150,774	88,200,891	177,123,119	279,107,637	182,112,596	85,755,539	143,444,686	94,733,982	181,882,142	299,086,616	202,681,266	1,950,374,458	4,355,577
GS Large 30-100kV	30,842,802	60,123,907	47,091,513	61,916,682	116,158,204	91,748,195	33,964,080	65,167,732	51,329,110	73,402,019	137,489,749	107,104,019	876,338,013	1,890,530
GS Large 30-100kV Curtailable	9,053,239	17,894,055	13,548,520	18,441,966	35,527,303	27,137,792	9,339,480	18,612,230	14,048,376	19,693,963	38,018,266	29,080,757	250,395,947	539,590
GS Large > 100kV	116,529,553	221,981,830	172,704,109	209,744,857	388,309,097	304,656,889	118,328,202	227,595,253	175,787,962	251,479,480	469,640,461	366,387,626	3,023,145,318	6,522,504
GS >100kV Curtailable	104,309,191	204,100,159	156,536,299	210,169,696	412,843,813	318,947,713	108,197,066	213,690,588	163,011,685	228,095,845	438,441,331	336,828,523	2,895,171,908	6,229,885
Street Lights	-	5,882,643	14,551,800	464,419	10,991,253	29,103,600	4,798,998	8,359,545	17,493,121	10,217,221	17,957,541	34,986,243	154,806,385	280,891
Totals	903,660,572	1,664,903,418	1,122,455,179	1,843,431,149	3,233,742,095	2,044,716,718	1,043,606,133	1,910,506,808	1,281,878,161	2,478,807,137	4,447,296,736	3,116,159,059	25,091,163,164	55,756,113
Exports	367,199,670	539,397,650	201,254,829	804,708,027	1,209,304,879	462,675,421	228,589,098	411,597,523	217,310,475	394,652,948	657,798,434	379,511,046	5,874,000,000	13,606,145
12 Season Wtgings	**2.513**	**2.144**	**1.246**	**3.258**	**2.388**	**1.000**	**2.624**	**2.155**	**1.396**	**3.406**	**2.262**	**1.796**		

2008 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report
Seasonal Coincident Peaks (2 CP) at Generation Peak

			Winter						*SUMMER*					D14
	Forcast Total Energy @ Generation	Avg % of Yearly Energy	Estimated Seasonal Energy	Seasonal CP LF	Estimated Seasonal Demand	Estimated Winter DSM Adder	Estimated Seasonal Demand incl DSM	Avg % of Yearly Energy	Estimated Seasonal Energy	Seasonal CP LF	Estimated Seasonal Demand	Estimated Summer DSM Adder	Estimated Seasonal Demand incl DSM	2CP Estimated Demand
Residential														
Residential	7,594,130,833	63.1%	4,794,857,598	84.6%	1,297,596	88,070	1,385,666	36.9%	2,799,273,234	88.0%	720,738	68,960	789,698	1,087,682
Seasonal	72,433,609	34.0%	24,643,092	162.5%	3,472	0	3,472	66.0%	47,790,517	162.5%	6,660	0	6,660	5,066
Water Heating	22,814,950	49.6%	11,316,215	126.0%	2,056	0	2,056	50.4%	8,809,416	126.0%	1,583	0	1,583	1,820
Total Residential	7,689,379,392		4,830,816,906		1,303,124	88,070	1,391,194		2,855,873,167		728,981	68,960	797,941	1,094,568
GS Small														
Non-Demand	1,533,277,628	57.8%	886,234,469	72.3%	280,597	32,070	312,667	42.2%	647,043,159	73.1%	200,408	28,520	228,928	270,797
Demand	2,353,934,217	57.6%	1,355,866,109	81.3%	381,807	33,960	415,767	42.4%	998,068,108	82.6%	273,622	30,210	303,832	359,799
Subtotal	3,887,211,846		2,242,100,579		662,403	66,030	728,433		1,645,111,267		474,030	58,730	532,760	630,597
Seasonal	5,564,622	20.2%	1,124,054	162.5%	158	0	158	79.8%	3,781,000	162.5%	527	0	527	343
Water Heating	7,135,809	49.6%	3,539,361	106.0%	764	0	764	50.4%	3,596,448	106.0%	768	0	768	766
Total GSS	3,899,912,277		2,246,763,994		663,326	66,030	729,356		1,652,488,715		475,325	58,730	534,055	631,706
General Service - Medium	3,392,121,243	53.2%	1,805,771,384	82.1%	503,543	56,950	560,493	46.8%	1,586,349,858	81.7%	439,691	50,630	490,321	525,407
General Service - Large														
0 - 30 Kv	1,838,244,462	51.0%	936,624,149	80.9%	265,071	25,340	290,411	49.0%	901,620,313	84.4%	241,909	22,520	264,429	277,420
30 - 100 Kv	853,284,107	52.4%	447,114,283	86.8%	117,918	5,470	123,388	47.6%	406,169,824	98.8%	93,125	4,859	97,983	110,686
30 - 100 Kv - Curtailed Cust	243,808,758	49.8%	121,416,761	111.8%	24,863	1,330	26,193	50.2%	122,391,996	98.9%	28,015	1,181	29,196	27,695
Over 100 Kv	2,917,852,601	53.1%	1,548,819,005	98.1%	361,577	25,850	387,427	46.9%	1,369,033,596	110.2%	281,330	22,952	304,282	345,855
Over 100 Kv - Curtailed Cust	2,794,336,359	51.1%	1,426,919,643	99.1%	329,688	22,140	351,828	48.9%	1,367,416,716	98.3%	314,854	19,658	334,512	343,170
Total G.S.- Large	8,647,526,287		4,480,893,842		1,099,117	80,130	1,179,247		4,166,632,445		959,233	71,170	1,030,403	1,104,825
Street Lighting	112,223,965	58.2%	65,306,569	86.7%	17,255	3,810	21,065	41.8%	46,917,396	0.0%	-	-	-	10,532
Total - General Consumers	23,741,163,164		13,429,552,695		3,586,365	294,990	3,881,355		10,308,261,582		2,603,231	249,490	2,852,721	3,367,038
Extra Provincial	8,462,000,000	40.3%	3,409,000,000	94.5%	826,171	0	826,171	59.7%	5,053,000,000	89.4%	1,280,245	0	1,280,245	1,053,208
Integrated System	32,203,163,164		16,838,552,695		4,412,536	294,990	4,707,526		15,361,261,582		3,883,476	249,490	4,132,966	4,420,246

SCHEDULE 4

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2008
Revenue Cost Coverage Analysis
MH Model of 116/08 Directives
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Pre Export Allocation	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	471,650	433,136	91.8%	20,721	453,857	96.2%
General Service - Small Non Demand	95,714	92,895	97.1%	4,205	97,100	101.4%
General Service - Small Demand	108,460	112,162	103.4%	4,765	116,926	107.8%
General Service - Medium	150,430	144,186	95.8%	6,609	150,795	100.2%
General Service - Large 0 - 30kV	77,138	65,925	85.5%	3,389	69,314	89.9%
General Service - Large 30-100kV*	34,003	35,367	104.0%	1,494	36,861	108.4%
General Service - Large >100kV*	152,443	164,004	107.6%	6,697	170,702	112.0%
*Includes Curtailment Customers						
SEP	1,748	1,561	89.3%	-	1,561	89.3%
Area & Roadway Lighting	19,105	19,243	100.7%	319	19,563	102.4%
Total General Consumers	1,110,690	1,068,480	96.2%	48,199	1,116,679	100.5%
Diesel	11,248	4,765	42.4%	494	5,259	46.8%
Export	426,726	475,419	111.4%	(48,693)	426,726	100.0%
Total System	1,548,664	1,548,664	100.0%	-	1,548,664	100.0%

SCHEDULE 5

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2008
Customer, Demand, Energy Cost Analysis
MH Model of 116/08 Directives
SUMMARY

	CUSTOMER			DEMAND				ENERGY		
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA	Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh
Residential	108,534	455,903	19.84	177,294	0%	n/a	n/a	165,101	6,577,526	5.21 **
GS Small - Non Demand	20,919	52,042	33.50	35,742	0%	n/a	n/a	34,848	1,328,832	5.31 **
GS Small - Demand	6,069	9,248	54.68	46,338	34%	2,124	7.40	51,288	2,038,415	4.02
General Service - Medium	5,349	1,801	247.49	64,090	100%	8,042	7.97	74,382	2,948,717	2.52
General Service - Large <30kV	2,629	252	n/a	31,655	100%	3,826	8.96 *	39,465	1,611,803	2.45
General Service - Large 30-100kV	1,526	28	n/a	8,965	100%	2,104	4.99 *	22,019	987,630	2.23
General Service - Large >100kV	1,868	14	n/a	28,331	100%	8,597	3.51 *	115,547	5,202,246	2.22
SEP	353	28	1,051.21	296	0%	n/a	n/a	1,099	23,700	5.88 **
Area & Roadway Lighting	13,213	150,000	7.34	3,028	0%	n/a	n/a	2,545	95,997	5.81 **
Total General Consumers	160,460	669,316		395,739		24,693		506,293	20,814,867	
Diesel	287	716	33.43	431	0%	n/a	n/a	10,036	13,250	78.99 **
Export	n/a	n/a	n/a	51,102	0%	n/a	n/a	375,624	7,707,000	5.54 ***
Total System	160,747	670,032		447,272		24,693		891,953	28,535,117	

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

SCHEDULE 6

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2008
Functional Breakdown
MH Model of 116/08 Directives
S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	450,929	165,101	36.6%	45,007	10.0%	33,910	7.5%	52,168	11.6%	154,743	34.3%
General Service - Small Non Demand	91,509	34,848	38.1%	11,180	12.2%	6,317	6.9%	13,450	14.7%	25,714	28.1%
General Service - Small Demand	103,695	51,288	49.5%	14,794	14.3%	8,086	7.8%	2,717	2.6%	26,810	25.9%
General Service - Medium	143,821	74,382	51.7%	21,604	15.0%	10,891	7.6%	4,365	3.0%	32,580	22.7%
General Service - Large <30kV	73,749	39,465	53.5%	11,407	15.5%	5,878	8.0%	2,397	3.3%	14,602	19.8%
General Service - Large 30-100kV	32,509	22,019	67.7%	5,690	17.5%	3,275	10.1%	1,478	4.5%	48	0.1%
General Service - Large >100kV	145,746	115,547	79.3%	28,331	19.4%	0	0.0%	1,843	1.3%	25	0.0%
SEP	1,748	1,099	62.9%	296	16.9%	0	0.0%	335	19.2%	18	1.1%
Area & Roadway Lighting	18,786	2,618	13.9%	445	2.4%	684	3.6%	554	2.9%	14,485	77.1%
Total General Consumers	1,062,492	506,365	47.7%	138,755	13.1%	69,041	6.5%	79,306	7.5%	269,025	25.3%
Diesel	10,754	10,036	93.3%	0	0.0%	0	0.0%	0	0.0%	718	6.7%
Export	426,726	375,624	88.0%	51,102	12.0%	0	0.0%	0	0.0%	0	0.0%
Total System	1,499,971	892,025	59.5%	189,857	12.7%	69,041	4.6%	79,306	5.3%	269,742	18.0%

SCHEDULE 7

PCOSS08 Variance Analysis

Effect of Changes Directed in Order 116/08 on Class RCC[1]

Customer Class	Revenue Cost Coverage Ratio (RCC)					Incremental Change in RCC				
	PCOSS08 117/06[2]	Thermal[3]	Multi Year TOU[4]	DSM[5]	Actual Exports & Imports (ie 116/08)[6]	Thermal[3]	Multi Year TOU[4]	DSM[5]	Actual Exports & Imports[6]	Net
Residential	96.4%	95.9%	95.7%	96.6%	96.2%	-0.5%	-0.2%	0.9%	-0.4%	-0.2%
General Service - Small Non Demand	104.3%	104.0%	104.1%	101.8%	101.4%	-0.3%	0.1%	-2.3%	-0.4%	-2.9%
General Service - Small Demand	107.2%	107.5%	107.3%	107.2%	107.8%	0.3%	-0.2%	-0.1%	0.6%	0.6%
General Service - Medium	101.1%	101.3%	101.3%	100.1%	100.2%	0.2%	0.0%	-1.2%	0.1%	-0.9%
General Service - Large 0 - 30kV	90.4%	90.3%	90.4%	90.3%	89.9%	-0.1%	0.1%	-0.1%	-0.4%	-0.5%
General Service - Large 30-100kV*	103.7%	104.6%	105.0%	107.7%	108.4%	0.9%	0.4%	2.7%	0.7%	4.7%
General Service - Large >100kV*	108.7%	110.2%	110.7%	110.8%	112.0%	1.5%	0.5%	0.1%	1.2%	3.3%
*Includes Curtailment Customers										
SEP	89.1%	89.1%	89.1%	89.1%	89.3%	0.0%	0.0%	0.0%	0.2%	0.2%
Area & Roadway Lighting	105.8%	105.6%	105.6%	99.5%	102.4%	-0.2%	0.0%	-6.1%	2.9%	-3.4%
Total General Consumers	100.4%	100.4%	100.5%	100.5%	100.5%	0.0%	0.1%	0.0%	0.0%	0.1%
Diesel	54.9%	53.0%	52.6%	51.3%	46.8%	-1.9%	-0.4%	-1.3%	-4.5%	-8.1%
Export	100.0%	100.0%	100.0%	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total System	100.0%	100.0%	100.0%	100.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%

[1]Changes to PCOSS methodology are cumulative, and the impact attributed to a specific change may vary depending on the sequence in which the steps are performed.

[2] Version of PCOSS submitted during the 2008/09 GRA prepared as directed in PUB Order 117/06

[3] Above with 50% of fixed and 100% of variable Thermal costs assigned to the export class

[4] Above with energy split between the 12 TOU periods based on the average distribution over the past four years

[5] Above with DSM costs assigned to Export class, and DSM energy and capacity savings added to domestic class load

[6] Above with most recent actual export/import prices used to establish export revenue and power purchases. PCOSS includes all changes directed in Order 116/08.