MIDLAND POWER UTILITY CORPORATION
16984 Highway#12 P.O. Box 820
Midland Ontario L4R 4P4

December 12, 2008

Kirsten Walli, Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli,

Midland Power Utility Corporation – License #ED-2002-0541
OEB File No.: EB-2008-0236

Enclosed please find Midland's Interrogatory Response to the OEB Staff Interrogatories. Also enclosed is an Interrogatory Response Summary providing details on all proposed changes to the Rate Application as a result of the interrogatories received from OEB Staff, VECC and SEC.

As indicated in the summary, please contact the undersigned should your require any further information.

Yours very truly,

MIDLAND POWER UTILITY CORPORATION

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MIDLAND POWER UTILITY CORPORATION
EB-2008-0236

INTERROGATORY RESPONSE SUMMARY

DECEMBER 12, 2008

Midland has been advised that the following have been granted intervenor status in regard to Midland's Rate Application:

1. AMPCO
2. VECC
3. SEC

Midland has received interrogatories and has submitted its response to the following:

1. OEB Staff
2. VECC
3. SEC

During the course of the interrogatory response, Midland has proposed some adjustments to the Rate Application which Midland would ask to be considered by the Board at the time of setting final rates. These adjustments, in Midland's view, would not require the refiling of the Rate Application at this time, however, we respectfully ask that once final rates are determined, these adjustments be taken into consideration.

A summary of these adjustments is as follows:

OEB Staff Response:

1. **OEB IR#3 - Street Lighting/Sentinel Lighting:** Midland is proposing to increase the R/C Ratios to 49% in this Rate Application and to further increase the R/C Ratios to 60% and 70% in the years 2010 and 2011 respectively. Although no adjustment is required to the Rate Application to reflect these changes, Midland is proposing that the two adjustments in 2010 and 2011 be implemented in those years.

2. **OEB IR#40 - PILS:** Midland has revised the income tax calculation to include the deduction for deemed interest. The impact on the revenue requirement as presented in the Rate Application will be a reduction of $124,171 (Income Tax per Rate Application of $204,993, less revised Income Tax $80,822). Midland is proposing to reflect this change to the revenue requirement once final rates are determined by the Board.

3. **OEB IR#5 - RTSR:** Midland has prepared an analysis of the impact to the Retail Transmission Rates in accordance with the OEB's guidelines of October 22, 2008. This analysis, if approved by the Board would result in a decrease to the cost of power projections and consequently, working capital. Midland is proposing to make this adjustment as the Board directs through our draft order.

4. **OEB IR#14 – Interest Charge**: The yearly interest charge of 19.56% was inadvertently omitted on Midland's proposed rate schedule. Midland has proposed to add this charge to the rate schedule at the time final rates are determined.

5. **OEB IR#23 – Regulatory Expense:** Midland is proposing an additional $25,000 in cost to Regulatory Expenses as it is anticipated the oral component of the Rate Application will require increased costs over and above those itemized in the Rate Application. Midland is proposing to reflect this increase should it be considered by the Board in the draft order. Midland is also proposing to recover the original $150,000 plus the additional $25,000 over four years vs. the three years as submitted in the Rate Application in August, 2008.

6. **OEB IR#15 – Capital Spending:**

Project #2009-01 – Bourgeois Lane: As indicated in this interrogatory, Midland obtained an engineering estimate of $143,000 for this project, which far exceeds the Rate Application budget of $53,100.

Project #2009-08 – Scada Software: Midland is proposing to defer this project to 2010. This would result in a reduction to our capital programs of $100,000 in 2009.

The result of these two adjustments and the adjustments referred to in VECC IR#21 would increase the capital programs in 2009 by $121,860. Midland is proposing to reflect this change at the time final rates are determined.

VECC Response:

7. **VECC IR#11 – Regulatory Expenses**: see OEB #5 above.

8. **VECC IR#15 – Power Supply Expense:** Midland is proposing to update the power supply expense using October 15, 2008 OEB forecasted rate of $0.0603 per kWh.

9. **VECC IR#19 – Capital Spending 2008**: Midland will not be incurring $400,000 in development contributions in 2008, but has additional capital work of $58,600. Midland is proposing to reduce the capital spending in 2008 by $341,400 and will reflect this change if approved by the Board.

10. **VECC IR#21 – Capital Spending 2009:** Midland is proposing a change to the capital spending in 2009. The net change is an increase of $121,860 to the 2009 projects. If approved by the Board, Midland will reflect this change in the rates when the draft order is provided.

SEC Response:

11. **SEC IR#1 – IFRS:** Midland is proposing to increase the OM&A Expenses by $25,000 per year over four years on account of expenses to be incurred as a result of the transition to IFRS. Midland will include this additional expense once final rates are approved by the Board.

As noted above, Midland is planning for the conversion from GAAP to IFRS and expects to incur an estimate of $100,000 in one-time costs for this transition, which we have respectfully requested to be included in our Rate Application. Midland also expects that it will incur operational expenses on a yearly basis, but at this point has not included an estimate of these costs in our Rate Application. Until Midland is aware of the OEB requirements vs. IFRS presentation of our financial records, we are unable to estimate the additional cost, however, we are concerned that due to the time lag between rebasing, Midland may incur additional costs for which we will not be able to recover. Consequently, we would appreciate the Board's guidance in determining whether Midland should, at this point include both the one-time costs and expected operational yearly expenses or whether the Board will be directing LDCs to include the costs in a variance account.

Other:

12. The appropriate adjustment will be made in calculating the Cost of Capital and long-term Debt rate, based on Board approved rates in place at the time final rates are determined.

13. The net change to OM&A Expenses is as follows:

Expenses Per Rate Application Aug 15/08	$	2,093,100
Regulatory ($175k over four years)	$	43,750
Regulatory ($150k over three years)	$	(50,000)
IFRS	$	25,000
Expenses Per Interrogatories Dec 12th	$	2,111,850

The Summary of Proposed Changes is set out on the table below:

Midland Power Utility Corporation
Summary of Proposed Changes

		Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance	Amortization	PILs	OM&A	Service Revenue Requirement	Base Revenue Requirement	Gross Revenue Deficiency
	Original Submission August 2008	**$780,334**	**6.33%**	**$12,318,654**	**$18,770,634**	**$2,815,595**	**$735,424**	**$204,993**	**$2,093,100**	**$3,813,852**	**$3,582,721**	**$897,322**
OEB IR#3	Street Lighting/Sentinel Lighting (no bill impact)	**$780,334**	**6.33%**	**$12,318,654**	**$18,770,634**	**$2,815,595**	**$735,424**	**$204,993**	**$2,093,100**	**$3,813,852**	**$3,582,721**	**$897,322**
	Change	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OEB IR#40	PILs Correction	**$780,334**	**6.33%**	**$12,318,654**	**$18,770,634**	**$2,815,595**	**$735,424**	**$80,822**	**$2,093,100**	**$3,689,681**	**$3,458,550**	**$773,151**
	Change	$0	$0	$0	$0	$0	$0	-$124,171	$0	-$124,171	-$124,171	-$124,171
OEB IR#5 &	Commodity & RTSR update	**$789,805**	**6.33%**	**$12,468,160**	**$19,767,341**	**$2,965,101**	**$735,424**	**$85,328**	**$2,093,100**	**$3,703,657**	**$3,472,526**	**$787,127**
VECC IR#15	Change	$9,471	$0	$149,506	$996,707	$149,506	$0	$4,506	$0	$13,976	$13,976	$13,976
OEB IR#14	Yearly Interest Rate (no bill impact)	**$789,805**	**6.33%**	**$12,468,160**	**$19,767,341**	**$2,965,101**	**$735,424**	**$85,328**	**$2,093,100**	**$3,703,657**	**$3,472,526**	**$787,127**
	Change	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
OEB IR#23	Regulatory Increase/over 4 years	**$789,745**	**6.33%**	**$12,467,222**	**$19,761,091**	**$2,964,164**	**$735,424**	**$82,441**	**$2,086,850**	**$3,694,461**	**$3,463,330**	**$777,931**
VECC IR#11	Change	-$60	$0	-$938	-$6,250	-$937	$0	-$2,887	-$6,250	-$9,196	-$9,196	-$9,196
SEC IR#11	IFRS Increase over 4 years	**$789,983**	**6.33%**	**$12,470,972**	**$19,786,091**	**$2,967,914**	**$735,424**	**$82,482**	**$2,111,850**	**$3,719,739**	**$3,488,609**	**$803,210**
	Change	$238	$0	$3,750	$25,000	$3,750	$0	$41	$25,000	$25,278	$25,279	$25,279
OEB IR#15	Capital 08 & 09 Amortization Change	**$772,976**	**6.33%**	**$12,202,496**	**$19,786,091**	**$2,967,914**	**$725,027**	**$82,898**	**$2,111,850**	**$3,692,751**	**$3,461,620**	**$776,221**
VECC IR#10	Change	-$17,007	$0	-$268,476	$0	$0	-$10,397	$416	$0	-$26,988	-$26,989	-$26,989
	Proposed at December 15, 2008	**$772,976**	**6.33%**	**$12,202,496**	**$19,786,091**	**$2,967,914**	**$725,027**	**$82,898**	**$2,111,850**	**$3,692,751**	**$3,461,620**	**$776,221**
	2006 EDR	**$545,706**	**6.90%**	**$7,914,515**	**$17,750,988**	**$2,662,648**	**$435,963**	**$168,350**	**$1,708,708**	**$2,858,727**	**$2,629,071**	
	Change - 2009 Proposed vs. 2006 EDR	**42%**		**54%**	**11%**	**11%**	**66%**	**-51%**	**24%**	**29%**	**32%**	
		$227,270		**$4,287,981**	**$2,035,103**	**$305,266**	**$289,064**	**-$85,452**	**$403,142**	**$834,024**	**$832,549**	
	Change - Proposed vs. Original	**-1%**		**-1%**	**5%**	**5%**	**-1%**	**-60%**	**1%**	**-3%**	**-3%**	**-13%**
		-$7,358		**-$116,158**	**$1,015,457**	**$152,319**	**-$10,397**	**-$122,095**	**$18,750**	**-$121,101**	**-$121,101**	**-$121,101**

Midland is proposing to make the above-noted rate adjustments and other adjustments as directed by the Board in their Decision. Midland has prepared the following summary showing the rate impacts on Residential and GS customers:

Residential RPP: Summer

1,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$11.37			$12.81	$1.44	12.7%
Distribution	kWh	1,000	$0.0198	$19.80	1,000	$0.0198	$19.80		
Sub-Total (Distribution)				**$31.17**			**$32.61**	**$1.44**	**4.6%**
Deferral/Variance	kWh	1,000			1,000	$0.0004	$0.40	$0.40	
Electricity (Commodity)	kWh	1,065	RPP-Summer	$57.44	1,065	RPP-Summer	$57.44		
Transmission - Network	kWh	1,065	$0.0038	$4.05	1,065	$0.0047	$5.01	$0.96	23.7%
Transmission - Connection	kWh	1,065	$0.0071	$7.56	1,065	$0.0044	$4.69	($2.87)	(38.0%)
Wholesale Market Service	kWh	1,065	$0.0052	$5.54	1,065	$0.0052	$5.54		
Rural Rate Protection	kWh	1,065	$0.0010	$1.07	1,065	$0.0010	$1.07		
Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
TOTAL BILL				**$113.83**			**$113.76**	**($0.07)**	**(0.1%)**

General Service <50 kW RPP: Summer

2,000 kWh's

		2008 BILL			2009 BILL			CHANGE IMPACT	
	Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
Monthly Service Charge				$12.61			$16.09	$3.48	27.6%
Distribution	kWh	2,000	$0.0140	$28.00	2,000	$0.0164	$32.80	$4.80	17.1%
Sub-Total (Distribution)				**$40.61**			**$48.89**	**$8.28**	**20.4%**
Deferral/Variance	kWh	2,000			2,000	$0.0004	$0.80	$0.80	
Electricity (Commodity)	kWh	2,130	RPP-Summer	$120.28	2,130	RPP-Summer	$120.28		
Transmission - Network	kWh	2,130	$0.0034	$7.24	2,130	$0.0042	$8.95	$1.71	23.6%
Transmission - Connection	kWh	2,130	$0.0065	$13.85	2,130	$0.0040	$8.52	($5.33)	(38.5%)
Wholesale Market Service	kWh	2,130	$0.0052	$11.08	2,130	$0.0052	$11.08		
Rural Rate Protection	kWh	2,130	$0.0010	$2.13	2,130	$0.0010	$2.13		
Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
TOTAL BILL				**$209.19**			**$214.65**	**$5.46**	**2.6%**

General Service >50 Kw RPP: n/a

750,000 kWh's 1,800 kW's	Metric	2008 BILL			2009 BILL			CHANGE IMPACT	
		Volume	Rate	Charge	Volume	Rate	Charge		%
Monthly Service Charge				$14.05			$58.99	$44.94	>100%
Distribution	kW	1,800	$2.3148	$4,166.64	1,800	$4.0971	$7,374.78	$3,208.14	77.0%
Sub-Total (Distribution)				**$4,180.69**			**$7,433.77**	**$3,253.08**	**77.8%**
Deferral/Variance	kW	1,800			1,800	$0.1645	$296.10	$296.10	
Electricity (Commodity)	kWh	798,825	$0.0603	$48,169.15	798,825	$0.0603	$48,169.15		
Transmission - Network	kW	1,800	$1.4180	$2,552.40	1,800	$1.7676	$3,181.68	$629.28	24.7%
Transmission - Connection	kW	1,800	$2.5532	$4,595.76	1,800	$1.5852	$2,853.36	($1,742.40)	(37.9%)
Wholesale Market Service	kWh	798,825	$0.0052	$4,153.89	798,825	$0.0052	$4,153.89		
Rural Rate Protection	kWh	798,825	$0.0010	$798.83	798,825	$0.0010	$798.83		
Debt Retirement Charge	kWh	750,000	$0.0070	$5,250.00	750,000	$0.0070	$5,250.00		
TOTAL BILL				**$69,700.72**			**$72,136.78**	**$2,436.06**	**3.5%**

Midland is providing the summary in response to Procedural Order #1 issued on October 29, 2008. We have used each of the interrogatory documents as a template for our responses. Each response is presented after each question in the document.

Midland has prepared the responses in as much detail as we hope will alleviate any misinterpretation, however, please do not hesitate to contact the undersigned should you require any further information or clarification of our responses.

Respectfully Submitted,

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President & CEO
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2009 Electricity Distribution Rates
Midland Power Utility Corporation ("Midland")

Response to Board Staff Interrogatories
(EB-2008-0236)

General – Economic Assumptions

1.

a) Given the general economic situation in Ontario has Midland assessed the situation and identified any specific issues that may have a material impact on its load and revenue forecasts and bad debt expense forecast?

b) If so, please indicate if Midland will be updating its current application, in whole or in part, to address any material impacts. If yes, please provide an estimate of the timing of the update.

RESPONSE:

1 a) With respect to the load forecast, Midland took into consideration the impact the loss of the bankruptcies referred to below had on our consumption levels and consequently, used two years history to forecast future loads rather than the 5 year trend. In 2008, a GS>50kW customer filed for bankruptcy. The impact on Midland's load is less than 2% of the total load in this class.

Midland's bad debt expenses over the past few years have given a strong indication of the downturn in the economy. Midland's customer base includes an auto manufacturing environment which has, in 2006 and 2007 produced two bankruptcies. As indicated in Ex1/T1/S7, Midland believed, given this history, in order to mitigate any further risks our bad debt expense at $80,000 per year would be reasonable and consistent.

b) In light of the above assumptions, Midland will not be updating our current application with respect to bad debts or load and revenue forecasts.

Cost Allocation and Rate Design

2.

[Ex8/T1/S2/Pg1]

Please file Sheets O1 and O2 from the Cost Allocation Informational Filing EB-2006-0247 as an official part of the record of this Application. Please file Run 1 or 2, whichever one is more closely representative of Midland's situation. Alternatively, file a modified run that is more closely representative than either of the runs in the Informational Filing.

RESPONSE:

Sheets O1 and O2 from the Cost Allocation Informational Filing EB-2007-0002 have been filed with our Application at Ex8/T1/S1 Attachment 3 and are reproduced here for your information.

Sheet O1 Revenue to Cost Summary Worksheet - Second Run

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue (sale)	$2,790,897	$1,582,535	$432,779	$736,272	$22,871	$2,188	$14,252
mi	Miscellaneous Revenue (mi)	$229,656	$119,473	$40,877	$62,568	$5,233	$416	$1,089
	Total Revenue	**$3,020,553**	**$1,702,008**	**$473,656**	**$798,840**	**$28,104**	**$2,604**	**$15,341**
	Expenses							
di	Distribution Costs (di)	$613,172	$254,879	$94,751	$225,286	$32,844	$2,540	$2,872
cu	Customer Related Costs (cu)	$539,592	$356,271	$99,338	$70,398	$10,438	$797	$2,351
ad	General and Administration (ad)	$717,768	$373,588	$119,657	$192,082	$27,127	$2,091	$3,224
dep	Depreciation and Amortization (dep)	$435,963	$182,632	$67,731	$162,294	$19,947	$1,540	$1,820
INPUT	PILs (INPUT)	$168,350	$64,313	$24,061	$71,835	$6,946	$533	$661
INT	Interest	$189,553	$72,413	$27,091	$80,883	$7,821	$600	$744
	Total Expenses	**$2,664,398**	**$1,304,096**	**$432,629**	**$802,778**	**$105,123**	**$8,101**	**$11,671**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$356,153	$136,058	$50,902	$151,971	$14,695	$1,128	$1,398
	Revenue Requirement (includes NI)	$3,020,551	$1,440,155	$483,531	$954,749	$119,818	$9,229	$13,070
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$11,406,434	$4,517,094	$1,668,310	$4,630,475	$505,853	$39,031	$45,671
gp	General Plant - Gross	$1,962,098	$750,626	$280,685	$835,627	$81,215	$6,235	$7,711
accum dep	Accumulated Depreciation	($7,904,045)	($3,177,210)	($1,167,282)	($3,138,863)	($360,882)	($27,901)	($31,907)
co	Capital Contribution	($212,621)	($83,984)	($31,062)	($86,556)	($9,440)	($728)	($850)
	Total Net Plant	**$5,251,867**	**$2,006,527**	**$750,651**	**$2,240,683**	**$216,746**	**$16,637**	**$20,623**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$15,757,503	$3,074,409	$1,717,720	$10,820,351	$86,118	$2,338	$56,567
	OM&A Expenses	$1,870,532	$984,737	$313,746	$487,766	$70,409	$5,427	$8,446
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$17,628,035***	***$4,059,147***	***$2,031,466***	***$11,308,117***	***$156,527***	***$7,765***	***$65,013***
	Working Capital	**$2,644,205**	**$608,872**	**$304,720**	**$1,696,218**	**$23,479**	**$1,165**	**$9,752**
	Total Rate Base	**$7,896,072**	**$2,615,399**	**$1,055,371**	**$3,936,900**	**$240,225**	**$17,802**	**$30,375**
		Rate Base Input equals Output						
	Equity Component of Rate Base	**$3,948,036**	**$1,307,699**	**$527,686**	**$1,968,450**	**$120,112**	**$8,901**	**$15,188**
	Net Income on Allocated Assets	**$356,155**	**$397,912**	**$41,027**	**($3,938)**	**($77,019)**	**($5,497)**	**$3,670**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$356,155**	**$397,912**	**$41,027**	**($3,938)**	**($77,019)**	**($5,497)**	**$3,670**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES %	100.00%	118.18%	97.96%	83.67%	23.46%	28.21%	117.38%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$2	$261,853	($9,875)	($155,909)	($91,715)	($6,625)	$2,272
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.02%	30.43%	7.77%	-0.20%	-64.12%	-61.76%	24.16%

2006 COST ALLOCATION INFORMATION FILING

Midland Power Utility Corporation

EB-2005-0390 EB-2007-0002

February 15, 2007

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Second Run

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$5.55	$10.00	$57.99	$0.59	$0.58	$2.29
Customer Unit Cost per month - Directly Related	$8.73	$16.11	$89.26	$0.96	$0.94	$3.78
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.13	$22.64	$91.76	$6.75	$6.72	$7.84
Fixed Charge per approved 2006 EDR	$11.27	$12.50	$13.93	$0.95	$1.45	$12.24

Information to be Used to Allocate PILs, ROD, ROE and A&G	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
General Plant - Gross Assets	$1,962,098	$750,626	$280,685	$835,627	$81,215	$6,235	$7,711
General Plant - Accumulated Depreciation	($1,599,174)	($611,785)	($228,767)	($681,063)	($66,193)	($5,082)	($6,284)
General Plant - Net Fixed Assets	$362,924	$138,841	$51,918	$154,564	$15,022	$1,153	$1,426
General Plant - Depreciation	$90,291	$34,542	$12,916	$38,454	$3,737	$287	$355
Total Net Fixed Assets Excluding General Plant	$4,888,943	$1,867,685	$698,734	$2,086,119	$201,724	$15,484	$19,197
Total Administration and General Expense	$717,768	$373,588	$119,657	$192,082	$27,127	$2,091	$3,224
Total O&M	$1,152,764	$611,149	$194,089	$295,684	$43,282	$3,337	$5,223

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

			1	2	3	7	8	9
USoA Account #	**Accounts**	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
	Distribution Plant							
1860	Meters	$849,424	$466,388	$143,252	$239,784	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($513,533)	($281,962)	($86,605)	($144,965)	$0	$0	$0
	Meter Net Fixed Assets	**$335,891**	**$184,425**	**$56,647**	**$94,819**	**$0**	**$0**	**$0**
	Misc Revenue							
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	($16,205)	($11,330)	($2,923)	($1,818)	($10)	($4)	($121)
4220	Other Electric Revenues	($354)	($135)	($51)	($151)	($15)	($1)	($1)
4225	Late Payment Charges	($24,085)	($15,583)	($8,502)	$0	$0	$0	$0
	Sub-total	*($40,644)*	*($27,048)*	*($11,475)*	*($1,969)*	*($25)*	*($5)*	*($122)*
	Operation							
5065	Meter Expense	$7,378	$4,051	$1,244	$2,083	$0	$0	$0
5070	Customer Premises - Operation Labour	$52,627	$36,234	$4,724	$839	$9,560	$742	$527
5075	Customer Premises - Materials and Expenses	$21	$14	$2	$0	$4	$0	$0
	Sub-total	*$60,025*	*$40,299*	*$5,971*	*$2,923*	*$9,563*	*$742*	*$527*
	Maintenance							
5175	Maintenance of Meters	$67,467	$37,044	$11,378	$19,045	$0	$0	$0
	Billing and Collection							
5310	Meter Reading Expense	$135,498	$91,431	$22,359	$20,985	$723	$0	$0
5315	Customer Billing	$146,900	$102,705	$26,497	$16,479	$91	$33	$1,095
5320	Collecting	$97,294	$68,023	$17,550	$10,914	$60	$22	$725
5325	Collecting- Cash Over and Short	($17)	($12)	($3)	($2)	($0)	($0)	($0)
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
	Sub-total	$379,675	$262,147	$66,403	$48,376	$875	$55	$1,820
	Total Operation, Maintenance and Billing	$507,167	$339,490	$83,752	$70,344	$10,438	$797	$2,347
	Amortization Expense - Meters	$28,700	$15,758	$4,840	$8,102	$0	$0	$0
	Allocated PILs	$10,767	$5,911	$1,816	$3,040	$0	$0	$0
	Allocated Debt Return	$12,123	$6,656	$2,044	$3,423	$0	$0	$0
	Allocated Equity Return	$22,778	$12,506	$3,841	$6,431	$0	$0	$0
	Total	**$540,891**	**$353,272**	**$84,818**	**$89,370**	**$10,413**	**$792**	**$2,225**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Distribution Plant							
1860	Meters	$849,424	$466,388	$143,252	$239,784	$0	$0	$0
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant - Meters only	($513,533)	($281,962)	($86,605)	($144,965)	$0	$0	$0
	Meter Net Fixed Assets	$335,891	$184,425	$56,647	$94,819	$0	$0	$0
	Allocated General Plant Net Fixed Assets	$24,944	$13,710	$4,209	$7,025	$0	$0	$0
	Meter Net Fixed Assets Including General Plant	$360,835	$198,135	$60,856	$101,844	$0	$0	$0
	Misc Revenue							
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	($16,205)	($11,330)	($2,923)	($1,818)	($10)	($4)	($121)
4220	Other Electric Revenues	($354)	($135)	($51)	($151)	($15)	($1)	($1)
4225	Late Payment Charges	($24,085)	($15,583)	($8,502)	$0	$0	$0	$0
	Sub-total	*($40,644)*	*($27,048)*	*($11,475)*	*($1,969)*	*($25)*	*($5)*	*($122)*
	Operation							
5065	Meter Expense	$7,378	$4,051	$1,244	$2,083	$0	$0	$0
5070	Customer Premises - Operation Labour	$52,627	$36,234	$4,724	$839	$9,560	$742	$527
5075	Customer Premises - Materials and Expenses	$21	$14	$2	$0	$4	$0	$0
	Sub-total	*$60,025*	*$40,299*	*$5,971*	*$2,923*	*$9,563*	*$742*	*$527*
	Maintenance							
5175	Maintenance of Meters	$67,467	$37,044	$11,378	$19,045	$0	$0	$0
	Billing and Collection							
5310	Meter Reading Expense	$135,498	$91,431	$22,359	$20,985	$723	$0	$0
5315	Customer Billing	$146,900	$102,705	$26,497	$16,479	$91	$33	$1,095
5320	Collecting	$97,294	$68,023	$17,550	$10,914	$60	$22	$725
5325	Collecting- Cash Over and Short	($17)	($12)	($3)	($2)	($0)	($0)	($0)
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
	Sub-total	*$379,675*	*$262,147*	*$66,403*	*$48,376*	*$875*	*$55*	*$1,820*
	Total Operation, Maintenance and Billing	$507,167	$339,490	$83,752	$70,344	$10,438	$797	$2,347
	Amortization Expense - Meters	$28,700	$15,758	$4,840	$8,102	$0	$0	$0
	Amortization Expense - General Plant assigned to Meters	*$6,206*	*$3,411*	*$1,047*	*$1,748*	*$0*	*$0*	*$0*
	Admin and General	$313,346	$207,526	$51,634	$45,697	$6,542	$499	$1,449
	Allocated PILs	$11,566	$6,351	$1,951	$3,265	$0	$0	$0
	Allocated Debt Return	$13,023	$7,151	$2,196	$3,676	$0	$0	$0
	Allocated Equity Return	$24,469	$13,435	$4,127	$6,907	$0	$0	$0
	Total	**$863,834**	**$566,073**	**$138,071**	**$137,770**	**$16,955**	**$1,291**	**$3,674**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	1 Residential	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel	9 Unmetered Scattered Load
	Distribution Plant							
1565	Conservation and Demand Management Expenditures and Recoveries	$86,137	$45,666	$14,503	$22,094	$3,234	$249	$390
1830	Poles, Towers and Fixtures	$0	$0	$0	$0	$0	$0	$0
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1830-4	Poles, Towers and Fixtures - Primary	$390,822	$269,086	$35,086	$6,234	$70,993	$5,509	$3,914
1830-5	Poles, Towers and Fixtures - Secondary	$360,758	$249,219	$32,495	$4,565	$65,751	$5,103	$3,625
1835	Overhead Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1835-4	Overhead Conductors and Devices - Primary	$398,990	$274,710	$35,819	$6,365	$72,476	$5,624	$3,996
1835-5	Overhead Conductors and Devices - Secondary	$99,748	$68,907	$8,985	$1,262	$18,180	$1,411	$1,002
1840	Underground Conduit	$0	$0	$0	$0	$0	$0	$0
1840-3	Underground Conduit - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1840-4	Underground Conduit - Primary	$0	$0	$0	$0	$0	$0	$0
1840-5	Underground Conduit - Secondary	($0)	($0)	($0)	($0)	($0)	($0)	($0)
1845	Underground Conductors and Devices	$0	$0	$0	$0	$0	$0	$0
1845-3	Underground Conductors and Devices - Bulk Delivery	$0	$0	$0	$0	$0	$0	$0
1845-4	Underground Conductors and Devices - Primary	$844,692	$581,581	$75,831	$13,474	$153,438	$11,907	$8,461
1845-5	Underground Conductors and Devices - Secondary	$0	$0	$0	$0	$0	$0	$0
1850	Line Transformers	$645,603	$445,994	$58,152	$8,170	$117,666	$9,131	$6,488
1855	Services	$778	$446	$116	$82	$118	$9	$6
1860	Meters	$849,424	$466,388	$143,252	$239,784	$0	$0	$0
	Sub-total	*$3,676,951*	*$2,401,998*	*$404,239*	*$302,030*	*$501,856*	*$38,944*	*$27,884*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	($2,207,602)	($1,436,353)	($239,423)	($188,185)	($303,297)	($23,529)	($16,814)
	Customer Related Net Fixed Assets	$1,469,350	$965,644	$164,815	$113,846	$198,559	$15,415	$11,070
	Allocated General Plant Net Fixed Assets	$109,223	$71,785	$12,246	$8,435	$14,787	$1,148	$822
	Customer Related NFA Including General Plant	$1,578,573	$1,037,429	$177,062	$122,281	$213,346	$16,563	$11,892
	Misc Revenue							
4082	Retail Services Revenues	$0	$0	$0	$0	$0	$0	$0
4084	Service Transaction Requests (STR) Revenues	$0	$0	$0	$0	$0	$0	$0
4090	Electric Services Incidental to Energy Sales	($16,205)	($11,330)	($2,923)	($1,818)	($10)	($4)	($121)
4220	Other Electric Revenues	($354)	($135)	($51)	($151)	($15)	($1)	($1)
4225	Late Payment Charges	($24,085)	($15,583)	($8,502)	$0	$0	$0	$0
4235	Miscellaneous Service Revenues	($63,754)	($44,573)	($11,500)	($7,152)	($40)	($14)	($475)
	Sub-total	*($104,398)*	*($71,622)*	*($22,975)*	*($9,120)*	*($64)*	*($19)*	*($597)*
	Operating and Maintenance							
5005	Operation Supervision and Engineering	$48,452	$33,075	$4,369	$1,156	$8,695	$675	$482
5010	Load Dispatching	$3,547	$2,421	$320	$85	$636	$49	$35
5020	Overhead Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0
5025	Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	$0	$0	$0	$0	$0	$0	$0
5035	Overhead Distribution Transformers- Operation	$15,788	$10,907	$1,422	$200	$2,877	$223	$159
5040	Underground Distribution Lines and Feeders - Operation Labour	$0	$0	$0	$0	$0	$0	$0
5045	Underground Distribution Lines & Feeders - Operation Supplies & Expenses	$0	$0	$0	$0	$0	$0	$0
5055	Underground Distribution Transformers - Operation	$0	$0	$0	$0	$0	$0	$0
5065	Meter Expense	$7,378	$4,051	$1,244	$2,083	$0	$0	$0
5070	Customer Premises - Operation Labour	$52,627	$36,234	$4,724	$839	$9,560	$742	$527
5075	Customer Premises - Materials and Expenses	$21	$14	$2	$0	$4	$0	$0
5085	Miscellaneous Distribution Expense	$0	$0	$0	$0	$0	$0	$0
5090	Underground Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5095	Overhead Distribution Lines and Feeders - Rental Paid	$0	$0	$0	$0	$0	$0	$0
5096	Other Rent	$0	$0	$0	$0	$0	$0	$0
5105	Maintenance Supervision and Engineering	$26,045	$17,779	$2,349	$622	$4,674	$363	$259
5120	Maintenance of Poles, Towers and Fixtures	$7,758	$5,350	$698	$111	$1,412	$110	$78
5125	Maintenance of Overhead Conductors and Devices	$15,866	$10,931	$1,425	$243	$2,884	$224	$159
5130	Maintenance of Overhead Services	$0	$0	$0	$0	$0	$0	$0
5135	Overhead Distribution Lines and Feeders - Right of Way	$6,738	$4,645	$606	$99	$1,225	$95	$68
5145	Maintenance of Underground Conduit	$360	$248	$32	$5	$66	$5	$4
5150	Maintenance of Underground Conductors and Devices	$16,743	$11,528	$1,503	$267	$3,041	$236	$168
5155	Maintenance of Underground Services	$0	$0	$0	$0	$0	$0	$0
5160	Maintenance of Line Transformers	$39,379	$27,204	$3,547	$498	$7,177	$557	$396
5175	Maintenance of Meters	$67,467	$37,044	$11,378	$19,045	$0	$0	$0
	Sub-total	*$308,167*	*$201,431*	*$33,619*	*$25,254*	*$42,252*	*$3,279*	*$2,333*
	Billing and Collection							
5305	Supervision	$0	$0	$0	$0	$0	$0	$0
5310	Meter Reading Expense	$135,498	$91,431	$22,359	$20,985	$723	$0	$0
5315	Customer Billing	$146,900	$102,705	$26,497	$16,479	$91	$33	$1,095
5320	Collecting	$97,294	$68,023	$17,550	$10,914	$60	$22	$725
5325	Collecting- Cash Over and Short	($17)	($12)	($3)	($2)	($0)	($0)	($0)
5330	Collection Charges	$0	$0	$0	$0	$0	$0	$0
5335	Bad Debt Expense	$31,942	$16,443	$15,499	$0	$0	$0	$0
5340	Miscellaneous Customer Accounts Expenses	$483	$338	$87	$54	$0	$0	$4
	Sub-total	*$412,100*	*$278,928*	*$81,989*	*$48,430*	*$875*	*$55*	*$1,824*
	Sub Total Operating, Maintenance and Biling	*$720,267*	*$480,358*	*$115,608*	*$73,683*	*$43,127*	*$3,333*	*$4,157*
	Amortization Expense - Customer Related	$125,053	$80,421	$14,207	$12,131	$16,130	$1,251	$914
	Amortization Expense - General Plant assigned to Meters	$27,173	$17,859	$3,047	$2,099	$3,679	$286	$205
	Admin and General	$444,460	$293,637	$71,273	$47,866	$27,029	$2,088	$2,566
	Allocated PILs	$50,597	$33,252	$5,675	$3,920	$6,837	$531	$381
	Allocated Debt Return	$56,969	$37,440	$6,390	$4,414	$7,699	$598	$429
	Allocated Equity Return	$107,040	$70,346	$12,007	$8,294	$14,465	$1,123	$806
	PLCC Adjustment for Line Transformer	$44,102	$37,896	$4,950	$703	$0	$0	$552
	PLCC Adjustment for Primary Costs	$28,202	$24,136	$3,150	$565	$0	$0	$351
	PLCC Adjustment for Secondary Costs	$22,608	$19,709	$2,189	$375	$0	$0	$335
	Total	$1,332,251	**$859,950**	**$194,944**	**$141,644**	**$118,901**	**$9,191**	**$7,621**

Scenario 1

Accounts included in Avoided Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 849,424	$ 466,388	$ 143,252	$ 239,784	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (513,533)	$ (281,962)	$ (86,605)	$ (144,965)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 335,891	$ 184,425	$ 56,647	$ 94,819	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (16,205)	$ (11,330)	$ (2,923)	$ (1,818)	$ (10)	$ (4)	$ (121)
NFA	$ (354)	$ (135)	$ (51)	$ (151)	$ (15)	$ (1)	$ (1)
LPHA	$ (24,085)	$ (15,583)	$ (8,502)	$ -	$ -	$ -	$ -
Sub-total	$ (40,644)	$ (27,048)	$ (11,475)	$ (1,969)	$ (25)	$ (5)	$ (122)
Operation							
CWMC	$ 7,378	$ 4,051	$ 1,244	$ 2,083	$ -	$ -	$ -
CCA	$ 52,647	$ 36,248	$ 4,726	$ 840	$ 9,563	$ 742	$ 527
Sub-total	$ 60,025	$ 40,299	$ 5,971	$ 2,923	$ 9,563	$ 742	$ 527
Maintenance							
1860	$ 67,467	$ 37,044	$ 11,378	$ 19,045	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 135,498	$ 91,431	$ 22,359	$ 20,985	$ 723	$ -	$ -
CWNB	$ 244,177	$ 170,716	$ 44,044	$ 27,391	$ 152	$ 55	$ 1,820
Sub-total	$ 379,675	$ 262,147	$ 66,403	$ 48,376	$ 875	$ 55	$ 1,820
Total Operation, Maintenance and Billing	$ 507,167	$ 339,490	$ 83,752	$ 70,344	$ 10,438	$ 797	$ 2,347
Amortization Expense - Meters	$ 28,700	$ 15,758	$ 4,840	$ 8,102	$ -	$ -	$ -
Allocated PILs	$ 10,767	$ 5,911	$ 1,816	$ 3,040	$ -	$ -	$ -
Allocated Debt Return	$ 12,123	$ 6,656	$ 2,044	$ 3,423	$ -	$ -	$ -
Allocated Equity Return	$ 22,778	$ 12,506	$ 3,841	$ 6,431	$ -	$ -	$ -
Total	**$ 540,891**	**$ 353,272**	**$ 84,818**	**$ 89,370**	**$ 10,413**	**$ 792**	**$ 2,225**

Scenario 2

Accounts included in Directly Related Customer Costs Plus General Administration Allocation

Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Distribution Plant							
CWMC	$ 849,424	$ 466,388	$ 143,252	$ 239,784	$ -	$ -	$ -
Accumulated Amortization							
Accum. Amortization of Electric Utility Plant - Meters only	$ (513,533)	$ (281,962)	$ (86,605)	$ (144,965)	$ -	$ -	$ -
Meter Net Fixed Assets	$ 335,891	$ 184,425	$ 56,647	$ 94,819	$ -	$ -	$ -
Allocated General Plant Net Fixed Assets	$ 24,944	$ 13,710	$ 4,209	$ 7,025	$ -	$ -	$ -
Meter Net Fixed Assets Including General Plant	$ 360,835	$ 198,135	$ 60,856	$ 101,844	$ -	$ -	$ -
Misc Revenue							
CWNB	$ (16,205)	$ (11,330)	$ (2,923)	$ (1,818)	$ (10)	$ (4)	$ (121)
NFA	$ (354)	$ (135)	$ (51)	$ (151)	$ (15)	$ (1)	$ (1)
LPHA	$ (24,085)	$ (15,583)	$ (8,502)	$ -	$ -	$ -	$ -
Sub-total	*$ (40,644)*	*$ (27,048)*	*$ (11,475)*	*$ (1,969)*	*$ (25)*	*$ (5)*	*$ (122)*
Operation							
CWMC	$ 7,378	$ 4,051	$ 1,244	$ 2,083	$ -	$ -	$ -
CCA	$ 52,647	$ 36,248	$ 4,726	$ 840	$ 9,563	$ 742	$ 527
Sub-total	*$ 60,025*	*$ 40,299*	*$ 5,971*	*$ 2,923*	*$ 9,563*	*$ 742*	*$ 527*
Maintenance							
1860	$ 67,467	$ 37,044	$ 11,378	$ 19,045	$ -	$ -	$ -
Billing and Collection							
CWMR	$ 135,498	$ 91,431	$ 22,359	$ 20,985	$ 723	$ -	$ -
CWNB	$ 244,177	$ 170,716	$ 44,044	$ 27,391	$ 152	$ 55	$ 1,820
Sub-total	*$ 379,675*	*$ 262,147*	*$ 66,403*	*$ 48,376*	*$ 875*	*$ 55*	*$ 1,820*
Total Operation, Maintenance and Billing	$ 507,167	$ 339,490	$ 83,752	$ 70,344	$ 10,438	$ 797	$ 2,347
Amortization Expense - Meters	$ 28,700	$ 15,758	$ 4,840	$ 8,102	$ -	$ -	$ -
Amortization Expense - General Plant assigned to Meters	$ 6,206	$ 3,411	$ 1,047	$ 1,748	$ -	$ -	$ -
Admin and General	$ 313,346	$ 207,526	$ 51,634	$ 45,697	$ 6,542	$ 499	$ 1,449
Allocated PILs	$ 11,566	$ 6,351	$ 1,951	$ 3,265	$ -	$ -	$ -
Allocated Debt Return	$ 13,023	$ 7,151	$ 2,196	$ 3,676	$ -	$ -	$ -
Allocated Equity Return	$ 24,469	$ 13,435	$ 4,127	$ 6,907	$ -	$ -	$ -
Total	**$ 863,834**	**$ 566,073**	**$ 138,071**	**$ 137,770**	**$ 16,955**	**$ 1,291**	**$ 3,674**

Scenario 3

Minimum System Customer Costs Adjusted for PLCC - High Limit Fixed Customer Charge

USoA Account #	Accounts	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
	Distribution Plant							
	CDMPP	$ 86,137	$ 45,666	$ 14,503	$ 22,094	$ 3,234	$ 249	$ 390
	Poles, Towers and Fixtures	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	BCP	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	PNCP	$ 1,634,504	$ 1,125,376	$ 146,736	$ 26,073	$ 296,907	$ 23,041	$ 16,371
	SNCP	$ 460,506	$ 318,126	$ 41,480	$ 5,828	$ 83,931	$ 6,513	$ 4,628
	Overhead Conductors and Devices	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	LTNCP	$ 645,603	$ 445,994	$ 58,152	$ 8,170	$ 117,666	$ 9,131	$ 6,488
	CWCS	$ 778	$ 446	$ 116	$ 82	$ 118	$ 9	$ 6
	CWMC	$ 849,424	$ 466,388	$ 143,252	$ 239,784	$ -	$ -	$ -
	Sub-total	*$ 3,676,951*	*$ 2,401,998*	*$ 404,239*	*$ 302,030*	*$ 501,856*	*$ 38,944*	*$ 27,884*
	Accumulated Amortization							
	Accum. Amortization of Electric Utility Plant -Line Transformers, Services and Meters	$ (2,207,602)	$ (1,436,353)	$ (239,423)	$ (188,185)	$ (303,297)	$ (23,529)	$ (16,814)
	Customer Related Net Fixed Assets	$ 1,469,350	$ 965,644	$ 164,815	$ 113,846	$ 198,559	$ 15,415	$ 11,070
	Allocated General Plant Net Fixed Assets	$ 109,223	$ 71,785	$ 12,246	$ 8,435	$ 14,787	$ 1,148	$ 822
	Customer Related NFA Including General Plant	$ 1,578,573	$ 1,037,429	$ 177,062	$ 122,281	$ 213,346	$ 16,563	$ 11,892
	Misc Revenue							
	CWNB	$ (79,959)	$ (55,903)	$ (14,423)	$ (8,970)	$ (50)	$ (18)	$ (596)
	NFA	$ (354)	$ (135)	$ (51)	$ (151)	$ (15)	$ (1)	$ (1)
	LPHA	$ (24,085)	$ (15,583)	$ (8,502)	$ -	$ -	$ -	$ -
	Sub-total	*$ (104,398)*	*$ (71,622)*	*$ (22,975)*	*$ (9,120)*	*$ (64)*	*$ (19)*	*$ (597)*
	Operating and Maintenance							
	1815-1855	$ 78,044	$ 53,275	$ 7,038	$ 1,863	$ 14,006	$ 1,087	$ 776
	1830 & 1835	$ 6,738	$ 4,645	$ 606	$ 99	$ 1,225	$ 95	$ 68
	1850	$ 55,167	$ 38,110	$ 4,969	$ 698	$ 10,055	$ 780	$ 554
	1840 & 1845	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	CWMC	$ 7,378	$ 4,051	$ 1,244	$ 2,083	$ -	$ -	$ -
	CCA	$ 52,647	$ 36,248	$ 4,726	$ 840	$ 9,563	$ 742	$ 527
	O&M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1830	$ 7,758	$ 5,350	$ 698	$ 111	$ 1,412	$ 110	$ 78
	1835	$ 15,866	$ 10,931	$ 1,425	$ 243	$ 2,884	$ 224	$ 159
	1855	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	1840	$ 360	$ 248	$ 32	$ 5	$ 66	$ 5	$ 4
	1845	$ 16,743	$ 11,528	$ 1,503	$ 267	$ 3,041	$ 236	$ 168
	1860	$ 67,467	$ 37,044	$ 11,378	$ 19,045	$ -	$ -	$ -
	Sub-total	*$ 308,167*	*$ 201,431*	*$ 33,619*	*$ 25,254*	*$ 42,252*	*$ 3,279*	*$ 2,333*
	Billing and Collection							
	CWNB	$ 244,659	$ 171,053	$ 44,131	$ 27,445	$ 152	$ 55	$ 1,824
	CWMR	$ 135,498	$ 91,431	$ 22,359	$ 20,985	$ 723	$ -	$ -
	BDHA	$ 31,942	$ 16,443	$ 15,499	$ -	$ -	$ -	$ -
	Sub-total	*$ 412,100*	*$ 278,928*	*$ 81,989*	*$ 48,430*	*$ 875*	*$ 55*	*$ 1,824*
	Sub Total Operating, Maintenance and Biling	*$ 720,267*	*$ 480,358*	*$ 115,608*	*$ 73,683*	*$ 43,127*	*$ 3,333*	*$ 4,157*
	Amortization Expense - Customer Related	$ 125,053	$ 80,421	$ 14,207	$ 12,131	$ 16,130	$ 1,251	$ 914
	Amortization Expense - General Plant assigned to Meters	$ 27,173	$ 17,859	$ 3,047	$ 2,099	$ 3,679	$ 286	$ 205
	Admin and General	$ 444,460	$ 293,637	$ 71,273	$ 47,866	$ 27,029	$ 2,088	$ 2,566
	Allocated PILs	$ 50,597	$ 33,252	$ 5,675	$ 3,920	$ 6,837	$ 531	$ 381
	Allocated Debt Return	$ 56,969	$ 37,440	$ 6,390	$ 4,414	$ 7,699	$ 598	$ 429
	Allocated Equity Return	$ 107,040	$ 70,346	$ 12,007	$ 8,294	$ 14,465	$ 1,123	$ 806
	PLCC Adjustment for Line Transformer	$ 44,102	$ 37,896	$ 4,950	$ 703	$ -	$ -	$ 552
	PLCC Adjustment for Primary Costs	$ 28,202	$ 24,136	$ 3,150	$ 565	$ -	$ -	$ 351
	PLCC Adjustment for Secondary Costs	$ 22,608	$ 19,709	$ 2,189	$ 375	$ -	$ -	$ 335
	Total	**$ 1,332,251**	**$ 859,950**	**$ 194,944**	**$ 141,644**	**$ 118,901**	**$ 9,191**	**$ 7,621**

3.

[Ex1/T1/S6/Pg6]

Preamble: Midland states at Ex1/T1/S6/page6 with respect to revenue-to-cost ratios that, Midland "is proposing to bring the Street Light[ing] customer revenue to cost ratio to 49%." Midland makes a similar comment in respect of Sentinel Lighting. Midland is scheduled for to file incentive rate mechanism (IRM) applications in 2010, 2011, and 2012.

Staff has prepared the following table regarding revenue-to-cost (R/C) ratios and included Midland's proposed cost allocation ratios for 2009.

a. Please complete the non-shaded cells in the table for Midland's intended cost allocation ratios for 2010 and 2011.

Table XX: Cost allocation ratios for Midland

Class	CA Report[1] Range	CA Info. Filing	2009 Rate Application, as requested	2010 IRM	2011 IRM
Residential	85-115	118.18	107		
GS < 50	80-120	97.96	98		
GS > 50 kW – regular	80-120	83.67	98		
Street Lighting	70-120	23.46	49		
Sentinel Lighting	70-120	28.21	49		
USL	80-120	117.38	100		

b. Please confirm that Midland proposes to implement the ratios in the 2010 and 2011 columns in the table in part (a) in its 2010 and 2011 IRM rate applications.

[1] Report of the Board, *Application of Cost Allocation for Electricity Distributors,* November 28, 2007

RESPONSE:

(a)

Table XX: Cost allocation ratios for Midland

Class	CA Report[2] Range	CA Info. Filing	2009 Rate Application, as requested	2010 IRM	2011 IRM
Residential	85-115	118.18	107		
GS < 50	80-120	97.96	98		
GS > 50 kW – regular	80-120	83.67	98		
Street Lighting	70-120	23.46	49	60	70
Sentinel Lighting	70-120	28.21	49	60	70
USL	80-120	117.38	100		

Midland proposes to implement the increases to Street Lighting and Sentinel Lighting classes in 2010 and 2011 with an offsetting decrease to the Residential class.

(b) Midland confirms it will be implementing the ratios in the 2010 and 2011 IRM Rate Applications.

4.

The total bill impact for the GS > 50 kW rate class is an increase of 16% over the previous rate. Please provide the drivers behind this rate of increase.

RESPONSE:

Midland's total bill impact for the GS>50kW rate class is an increase of 5.8% over the previous rate as indicated at E1/T1/S6/Pg3.

[2] Report of the Board, *Application of Cost Allocation for Electricity Distributors,* November 28, 2007

Retail Transmission Service Rates (RTSR)

5.

Reference: "Electricity Distribution Retail Transmission Service Rates", Guideline G-2008-0001, October 22, 2008

Under the OEB Guideline, Midland is expected to file an update to its Cost of Service application with evidence to support a change in its RTSRs. The adjustment in RTSRs is intended to eliminate future growth in the Applicant's variance accounts that are related to the pass-through of transmission costs.

a. Please file a table showing 2 years of Midland's wholesale Network and Connection costs, and its retail billings for Network and Connection service to its retail customers.
b. Please provide an analysis of the variances between costs and the corresponding revenues, and any trends in these amounts.
c. Please file proposed RTSR rates for each customer class that are an adjustment to the currently approved RTSRs and would recover the wholesale cost of transmission service assuming that the Uniform Transmission Rates effective January 1, 2009 had been in effect during the 2-year period in part a). Please provide the calculations used to derive the proposed RTSR rates.

RESPONSE:

a) The following tables represent Midland wholesale Network and Connection costs, in the months the invoices were received, from Hydro One from January 2006 to October 31, 2008.

Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
NW	$ 99,855.99	$ 103,784.04	$ 100,054.35	$ 96,606.54	$ 92,300.04	$ 87,627.95	$ 98,448.84	$ 92,274.84	$ 101,767.68	$ 89,205.48	$ 84,677.04	$ 87,834.60	$ 1,134,437.39
CN	$ 84,552.39	$ 87,878.44	$ 84,720.35	$ 81,800.94	$ 78,154.44	$ 74,001.42	$ 81,650.03	$ 76,529.53	$ 84,402.56	$ 73,984.01	$ 70,228.18	$ 72,846.95	$ 950,749.24
	$ 184,408.38	$ 191,662.48	$ 184,774.70	$ 178,407.48	$ 170,454.48	$ 161,629.37	$ 180,098.87	$ 168,804.37	$ 186,170.24	$ 163,189.49	$ 154,905.22	$ 160,681.55	$ 2,085,186.63

Description	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
NW	$ 95,064.48	$ 99,421.56	$ 99,368.64	$ 98,683.20	$ 104,167.00	$ 87,824.52	$ 93,764.16	$ 103,950.00	$ 99,043.56	$ 94,835.16	$ 96,941.88	$ 82,792.08	$ 1,155,856.24
CN	$ 78,843.16	$ 82,456.77	$ 82,412.88	$ 81,844.40	$ 101,585.60	$ 72,838.59	$ 77,764.72	$ 86,212.50	$ 82,143.27	$ 78,652.97	$ 80,400.21	$ 68,664.86	$ 973,819.93
	$ 173,907.64	$ 181,878.33	$ 181,781.52	$ 180,527.60	$ 205,752.60	$ 160,663.11	$ 171,528.88	$ 190,162.50	$ 181,186.83	$ 173,488.13	$ 177,342.09	$ 151,456.94	$ 2,129,676.17

Description	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
NW	$ 94,076.64	$ 92,738.52	$ 95,505.48	$ 94,953.60	$ 89,598.60	$ 79,299.76	$ 67,401.33	$ 74,981.04	$ 76,273.47	$ 75,226.46			$ 840,054.90
CN	$ 78,023.88	$ 76,914.09	$ 79,208.91	$ 78,751.20	$ 74,309.95	$ 66,885.88	$ 63,042.04	$ 70,131.52	$ 71,552.80	$ 70,398.48			$ 729,218.75
	$ 172,100.52	$ 169,652.61	$ 174,714.39	$ 173,704.80	$ 163,908.55	$ 146,185.64	$ 130,443.37	$ 145,112.56	$ 147,826.27	$ 145,624.94	$ -	$ -	$ 1,569,273.65

The following two tables represent Midland’s Wholesale Network and Connection monthly billings to its retail customers from January, 2006 to October, 2008.

NW Billings

Customer Class	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential	$ 36,993.24	$ 34,281.78	$ 31,584.75	$ 24,492.94	$ 26,004.67	$ 14,621.49	$ 16,756.47	$ 19,967.06	$ 20,033.29	$ 16,218.52	$ 15,267.37	$ 19,888.62	$ 276,110.20
GS<50	$ 12,654.26	$ 12,531.87	$ 12,387.83	$ 11,094.14	$ 12,429.49	$ 8,246.60	$ 9,132.13	$ 11,031.69	$ 10,694.55	$ 8,817.68	$ 7,842.69	$ 9,278.72	$ 126,141.65
GS>50	$ 52,092.70	$ 63,882.32	$ 62,384.72	$ 61,631.69	$ 64,463.41	$ 47,150.14	$ 50,503.83	$ 63,584.67	$ 53,550.30	$ 52,133.11	$ 52,625.20	$ 50,000.50	$ 674,002.59
Street Lights	$ 412.04	$ 412.04	$ 412.04	$ 412.04	$ 335.84	$ 335.84	$ 335.84	$ 341.98	$ 341.98	$ 341.98	$ 341.98	$ 346.66	$ 4,370.26
Sentinel Lights	$ 14.61	$ 1.70	$ 9.62	$ 8.66	$ 8.66	$ 7.66	$ 7.07	$ 7.50	$ 7.07	$ 7.07	$ 6.09	$ 4.66	$ 90.37
USL					$ 1.09	$ 320.82	$ 293.73	$ 268.87	$ 270.21	$ 265.30	$ 266.28	$ 257.17	$ 1,943.47
	$ 102,166.85	$ 111,109.71	$ 106,778.96	$ 97,639.47	$ 103,243.16	$ 70,682.55	$ 77,029.07	$ 95,201.77	$ 84,897.40	$ 77,783.66	$ 76,349.61	$ 79,776.33	$ 1,082,658.54

Customer Class	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Residential	$ 21,231.00	$ 23,552.14	$ 24,804.72	$ 25,481.07	$ 13,350.83	$ 17,016.69	$ 17,033.53	$ 17,683.08	$ 19,146.36	$ 17,670.44	$ 15,603.98	$ 19,351.42	$ 231,925.26
GS<50	$ 9,460.72	$ 10,318.47	$ 13,692.54	$ 12,465.78	$ 6,491.06	$ 9,315.12	$ 9,439.43	$ 10,310.88	$ 10,087.50	$ 10,290.10	$ 8,855.86	$ 9,587.97	$ 120,315.43
GS>50	$ 49,913.52	$ 51,360.06	$ 46,322.47	$ 53,047.57	$ 46,338.45	$ 54,121.01	$ 51,844.33	$ 51,954.18	$ 52,088.98	$ 51,748.48	$ 50,134.04	$ 49,015.12	$ 607,888.21
Street Lights	$ 346.11	$ 346.11	$ 346.11	$ 346.11	$ 346.11	$ 346.81	$ 346.81	$ 346.81	$ 346.81	$ 346.81	$ 346.81	$ 346.81	$ 4,158.22
Sentinel Lights	$ 4.89	$ 4.71	$ 4.72	$ 5.31	$ 5.11	$ 4.76	$ 4.48	$ 4.18	$ 4.83	$ 4.83	$ 5.11	$ 4.83	$ 57.76
USL	$ 189.46	$ 187.63	$ 186.15	$ 346.72	$ 32.61	$ 199.90	$ 183.09	$ 180.75	$ 186.41	$ 182.47	$ 192.79	$ 191.53	$ 2,259.51
	$ 81,145.70	$ 85,769.12	$ 85,356.71	$ 91,692.56	$ 66,564.17	$ 81,004.29	$ 78,851.67	$ 80,479.88	$ 81,860.89	$ 80,243.13	$ 75,138.59	$ 78,497.68	$ 966,604.39

Customer Class	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Residential	$ 23,241.26	$ 25,095.41	$ 23,427.99	$ 22,723.08	$ 16,198.65	$ 14,486.41	$ 14,442.48	$ 15,048.48	$ 15,776.68	$ 14,647.72			$ 185,088.16
GS<50	$ 10,111.38	$ 11,206.60	$ 10,111.02	$ 10,581.47	$ 8,462.47	$ 7,271.15	$ 7,495.94	$ 7,751.07	$ 8,254.05	$ 7,979.17			$ 89,224.32
GS>50	$ 49,348.36	$ 50,008.97	$ 49,619.47	$ 47,865.92	$ 49,401.73	$ 40,756.24	$ 41,423.93	$ 40,705.24	$ 41,632.19	$ 41,425.42			$ 452,187.47
Street Lights	$ 346.81	$ 346.81	$ 346.81	$ 346.81	$ 346.81	$ 57.36	$ 70.57	$ 70.62	$ 70.62	$ 112.93			$ 2,116.15
Sentinel Lights	$ 4.48	$ 5.44	$ 4.83	$ 4.94	$ 4.65	$ 4.04	$ 3.72	$ 3.97	$ 3.84	$ 3.97			$ 43.88
USL	$ 192.32	$ 192.29	$ 190.73	$ 192.32	$ 191.53	$ 187.04	$ 170.78	$ 155.65	$ 155.65	$ 155.01			$ 1,783.32
	$ 83,244.61	$ 86,855.52	$ 83,700.85	$ 81,714.54	$ 74,605.84	$ 62,762.24	$ 63,607.42	$ 63,735.03	$ 65,893.03	$ 64,324.22	$ -	$ -	$ 730,443.30

CN Billings

Customer Class	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential	$ 27,894.23	$ 29,951.89	$ 27,664.97	$ 21,470.67	$ 23,348.14	$ 20,659.33	$ 27,320.59	$ 32,555.70	$ 32,663.27	$ 26,442.94	$ 24,892.81	$ 32,058.40	$ 326,922.94
GS<50	$ 10,950.80	$ 10,844.68	$ 10,720.25	$ 9,600.72	$ 10,889.23	$ 11,421.75	$ 14,786.46	$ 17,860.75	$ 17,314.84	$ 14,276.30	$ 12,697.62	$ 14,587.77	$ 155,951.17
GS>50	$ 43,950.69	$ 53,859.15	$ 52,636.85	$ 51,985.45	$ 54,712.94	$ 70,272.52	$ 81,305.61	$ 96,199.41	$ 83,321.04	$ 81,223.98	$ 81,902.40	$ 77,882.16	$ 829,252.20
Street Lights	$ 355.97	$ 355.97	$ 355.97	$ 358.26	$ 538.45	$ 538.45	$ 538.45	$ 544.80	$ 544.80	$ 544.80	$ 544.80	$ 544.80	$ 5,765.52
Sentinel Lights	$ 12.81	$ 1.48	$ 8.44	$ 7.59	$ 7.59	$ 11.79	$ 11.42	$ 12.19	$ 11.37	$ 11.42	$ 9.84	$ 7.61	$ 113.55
USL					$ 1.14	$ 418.20	$ 475.54	$ 435.31	$ 437.44	$ 429.51	$ 431.10	$ 416.36	$ 3,044.60
	$ 83,164.50	$ 95,013.17	$ 91,386.48	$ 83,422.69	$ 89,497.49	$ 103,322.04	$ 124,438.07	$ 147,608.16	$ 134,292.76	$ 122,928.95	$ 120,478.57	$ 125,497.10	$ 1,321,049.98

Customer Class	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Residential	$ 34,616.19	$ 38,400.31	$ 40,442.74	$ 41,545.29	$ 21,772.75	$ 27,757.68	$ 27,779.04	$ 28,837.49	$ 31,223.46	$ 28,817.60	$ 25,447.76	$ 31,558.33	$ 378,198.64
GS<50	$ 15,317.26	$ 16,705.77	$ 19,980.03	$ 20,182.85	$ 10,509.10	$ 15,081.30	$ 15,282.93	$ 16,693.34	$ 16,332.02	$ 16,660.34	$ 14,338.33	$ 15,523.39	$ 192,606.66
GS>50	$ 77,871.76	$ 80,120.32	$ 75,465.74	$ 82,554.14	$ 72,443.09	$ 85,035.89	$ 81,263.95	$ 81,424.10	$ 81,496.09	$ 81,311.84	$ 78,252.88	$ 76,333.70	$ 953,573.50
Street Lights	$ 544.80	$ 544.80	$ 552.47	$ 552.47	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 6,614.38
Sentinel Lights	$ 7.90	$ 7.57	$ 7.62	$ 8.57	$ 8.31	$ 7.78	$ 7.27	$ 6.75	$ 7.78	$ 7.78	$ 8.31	$ 7.78	$ 93.42
USL	$ 306.76	$ 303.77	$ 301.37	$ 561.35	$ 52.79	$ 323.64	$ 296.46	$ 292.70	$ 301.84	$ 295.41	$ 312.13	$ 310.07	$ 3,658.29
	$ 128,664.67	$ 136,082.54	$ 136,749.97	$ 145,404.67	$ 105,338.52	$ 128,758.77	$ 125,182.13	$ 127,806.86	$ 129,913.67	$ 127,645.45	$ 118,911.89	$ 124,285.75	$ 1,534,744.89

Customer Class	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Residential	$ 37,904.49	$ 40,928.30	$ 38,205.23	$ 37,055.24	$ 26,418.60	$ 25,609.59	$ 26,983.60	$ 28,117.78	$ 29,478.54	$ 27,363.93			$ 318,065.30
GS<50	$ 16,370.65	$ 18,143.91	$ 16,370.18	$ 17,131.82	$ 13,708.59	$ 12,975.87	$ 14,329.26	$ 14,818.42	$ 15,779.86	$ 15,254.87			$ 154,883.43
GS>50	$ 76,912.88	$ 77,802.75	$ 77,964.01	$ 74,685.76	$ 77,417.76	$ 73,112.14	$ 75,998.62	$ 74,584.84	$ 76,398.32	$ 75,964.39			$ 760,841.47
Street Lights	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 524.86	$ 524.86	$ 524.86	$ 524.86	$ 524.86			$ 5,386.70
Sentinel Lights	$ 7.27	$ 8.83	$ 7.78	$ 8.03	$ 7.50	$ 7.37	$ 6.94	$ 7.44	$ 7.23	$ 7.44			$ 75.83
USL	$ 311.36	$ 311.38	$ 308.78	$ 311.36	$ 310.07	$ 307.41	$ 296.38	$ 297.62	$ 297.62	$ 296.38			$ 3,048.36
	$ 132,059.13	$ 137,747.65	$ 133,408.46	$ 129,744.69	$ 118,415.00	$ 112,537.24	$ 118,139.66	$ 118,350.96	$ 122,486.43	$ 119,411.87	$ -	$ -	$ 1,242,301.09

b) The following table represents the variance analysis of the RSTR deferral accounts from January 2006 to October 2008.

APH	Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Ytd change	Account Balance at Dec 31, 2005	Account Balance at Dec 31, 2006
1584	RSVANW	2,773	(8,035)	(6,502)	(1,033)	101,643	16,907	21,440	(2,833)	16,954	11,564	8,565	(78,891)	82,552	(99,259)	(16,707)
1586	RSVACN	1,899	(5,950)	(8,457)	253	(935,048)	(29,423)	(42,994)	(71,436)	(50,498)	(49,728)	(51,515)	(126,750)	(1,369,646)	917,939	(451,706)
	Total	4,673	(13,984)	(14,959)	(780)	(833,405)	(12,516)	(21,554)	(74,268)	(33,543)	(38,164)	(42,950)	(205,641)	(1,101,630)	818,681	(468,413)

APH	Description	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Ytd change	Account Balance at Dec 31, 2006	Account Balance at Dec 31, 2007
1584	RSVANW	101,684	8,272	14,362	7,394	50,632	7,443	15,561	24,176	17,978	15,556	15,373	5,383	283,814	(16,707)	267,107
1586	RSVACN	21,283	(60,980)	(56,218)	(65,649)	(3,485)	(58,257)	(49,968)	(44,326)	(50,661)	(52,434)	(49,620)	(59,470)	(529,785)	(451,706)	(981,491)
	Total	122,967	(52,708)	(41,856)	(58,255)	47,147	(50,814)	(34,407)	(20,150)	(32,683)	(36,878)	(34,246)	(54,087)	(245,971)	(468,413)	(714,384)

APH	Description	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Ytd change	Account Balance at Dec 31, 2007	Account Balance at Oct 31, 2008
1584	RSVANW	11,939	7,031	12,988	14,214	16,579	17,611	4,351	12,183	11,349	11,940	-	-	120,184	267,107	387,291
1586	RSVACN	(58,122)	(65,152)	(58,778)	(54,812)	(47,688)	(49,792)	(59,228)	(51,902)	(54,751)	(52,973)	-	-	(553,199)	(981,491)	(1,534,690)
	Total	(46,184)	(58,121)	(45,791)	(40,598)	(31,108)	(32,181)	(54,877)	(39,719)	(43,402)	(41,034)	-	-	(433,016)	(714,384)	(1,147,400)

c) The OEB issued guidelines to change the Hydro One Retail Transmission Service Rates (RTSR) on October 22, 2008. These changes have not been reflected in Midland's Rate Application which was filed on August 15, 2008. As the 2008 variance balances in response to question (b) above show, the Network variance as at October 31, 2008 totalled $387,291 and the Connection variance totaled ($1,534,690). Midland completed the table shown below to reflect the Hydro One RTSR changes, along with Midland's proposed further changes in order to mitigate large variances in the deferral accounts.

Midland is an embedded utility which means we are charged retail transmission rates from Hydro One for the transmission service provided to our customers. We do not pay the IESO for transmission. As a result, there could be differences between the retail transmission rates charged by Hydro One and those charged by the IESO for transmission service to an LDC that is directly connected.

MPUC Proposed Retail Transmission Service Rates

RTS Category	Customer Class	Unit of Measure	2009 Test Year Rates	Uniform Transmission Rates % Inc/Dec	MPUC 2008 Variance Account Averages % Inc/Dec	Proposed 2009 Updated RTSR
Network	Residential	kWh	0.0038	1.113	1.1200	0.0047
	GS<50	kWh	0.0034	1.113	1.1200	0.0042
	GS>50	kW	1.4180	1.113	1.1200	1.7676
	Street Lights	kW	1.0694	1.113	1.1200	1.3331
	Sentinel Lights	kW	1.0749	1.113	1.1200	1.3399
	USL	kWh	0.0034	1.113	1.1200	0.0042
Connection	Residential	kWh	0.0071	1.055	0.5885	0.0044
	GS<50	kWh	0.0065	1.055	0.5885	0.0040
	GS>50	kW	2.5532	1.055	0.5885	1.5852
	Street Lights	kW	1.9738	1.055	0.5885	1.2255
	Sentinel Lights	kW	2.0150	1.055	0.5885	1.2510
	USL	kWh	0.0065	1.055	0.5885	0.0040

The monthly customer billings provided in question a) for the period January, 2006 to October, 2008 were then used to calculate kWh/KW consumption figures for each class during each year. These consumption figures were then multiplied by the 2009 Proposed RTSR rates above to calculate the Network and Connection revenues. Similarly, the Network and Connection KW charges billed to Midland by Hydro One were multiplied by the 2009 proposed rates from Hydro One to calculate the costs. The revenue and costs for both Network and Connection charges per year are summarized below, along with the resulting variance analysis balance.

The data shown in black represents the historical information and rates. The data shown in blue represents the RTSR revenue and costs assuming that the 2009 Proposed Retail Transmission Service Rates had been in effect during the period January, 2006 to October, 2008. The data shown in red represents the resulting variance between the blue data – revenue and costs.

NW Variance Analysis - Using UTR Increases and MPUC Proposed Increases

NW Billings

Customer Class	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential	36,993.24	34,281.78	31,584.75	24,492.94	26,004.67	14,621.49	16,756.47	19,967.06	20,033.29	16,218.52	15,267.37	19,888.62	276,110.20
GS<50	12,654.26	12,531.87	12,387.83	11,094.14	12,429.49	8,246.60	9,132.13	11,031.69	10,694.55	8,817.68	7,842.69	9,278.72	126,141.65
GS>50	52,092.70	63,882.32	62,384.72	61,631.69	64,463.41	47,150.14	50,503.83	63,584.67	53,550.30	52,133.11	52,625.20	50,000.50	674,002.59
Street Lights	412.04	412.04	412.04	412.04	335.84	335.84	335.84	341.98	341.98	341.98	341.98	346.66	4,370.26
Sentinel Lights	14.61	1.70	9.62	8.66	8.66	7.66	7.07	7.50	7.07	7.07	6.09	4.66	90.37
USL					1.09	320.82	293.73	268.87	270.21	265.30	266.28	257.17	1,943.47
	102,166.85	111,109.71	106,778.96	97,639.47	103,243.16	70,682.55	77,029.07	95,201.77	84,897.40	77,783.66	76,349.61	79,776.33	1,082,658.54

Customer Class	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Residential	21,231.00	23,552.14	24,804.72	25,481.07	13,350.83	17,016.69	17,033.53	17,683.08	19,146.36	17,670.44	15,603.98	19,351.42	231,925.26
GS<50	9,460.72	10,318.47	13,692.54	12,465.78	6,491.06	9,315.12	9,439.43	10,310.88	10,087.50	10,290.10	8,855.86	9,587.97	120,315.43
GS>50	49,913.52	51,360.06	46,322.47	53,047.57	46,338.45	54,121.01	51,844.33	51,954.18	52,088.98	51,748.48	50,134.04	49,015.12	607,888.21
Street Lights	346.11	346.11	346.11	346.11	346.11	346.81	346.81	346.81	346.81	346.81	346.81	346.81	4,158.22
Sentinel Lights	4.89	4.71	4.72	5.31	5.11	4.76	4.48	4.18	4.83	4.83	5.11	4.83	57.76
USL	189.46	187.63	186.15	346.72	32.61	199.90	183.09	180.75	186.41	182.47	192.79	191.53	2,259.51
	81,145.70	85,769.12	85,356.71	91,692.56	66,564.17	81,004.29	78,851.67	80,479.88	81,860.89	80,243.13	75,138.59	78,497.68	966,604.39

Customer Class	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Residential	23,241.26	25,095.41	23,427.99	22,723.08	16,198.65	14,486.41	14,442.48	15,048.48	15,776.68	14,647.72			185,088.16
GS<50	10,111.38	11,206.60	10,111.02	10,581.47	8,462.47	7,271.15	7,495.94	7,751.07	8,254.05	7,979.17			89,224.32
GS>50	49,348.36	50,008.97	49,619.47	47,865.92	49,401.73	40,756.24	41,423.93	40,705.24	41,632.19	41,425.42			452,187.47
Street Lights	346.81	346.81	346.81	346.81	346.81	57.36	70.57	70.62	70.62	112.93			2,116.15
Sentinel Lights	4.48	5.44	4.83	4.94	4.65	4.04	3.72	3.97	3.84	3.97			43.88
USL	192.32	192.29	190.73	192.32	191.53	187.04	170.78	155.65	155.65	155.01			1,783.32
	83,244.61	86,855.52	83,700.85	81,714.54	74,605.84	62,762.24	63,607.42	63,735.03	65,893.03	64,324.22	-	-	730,443.30

NW kWh/KW - Billings

Customer Class	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential	6,490,042.11	6,014,347.37	5,541,184.21	4,297,007.02	5,640,926.25	3,171,689.80	3,634,809.11	4,331,249.46	4,345,616.05	3,518,117.14	3,311,793.93	4,314,234.27	54,611,016.71
GS<50	2,433,511.54	2,409,975.00	2,382,275.00	2,133,488.46	2,959,402.38	1,963,476.19	2,174,316.67	2,626,592.86	2,546,321.43	2,099,447.62	1,867,307.14	2,209,219.05	27,805,333.33
GS>50	24,551.18	30,107.61	29,401.79	29,046.89	37,277.17	27,265.45	29,204.78	36,769.02	30,966.46	30,146.94	30,431.50	28,913.72	364,082.52
Street Lights	257.49	257.49	257.49	257.49	257.51	265.92	265.92	265.92	265.92	265.92	265.92	265.92	3,148.90
Sentinel Lights	9.08	1.06	5.98	5.38	6.61	5.84	5.39	5.72	5.39	5.39	4.65	3.56	64.06
USL					259.52	76,385.71	69,935.71	64,016.67	64,335.71	63,166.67	63,400.00	61,230.95	462,730.95

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Residential	4,605,422.99	5,108,924.08	5,380,633.41	5,527,347.07	2,896,058.57	3,691,255.97	3,694,908.89	3,835,809.11	4,153,223.43	3,833,067.25	3,384,811.28	4,197,704.99	50,309,167.03
GS<50	2,252,552.38	2,456,778.57	3,260,128.57	2,968,042.86	1,545,490.48	2,217,885.71	2,247,483.33	2,454,971.43	2,401,785.71	2,450,023.81	2,108,538.10	2,282,850.00	28,646,530.95
GS>50	28,863.42	29,699.91	26,786.83	30,675.75	26,796.07	31,296.48	29,979.95	30,043.47	30,121.42	29,924.52	28,990.94	28,343.91	351,522.70
Street Lights	265.38	265.38	265.38	265.38	265.38	265.92	265.92	265.92	265.92	265.92	265.92	265.92	3,188.33
Sentinel Lights	3.42	4.15	3.68	3.77	3.55	3.08	2.84	3.03	2.93	3.03	-	-	33.48
USL	45,109.52	44,673.81	44,321.43	82,552.38	7,764.29	47,595.24	43,592.86	43,035.71	44,383.33	43,445.24	45,902.38	45,602.38	537,978.57

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Residential	5,041,488.07	5,443,689.80	5,081,993.49	4,929,084.60	4,262,802.63	3,812,213.16	3,800,652.63	3,960,126.32	4,151,757.89	3,854,663.16			44,338,471.75
GS<50	2,407,471.43	2,668,238.10	2,407,385.71	2,519,397.62	2,488,961.76	2,138,573.53	2,204,688.24	2,279,726.47	2,427,661.76	2,346,814.71			23,888,919.33
GS>50	28,536.61	28,918.62	28,693.38	27,679.36	34,839.02	28,742.06	29,212.93	28,706.09	29,359.80	29,213.98			293,901.85
Street Lights	265.92	265.92	265.92	265.92	324.30	53.64	65.99	66.04	66.04	105.60			1,745.28
Sentinel Lights	3.42	4.15	3.68	3.77	4.33	3.76	3.46	3.69	3.57	3.69			37.53
USL	45,790.48	45,783.33	45,411.90	45,790.48	56,332.35	55,011.76	50,229.41	45,779.41	45,779.41	45,591.18			481,499.72

NW Rates (Billing)

	Rate Effective Date Jan 1/06	Rate Effective Date May 1/06	Rate Effective Date May 1/08	
Residential	$ 0.00570	$ 0.0046	$ 0.0038	kWh
GS<50	$ 0.00520	$ 0.0042	$ 0.0034	kWh
GS>50	$ 2.12180	$ 1.7293	$ 1.4180	KW
Street Lights	$ 1.60020	$ 1.3042	$ 1.0694	KW
Sentinel Lights	$ 1.60830	$ 1.3108	$ 1.0749	KW
USL		$ 0.0042	$ 0.0034	kWh

NW Rate Estimate - Revenue- using Proposed NW rates

Customer Class	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential	30,742.86	28,489.53	26,248.19	20,354.61	26,720.66	15,024.07	17,217.83	20,516.82	20,584.87	16,665.07	15,687.73	20,436.22	258,688.45
GS<50	10,313.96	10,214.21	10,096.81	9,042.37	12,542.85	8,321.81	9,215.42	11,132.30	10,792.08	8,898.10	7,914.22	9,363.34	117,847.46
GS>50	43,397.21	53,218.87	51,971.25	51,343.92	65,891.95	48,195.01	51,623.02	64,993.74	54,737.00	53,288.40	53,791.40	51,108.53	643,560.31
Street Lights	343.26	343.26	343.26	343.26	343.27	354.49	354.49	354.49	354.49	354.49	354.49	354.49	4,197.71
Sentinel Lights	12.17	1.42	8.01	7.21	8.85	7.83	7.23	7.67	7.23	7.23	6.23	4.76	85.84
USL	-	-	-	-	1.10	323.75	296.41	271.32	272.67	267.72	268.71	259.52	1,961.19
	84,809.47	92,267.28	88,667.52	81,091.38	105,508.68	72,226.95	78,714.39	97,276.33	86,748.34	79,481.00	78,022.76	81,526.86	1,026,340.96

Customer Class	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Residential	21,815.56	24,200.61	25,487.67	26,182.65	13,718.42	17,485.21	17,502.52	18,169.95	19,673.52	18,156.96	16,033.61	19,884.23	238,310.90
GS<50	9,547.00	10,412.57	13,817.42	12,579.47	6,550.26	9,400.07	9,525.52	10,404.92	10,179.50	10,383.95	8,936.63	9,675.41	121,412.71
GS>50	51,019.63	52,498.22	47,349.00	54,223.13	47,365.33	55,320.36	52,993.22	53,105.51	53,243.30	52,895.25	51,245.03	50,101.32	621,359.29
Street Lights	353.77	353.77	353.77	353.77	353.77	354.49	354.49	354.49	354.49	354.49	354.49	354.49	4,250.27
Sentinel Lights	4.58	5.56	4.94	5.05	4.75	4.13	3.80	4.06	3.93	4.06	-	-	44.86
USL	191.19	189.34	187.85	349.88	32.91	201.72	184.76	182.40	188.11	184.13	194.55	193.28	2,280.12
	82,931.72	87,660.08	87,200.64	93,693.95	68,025.44	82,765.98	80,564.31	82,221.32	83,642.84	81,978.84	76,764.30	80,208.72	987,658.14

Customer Class	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Residential	23,881.17	25,786.37	24,073.04	23,348.72	20,192.59	18,058.18	18,003.42	18,758.83	19,666.58	18,259.26	-	-	210,028.15
GS<50	10,203.60	11,308.80	10,203.23	10,677.97	10,548.98	9,063.92	9,344.14	9,662.17	10,289.17	9,946.51	-	-	101,248.50
GS>50	50,441.94	51,117.19	50,719.06	48,926.65	61,582.22	50,805.10	51,637.41	50,741.52	51,897.02	51,639.27	-	-	519,507.40
Street Lights	354.49	354.49	354.49	354.49	432.32	71.50	87.97	88.03	88.03	140.77	-	-	2,326.58
Sentinel Lights	4.58	5.56	4.94	5.05	5.80	5.04	4.64	4.95	4.79	4.95	-	-	50.28
USL	194.07	194.04	192.47	194.07	238.75	233.16	212.89	194.03	194.03	193.23	-	-	2,040.74
	85,079.84	88,766.45	85,547.22	83,506.95	93,000.66	78,236.90	79,290.47	79,449.54	82,139.62	80,184.00	-	-	835,201.65

Network Costs

Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Network	$ 99,855.99	$ 103,784.04	$ 100,054.35	$ 96,606.54	$ 92,300.04	$ 87,627.95	$ 98,448.84	$ 92,274.84	$ 101,767.68	$ 89,205.48	$ 84,677.04	$ 87,834.60	$ 1,134,437.39
Description	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**	**Nov-07**	**Dec-07**	**Total**
Network	$ 95,064.48	$ 99,421.56	$ 99,368.64	$ 98,683.20	$ 104,167.00	$ 87,824.52	$ 93,764.16	$ 103,950.00	$ 99,043.56	$ 94,835.16	$ 96,941.88	$ 82,792.08	$ 1,155,856.24
Description	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Oct-08**	**Nov-08**	**Dec-08**	**Total**
Network	$ 94,076.64	$ 92,738.52	$ 95,505.48	$ 94,953.60	$ 89,598.60	$ 79,299.76	$ 67,401.33	$ 74,981.04	$ 76,273.47	75,226.46			$ 840,054.90

Hydro One charges MPUC:	Estimate @ 5/09	Actual @ 5/08	Actual @ 5/06	Actual @ 1/06
Network-kw with losses	2.24	2.01	2.52	2.61

Network Costs per KW - (months bills received by MPUC)

Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Network	38,259.00	39,764.00	38,335.00	37,014.00	36,627.00	34,773.00	39,067.00	36,617.00	40,384.00	35,399.00	33,602.00	34,855.00	444,696.00
Description	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**	**Nov-07**	**Dec-07**	**Total**
Network	37,724.00	39,453.00	39,432.00	39,160.00	41,336.11	34,851.00	37,208.00	41,250.00	39,303.00	37,633.00	38,469.00	32,854.00	458,673.11
Description	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Oct-08**	**Nov-08**	**Dec-08**	**Total**
Network	37,332.00	36,801.00	37,899.00	37,680.00	35,555.00	39,452.62	33,533.00	37,304.00	37,947.00	37,426.10			370,929.72

Network Costs Estimate per KW - (at new rates effective Jan 1, 2009)

Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Network	$ 85,590.36	$ 88,957.24	$ 85,760.38	$ 82,805.13	$ 81,939.36	$ 77,791.71	$ 87,397.96	$ 81,916.99	$ 90,344.26	$ 79,192.16	$ 75,172.04	$ 77,975.17	$ 994,842.75
Description	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**	**Nov-07**	**Dec-07**	**Total**
Network	$ 84,393.49	$ 88,261.49	$ 88,214.51	$ 87,606.01	$ 92,474.25	$ 77,966.22	$ 83,239.13	$ 92,281.61	$ 87,925.92	$ 84,189.91	$ 86,060.15	$ 73,498.67	$ 1,026,111.38
Description	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Oct-08**	**Nov-08**	**Dec-08**	**Total**
Network	$ 83,516.54	$ 82,328.62	$ 84,784.99	$ 84,295.06	$ 79,541.16	$ 88,260.63	$ 75,017.68	$ 83,453.90	$ 84,892.37	83,727.05			$ 829,818.00

Variance Balance

Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	
Network/mth	780.89	-3,310.04	-2,907.14	1,713.75	-23,569.32	5,564.77	8,683.57	-15,359.34	3,595.92	-288.84	-2,850.72	-3,551.69	-31,498.21
Network/YTD	780.89	-2,529.15	-5,436.30	-3,722.55	-27,291.87	-21,727.10	-13,043.53	-28,402.87	-24,806.95	-25,095.79	-27,946.51	-31,498.21	-31,498.21
Description	**Jan-07**	**Feb-07**	**Mar-07**	**Apr-07**	**May-07**	**Jun-07**	**Jul-07**	**Aug-07**	**Sep-07**	**Oct-07**	**Nov-07**	**Dec-07**	
Network/mth	1,461.77	601.41	1,013.87	-6,087.93	24,448.81	-4,799.77	2,674.82	10,060.29	4,283.08	2,211.07	9,295.85	-6,710.05	38,453.23
Network/YTD	-30,036.44	-29,435.03	-28,421.16	-34,509.09	-10,060.28	-14,860.05	-12,185.22	-2,124.93	2,158.15	4,369.23	13,665.08	6,955.03	6,955.03
Description	**Jan-08**	**Feb-08**	**Mar-08**	**Apr-08**	**May-08**	**Jun-08**	**Jul-08**	**Aug-08**	**Sep-08**	**Oct-08**	**Nov-08**	**Dec-08**	
Network/mth	-1,563.31	-6,437.83	-762.23	788.10	-13,459.50	10,023.73	-4,272.79	4,004.36	2,752.76	3,543.05			-5,383.65
Network/YTD	5,391.72	-1,046.11	-1,808.35	-1,020.24	-14,479.74	-4,456.01	-8,728.79	-4,724.43	-1,971.68	1,571.37			1,571.37

NW Variance Analysis - Using UTR Increases and MPUC Proposed Decreases

CN Billings

Customer Class	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential	$ 27,894.23	$ 29,951.89	$ 27,664.97	$ 21,470.67	$ 23,348.14	$ 20,659.33	$ 27,320.59	$ 32,555.70	$ 32,663.27	$ 26,442.94	$ 24,892.81	$ 32,058.40	$ 326,922.94
GS<50	$ 10,950.80	$ 10,844.68	$ 10,720.25	$ 9,600.72	$ 10,889.23	$ 11,421.75	$ 14,786.46	$ 17,860.75	$ 17,314.84	$ 14,276.30	$ 12,697.62	$ 14,587.77	$ 155,951.17
GS>50	$ 43,950.69	$ 53,859.15	$ 52,636.85	$ 51,985.45	$ 54,712.94	$ 70,272.52	$ 81,305.61	$ 96,199.41	$ 83,321.04	$ 81,223.98	$ 81,902.40	$ 77,882.16	$ 829,252.20
Street Lights	$ 355.97	$ 355.97	$ 355.97	$ 358.26	$ 538.45	$ 538.45	$ 538.45	$ 544.80	$ 544.80	$ 544.80	$ 544.80	$ 544.80	$ 5,765.52
Sentinel Lights	$ 12.81	$ 1.48	$ 8.44	$ 7.59	$ 7.59	$ 11.79	$ 11.42	$ 12.19	$ 11.37	$ 11.42	$ 9.84	$ 7.61	$ 113.55
USL					$ 1.14	$ 418.20	$ 475.54	$ 435.31	$ 437.44	$ 429.51	$ 431.10	$ 416.36	$ 3,044.60
	$ 83,164.50	$ 95,013.17	$ 91,386.48	$ 83,422.69	$ 89,497.49	$ 103,322.04	$ 124,438.07	$ 147,608.16	$ 134,292.76	$ 122,928.95	$ 120,478.57	$ 125,497.10	$ 1,321,049.98

Customer Class	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Residential	$ 34,616.19	$ 38,400.31	$ 40,442.74	$ 41,545.29	$ 21,772.75	$ 27,757.68	$ 27,779.04	$ 28,837.49	$ 31,223.46	$ 28,817.60	$ 25,447.76	$ 31,558.33	$ 378,198.64
GS<50	$ 15,317.26	$ 16,705.77	$ 19,980.03	$ 20,182.85	$ 10,509.10	$ 15,081.30	$ 15,282.93	$ 16,693.34	$ 16,332.02	$ 16,660.34	$ 14,338.33	$ 15,523.39	$ 192,606.66
GS>50	$ 77,871.76	$ 80,120.32	$ 75,465.74	$ 82,554.14	$ 72,443.09	$ 85,035.89	$ 81,263.95	$ 81,424.10	$ 81,496.09	$ 81,311.84	$ 78,252.88	$ 76,333.70	$ 953,573.50
Street Lights	$ 544.80	$ 544.80	$ 552.47	$ 552.47	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 6,614.38
Sentinel Lights	$ 7.90	$ 7.57	$ 7.62	$ 8.57	$ 8.31	$ 7.78	$ 7.27	$ 6.75	$ 7.78	$ 7.78	$ 8.31	$ 7.78	$ 93.42
USL	$ 306.76	$ 303.77	$ 301.37	$ 561.35	$ 52.79	$ 323.64	$ 296.46	$ 292.70	$ 301.84	$ 295.41	$ 312.13	$ 310.07	$ 3,658.29
	$ 128,664.67	$ 136,082.54	$ 136,749.97	$ 145,404.67	$ 105,338.52	$ 128,758.77	$ 125,182.13	$ 127,806.86	$ 129,913.67	$ 127,645.45	$ 118,911.89	$ 124,285.75	$ 1,534,744.89

Customer Class	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Residential	$ 37,904.49	$ 40,928.30	$ 38,205.23	$ 37,055.24	$ 26,418.60	$ 25,609.59	$ 26,983.60	$ 28,117.78	$ 29,478.54	$ 27,363.93			$ 318,065.30
GS<50	$ 16,370.65	$ 18,143.91	$ 16,370.18	$ 17,131.82	$ 13,708.59	$ 12,975.87	$ 14,329.26	$ 14,818.42	$ 15,779.86	$ 15,254.87			$ 154,883.43
GS>50	$ 76,912.88	$ 77,802.75	$ 77,964.01	$ 74,685.76	$ 77,417.76	$ 73,112.14	$ 75,998.62	$ 74,584.84	$ 76,398.32	$ 75,964.39			$ 760,841.47
Street Lights	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 552.48	$ 524.86	$ 524.86	$ 524.86	$ 524.86	$ 524.86			$ 5,386.70
Sentinel Lights	$ 7.27	$ 8.83	$ 7.78	$ 8.03	$ 7.50	$ 7.37	$ 6.94	$ 7.44	$ 7.23	$ 7.44			$ 75.83
USL	$ 311.36	$ 311.38	$ 308.78	$ 311.36	$ 310.07	$ 307.41	$ 296.38	$ 297.62	$ 297.62	$ 296.38			$ 3,048.36
	$ 132,059.13	$ 137,747.65	$ 133,408.46	$ 129,744.69	$ 118,415.00	$ 112,537.24	$ 118,139.66	$ 118,350.96	$ 122,486.43	$ 119,411.87	$ -	$ -	$ 1,242,301.09

CN kWh/KW (billings)

Customer Class	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential	5,578,846.00	5,990,378.00	5,532,994.00	4,294,134.00	3,113,085.33	2,754,577.33	3,642,745.33	4,340,760.00	4,355,102.67	3,525,725.33	3,319,041.33	4,274,453.33	50,721,842.67
GS<50	2,433,511.11	2,409,928.89	2,382,277.78	2,133,493.33	1,601,357.35	1,679,669.12	2,174,479.41	2,626,580.88	2,546,300.00	2,099,455.88	1,867,297.06	2,145,260.29	26,099,611.11
GS>50	24,578.17	30,119.20	29,435.66	29,071.38	20,357.55	26,146.94	30,252.12	35,793.80	31,002.02	30,221.75	30,474.18	28,978.33	346,431.11
Street Lights	257.50	257.50	257.50	259.16	259.16	259.16	259.16	262.21	262.21	262.21	262.21	262.21	3,120.20
Sentinel Lights	9.08	1.05	5.98	5.38	3.58	5.56	5.38	5.75	5.36	5.38	4.64	3.59	60.72
USL					167.65	61,500.00	69,932.35	64,016.18	64,329.41	63,163.24	63,397.06	61,229.41	447,735.29

	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Residential	4,615,492.00	5,120,041.33	5,392,365.33	5,539,372.00	2,903,033.33	3,701,024.00	3,703,872.00	3,844,998.67	4,163,128.00	3,842,346.67	3,393,034.67	4,207,777.33	50,426,485.33
GS<50	2,252,538.24	2,456,730.88	2,938,239.71	2,968,066.18	1,545,455.88	2,217,838.24	2,247,489.71	2,454,902.94	2,401,767.65	2,450,050.00	2,108,577.94	2,282,851.47	28,324,508.82
GS>50	28,974.46	29,811.10	28,079.23	30,716.68	26,954.57	31,640.08	30,236.62	30,296.21	30,323.00	30,254.44	29,116.27	28,402.18	354,804.84
Street Lights	262.21	262.21	265.90	265.90	265.91	265.91	265.91	265.91	265.91	265.91	265.91	265.91	3,183.51
Sentinel Lights	3.72	3.57	3.59	4.04	3.92	3.67	3.43	3.18	3.67	3.67	3.92	3.67	44.04
USL	45,111.76	44,672.06	44,319.12	82,551.47	7,763.24	47,594.12	43,597.06	43,044.12	44,388.24	43,442.65	45,901.47	45,598.53	537,983.82

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Residential	5,053,932.00	5,457,106.67	5,094,030.67	4,940,698.67	3,720,929.58	3,606,984.51	3,800,507.04	3,960,250.70	4,151,907.04	3,854,074.65			43,640,421.52
GS<50	2,407,448.53	2,668,222.06	2,407,379.41	2,519,385.29	2,109,013.85	1,996,287.69	2,204,501.54	2,279,756.92	2,427,670.77	2,346,903.08			23,366,569.14
GS>50	28,617.68	28,948.78	29,008.78	27,789.02	30,321.85	28,635.49	29,766.03	29,212.30	29,922.58	29,752.62			291,975.13
Street Lights	265.91	265.91	265.91	265.91	279.91	265.91	265.91	265.91	265.91	265.91			2,673.11
Sentinel Lights	3.43	4.16	3.67	3.79	3.72	3.66	3.44	3.69	3.59	3.69			36.84
USL	45,788.24	45,791.18	45,408.82	45,788.24	47,703.08	47,293.85	45,596.92	45,787.69	45,787.69	45,596.92			460,542.62

CN Rates

	Rate Effective Date Jan 1/06	Rate Effective Date May 1/06	Rate Effective Date May 1/08	
Residential	$ 0.00500	$ 0.0075	$ 0.0071	kWh
GS<50	$ 0.00450	$ 0.0068	$ 0.0065	kWh
GS>50	$ 1.78820	$ 2.6876	$ 2.5532	KW
Street Lights	$ 1.38240	$ 2.0777	$ 1.9738	KW
Sentinel Lights	$ 1.41130	$ 2.1211	$ 2.0150	KW
USL		$ 0.0068	$ 0.0065	kWh

CN Rate Estimate - Revenue- using Proposed CN rates

Customer Class	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Residential	$ 24,487.97	$ 26,294.36	$ 24,286.71	$ 18,848.81	$ 13,664.68	$ 12,091.03	$ 15,989.59	$ 19,053.48	$ 19,116.43	$ 15,475.94	$ 14,568.71	$ 18,762.43	$ 222,640.13
GS<50	$ 9,779.05	$ 9,684.29	$ 9,573.17	$ 8,573.43	$ 6,435.05	$ 6,749.74	$ 8,738.13	$ 10,554.90	$ 10,232.29	$ 8,436.65	$ 7,503.72	$ 8,620.72	$ 104,881.16
GS>50	$ 38,795.78	$ 47,542.10	$ 46,463.16	$ 45,888.16	$ 32,133.67	$ 41,272.03	$ 47,751.91	$ 56,499.25	$ 48,935.60	$ 47,703.97	$ 48,102.42	$ 45,741.28	$ 546,829.33
Street Lights	$ 314.22	$ 314.22	$ 314.22	$ 316.24	$ 316.24	$ 316.24	$ 316.24	$ 319.97	$ 319.97	$ 319.97	$ 319.97	$ 319.97	$ 3,807.46
Sentinel Lights	$ 11.31	$ 1.31	$ 7.45	$ 6.70	$ 4.46	$ 6.92	$ 6.71	$ 7.16	$ 6.68	$ 6.71	$ 5.78	$ 4.47	$ 75.64
USL	$ -	$ -	$ -	$ -	$ 0.67	$ 247.14	$ 281.02	$ 257.25	$ 258.51	$ 253.82	$ 254.76	$ 246.05	$ 1,799.22
	$ 73,388.33	$ 83,836.27	$ 80,644.70	$ 73,633.34	$ 52,554.77	$ 60,683.10	$ 73,083.61	$ 86,692.00	$ 78,869.48	$ 72,197.06	$ 70,755.36	$ 73,694.91	$ 880,032.94

Customer Class	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Residential	$ 20,259.39	$ 22,474.08	$ 23,669.43	$ 24,314.70	$ 12,742.67	$ 16,245.40	$ 16,257.90	$ 16,877.36	$ 18,273.77	$ 16,865.72	$ 14,893.50	$ 18,469.76	$ 221,343.68
GS<50	$ 9,051.81	$ 9,872.36	$ 11,807.30	$ 11,927.16	$ 6,210.41	$ 8,912.37	$ 9,031.53	$ 9,865.02	$ 9,651.49	$ 9,845.51	$ 8,473.31	$ 9,173.63	$ 113,821.90
GS>50	$ 45,735.17	$ 47,055.78	$ 44,322.08	$ 48,485.19	$ 42,546.83	$ 49,942.76	$ 47,727.45	$ 47,821.51	$ 47,863.79	$ 47,755.57	$ 45,959.00	$ 44,831.84	$ 560,046.97
Street Lights	$ 319.97	$ 319.97	$ 324.47	$ 324.47	$ 324.48	$ 324.48	$ 324.48	$ 324.48	$ 324.48	$ 324.48	$ 324.48	$ 324.48	$ 3,884.72
Sentinel Lights	$ 4.64	$ 4.45	$ 4.48	$ 5.03	$ 4.88	$ 4.57	$ 4.27	$ 3.96	$ 4.57	$ 4.57	$ 4.88	$ 4.57	$ 54.87
USL	$ 181.28	$ 179.51	$ 178.10	$ 331.73	$ 31.20	$ 191.26	$ 175.19	$ 172.97	$ 178.37	$ 174.57	$ 184.45	$ 183.24	$ 2,161.89
	$ 75,552.26	$ 79,906.15	$ 80,305.85	$ 85,388.29	$ 61,860.47	$ 75,620.83	$ 73,520.82	$ 75,065.30	$ 76,296.47	$ 74,970.43	$ 69,839.63	$ 72,987.51	$ 901,314.02

Customer Class	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Residential	$ 22,183.90	$ 23,953.60	$ 22,359.91	$ 21,686.87	$ 16,332.77	$ 15,832.62	$ 16,682.07	$ 17,383.26	$ 18,224.52				$ 174,639.50
GS<50	$ 9,674.32	$ 10,722.24	$ 9,674.04	$ 10,124.14	$ 8,475.06	$ 8,022.07	$ 8,858.78	$ 9,161.19	$ 9,755.58				$ 84,467.42
GS>50	$ 45,172.00	$ 45,694.64	$ 45,789.35	$ 43,863.98	$ 47,861.98	$ 45,200.12	$ 46,984.63	$ 46,110.59	$ 47,231.73				$ 413,909.02
Street Lights	$ 324.48	$ 324.48	$ 324.48	$ 324.48	$ 341.56	$ 324.48	$ 324.48	$ 324.48	$ 324.48				$ 2,937.41
Sentinel Lights	$ 4.27	$ 5.19	$ 4.57	$ 4.72	$ 4.64	$ 4.56	$ 4.29	$ 4.60	$ 4.47				$ 41.29
USL	$ 184.00	$ 184.01	$ 182.48	$ 184.00	$ 191.69	$ 190.05	$ 183.23	$ 184.00	$ 184.00				$ 1,667.46
	$ 77,542.97	$ 80,884.15	$ 78,334.82	$ 76,188.18	$ 73,207.71	$ 69,573.90	$ 73,037.48	$ 73,168.11	$ 75,724.79	$ -	$ -	$ -	$ 677,662.11

Connection Costs

Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Connection	$ 84,552.39	$ 87,878.44	$ 84,720.35	$ 81,800.94	$ 78,154.44	$ 74,001.42	$ 81,650.03	$ 76,529.53	$ 84,402.56	$ 73,984.01	$ 70,228.18	$ 72,846.95	$ 950,749.24

Description	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Connection	$ 78,843.16	$ 82,456.77	$ 82,412.88	$ 81,844.40	$ 101,585.60	$ 72,838.59	$ 77,764.72	$ 86,212.50	$ 82,143.27	$ 78,652.97	$ 80,400.21	$ 68,664.86	$ 973,819.93

Description	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Connection	$ 78,023.88	$ 76,914.09	$ 79,208.91	$ 78,751.20	$ 74,309.95	$ 66,885.88	$ 63,042.04	$ 70,131.52	$ 71,552.80	$ 70,398.48			$ 729,218.75

Hydro One charges MPUC:	Estimate @ 5/09	Actual @ 5/08	Actual @ 5/06	Actual @ 1/06
Connection-kw with losses	1.98	1.88	2.09	2.21

Network Costs per KW

Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Connection	38,259.00	39,764.00	38,335.00	37,014.00	37,394.47	35,407.38	39,067.00	36,617.00	40,384.00	35,399.05	33,602.00	34,855.00	446,097.89

Description	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Connection	37,724.00	39,453.00	39,432.00	39,160.00	48,605.55	34,851.00	37,208.00	41,250.00	39,303.00	37,633.00	38,469.00	32,854.00	465,942.55

Description	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Connection	37,332.00	36,801.00	37,899.00	37,680.00	39,526.57	35,577.60	33,533.00	37,304.00	38,060.00	37,446.00			371,159.16

Network Costs Estimate per KW - (at new rates effective Jan 1, 2009)

Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Total
Connection	$ 75,882.90	$ 78,867.92	$ 76,033.64	$ 73,413.57	$ 74,168.19	$ 70,226.99	$ 77,485.49	$ 72,626.16	$ 80,097.63	$ 70,210.47	$ 66,646.21	$ 69,131.41	$ 884,790.56

Description	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Total
Connection	$ 74,821.78	$ 78,251.08	$ 78,209.43	$ 77,669.94	$ 96,404.25	$ 69,123.47	$ 73,798.35	$ 81,815.25	$ 77,953.57	$ 74,641.29	$ 76,299.41	$ 65,162.62	$ 924,150.45

Description	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
Connection	$ 74,044.29	$ 72,991.10	$ 75,168.88	$ 74,734.51	$ 78,397.00	$ 70,564.60	$ 66,509.35	$ 73,988.75	$ 75,488.20	$ 74,270.40			$ 736,157.09

Variance Balance

Description	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	
Connection/mth	2,181.48	-5,326.02	-4,955.11	-533.91	21,389.21	9,285.00	4,090.09	-14,435.69	891.67	-2,294.59	-4,411.01	-4,877.90	1,003.22
Connection/YTD	2,181.48	-3,144.54	-8,099.65	-8,633.56	12,755.65	22,040.65	26,130.75	11,695.05	12,586.72	10,292.13	5,881.12	1,003.22	1,003.22

Description	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	
Connection/mth	-1,052.80	-1,995.96	-2,439.02	-8,082.64	34,279.87	-6,819.98	-36.12	6,429.70	1,331.60	-648.98	6,161.84	-8,136.27	18,991.24
Connection/YTD	-49.59	-2,045.55	-4,484.57	-12,567.21	21,712.67	14,892.69	14,856.57	21,286.27	22,617.87	21,968.89	28,130.73	19,994.46	19,994.46

Description	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	
Connection/mth	-3,829.49	-8,238.12	-3,500.14	-1,778.71	4,876.97	693.89	-6,839.72	508.49	-559.64	131.45			-18,535.02
Connection/YTD	16,164.97	7,926.85	4,426.71	2,648.00	7,524.98	8,218.87	1,379.14	1,887.63	1,327.99	1,459.44			1,459.44

Based on this analysis, the Network deferral account results in a variance of $1,571, and the Connection deferral account results in a variance of $1,459.

Midland is therefore proposing to change the RTSR to reflect the rates shown as follows.

MPUC Proposed Retail Transmission Service Rates

RTS Category	Customer Class	Unit of Measure	Proposed 2009 Updated RTSR
Network	Residential	kWh	0.0047
	GS<50	kWh	0.0042
	GS>50	kW	1.7676
	Street Lights	kW	1.3331
	Sentinel Lights	kW	1.3399
	USL	kWh	0.0042
Connection	Residential	kWh	0.0044
	GS<50	kWh	0.0040
	GS>50	kW	1.5852
	Street Lights	kW	1.2255
	Sentinel Lights	kW	1.2510
	USL	kWh	0.0040

When final rates are determined, this item will be reflected in those rates.

Deferral and Variance Accounts

6.

[Ex5/T1/S1/Pg2]

Midland is requesting disposition of regulatory deferral and variance accounts.

a. Please provide the information as shown in the continuity schedule attached as Appendix A in excel format for regulatory assets. Please note that forecasting principal transactions beyond 2007 and the accrued interest on these forecasted balances and including them in the attached continuity schedule is optional.

b. Please provide a schedule reconciling the completed continuity schedule in part (a) with the table at Ex5/T1/S3/Att1/page1 of Midland's application.

c. Please specifically breakout the continuity schedule for the following areas and provide quarterly data for at least 2006 and 2007 for Account 1550 – Low Voltage Costs.

RESPONSE:

a. Midland has completed the continuity schedule as Appendix A, a copy of which is filed as an attachment to this document.

b. The following schedule reconciles the completed continuity schedule in part (a) with the table at Ex5/T1/S3/Att1/page 1 of Midland's application.

		Reconciliaiton Principle Dec-07	Interest Dec-07	Interest Jan 08 - Apr 08	Interest May 08 - Dec 08	Interest Jan 09 - Apr 09	Total
Amount Per Rate Application (Ex5/T1/S3/Att1 page1)							
#1508 - Other Regulatory Assets	**$ 50,144.00**	$ 49,043.00	-$ 1,090.00	$ 547.65	$ 1,095.29	$ 547.65	**$ 50,143.59**
Amount Per Continuity Schedule							
#1508 - Other Regulatory Assets - OEB Cost Assessments	**$ 15,791.00**	$ 14,040.99	$ 1,034.47	$ 228.17	$ 330.67	$ 156.80	$ 15,791.10
#1508 - Other Regulatory Assets - OEB Pension Contributions	**$ 73,277.00**	$ 63,744.36	$ 6,283.45	$ 1,035.85	$ 1,501.18	$ 711.80	$ 73,276.64
#1508 - Other Regulatory Assets - OEB Transition Costs	**-$ 38,615.00**	-$ 28,742.71	-$ 8,407.63	-$ 467.07	-$ 676.89	-$ 320.96	-$ 38,615.26
	$ 50,453.00	$ 49,042.64	-$ 1,089.71	$ 796.95	$ 1,154.96	$ 547.64	$ 50,452.48
Unreconciled Balance	**-$ 309.00**	**$ 0.36**	**-$ 0.29**	**-$ 249.30**	**-$ 59.67**	**$ 0.01**	**-$ 308.89**

		Reconciliaiton Principle Dec-07	Interest Dec-07	Interest Jan 08 - Apr 08	Interest May 08 - Dec 08	Interest Jan 09 - Apr 09	Total
Amount Per Rate Application (Ex5/T1/S3/Att1 page1)							
#1550 - LV Variance Account	**$ 121,481.00**	$ 113,626.00	$ 2,780.00	$ 1,268.82	$ 2,537.65	$ 1,268.82	**$ 121,481.29**
Amount Per Continuity Schedule							
#1550 - LV Variance Account	**$ 122,180.00**	$ 113,626.00	$ 2,780.00	$ 1,846.42	$ 2,675.89	$ 1,251.44	$ 122,179.75
Unreconciled Balance	**-$ 699.00**	**$ -**	**$ -**	**-$ 577.60**	**-$ 138.24**	**$ 17.38**	**-$ 698.46**

The unreconciled balance of $309 and $699 in the Other Regulatory Asset #1550 and LV Variance #1550 account balances represent a difference in the interest rate used for the purposes of the Rate Application vs. the interest rates prescribed by the OEB in Q1, Q2 and Q3. The Rate Application interest component from January 1, 2008 to April 30, 2009 was calculated based on the OEB Q3 rate of 3.35%. The interest component calculation pursuant to the

Continuity Schedule in Appendix A was based on the OEB prescribed rates for Q1, Q2 and Q3 which were 5.14%, 4.08% and 3.35%.

c) The following schedule provides the quarterly data for the years 2006 and 2007 with respect to Account 1550 – Low Voltage Costs:

Low Voltage Variance Account # 1550

	Change in Principal Amounts	Change in Interest Amounts	Balance of Account #1550
Opening Balance - Low Voltage Variance Account #1550 - Jan 1, 2006	$ -	$ -	$ -
Quarterly Transactions - Jan 06 - Mar 06	$ -	$ -	$ -
Quarterly Transactions - Apr 06 - Jun 06	-$ 13,499.62	-$ 1.39	-$ 13,501.01
Quarterly Transactions - Jul 06 - Sep 06	$ 11,279.64	-$ 96.24	-$ 2,317.61
Quarterly Transactions - Oct 06 - Dec 06	$ 8,838.86	$ 8.35	$ 6,529.60
Closing Balance Low Voltage Variance Account #1550 - Dec 31, 2006	$ 6,618.88	-$ 89.28	$ 6,529.60
Opening Balance - Low Voltage Variance Account #1550 - Jan 1, 2007	$ 6,618.88	-$ 89.28	$ 6,529.60
Quarterly Transactions - Jan 07 - Mar 07	$ 22,099.43	$ 188.07	$ 22,287.50
Quarterly Transactions - Apr 07 - Jun 07	$ 41,354.39	$ 490.16	$ 64,132.05
Quarterly Transactions - Jul 07 - Sep 07	$ 23,781.05	$ 890.81	$ 88,803.91
Quarterly Transactions - Oct 07 - Dec 07	$ 19,772.14	$ 1,300.55	$ 109,876.60
Closing Balance Low Voltage Variance Account #1550 - Dec 31, 2007	$ 113,625.89	$ 2,780.31	$ 116,406.20

7.

For 2007 revenues please clarify that Midland reported the following amounts in its application:

- $ 2,671,332 for Distribution Services Revenue in APH account 4080
- $ 249,029 for Revenues from non-utility operations in APH account 4375

For account 4080 and account 4375 please:

a) Provide the amount reported to the Board in Midland's 2007 annual filing pursuant to RRR 2.1.7.

b) Identify any differences between the amounts provided in response to a) and the amount reported in exhibit E4/T2/S1/A2 and explain any differences.

c) Clarify whether the amount stated in a) or the amount in exhibit E4/T2/S1/A2 has been reflected in Midland's 2007 audited financial statements and identify the line item in the audited financial statements.

d) State the value which should be relied upon in this proceeding, and why.

RESPONSE:

7. Midland confirms that the revenues reported in the rate application are as follows:

- $ 2,671,332 for Distribution Services Revenue in APH account 4080
- $ 249,029 for Revenues from non-utility operations in APH account 4375

a) In Midland's 2007 annual filing pursuant to RRR 2.1.7 the following amounts were reported:

- $ 2,808,256 for Distribution Services Revenue in APH account 4080
- $ 112,105 for Revenues from non-utility operations in APH account 4375

b) Reconciliation of differences between the amounts reported in the application and the RRR filing is as follows:

2007 Distribution Revenue & Non-Utility Revenue Reconciliation

	Distribution Revenue	Non-Utility Revenue
RRR 2.1.7	$2,808,256	$112,105
PreMarket Opening Cost of Power	-$136,924	$136,924
Rate Application Revenues	$2,671,332	$249,029

Midland is one of the LDCs who, on the advice of our auditors, wrote off the Pre-Market Opening Cost of Power from a tax perspective in 2002. Subsequent to this, Midland was awarded recovery of the Pre-Market Opening Cost of Power to be collected over the four year period ending in April, 2008 through a rate rider. In order to reverse the write-down we were advised by BDO Dunwoody to create a revenue account and add $136,924 per year to return the asset to our financial statements to correctly represent our financial position for tax purposes. In utilizing our financial statements for OEB reporting purposes, this additional revenue needed to be removed for rate setting purposes as it is a tax oriented adjustment only. Consequently, Midland has adjusted the 2006 and 2007 Distribution Revenues by removing the $136,924 from Account 4080 and adding the amount to Account 4375.

c) The amount of $136,924 has been reflected in Midland's audited financial statements under Net Distribution Revenue. A reconciliation of Midland's audited financial statements to the Rate Application Revenues is as follows:

2007 Audited Fin Stmts & Rate Application Reconciliation

Audited F/S - Net Dist Rev	$2,799,859
PreMarket Opening COP	-$136,924
Conservation & Demand Mgt (#5415)	$8,397
Rate Application Revenues	$2,671,332

The Conservation & Demand Management adjustment of $8,397 represents expenses by Midland through the third tranche recovery of revenues. This amount has been shown under Account 5415 in Midland's Rate Application.

d) The value to be relied upon in this proceeding is $2,671,332 which represents distribution revenues net of any rate riders, Premarket Opening Cost of Power recoveries, and third tranche expenses.

8.

[Ex5/T1/S3/Att1/Pg1]

Midland provides details and calculations of the proposed deferral and variance account rate rider by classification in the table at Ex5/T1/S3/Att1/page1. Midland has proposed a recovery period of two years.

a) Please provide a table similar to Ex5/T1/S3/Att1/page1 of the Board were to authorize the recovery of the requested accounts over a period of :

i) one year

ii) three years.

RESPONSE:

i) The following schedule provides the rate rider by classification with respect to the proposed recovery of requested deferral/variance accounts over a period of one year.

Rate Rider Recovery Over 1 Year

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service <50 kW	General Service >50 Kw	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
1508-Other Regulatory Assets	50,144	kWh's	11,422	6,343	31,983	274	4	118
1550-LV Variance Account	121,481	kWh's	27,671	15,367	77,485	665	9	285
Total Recoveries Required (1 years)	**171,625**		**39,093**	**21,709**	**109,468**	**939**	**13**	403
Annual Recovery Amounts	171,625		39,093	21,709	109,468	939	13	403
Annual Volume			49,791,737	27,650,878	332,681	3,052	44	513,550
Proposed Rate Rider			**$0.0008** kWh	**$0.0008** kWh	**$0.3290** kW	**$0.3076** kW	**$0.2846** kW	**$0.0008** kWh

Allocators		2009 Projection Total	Residential	General Service <50 kW	General Service >50 Kw	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
kWh's		218,595,966	49,791,737	27,650,878	139,428,070	1,195,783	15,948	513,550
Approved Recoveries		100.0%	42.7%	12.7%	44.4%	0.0%	0.0%	0.2%

ii) The following schedule provides the rate rider by classification with respect to the proposed recovery of requested deferral/variance accounts over a period of three years.

Rate Rider Recovery Over 3 Years

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service <50 kW	General Service >50 Kw	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
1508-Other Regulatory Assets	50,144	kWh's	11,422	6,343	31,983	274	4	118
1550-LV Variance Account	121,481	kWh's	27,671	15,367	77,485	665	9	285
Total Recoveries Required (3 years)	**171,625**		**39,093**	**21,709**	**109,468**	**939**	**13**	403
Annual Recovery Amounts	57,208		13,031	7,236	36,489	313	4	134
Annual Volume			49,791,737	27,650,878	332,681	3,052	44	513,550
Proposed Rate Rider			**$0.0003** kWh	**$0.0003** kWh	**$0.1097** kW	**$0.1025** kW	**$0.0949** kW	**$0.0003** kWh

Allocators		2009 Projection Total	Residential	General Service <50 kW	General Service >50 Kw	Street Lighting	Sentinel Lighting	Unmetered Scattered Load
kWh's		218,595,966	49,791,737	27,650,878	139,428,070	1,195,783	15,948	513,550
Approved Recoveries		100.0%	42.7%	12.7%	44.4%	0.0%	0.0%	0.2%

9.

Midland has not provided a clear description of the amounts recorded in Account 1508. Please provide further details of the amounts that have been recorded in this account.

RESPONSE:

In accordance with the Accounting Procedures Handbook, Midland has established three sub-accounts to record regulatory – created assets, which are not included in other accounts. The first sub-account includes costs associated with the difference between the OEB cost assessments invoiced to Midland for the OEB's 2004/2005 and 2005/2006 (up to April 30, 2006) fiscal years and OEB cost assessments previously included in Midland's rates. As at December 31, 2008 this account is projected to show a balance of $5,703.

The second sub-account includes pension costs associated with the cash contributions paid to OMERS for the period January 1, 2005 to April 30, 2006. As at December 31, 2008 this account is projected to show a balance of $72,875.

The third sub-account includes the recovery of transition costs for the period of April 2002 to March 2004. As at December 31, 2008 this account is projected to show a balance of ($38,434).

Account # 1508	Principal Balance at 31-Dec-07	Interest Balance at 31-Dec-07	Interest Jan 08 - Dec 08	Interest Jan 08 - Dec 08	Total
Other Regulatory Assets - Sub-Account - OEB Assessments	$ 14,040.99	$ 1,034.47	$ 470.37	$ 56.79	$ 5,702.62
Other Regulatory Assets - Sub-Account - Pension Contributions	$ 63,744.36	$ 6,283.45	$ 2,135.44	$ 711.81	$ 72,875.06
Other Regulatory Assets - Sub-Account - Transition Costs	-$ 28,742.71	-$ 8,407.63	-$ 962.88	-$ 320.96	-$ 38,434.18
	$ 49,042.64	-$ 1,089.71	$ 1,642.93	$ 547.64	$ 50,143.50

Loss Factors

10.

[Ex4/T2/S9/Pg1]

Preamble: Midland is an embedded distributor of Hydro One. Midland is proposing no change in this proceeding to its Total Loss Factor (TLF) of 1.0651. Midland reports data for 2006 was flawed and has taken measures to account for this. The following table provides a summary of Distribution Loss Factor (DLF) and TLF for Midland.

	5 year average (2002-2007)	4 year average	4 year average (excluding 2006)	2007 approved*	2009 proposed
Embedded DLF	1.0318	1.0313	1.0294	1.0301	1.0301
TLF	1.0669	1.0664	**1.0644**	1.0651	**1.0651**

*assumes DLF,Hydro One = 1.0340

As indicated in the table, the total loss factor indicated by the removal of 2006 is 1.0644.

Given that Midland reports that data for 2006 was flawed, why has Midland not considered using the “4-year average, excluding 2006” data. This corresponds to a TLF of 1.0644.

RESPONSE:

Midland proposes to use the current loss factor for the 2009 year as it represents a relative average of the rates between 1.0669 and 1.0644. Midland’s power variance account #1588 is projected to April 30, 2009 to total $672,930 as set out in the Regulatory Asset Continuity Schedule - Appendix A. Consequently, Midland is proposing that the TLF remain at 1.0651 as we believe this will be a better reflection of losses and will further reduce the balance in Account #1588.

12.

[Ex4/T2/S11/Pg]

Midland provides a materiality analysis on distribution losses at Ex4/T2/S11/page1. Please comment on the source and/or drivers of the variability in the loss factors from the period 2003-2007.

RESPONSE:

As stated in the evidence in Exhibit 4, Tab 2, Schedule 11, Page 1, Line 11 and 12, "In 2006, one of MPUC's metering points read by Hydro One was malfunctioning". This may have caused some variability in the loss factor for 2006 and possibility for 2005 assuming the meter was not recording correctly prior to 2006. In addition, the residential load, which is generally at a lower voltage, is increasing in the MPUC service area. This increase can cause losses to increase along with some variability in the level of losses. MPUC's power variance account (i.e. 1588) is also increasing which indicates that the difference between the actual loss factor and the approved loss factor is increasing. Although there are indications that the current loss factor should increase, MPUC is not proposing a change until additional historical data is available to substantiate a change.

13.

[Ex4/T2/S9/Pg]

Midland has provided a loss adjustment factor calculation at Ex4/T2/S9/page1

Please complete the following table:

Modified Schedule 10-5: Determination of Loss Factors

		Year1	Year2	Year3	3-yr Average
	Losses in Distributor's System				
A	"Wholesale" kWh delivered to distributor[1]				
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)[2]				
C	Net "Wholesale" kWh delivered to distributor (A)-(B)				
D	"Retail" kWh delivered by distributor[3]				
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)				
F	Net "Retail" kWh delivered by distributor (D)-(E)				
G	Loss Factor in distributor's system [(C)/(F)][4]				
	Losses Upstream of Distributor's System				
H	Supply Facility Loss Factor[5]				
	Total Losses				
I	Total Loss Factor [(G)x(H)] [4]				

[1]**Line A** If directly connected to IESO controlled grid, kWh pertain to metering installation on the secondary or low voltage side of the transformer at the interface with the transmission grid. This corresponds to the "With Losses" kWh value provided by the IESO's MV-WEB. Additionally, kWh pertaining to distributed generation should be included.

If fully embedded within a host distributor, kWh pertains to virtual meter at the interface between the embedded distributor and the host distributor.

> e.g. if the host distributor is Hydro One, kWh from the Hydro One invoice corresponding to “Total kWh” rather than “Total kWh w Losses” should be reported. Additionally, kWh pertaining to distributed generation should be included.

If partially embedded, kWh pertains to sum of above.

[2]**Line B** If Large Customer is metered on the secondary or low voltage side of the transformer, the default loss is 1%, i.e. Line B = 1.01 x Line E.

[3]**Line D** kWh corresponding to D should equal total of “total billed energy sales in kWhs for each rate class” in item 1 of Section 2.1.3 in Electricity Reporting and Record Keeping Requirements dated April 4, 2008.

[4]**Lines G&I** This loss factor pertains to secondary metered customers less than 5,000 kW.

[5]**Line H** If directly connected to IESO controlled grid, SFLF = 1.0045.

If fully embedded within a host distributor,

$$SFLF = LF_{Grid} \times LF_{Host}$$

Where,

SFLF is the supply facilities loss factor

LF_{Grid} is the loss factor from losses in the transformer at the grid interface

LF_{Host} is the loss factor in host distributor’s system

If the host distributor is Hydro One, SFLF = 1.0060 x 1.0278 = 1.0340.

If partially embedded, SFLF is weighted average of above.

RESPONSE:

The following table has been completed using Midland's loss factor data for the three most recent years 2005, 2006 and 2007. This table also includes the three year average of the data provided.

Modified Schedule 10-5: Determination of Loss Factors

		2005	2006	2007	3-yr Average
A	"Wholesale" kWh delivered to distributor[1]	238,157,129	234,992,610	232,327,828	235,159,189
B	Portion of "Wholesale" kWh delivered to distributor for Large Use Customer(s)[2]	0	0	0	0
C	Net "Wholesale" kWh delivered to distributor (A)-(B)	238,157,129	234,992,610	232,327,828	235,159,189
D	"Retail" kWh delivered by distributor[3]	233,239,879	225,666,128	224,566,924	227,824,310
E	Portion of "Retail" kWh delivered by distributor for Large Use Customer(s)	0	0	0	0
F	Net "Retail" kWh delivered by distributor (D)-(E)	233,239,879	225,666,128	224,566,924	227,824,310
G	Loss Factor in distributor's system [(C)/(F)][4]	1.0211	1.0413	1.0346	1.0323
	Losses Upstream of Distributor's System				
H	Supply Facility Loss Factor[5]	1.0340	1.0340	1.0340	1.0340
	Total Losses				
I	Total Loss Factor [(G)x(H)] [4]	1.0558	1.0767	1.0697	1.0674

Specific Service Charges

14.

[Ex1/T1/S5/Pg3]

Midland has included the monthly interest charge, but has omitted the yearly interest charge of 19.56%. Please indicate why this charge has been omitted from the proposed rate schedule.

RESPONSE:

The yearly interest charge of 19.56% was inadvertently omitted from Midland's application in error. When final rates are determined this item will be reflected in those rates.

Rate Base – Maintenance and Capital Programs and Projects

15.

In regards to Midland's 2009 maintenance and capital plans:

a) Please provide a list of criteria and rationale that Midland has used in the prioritization and selection of its 2009 maintenance and capital projects.

b) Given the economic situation, please identify separately both maintenance and capital programs, if any, that Midland may have considered as a candidate for a deferral, cut, or partial adjustments. Please identify these programs, if any, in a ranking order that Midland would consider, using a ranking of "1" as the first suitable candidate, ranking of "2" as the second suitable candidate, ranking "3" as the third suitable candidate, etc. Please identify the rationale for the selection of these maintenance and capital programs and projects.

RESPONSE:

a) List of criteria and rationale used to prioritize and select 2009 capital and maintenance projects:

- condition of the asset
- capacity for future demand for development and expansion
- system reliability
- safety
- legislative requirements – ESA Regulation 22-04

b) Midland's 2009 Projects are outlined as follows:

Project # 2009-01 – Replace Bourgeois Lane Transformer Kiosk

The scope of this project as set out in the Rate Application submitted by Midland, is to replace the existing transformer installation and to install a backup primary feed to the transformers. The existing connection consists of three 167 Kva pole mounted transformers (500 Kva total) set in a steel kiosk on a concrete pad. The transformer bank, which services several commercial customers, is a non-standard transformer wiring configuration permitting the connection of 120/240 volt single-phase services and 120/208 volt three-phase services.

An engineering firm was contracted in 2008 to survey the existing transformer bank and to make recommendations for its replacement. The engineer's estimated cost to replace the existing 3, three-phase pole mounted transformers with 3, single-phase padmount transformers is $143,000, which exceeds Midland's Rate Application budget of $53,100.

A loss of one or all of these transformers or underground cable would result in a lengthy outage to the commercial services. Consequently, system reliability is at risk. Midland does not view that this project is a candidate for deferral, cut or partial adjustment.

Project #2009-02 – Development Contributions – Economic Evaluation

Capital funds are required for capital contributions from Midland to developers. As indicated in our Rate Application, Christian Midprop, Georgian Landing and Galloway Lands are developments that Midland believes will require development charges to be paid in 2009. Consequently, Midland does not view that this project is a candidate for deferral, cut or partial adjustment.

Project #2009-03 – Fourth Street Substation

The existing substation station equipment is fifty years old. The breakers are installed in a building below flood level creating a potentially hazardous condition. They are also located in a publicly owned building with offices for several local community groups. This substation upgrade is required to enable MPUC to serve customers without putting safety and reliability at risk. If substation upgrades are delayed, MPUC will be faced with multiple infrastructure replacements at the same time, or in emergency situations which would increase costs due to the nature of the emergency.

Midland does not view that this project is a candidate for deferral, cut or partial adjustment.

Project # 2009-04 – Yonge Street Pole Line

The Yonge Street pole line, which carries 2.4/4.16 Kv and 44 Kv distribution feeders, is an area of Midland's distribution infrastructure requiring immediate attention. The aged poles are in bad shape from years of adverse weather conditions. There are also safety and system reliability concerns as the poor condition of the pole tops and wooden cross arms provide little solid, wood surface to secure the mounting hardware which hold the conductors. A 30-pole span length of open-wire secondary bus is undersized as a result of years of added loads. It will be upgraded with a factory spun bus triplex and sized accordingly.

Midland does not view that this project is a candidate for deferral, cut or partial adjustment.

Project # 2009-05 – Hugel Avenue Pole Line

The Hugel Avenue pole line, which carries 2.4/4.16 Kv and 44 Kv distribution feeders, is an area of Midland's distribution infrastructure requiring immediate attention. The aged poles are in bad shape from years of adverse weather conditions. There are also safety and system reliability concerns as the poor condition of the pole tops and wooden cross arms provide little solid, wood surface to secure the mounting hardware which hold the conductors. The open-wire secondary bus is undersized as a result of years of added loads. It will be upgraded with a factory spun bus triplex and sized accordingly.

Midland does not view that this project is a candidate for deferral, cut or partial adjustment.

Project # 2009-06 – Sunnyside Pole Line

This pole line is scheduled for reconstruction in 2009. The existing poles have been badly affected by years of adverse weather conditions. The pole line is required to be completed in 2009 to enable Midland to serve customers without putting safety and reliability at risk.

Midland does not view that this project is a candidate for deferral, cut or partial adjustment.

Project # 2009-07 – Vehicle replacement

Midland PUC has two vehicles scheduled for replacement in 2009. The first is a 20 year old double-bucket truck, which over the past few years has required many repairs to the chassis to keep it certified as per MTO regulations. Major repairs to the boom and turret were also required. A well maintained aerial truck provides safety to the workers and ensures the workers have reliable control and maneuverability of the booms while working aloft.

The 1990 GMC Topkick has a 51' working height (straight up) which now poses a problem as higher poles are being installed to accommodate clearance requirements as per the Electrical Safety Code. The new truck will have a working height of 56' making working aloft on higher poles safer.

The second vehicle to be replaced is a 1997 GMC Safari van which is used by the metering department. Not only is there major rusting of the front and rear quarter panels and the doors, the undercarriage is badly rusted and will not pass certification at the next scheduled safety maintenance.

Midland does not view that this project is a candidate for deferral, cut or partial adjustment.

Project # 2009-08 – Scada Software Upgrade

This project will see an upgrade to our Scada software from a VMS based Scada system to a Windows system. Midland is able to defer this project, however, we have done so in the past, at the expense of continuing with technology that has not been upgraded for 15 years. If this project is deferred, Midland would see 2010 as the year of the upgrade.

Projects #2009-10 to #2009-18 – Projects less than 1%

These Projects represent small maintenance and purchases that include material and equipment purchases for distribution assets as in transformers, load breaker switches and metering equipment which are required for the safety and reliability of our distribution system on an ongoing basis.

Midland does not view these projects as candidates for deferral, cut or partial adjustment

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

16.

[Ex4/T1/S1]

The figures in the table below are taken directly from the public information filing in the Reporting and Record-keeping Requirements ("RRR") initiative of the OEB. The figures are available on the OEB's public website. Please confirm Midland's agreement with the numbers for OM&A, which are summarized in the table below. Where Midland does not agree with the OM&A numbers in the table below, please provide the revised number and an explanation of why it has been revised.

	2003	2004	2005
Operation	$320,276	$272,722	$303,349
Maintenance	$370,154	$306,118	$199,512
Billing and Collection	$379,401	$439,712	$406,928
Community Relations	$9,211	$15,581	$76,748
Administrative and General Expenses	$604,099	$634,480	$669,997
Total OM&A Expenses	**$ 1,683,140**	**$ 1,668,613**	**$ 1,656,533**

RESPONSE:

Midland has amended the Total OM&A Expenses as follows:

	2003	2004	2005
Operation	$320,276	$272,722	$303,349
Reallocation of Overheads - #5665	$42,132	$16,646	$21,044
Net Operations	$362,408	$289,368	$324,393
Maintenance	$370,154	$306,118	$199,512
Reallocation of Overheads - #5665	$48,693	$18,684	$13,841
Net Maintenance	$418,847	$324,802	$213,353
Billing and Collection	$379,401	$439,712	$406,928
Community Relations	$9,211	$15,581	$76,748
Administrative and General Expenses	$604,099	$634,480	$669,997
Reallocation of Overheads – Op'n	-$42,132	-$16,646	-$21,044
Reallocation of Overheads – Maint	-$48,693	-$18,684	-$13,841
Net Admin & General Expenses	$513,273	$599,150	$635,112
Total OM&A Expenses Per OEB	**$ 1,683,140**	**$ 1,668,613**	**$ 1,656,533**
Property Taxes Acct #6105	**$26,083**	**$28,420**	**$29,241**
Capital Taxes Acct #6105	**$10,854**	**$16,091**	**$11,209**
Penalties Acct #6215	**$1,358**	**$13**	**$41**
Adjusted Total OM&A Expenses	**$1,721,435**	**$1,713,137**	**$1,697,024**

Midland has revised the OM&A numbers to include Property Taxes on property owned by Midland and included as Distribution Assets, Capital Taxes as paid to CRA and Penalties paid on account of late payment fees, all of which are a part of Midland's OM&A Expenses.

In addition, Midland has reallocated costs from Administration and General Expenses to Operations and Maintenance Expenses. In the years 2003-2005 the net vehicle and overhead expenses after direct allocation to capital and rework projects were allocated to Account #5665, Miscellaneous General Expenses under the category of Administrative and General Expenses. This allocation was done in error and the vehicle and overhead expenses should have been allocated to Operations and Maintenance. For the purposes of this analysis the allocation in 2003-2005 has been shown as a credit to Administrative and General Expenses and a debit to Operations and Maintenance expenses on a pro-rata basis.

17.

[Ex1/T1/S7/Pg2]

What inflation rate is used for the 2009 OM&A forecast and what is the source document for inflation assumptions?

RESPONSE:

Midland used a 3% inflation factor in its forecast. Midland considered the Bank of Canada CPI index and reviewed the Collective Bargaining Agreement in setting the rate.

18.

[Ex4/T2/ S2]

The utility's variance analysis spans some 76 pages. Please provide an abbreviated summary of the major expense variances for each year, broken down by cost category (Operations, Maintenance, Billing & Collections, and Administrative and General). Please provide explanations for the largest 4 variances in each cost category for each year for which variance explanations are required. The variance explanations should cover the following annual variances:

- 2009 vs 2008
- 2008 vs 2007
- 2007 vs 2006
- Overall 2009 vs 2006

RESPONSE:

2007 Actual VS 2006 Actual

Total OM&A Expenses decreased $18,182 in 2007 over 2006 Actual balances. The cost drivers for this increase are:

2007 vs. 2006	2007 Actual	2006 Actual	Variance
3500-Distribution Expenses - Operation	**$ 352,987**	**$ 374,509**	**-$ 21,521**
Removal of PCBs decrease over 2006			$6,814
Labour/Burden decrease over 2006			$21,040
Substation Maint/MSP Reg'n inc. over 2006			-$5,331
Miscellaneous increase over 2006			-$1,002
Net Variance			0.00

Explanation:

Expenses incurred in 2006 from Green Port Environmental were for the removal and assessment of contaminated soil due to PCBs. No expenses were incurred in 2007. In 2007 more labour charges were allocated to capital projects, rework and jobbing and contributed capital projects than in 2006.

Substation maintenance expenses increased in 2007 over 2006 expenses. These costs include maintenance work performed by Rondar Engineering Inc. on our six distribution substations. Maintenance is performed on each of Midland's substations every two years by Rondar Engineering Inc. In 2006 only two of Midland's substations had maintenance work performed, while in 2007 three of Midland's substations had maintenance work performed which resulted in the increase. Costs will vary depending on the needs as identified during the maintenance inspections. In 2007 MPUC registered it's two remaining wholesale metering points with the IESO. Peterborough Utilities was retained as our Meter Service Provider (MSP), and handles our wholesale meter related issues with the

IESO. The variance represents the costs paid to Peterborourgh Utilities on the two additional metering points in 2007.

2007 vs. 2006	2007 Actual	2006 Actual	Variance
3550-Distribution Expenses – Maintenance	**$ 283,582**	**$ 336,041**	**-$ 52,459**
Labour/Burden decrease over 2006			$31,831
Subcontracting decrease over 2006			$9,181
Training decrease over 2006			$4,387
Materials decrease over 2006			$8,532
Miscellaneous increase over 2006			-$1,472
Net Variance			0.00

Explanation:

In 2007 more labour/burden charges were allocated to capital projects, rework and jobbing and contributed capital projects than in 2006. Midland did not require the subcontracting services in 2007. Training expenses for EUSA courses were provided to staff over and above yearly training requirements in 2006. Materials expenses decreased in 2007 as a one time cost for scrap Inventory was written off in 2006.

2007 vs. 2006	2007 Actual	2006 Actual	Variance
3650-Billing & Collecting	$ 451,821	$ 379,313	$ 72,507
Labour/Burden decrease over 2006			$2,291
IT Expense increase over 2006			-$20,453
Notice Delivery increase over 2006			-$5,332
Bad Debts increase over 2006			-$47,407
Miscellaneous increase over 2006			-$1,606
Net Variance			0.00

Explanation:

In 2007 there was a slight decrease in Midland's labour/burden allocations over 2006 labour/burden. In 2006, a change in staff in hourly workers resulted in a 30 year employee taking over the duties of a one year employee. The pay grade for the 30 year employee is higher than a one year employee. During the transition period of approximately 2 months, both employees performed the function, which resulted in additional wages in the Collection Department in 2006. In November, 2007 MPUC had a change in billing staff. The new billing clerk hired commenced employment at a lower pay rate than the previous incumbent. Therefore the net of these two changes resulted in a slight decrease in labour/burden.

Midland converted to the Harris billing software in May 2007 from the Advanced Infinity System. As a result of the conversion the IT function was outsourced which resulted in the reduction in labour/burden as Midland's internal IT position has been eliminated. Until May of 2007, the labour/burden allocation for this position was posted to Account #5610 Management Salaries and Expenses, as the IT position was in Management. Due to these changes, IT expenses therefore increased in 2007 over 2006.

The Notice Delivery increase is attributed to costs associated with the delivery of disconnection notices for a full year in 2007. In 2006 the delivery of disconnection notice charges commenced in June.

A decrease in MPUC residential bad debts in 2007 over 2006 bad debts totalled $11,654. An increase in commercial bad debts in 2007 over 2006 bad debts totaled $59,061 for a net increase of $47,407. MPUC suffered bad debt losses due to the bankruptcy one of our GS>50 customers again in 2007.

2007 vs. 2006	**2007 Actual**	**2006 Actual**	**Variance**
3800-Administrative & General Expenses	**$ 650,232**	**$ 655,050**	**-$ 4,819**
Labour/Burden decrease over 2006			$46,895
Office Supply increase over 2006			-$3,432
Legal Fees, Audit Fees, Regulatory Consulting Fees increase over 2006			-$17,895
OEB Regulatory fees increase over 2006			-$4,931
Other Plant Expenses increase over 2006			-$14,014
Miscellaneous increase over 2006			-$1,804

In 2006, MPUC's Administrative/Finance management labour totalled 3.8 staff members. In 2007, MPUC's Administrative/Finance management labour decreased by .8 to 3 staff members in June as a result of our billing system conversion. MPUC converted to the Harris billing software in May 2007 from the Advanced Infinity System. As a result of the conversion, the IT management position was outsourced which resulted in a reduction in labour/burden. Due to these changes, IT expenses in Account # 5315 Customer Billing increased. 2007 labour/burden expenses would have also taken into account salary increases for management staff from 2006, along with increases in wages paid to managers who moved to the next level of their salary scale and incentives paid for the year. In 2007, management salaries included one management position at the probationary level for part of the year.

Office supplies increased over 2006 expenses as a result of increases in costs associated with various general office supplies including telephone charges, utility charges, bank charges and internet access fees.

An increase in legal and audit fees in 2007 over 2006 balances is as a result of an increase in audit fees coupled with increased legal fees due to the review of legal agreements with respect to the property lease agreement with SCBN, MPUC's building lease agreement with Bright Side Management and legal fees associated with billing. In addition, legal reviews of two of MPUC's GS>50 customer bankruptcy protection agreements were required in 2007. Consulting fees also increased in 2007 over the 2006 as MPUC required services for review of the 2007 cost allocation filing, and general business consulting.

2007 Regulatory expenses increased over 2006 expenses. In 2006 OEB cost assessment expenses over the 1999/2000 approved balances were reallocated to a variance account, as approved by the OEB. This reallocation ceased as of

April 30, 2006. In addition, MPUC paid additional expenses in 2007 for cost awards over 2006 expenses.

Other plant expenses increased due to snowplowing, gas and hydro charges, and general repairs.

2008 Bridge Year VS 2007 Actual

Total OM&A Expenses are expected to increase $149,700 over 2007 actual year balances. The cost drivers for this increase are:

2008 Bridge Year vs. 2007 Actual Year	2008 Bridge Year	2007 Actual	Variance
3500-Distribution Expenses - Operation	$392,900	$352,987	$39,913
Labour/Burden increase over 2007			-$17,688
Subcontracting increase over 2007			-$3,280
Property Taxes/Leases increase over 2007			-$20,189
Substation Maintenance decrease over 2007			$2,490
Miscellaneous increase over 2007			-$1,246
Net Variance			0.00

At the time of filing of the rate application, Midland assumed an increase in staffing levels by one management position in 2008. This increased labour compliment is necessary to ensure the safety and other regulatory requirements are kept current with the changing business environment. It is anticipated that this person will provide for succession planning in the operations department. Midland is responding to the regulatory and safety needs by moving toward increasing and improving business practices and processes. These improvements and upgrades to its business practices will pay benefits in the long run and Midland recognizes that there is a cost associated with achieving these benefits. Midland is also undergoing substantial increases in its fixed assets due to the enhancement and/or replacement of system infrastructure and system enhancements. This management position will play an important role in the design and implementation of our capital plans. .

Midland shares after hours on-call with neighbouring LDC, Tay-Newmarket Hydro. The on-call expense will fluctuate from year to year based on the number and nature of the callout required.

Property Taxes/Lease expenses are projected to increase over 2007 actual expenses due to property tax increases and the renegotiation of the leases on our substations and the new land lease required for the move of the 4th Street Substation. Midland's lease was renewed in 2008 and has not received an increase in the lease costs since 2000.

Substation maintenance expenses are projected to decrease over 2007 expenses. As noted previously, these costs include maintenance work performed by Rondar Engineering Inc. on our six distribution substations. Rondar performs maintenance inspections on Midland's distribution substations on a two year rotation. In 2007, three of Midland's substations had maintenance work performed, while in 2008 only two of the substations will require the yearly inspection and maintenance work, thus resulting in a decrease. Costs will vary depending on the needs as identified during the maintenance inspections, although one of the substations was fully upgraded in 2007, therefore yearly inspection and maintenance work are projected to be minimal in 2008.

2008 Bridge Year vs. 2007 Actual Year	2008 Bridge Year	2007 Actual	Variance
3550-Distribution Expenses – Maintenance	$338,200	$283,582	$54,618
Labour/Burden increase over 2007			-$56,159
Material expenses decrease over 2007			$4,031
Miscellaneous increase over 2007			-$2,490
Net Variance			0.00

Explanation:

In 2008, one of our outside workers was transferred into the engineering department and a new outside worker was hired. Consequently, labour/burden has increased for the full time position.

Material expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account and in 2008 it is expected that material expenses will decrease over 2007 levels.

2008 Bridge Year vs. 2007 Actual Year	2008 Bridge Year	2007 Actual	Variance
3650-Billing & Collecting	$420,400	$451,821	-$31,421
Labour/Burden decrease over 2007			$4,438
IT increase over 2007			-$19,217
Bad Debt decrease over 2007			$50,344
Collection Supply Expense increase over 2007			-$1,957
Miscellaneous increase over 2007			-$2,187
Net Variance			0.00

Explanation:

Labour/Burden expenses in 2007 were allocated to this cost category for meter reading done by Midland's metering technician. For the purposes of this Application, the metering technician labour/burden costs were allocated to Account #5175.

IT expenses are projected to increase to account for a full year of IT services in 2008. MPUC converted to the Harris Billing System in May 2007, therefore the IT services were not provided for a full year in 2007.

In 2006 and 2007, two General Service Customers declared bankruptcy. Midland followed the OEB regulatory requirements in dealing with these customers. Midland was not able to collect deposits from these customers prior to their bankruptcy as both customers had excellent payment history and were grandfathered into the new rules at the time of incorporation of Midland. Midland has therefore set its bad debt expense at $80,000 per year which we believe will more accurately reflect Midland's exposure to uncollectible accounts.

Collection supply expenses for printing and collection notices are expected to increase over 2007 levels due to rising transportation and economic conditions.

2008 Bridge Year vs. 2007 Actual Year	**2008 Bridge Year**	**2007 Actual**	**Variance**
3800-Administrative & General Expenses	$744,600	$650,232	$94,368
Labour/Burden increase over 2007			-$20,275
Office Supply increase over 2007			-$16,393
Outside Services increase over 2007			-$28,232
General Plant increase over 2007			-$18,360
Miscellaneous increase over 2007			-$11,108
Net Variance			0.00

Explanation:
In 2007, management salaries included one management position at the probationary level for part of the year. In late spring of 2007, this manager reached full time status and received a step increase for the remainder of the year. In 2008, management salaries increased as a result of this manager moving to the next step increase for the year, in addition to other management receiving 3% increases. Burden will increase as a result of the increases in salaries.

Office supply increases are projected to increase due to additional charges for internet access as a result of the change in internet services due to the Harris conversion, bank charges, general office supply increases and software support increases.

Consulting fees are expected to increase $12,714 as a result of the increased need for regulatory and safety compliance work, while safety audit fees are projected to increase by $300. 2008 Bridge Year consulting fees for business and human resource related functions are projected to increase expenses $15,218 over 2007.

Wireless expenses are projected to increase over 2007 expenses. Other plant expenses are projected to increase over 2007 expenses as a result of increased costs associated with emergency telephone access, snowplowing and general plant material and utility increases.

2009 Test Year VS 2008 Bridge Year

Total OM&A Expenses for the 2009 Test Year are expected to increase $158,400 over the 2008 Bridge Year balances. The cost drivers for this increase are:

2009 Test Year vs. 2008 Bridge Year	2009 Test Year	2008 Bridge Year	Variance
3500-Distribution Expenses – Operation	$455,700	$392,900	$62,800
Labour/Burden Increase over 2008			-$60,600
Miscellaneous increase over 2008			-$2,200
Net Variance			0.00

Explanation:

At the time of filing of the rate application, Midland assumed an increase in staffing levels by one management position in 2008. This increased labour compliment is necessary to ensure the safety and other regulatory requirements are kept current with the changing business environment. It is anticipated that this person will provide for succession planning in the operations department. Midland is responding to the regulatory and safety needs by moving towards increasing and improving business practices and processes. These improvements and upgrades to its business practices will pay benefits in the long run and Midland recognizes that there is a cost associated with achieving these benefits. Midland is also undergoing substantial increases in its fixed assets due to the enhancement and/or replacement of system infrastructure and system enhancements. This management position will play an important role in the design and implementation of our capital plans.

2009 Test Year vs. 2008 Bridge Year	2009 Test Year	2008 Bridge Year	Variance
3550-Distribution Expenses– Maintenance	$353,900	$338,200	$15,700
Labour/Burden Increase over 2008			-$14,500
Miscellaneous increase over 2008			-$1,200
Net Variance			0.00

Explanation:

It is expected that hourly labour/burden expenses will fluctuate year over year based on the volume and type of work (capital work vs. maintenance work) performed with respect to each particular account, and in Account #5105 we are projecting labour/burden to increase over the 2008 projected expenses.   The 2008 labour/burden expenses are allocated to USoA numbers based on the percentage of labour dollars allocated to the particular USoA number in 2007.   In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement.   As indicated in 2008, one of the outside workers was transferred to the engineering department. In 2009, it is expected that this engineering staff will move to the next progressive level in accordance with the Collective Bargaining Agreement.

2009 Test Year vs. 2008 Bridge Year	2009 Test Year	2008 Bridge Year	Variance
3650-Billing & Collecting	$435,800	$420,400	$15,400
Labour/Burden increase over 2008			-$11,200
Postage/Office Supplies inc. over 2008			-$3,900
Miscellaneous increase over 2008			-$300
Net Variance			0.00

Explanation:

Customer Billing labour/burden expenses are projected to increase due to the billing staff member progressing to the next level in their wage category. In addition, hourly labour increases occur year over year in accordance with the Collective Bargaining Agreement. Office supplies include a minimal increase to allow for supply cost increases during the year, while postage expenses are also projected to increase to allow for an increase in postage rates. IT expenses are projected to increase over 2008 projected expenses to allow for increases in costs.

2009 Test Year vs. 2008 Bridge Year	**2009 Test Year**	**2008 Bridge Year**	**Variance**
3800-Administrative & General Expenses	$807,900	$744,600	$63,300
Labour/burden Increase over 2008			-$5,900
Regulatory Increase over 2008			-$50,000
Office Supplies increase over 2008			-$2,000
Outside Services increase over 2008			-$2,200
Miscellaneous increase over 2008			-$3,200
Net Variance			0.00

Explanation:

Labour/burden expenses are projected to increase over 2008 projected expenses to allow for increases that occur year over year in accordance with the Collective Bargaining Agreement and to provide for year over year increases to Management salaries.

Midland expects to incur costs from the Ontario Energy Board as a result of the 2009 Rate Application process. These costs include supporting the review process of the application which could include a technical or oral hearing, along with intervener and other cost awards and are expected to total $150,000. Midland has included only $50,000 in this Rate Application expecting recovery over three years. However, due to the increased costs involved in the oral component Midland expects these costs to rise to $175,000.

Office supply increases are projected to increase over 2008 projected expenses to allow for general cost increases over the year.

Consulting Fees for 2009 are projected to increase over 2008 projected expenses to allow for general cost increases associated with accounting, legal and general consulting fees.

<u>2009 Test Year VS 2006 Actual Year</u>

Total OM&A Expenses for the 2009 Test Year are expected to increase $289,918 over the 2006 Year balances.   The cost drivers for this increase are:

2009 Test Year vs. 2006 Actual Year	2009 Test Year	2006 Actual Year	Variance
3500-Distribution Expenses – Operation	$455,700	$374,509	$81,191
Labour/Burden Increase over 2006			-$57,248
Property Taxes/Leases Increase over 2006			-$22,693
Substn Maint/MSP increase over 2006			-$3,441
Removal of PCBs decrease over 2006			$6,814
Miscellaneous increase over 2006			-$4,623
Net Variance			0.00

Explanation:

Labour/Burden has increased over 2006 levels as a result of a change in staffing levels by employee grouping. The Operations Department included 8 FTE positions in 2006 and in 2009 will see 10 FTE positions. In 2009, labour expense is expected to increase over 2008 levels due to the hiring of an additional manager in the operations department as a result of increased regulatory and safety requirements. In addition, the hourly staff compliment was increased in the engineering department. Midland also had staff changeover in 2007 which would reduce the benefit expense in 2007 and 2008 until new staff reached fulltime status.

Property Taxes/Lease expenses will increase due to property tax increases and the renegotiation of the leases and the new land lease required for the move of the 4th Street Substation. Midland's lease was renewed in 2008 and has not received an increase in the lease costs since 2000.

In 2008, Midland will pay for Meter Service Provider (MSP) Fees on each of our four registered wholesale metering points.   Peterborough Utilities was retained as our Meter Service Provider (MSP), and handles our wholesale meter related issues with the IESO.   In 2007, Midland completed the final meter point registration with the IESO. The increase represents the costs paid to Peterborourgh Utilities on the final metering point that was registered in 2007.

Expenses incurred in 2006 from Green Port Environmental were for the removal and assessment of contaminated soil due to PCBs. No expenses were incurred in 2009.

2009 Test Year vs. 2006 Actual Year	**2009 Test Year**	**2006 Actual Year**	**Variance**
3550-Distribution Expenses – Maintenance	$353,900	$336,041	$17,859
Labour/Burden Increase over 2006			-$38,828
Subcontracting decrease over 2006			$9,181
Training decrease over 2006			$6,502
Materials decrease over 2006			$12,563
Miscellaneous increase over 2006			-$7,277
Net Variance			0.00

Explanation:

Labour/burden has increased over 2006 levels as a result of a change in staffing levels by employee grouping. The Operations Department included 8 FTE positions in 2006 and in 2009 will see 10 FTE positions. In 2009, labour/burden expense is expected to increase over 2008 levels. In 2008, one of our outside workers was transferred into the engineering department and a new outside worker was hired. Consequently, labour/burden has increased for the full time position. Midland also had staff changeover in 2007 which would reduce the benefit expense in 2007 and 2008 until new staff reached fulltime status.

Subcontracting services are not expected to be incurred in 2009. Training is expected to decrease in 2009 as a result of the one time charges in 2006. Materials expenses decreased as a result of a one-time write off of scrap materials in 2006 and a decrease number labour hours being spent with respect to the maintenance of overhead conductors and devices.

2009 Test Year vs. 2006 Actual Year	2009 Test Year	2006 Actual Year	Variance
3650-Billing & Collecting	$435,800	$379,313	$56,487
Labour/Burden Increase over 2006			-$4,471
IT increase over 2006			-$44,665
Notice Del/Supply increase over 2006			-$7,589
Miscellaneous decrease over 2006			$238
Net Variance			0.00

Explanation:

Labour/burden increases from 2006 to 2009 would include union contract increases year over year. In addition, in November, 2007 a change in billing staff resulted in a new billing clerk replacing a previous incumbent at a lower pay rate.

Midland converted to the Harris billing software in May, 2007 from the Advanced Infinity System. As a result of the conversion, the IT function was outsourced which resulted in the reduction in labour/burden as Midland's internal IT position was eliminated. Until May of 2007, the labour/burden allocation for this position was posted to Account #5610 Management Salaries and Expenses, as the IT position was at a Management level. Due to these changes, IT expenses therefore increased in 2009 over 2006.

The Notice Delivery increase is attributed to costs associated with the delivery of disconnection notices for a full year in 2009. In 2006 the delivery of disconnection notice charges commenced in June. Collection supply expenses are expected to increase over 2006 levels due to transportation costs and economic conditions.

2009 Test Year vs. 2006 Actual Year	2009 Test Year	2006 Actual Year	Variance
3800-Administrative & General Expenses	$807,900	$655,050	$152,850
Labour/Burden decrease over 2006			$20,720
Office Supplies & Exp increase over 2006			-$21,825
Outside Services Exp increase over 2006			-$48,327
OEB Regulatory fees increase over 2006			-$57,980
General Plant Exp increase over 2006			-$34,274
Miscellaneous increase over 2006			-$11,164
Net Variance			0.00

Explanation:

Labour/burden has decreased over 2006 levels as a result of a change in staffing levels by employee grouping. The Administrative Department included 6.8 FTE positions in 2006 and in 2009 will see 6 FTE positions. Midland also had staff changeover in 2007 which would reduce the benefit expense in 2007 and 2008 until new staff reached fulltime status. The reduction in staff is due to the outsourcing of the IT function as a result of the conversion to the Harris CIS. In addition, expenses would increase as a result of year over year increases in accordance with the Collective Bargaining Agreement and increases to management salaries as previously indicated.

Office supplies increased over 2006 expenses as a result of increases in costs due to inflation for office supplies, telephone charges, bank charges, internet access fees and software support fees.

Audit fees have increased over 2006 fees as a result of the increased auditing requirements. Legal fees have increased year over year due to the increased legal issues surrounding the bankruptcy of customers and customer deposit requirements. Human resource consulting fees and costs associated with regulatory consulting for future IRM and Cost Allocation applications will be required. Regulatory and Safety compliance requirements will require legal and other consulting related fees.

As indicated above, Midland expects to incur costs from the Ontario Energy Board as a result of the 2009 Rate Application process. Midland has included only $50,000 in this Rate Application expecting recovery over three years. In addition, Midland has incurred additional OEB assessments and cost awards over 2006 levels.

General Plant expenses have increased as a result of increased costs associated with emergency telephone access, snowplowing, grass cutting, wireless telephone expenses, and general plant material and utility increases.

19.

[Exh4/T2/S2]

Has the utility assessed its own workforce in the context of the risks associated with an aging workforce? If so, please provide a description of the utility's plan to address the aging workforce issue. In doing so, please address the expected timeframe, costs, and benefits of implementing the plan.

RESPONSE:

At the time of filing of the rate application, Midland assumed an increase in staffing levels by one management position in 2008, due to the hiring of an additional manager in the operations department as a result of increased regulatory and safety requirements. It is anticipated that this person will provide for succession planning in the operations department. This person will be an integral part of the management team of Midland as our senior manager looks to retire over the next five years. Midland's unionized labour will see retirements in late 2010 in the Administration Department and these positions will be filled at the time of those retirements. Midland does not anticipate additional costs as new staff will be hired at the lower pay range, however, additional training expenses will be incurred in order to provide the incumbents with the appropriate skill set required in a utility environment. This succession plan will provide

Midland with the appropriate workforce compliment to maintain service and reliability requirements.

20.

[Ex4/T2/S8/Pg2]

The evidence mentions the Management Performance & Compensation Plan for salaried employees. Please list the specific targets and describe how compensation is linked to those targets. Please provide additional detail about how the performance plan is aligned with utility ratepayer (i.e. customer) interests. Does the utility have a special bonus (or incentive) plan over and above the base plan and if so, please provide the details, including who is eligible, and the specific nature of the plan.

RESPONSE:

The incentive plan for salaried employees is based on the following targets:

Continuous process improvements and cost reductions in expenses/capital projects in comparison to budgets. Ratepayers will benefit from these programs in future years as expenses and return on fixed assets is reduced which will then reduce rates. These processes have reduced the costs of the capital project and will ultimately reduce the cost to the customer in that less return on ratebase will be built into the rate structure.

Safety: Providing a safe working environment by adherence to safety standards will benefit customers as Midland performs its work in a safe and controlled environment taking all necessary forms of safety precautions. Customers will benefit in WSIB premium and general insurance reductions and in the reduction of lost productivity. Vehicle insurance claims, lost time injuries, and general health and safety precautions are performance measures that are taken into account.

Exceeding OEB Service Quality Indicators will provide better service to Midland customers over what is a mandated requirement by the OEB.

Midland does not have a special bonus plan over and above the incentive plan. Midland's incentive plan is also set up to compensate salaried staff for the extra hours they have expended to the corporation over the year. Management on average work between 5-10 hours per week over and above their normal work hours. These additional hours which are not paid to salaried employees, benefit the customer. Midland salaried employees are also paid at a lower pay scale than their counterparts as set out in the EDA Management Salary Survey.

21.

[Ex4/T2/S8]

Please provide a table showing the percentage increases in base salary and total compensation (salary wages and benefits) budgeted for 2009 broken down by major employee grouping (e.g., executive, management, non-union and unionized workers).

RESPONSE:

Base Salary	2008	2009	% Increase
Management	$ 372,000.00	$ 423,400.00	13.8%
Union	$ 568,100.00	$ 616,600.00	8.5%

The management grouping shows an increase of 13.8% which is made up of a 2.4% increase in FTE salaried staff and an 11.4% increase over 2008 levels as a result of the hiring of a new manager in the latter part of 2008.

The unionized grouping shows an increase of 8.5%. Midland's Collective Bargaining Agreement will be renegotiated in the spring of 2009. At that time Midland projects an overall increase of 3%. In addition, it is expected that outside staff hourly rates will increase an additional 3% reaching levels of comparable LDC's adjacent to Midland's service territory. Over the past number of years Midland has lagged behind other LDC's in linecrew rates and has suffered excessive turnover as a result. Consequently, one of the steps Midland is taking is to reach wage parity with comparable LDC's. In 2008, Midland's unionized staff included a full compliment of staff for 10 months of the year. In addition, the transfer of one outside worker to the engineering department and an inside worker will result in step increases in 2009. These two factors will result in an addition increase of 2.5% over 2008 levels.

Total Compensation	**2008**	**2009**	**% Increase**
Management	$ 508,190.00	$ 569,875.00	12.1%
Union	$ 717,062.00	$ 781,798.00	9.0%

The management group shows an increase of 12% which is made up of a 13% increase as a result of the addition of a new engineering manager to the management team. The additional -1% decrease is the result of decreases in employee incentives.

The unionized group shows an increase of 9%. Staff members stepping to higher pay levels as mentioned above, result in 3% of the overall increase in total compensation. Two new staff members were on probationary status for 6 months during 2008, at which time they were not eligible for medical/dental and insurance benefits. These staff will receive benefits for a full year in 2009, which accounts for 2.6% of the overall increase. Increases in the linecrew pay rates, combined with the overall 3% wage increase accounts for the remaining 3.4% increase in total compensation.

22.

[Ex4/T2/S2]

Please describe any productivity or cost efficiency programs at the utility that are either in place now or contemplated at some future time. Please describe the nature of any such program and the scope, timing and benefits expected.

RESPONSE:

Midland's productivity and cost efficiency programs have resulted in the following:

1. In the spring of 2006, Midland became aware that Advanced, our billing CIS would be upgrading their CIS and the cost for this upgrade would be at least $50,000. This cost would be over an above the annual support and other regulatory costs that Advanced was currently charging. In Midland's case, these costs ranged from $70,000 in 2003, to $65,000 in 2004, to $46,000 in 2005 and $47,000 in 2006. In addition to those costs, Midland incurred the inhouse IT expenses of over $50,000. Midland was also aware that a number of LDCs had moved their CIS away from Advanced leaving a smaller number of Ontario LDCs to share the costs of the various upgrades that were needed due to regulatory requirements. Consequently, Midland believed that the costs of maintaining the Advanced CIS system were going to increase and looked at other alternatives for its CIS. In addition, Midland saw the need to reduce the vulnerability it had to staffing changes in the billing department and the time lag in training new staff to become proficient in the billing software.

Midland is a member of the CHEC Group and through this affiliation knew that a number of LDCs in the group were using the software program Harris. Midland also made some inquiries on the SAP model, but our initial investigation revealed that the costs of this program would far exceed the Harris model. The Harris billing system was used by over 40 LDC's throughout Ontario. Midland then made the decision to convert its billing CIS to Harris from Advanced. Once the decision was made to move to Harris, Midland looked at various alternatives open to it:

a) Purchase software and provide billing and IT support inhouse
b) Contract out billing and IT
c) Contract out IT but retain billing inhouse
d) Billing Co-operative – ASP model

Midland determined the most cost effective alternative was the Billing Co-operative and became one of the founding owners of Utility Collaborative Services Inc. which provides back office billing solutions to billing. Synergies are achieved through standards, pricing in volume amounts from vendors based on combined customer numbers rather than single utility counts. Conversions, updates and programming costs are also priced at combined volume levels. As with most group efforts individual price levels would make most programs and services out of reach. In 2007, Midland's billing costs were reduced by .5 of a person as the IT position was eliminated in June of 2007. Future years will see a decrease of one salaried position. Annual maintenance fees from Advanced have been eliminated. Purchase of software is not required and Midland's combined cost for 2009 for IT, software and Harris annual maintenance are expected to be $44,700.

Midland shares in a spare metering transformer with other LDCs in the CHEC Group which alleviates the necessity of each LDC purchasing a spare metering unit and which would therefore reduce the cost to the customer by reducing the return component of the ratebase.

23.

[Ex4/T2/S2/Pg74]

For Regulatory Expenses, please provide a breakdown by expense category/grouping of the $73,700 amount requested for 2009. Please indicate which cost elements are proposed for a thee-year amortization. Please provide an alternate scenario where the costs are amortized over a four-year recovery period rather than three.

RESPONSE:

Cost Elements Over Three Years:

OEB Regulatory Assessment and Cost Awards	$23,700
Rate Application 2009 (three year cost)	$50,000
Total Costs Over Three Years	**$73,700**

Although Midland estimated the rate application expenses to be $150,000 and have initially recorded the $50,000 per year over 3 years, Midland believes that the oral component will require additional costs to be expended by the ratepayers over and above what was originally budgeted. We would therefore respectfully ask that the Board consider an increase of $25,000 for a total rate application expense of $175,000. If recovered over three years this expense would be $58,300 and if recovered over four years this expense would be $43,750. The total regulatory expenses would therefore be:

Cost Elements Over Three Years:

OEB Regulatory Assessment and Cost Awards	$23,700
Rate Application 2009	$58,300
Total Costs Over Three Years	**$82,000**

Cost Elements Over Four Years:

OEB Regulatory Assessment and Cost Awards	$23,700
Rate Application 2009	$43,750
Total Costs Over Four Years	**$67,450**

24.

[Ex4/T2/S2]

Please identify any one-time expenses in 2009 that could be amortized over a period of more than a single year and suggest an appropriate amortization period for those expenses.

RESPONSE:

Midland is not aware of any one-time expenses in 2009 that could be amortized over a period of more than a single year.

25.

[Ex4/T2/S2]

Please confirm that Midland has no one-time expenses in 2008 that were inadvertently carried over into the 2009 budget. If there are such expenses, please identify the item and provide the dollar amount of the inadvertent carry-over.

RESPONSE:

Midland confirms that there are no one-time expenses in 2008 that were inadvertently carried into the 2009 budget.

26.

[Ex4/T3/S1/Pg4]

Please confirm that charitable donations are not included in the revenues sought from utility ratepayers. If they are, please provide the dollar amount and reason why these should be recovered through distribution rates.

RESPONSE:

Midland confirms there are no charitable donations included in revenues sought from utility ratepayers.

Customer Connections

[Ex3/T2/S9]

Preamble: At Ex 3/T2/S9/page 13, Midland states "The annual trend growth rate is used to project customer growth/decline into the 2008 Bridge and 2009 Test Year. A trend forecast for the number of customers in each rate class for the 2008 Bridge and 2009 Test Year is calculated based on the most recent 2 years of growth".

27.

a) Please explain the rationale for using "most recent 2 years of growth" to develop the customer forecast when Midland has access to 5-years of customer data as presented in Table 28 (Ex 3/T2/S4/page 1).

b) Please provide a customer forecast based on 5 years (2003-2007) of average customer growth. Please also provide the impact on the proposed test year load and revenue forecast if this alternate customer forecast were adopted.

c) Please develop a total customer forecast using a simple linear trend method based on data from 2003 to 2007, for bridge year and test year. Please also provide the impact on the proposed test year load and revenue forecast if this alternate customer forecast were adopted.

RESPONSE:

b) The most recent 2 years was adopted as the trend growth in Residential, GS<50, GS>50 and Street Lighting as it is our view this most accurately reflects the customer growth likely to be seen in the next 2 years. For example, customer attachments in the Residential class have been growing at a faster rate in the 2005 to 2007 period than the 2003 to 2005 period. The large rate of growth in the GS<50 class in 2004 has not occurred in any other year, but the growth rate in this class has been relatively stable in other years.

b)

The table below displays a trend customer forecast based on average growth from 2003 to 2007

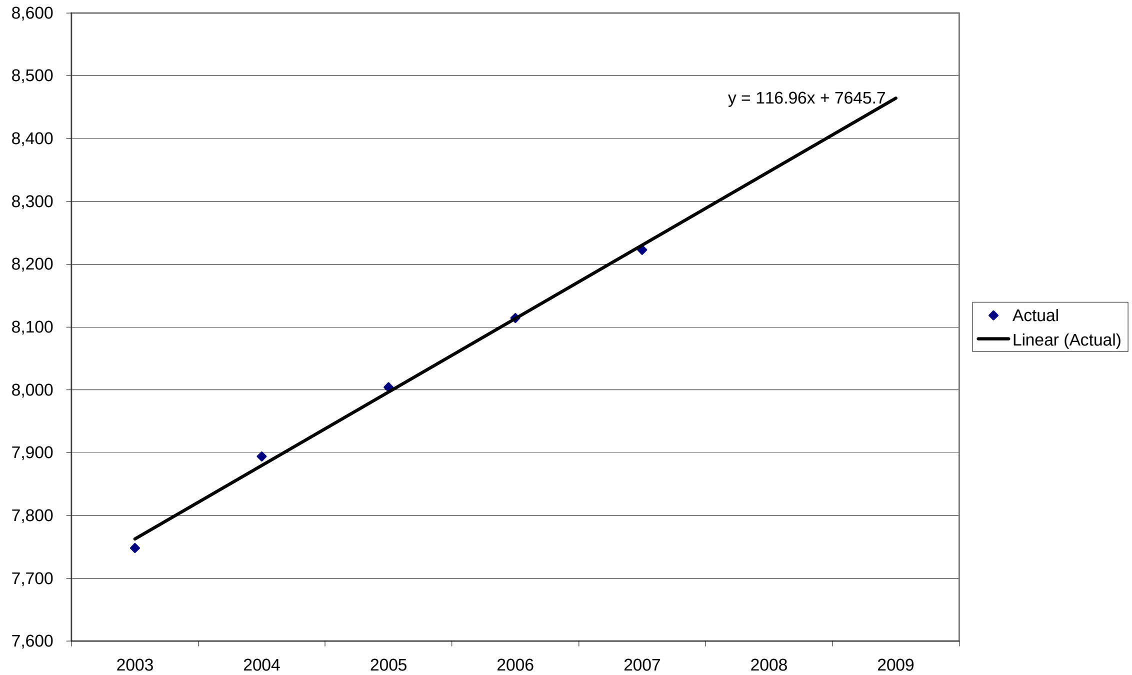
Customer Growth Based on 2003 – 2007 Data			
	Average Growth	Customers 2008	Customers 2009
Residential	1.3%	5,912	5,991
GS<50 kW	1.0%	730	737
GS>50 kW	-1.7%	105	103
Street Lighting	2.5%	1,563	1,602
Sentinel Lighting	9.2%	24	26
USL	-		

The customer connections have no direct impact on the load and revenue forecast.

c) A simple linear trend was developed and is displayed below. The total customer count (including Street Lights) in 2008 and 2009 based on this trend would be 8,347 and 8,464, respectively. This compares to a total customer count (including Street Lights) of 8,334 and 8,448 in 2008 and 2009 using the ERA methodology as outlined in the ERA Load Forecast report. Using the simple linear trend, the customer count in 2008 increases by 13 and the customer count in 2009 increases by 16, a difference of less than 0.2% in each year. The two methods yield almost identical results.

MPUC's revenues are not based on total customer count, so it is difficult to tell what the impact of using this methodology would be. Since the results are so close, we have not developed the analysis further.

MPUC - Total Customers, Trend Line



28.

Please explain if Midland's test year customer count forecast for 2009 is consistent with one or more external forecasts (such as Housing Outlook reports from CMHC or the national Banks). Please provide the reference to the reports/forecasts used and explain how these forecasts support Midland's projections for customer additions in the test year. If the external reports/forecasts do not support Midland's proposed customer forecast, then please explain the reasons for any variances.

RESPONSE:

To our knowledge, forecasts for Midland are not available from any external source, including CMHC and the Banks. However, the table attached to this document shows the community profile for the Town of Midland from the Census in 2001 and 2006. Population growth has been very modest, growing only 0.5% in the 5 years from 2001 to 2006. However, private dwellings have grown from 6,872 in 2001 to 7,248 in 2006, an increase of about 1.1% per year. We believe this is consistent with the observed history and projected growth in customers in the Residential and GS<50 classes.

29.

Based on the responses to the questions above, if Midland decides to restate its as-filed customer forecast, then please also update the load and revenue forecasts to reflect the change in the customer forecast.

RESPONSE:

Based on the responses to question #28 above, Midland will not be restating the customer forecast.

Weather Forecast

[Ex 3/T2/S9/page 6]

Preamble: Midland is seeking Board approval for a test year weather normal of 3,631 HDD and 390 CDD, based on a 10-year simple average of weather data recorded at Toronto Pearson Airport. At Ex 3/T2/S9/page 8, Midland states "Our view is that a ten-year average based on the most recent ten calendar years available is a reasonable compromise that likely reflects the "average" weather experienced in recent years".

30.

Similar to the method used to develop the test year 2009 weather normal, please provide the following "back-cast" scenarios:

a. Assuming Midland is preparing a 2006 test year forecast, please develop a weather normal using 10-years of historical weather data from 1995-2004 and compare this forecast to actual observed weather in 2006. Please calculate the variance and percent variance from actual observed weather.

b. Assuming Midland is preparing a 2007 test year forecast, please develop a weather normal using 10-years of historical data from 1996-2005 and compare this forecast to actual observed weather in 2007. Please calculate the variance and percent variance from actual observed weather.

c. Assuming Midland is preparing a 2008 test year forecast, please develop a weather normal using 10-years of historical data from 1997-2006 and compare this forecast to actual year-to-date observed weather in 2008. Please calculate the variance and percent variance from actual observed weather.

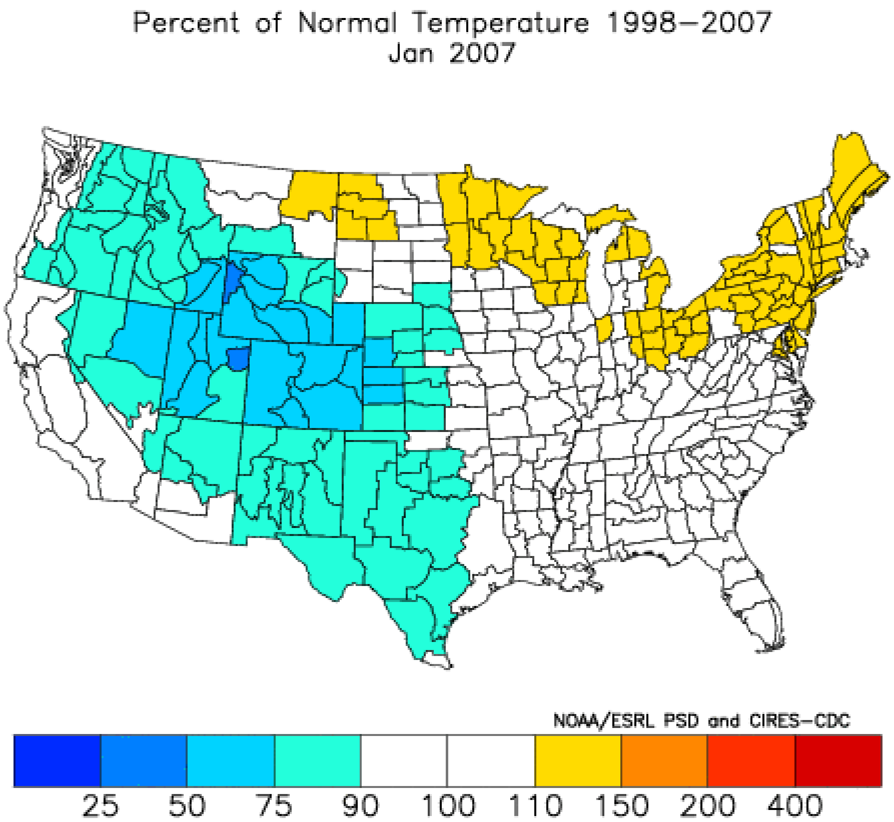
RESPONSE:

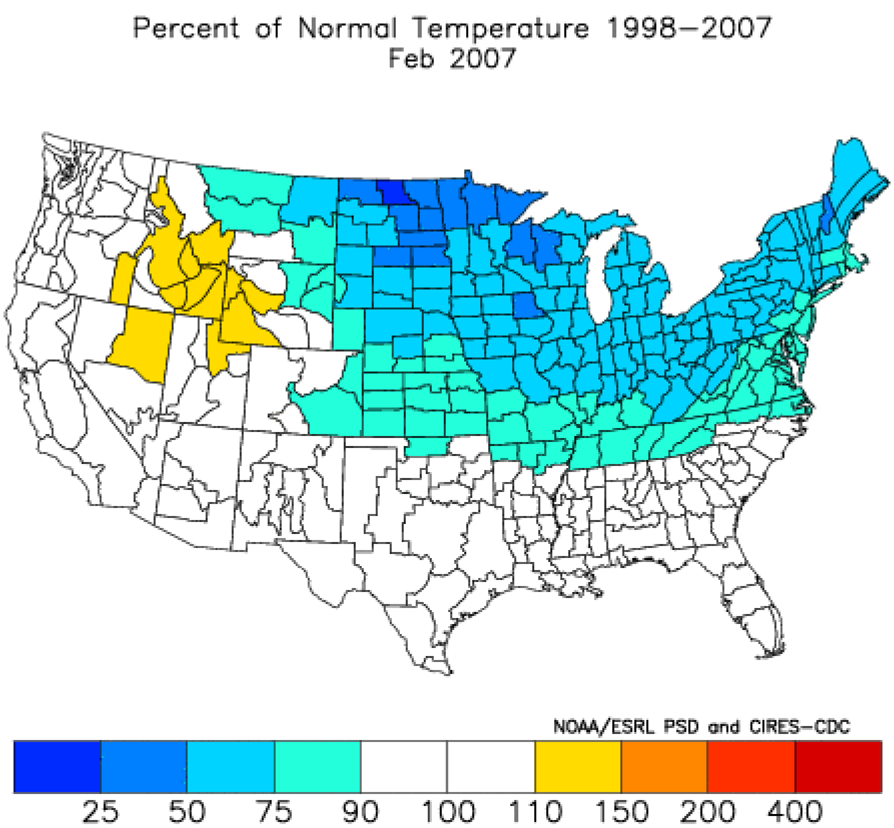
a) - c) Below, please find tables which outline the three different 10 year weather normal scenarios for Pearson Airport asked for by Board Staff (1995-2004, 1996-2005, and 1997-2006) and comparing these to actual degree days in 2006, 2007, and 2008 year-to-date, respectively. We have presented data and comparison on a monthly and annual basis as there are significant variations from month-to-month. For example, as can be seen below, HDD in 2007 are almost exactly equivalent to the 10 year normal defined as 1996-2005 (10 year average of 3,742 vs. 2007 annual of 3,719, a difference of less than 1%). However, several months in 2007 were much warmer than normal. January was warmer than normal and October was one of the warmest on record (HDD 45% less than the 10 year average as defined). To illustrate this, we have also attached two graphics for the Continental USA illustrating the temperature per cent of normal for the average 1998-2007 for the months of January 2007 and February 2007 (produced by NOAA/ESRL, the US National Oceanic and Atmospheric Administration, Earth System Research Laboratory).

Part A								
Degree Days for Pearson International Airport								
10-yr Weather Normal 1995-2004			Year 2006 Actual		2006 Variance from 10 yr 1995-2004 (Degree Days)		2006 Variance from 10 yr 1995-2004 (per cent)	
	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD
Jan	720.9	0.0	551.8	0	-169.1	0.0	-23.5%	N/A
Feb	612.1	0.0	604.3	0	-7.8	0.0	-1.3%	N/A
Mar	538.6	0.0	516.6	0	-22.0	0.0	-4.1%	N/A
Apr	343.8	1.2	293.3	0	-50.5	-1.2	-14.7%	-100.0%
May	158.8	11.2	136.9	26	-21.9	14.8	-13.8%	131.3%
Jun	32.9	64.3	19.5	73.6	-13.4	9.3	-40.8%	14.4%
Jul	5.4	116.1	0	167.3	-5.4	51.2	-100.0%	44.1%
Aug	6.2	103.6	4.2	101.6	-2.0	-2.0	-32.7%	-2.0%
Sep	66.1	36.9	80.9	12.9	14.8	-24.0	22.4%	-65.1%
Oct	249.0	2.1	288.3	1.1	39.3	-1.0	15.8%	-46.9%
Nov	423.1	0.0	382.2	0	-40.9	0.0	-9.7%	N/A
Dec	609.9	0.0	500.5	0	-109.4	0.0	-17.9%	N/A
Annual	**3,766.8**	**335.5**	**3,378.5**	**382.5**	**-388.3**	**47.0**	**-10.3%**	**14.0%**

Part B								
Degree Days for Pearson International Airport								
10-yr Weather Normal 1996-2005			Year 2007 Actual		2007 Variance from 10 yr 1996-2005 (Degree Days)		2007 Variance from 10 yr 1996-2005 (per cent)	
	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD
Jan	732.6	0.0	647.1	0	-85.5	0.0	-11.7%	N/A
Feb	603.1	0.0	740.1	0	137.0	0.0	22.7%	N/A
Mar	549.6	0.0	546.7	0	-2.9	0.0	-0.5%	N/A
Apr	332.7	1.2	356.4	0	23.7	-1.2	7.1%	-100.0%
May	162.8	11.0	136.4	22.4	-26.4	11.4	-16.2%	104.2%
Jun	31.8	71.2	16.5	99.2	-15.3	28.1	-48.1%	39.4%
Jul	4.3	121.9	3.2	106.1	-1.1	-15.8	-26.3%	-13.0%
Aug	5.8	105.4	5.2	141	-0.6	35.6	-10.3%	33.8%
Sep	55.0	40.9	36.9	47.5	-18.1	6.7	-32.9%	16.3%
Oct	249.1	2.5	137.7	19.8	-111.4	17.3	-44.7%	688.8%
Nov	410.8	0.0	462.5	0	51.8	0.0	12.6%	N/A
Dec	604.7	0.0	630.7	0	26.0	0.0	4.3%	N/A
Annual	**3,742.3**	**354.0**	**3,719.4**	**436**	**-22.9**	**82.0**	**-0.6%**	**23.2%**

Part C								
Degree Days for Pearson International Airport								
10-yr Weather Normal 1997-2006			Year 2008 Actual		2008 Variance from 10 yr 1997-2006 (Degree Days)		2008 Variance from 10 yr 1997-2006 (per cent)	
	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD
Jan	711.3	0.0	623.5	0	-87.8	0.0	-12.3%	N/A
Feb	594.5	0.0	674.7	0	80.2	0.0	13.5%	N/A
Mar	536.7	0.0	610.2	0	73.5	0.0	13.7%	N/A
Apr	321.2	1.2	253.9	0	-67.3	-1.2	-21.0%	-100.0%
May	155.9	12.7	193.5	2.5	37.6	-10.2	24.1%	-80.3%
Jun	31.7	74.7	22.7	71.5	-9.0	-3.2	-28.3%	-4.3%
Jul	3.3	132.7	1	111	-2.3	-21.7	-69.8%	-16.3%
Aug	6.0	106.9	12.7	64	6.7	-42.9	112.7%	-40.1%
Sep	55.9	39.4	59.5	26.7	3.6	-12.7	6.4%	-32.3%
Oct	250.6	2.6	278.6	0	28.0	-2.6	11.2%	-100.0%
Nov	397.8	0.0						
Dec	597.6	0.0						
Annual	**3,662.5**	**370.2**						


Percent of Normal Temperature 1998–2007
Jan 2007
NOAA/ESRL PSD and CIRES–CDC
25 50 75 90 100 110 150 200 400


Percent of Normal Temperature 1998–2007
Feb 2007
NOAA/ESRL PSD and CIRES–CDC
25 50 75 90 100 110 150 200 400

It should be noted that ERA has developed weather-normal load forecasts for several LDCs including MPUC and has consistently adopted the most recent 10 years (1998 to 2007) as the definition of weather normal. ERA adopted this definition of “weather normal” as the Board has accepted this definition in other cases involving electricity distribution; namely, Toronto Hydro Electric System Limited (“THESL”). For example, in their forward test year filing in the 2006 EDR process (EB-2005-0421), THESL proposed to use the most recent 10 years (1995 to 2004) as the definition of “weather normal.” In its Decision with Reasons, dated April 12, 2006, the Board accepted the load forecast as proposed by the Applicant.

THESL again proposed the most recent 10 years (1996 to 2005) in their multi-year rate filing for 2008 – 2010 rates (EB-2007-0680). In their Application, THESL explained that the 10 year average was chosen over the 30 year average due to a pronounced trend in HDD and CDD, as illustrated in Figure 2 at Exhibit K1, Tab 1, Schedule 1, Page 7 of their Application. Again, the Board in their Decision with Reasons issued May 15, 2008, accepted this definition of weather normal.

MPUC and ERA have developed a model to weather normalize MPUC’s throughput based on best efforts and relying upon a definition that was previously filed and approved by the Board with the least amount of complexity necessary and that is consistent across LDCs (to the extent that data allows). MPUC and ERA were careful to design the model and definition of weather normal based on what appeared to be reasonable and based on past practice of other LDCs that have had approval by the Board. In developing the model, it was paramount that the model specification and weather normal definition be as consistent as possible across LDCs.

We note that while there are many definitions of weather normal, the US NOAA/ESRL also uses the 10 year period 1998-2007 (among others) as a long term climatological base period comparator.

31.

Similar to the scenarios described above, please provide the following “back-cast” scenario’s using a linear trend method based on 20-years of historical weather data.

a. Assuming Midland is preparing a 2006 test year forecast, please develop a weather normal for the 2006 test year using historical weather data from 1985-2004 and compare this forecast to actual observed weather in 2006. Please calculate the variance and percent variance from actual observed weather.

b. Assuming Midland is preparing a 2007 test year forecast, please develop a weather normal for the 2007 test year using historical data from 1986-2005 and compare this forecast to actual observed weather in 2007. Please calculate the variance and percent variance from actual observed weather.

c. Assuming Midland is preparing a 2008 test year forecast, please develop a weather normal for the 2008 test year using historical data from 1987-2006 and compare the forecast to actual observed weather in 2008. Please calculate the variance and percent variance from actual observed weather.

RESPONSE:

a) – c) Similar to what has been provided in response to Board Staff IR #30, below please find tables which outline the three different 20 year weather normal scenarios for Pearson Airport (1985-2004, 1986-2005, and 1987-2006) and comparing these to actual degree days in 2006, 2007, and 2008 year-to-date, respectively. We have presented data and comparison on a monthly and annual basis as there are significant variations from month-to-month.

The additional discussion provided in response to Board Staff IR #30 also applies to this response.

Part A								
Degree Days for Pearson International Airport								
20-yr Weather Normal 1985-2004			Year 2006 Actual		2006 Variance from 10 yr 1995-2004 (Degree Days)		2006 Variance from 20 yr 1985-2004 (per cent)	
	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD
Jan	720.3	0.0	551.8	0	-168.5	0.0	-23.4%	N/A
Feb	640.8	0.0	604.3	0	-36.5	0.0	-5.7%	N/A
Mar	551.1	0.0	516.6	0	-34.5	0.0	-6.3%	N/A
Apr	336.7	1.9	293.3	0	-43.4	-1.9	-12.9%	-100.0%
May	159.9	13.7	136.9	26	-23.0	12.3	-14.4%	90.3%
Jun	40.3	54.5	19.5	73.6	-20.8	19.1	-51.6%	35.0%
Jul	5.7	109.6	0	167.3	-5.7	57.7	-100.0%	52.7%
Aug	12.5	88.5	4.2	101.6	-8.3	13.1	-66.4%	14.8%
Sep	84.7	29.3	80.9	12.9	-3.8	-16.4	-4.5%	-56.0%
Oct	268.9	1.6	288.3	1.1	19.4	-0.5	7.2%	-31.9%
Nov	432.0	0.0	382.2	0	-49.8	0.0	-11.5%	N/A
Dec	625.4	0.0	500.5	0	-124.9	0.0	-20.0%	N/A
Annual	**3,878.4**	**299.1**	**3,378.5**	**382.5**	**-499.9**	**83.4**	**-12.9%**	**27.9%**

Part B								
Degree Days for Pearson International Airport								
20-yr Weather Normal 1986-2005			Year 2007 Actual		2007 Variance from 20 yr 1986-2005 (Degree Days)		2007 Variance from 20 yr 1986-2005 (per cent)	
	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD
Jan	717.8	0.0	647.1	0	-70.7	0.0	-9.9%	N/A
Feb	638.4	0.0	740.1	0	101.7	0.0	15.9%	N/A
Mar	554.1	0.0	546.7	0	-7.4	0.0	-1.3%	N/A
Apr	335.7	1.7	356.4	0	20.7	-1.7	6.2%	-100.0%
May	161.4	13.3	136.4	22.4	-25.0	9.1	-15.5%	68.4%
Jun	36.8	61.4	16.5	99.2	-20.3	37.8	-55.1%	61.6%
Jul	5.2	116.1	3.2	106.1	-2.0	-10.0	-38.6%	-8.6%
Aug	11.8	92.6	5.2	141	-6.6	48.4	-55.9%	52.3%
Sep	81.8	29.4	36.9	47.5	-44.9	18.1	-54.9%	61.5%
Oct	266.6	2.0	137.7	19.8	-128.9	17.8	-48.4%	892.5%
Nov	429.6	0.0	462.5	0	32.9	0.0	7.7%	N/A
Dec	623.6	0.0	630.7	0	7.1	0.0	1.1%	N/A
Annual	**3,862.8**	**316.5**	**3,719.4**	**436**	**-143.4**	**119.5**	**-3.7%**	**37.8%**

Part C								
Degree Days for Pearson International Airport								
20-yr Weather Normal 1987-2006			Year 2008 Actual		2008 Variance from 20 yr 1987-2006 (Degree Days)		2008 Variance from 20 yr 1987-2006 (per cent)	
	HDD	CDD	HDD	CDD	HDD	CDD	HDD	CDD
Jan	708.9	0.0	623.5	0	-85.4	0.0	-12.0%	N/A
Feb	634.8	0.0	674.7	0	39.9	0.0	6.3%	N/A
Mar	552.9	0.0	610.2	0	57.3	0.0	10.4%	N/A
Apr	334.8	1.7	253.9	0	-80.9	-1.7	-24.2%	-100.0%
May	161.6	13.7	193.5	2.5	31.9	-11.2	19.8%	-81.7%
Jun	34.4	64.2	22.7	71.5	-11.7	7.3	-34.0%	11.4%
Jul	4.7	119.2	1	111	-3.7	-8.2	-78.7%	-6.9%
Aug	10.1	95.1	12.7	64	2.6	-31.1	25.5%	-32.7%
Sep	80.5	29.6	59.5	26.7	-21.0	-2.9	-26.1%	-9.9%
Oct	266.7	2.1	278.6	0	11.9	-2.1	4.5%	-100.0%
Nov	424.0	0.0						
Dec	618.9	0.0						
Annual	**3,832.4**	**325.6**						

Load Forecast

32.

[Ex 3/T2/S9/Pg5 & 6]

Midland states that the forecasts for the Residential and the GS<50 kWh rate classes are based on "OLS estimates using the 68 observations from 2002:05 to 2007:12". Please explain the rationale for using only 68 observations to develop the load forecast?

RESPONSE:

We believe the reference should be to Ex3/T2/S1,Attachment, pp.5-6.

The rationale for using 68 observations was to use all the data available (e.g., May 2002 to November 2007).

33.

[Ex 3/T2/S9/Og6]

Please provide the following information regarding the accuracy of previous load forecasts:

a. What was the forceast error (i.e. variance between total normalized actual 2004 load versus forecast 2004 load) of the 2004 load forecast?

b. What was the forecast error (i.e. variance between total normalized actual 2005 load versus forecast 2005 load) of the 2005 load forecast?

c. What was the forecast error (i.e. variance between total normalized actual 2006 load versus forecast 2006 load) of the 2006 load forecast?

d. What was the forecast error (i.e. variance between total normalized actual 2007 load versus forecast 2007 load) of the 2007 load forecast?

e. What was the year-to-date (Jan-08 to Aug-08) forecast error (i.e. variance between total normalized actual 2008 load versus forecast 2008 load) of the 2008 Bridge year load forecast?

RESPONSE:

MPUC does not prepare annual load forecasts or a regular basis. Therefore, MPUC is unable to answer this question.

34.

[Ex3/T2/S1/Pg2]

Preamble: Midland states "Short-term variation in electricity consumption is heavily influenced by three main factors – weather (e.g. heating and cooling), which is by far the dominant effect for most systems; economic factors (increases or decreases in economic activity leads to changes in employment, industrial and commercial activity, building and population change); and timing factors (non-holiday weekdays when businesses are typically operating)". [Emphasis added]

a. Please explain the rationale for not using ‘number of customers’ as an explanatory variable in the Residential and GS< 50 kWh regression equations.
b. Please prepare an alternative forecast for the residential and GS<50 kWh rate class using the following regression equations: Res kWh=f(Residential customers, HDD, CDD, Employment)+constant and GS<50 kWh=f(GS<50 customers, HDD, CDD, Peak days)+constant. If monthly customer data is not available, please make a reasonable assumption for the purposes of completing the interrogatory.
c. Please provide the statistical results of the above equations and please also update Table 3 (Ex 3/T2/S1/page 7) based on results of the above regression equations.
d. Please provide the impact on the proposed test year load and revenue forecast, if a load forecast based on the above equations were adopted?

RESPONSE:

a) There are several reasons why the number of customers was not used as an explanatory variable in the residential and GS<50 kW class kWh regression equations. The summary answer is that the best specification of the model (based on explanation of variance and statistical significance of the estimates) occurred when number of customers was excluded. When number of customers was included as an explanatory variable along with full-time employment in the Residential class specification, the coefficient estimate was statistically insignificant and of the wrong sign. When included in the specification without full-time employment, the overall performance of the equation was less robust than when full-time employment was included (without number of customers). Similar results occur with GS<50. When number of customers is included in the equation, it is statistically insignificant.

b) - c) The following equations have been estimated as requested.

1. Res kWh = *f*(Res Cust, HDD, CDD, Employ) + const
OLS estimates using the 68 observations 2002:05-2007:12
Unadjusted R^2 = 0.82856
Adjusted R^2 = 0.81767
F-statistic (4, 63) = 76.1184 (p-value < 0.00001)
Durbin-Watson statistic = 1.73561

Variable Name	Estimated Coeff.	T-Ratio	P-Value
const	3.04292E+06	2.099	0.03987
Res Cust	-508.781	-1.343	0.18409
HDD	2229.78	16.909	<0.00001
CDD	13990.8	10.062	<0.00001
FTE Employ	5404.12	3.110	0.00281

2. GS<50 kWh = *f*(GS<50 Cust, HDD, CDD, Peak days) + const
OLS estimates using the 68 observations 2002:05-2007:12
Unadjusted R^2 = 0.81886
Adjusted R^2 = 0.80736
F-statistic (4, 63) = 71.1984 (p-value < 0.00001)
Durbin-Watson statistic = 1.62149

Variable Name	Estimated Coeff.	T-Ratio	P-Value
const	660745	0.835	0.40661
GS<50 Cust	922.000	0.888	0.37792
HDD	1197.15	16.604	<0.00001
CDD	8021.05	10.114	<0.00001
Peak days	17612.5	1.382	0.17198

Statistical results of the equations are provided above. Forecast results based on these equations are provided in the updated table below.

Weather Corrected Consumption for Midland PUC Based On Board Staff Equation Specification from Board Staff IR 34 (b) Response.				
			10-yr (1998-2007)	
Year	Actual residential kWh	%chg	Weather Normal	%chg
2003	46,627,475		47,575,338	
2004	46,604,134	-0.1%	48,503,757	2.0%
2005	48,370,214	3.8%	49,248,286	1.5%
2006	46,479,977	-3.9%	49,750,795	1.0%
2007	47,886,438	3.0%	48,818,162	-1.9%
2008F			48,575,377	-0.5%
2009F			48,247,520	-0.7%
Year	Actual GS<50 kWh	%chg	Weather Normal	%chg
2003	27,036,581		27,494,093	
2004	26,788,352	-0.92%	27,775,492	1.0%
2005	26,768,115	-0.08%	27,731,969	-0.2%
2006	25,943,176	-3.08%	27,701,543	-0.1%
2007	27,070,448	4.35%	27,835,422	0.5%
2008F			27,857,455	0.1%
2009F			27,873,035	0.1%

d) The test year load impact of using the above equations is summarized in the table below:

Impact of Using Equations in Board Staff 34 (b) rather than Application		
Class	Impact (kWh)	Impact (per cent)
Residential	-1,544,217	-3.1%
GS<50 kW	+222,157	+0.8%

In applying the above load forecast for Residential and GS<50 customers, the resulting revenue impact will be an increase in our revenue deficiency of $26,510. The calculations are as follows:

- The table below provides for the calculation of the Cost of Power projections based on the rate application projections ($16,677,534)and the new OEB Load Forecast projections ($16,576,986).

Cost of Power Projections

				Rate Application			OEB Revised Load Forecast		
Electricity (Commodity)		**Revenue**	**Expense**	**2009**	*rate ($/kWh):*	**$0.05450**	**2009**	*rate ($/kWh):*	**$0.05450**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4006	4705	53,033,179		2,890,308	51,388,434		2,800,670
kWh	General Service <50 kW	4035	4705	29,450,950		1,605,077	29,687,570		1,617,973
kWh	General Service >50 Kw	4035	4705	148,504,837		8,093,514	148,504,837		8,093,514
kWh	Street Lighting	4025	4705	1,273,628		69,413	1,273,628		69,413
kWh	Sentinel Lighting	4030	4705	16,986		926	16,986		926
kWh	Unmetered Scattered Load	4035	4705	546,982		29,811	546,982		29,811
	TOTAL	0	0	**232,826,563**		**12,689,048**	**231,418,437**		**12,612,305**
Transmission - Network		**Revenue**	**Expense**	**2009**			**2009**		
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4066	4714	53,033,179	$0.0038	201,526	51,388,434	$0.0038	195,276
kWh	General Service <50 kW	4066	4714	29,450,950	$0.0034	100,133	29,687,570	$0.0034	100,938
kW	General Service >50 Kw	4066	4714	332,681	$1.4180	471,742	332,681	$1.4180	471,742
kW	Street Lighting	4066	4714	3,052	$1.0694	3,264	3,052	$1.0694	3,264
kW	Sentinel Lighting	4066	4714	44	$1.0749	47	44	$1.0749	47
kWh	Unmetered Scattered Load	4066	4714	546,982	$0.0034	1,860	546,982	$0.0034	1,860
	TOTAL	0	0	**83,366,888**		**778,572**	**81,958,762**		**773,126**
Transmission - Connection		**Revenue**	**Expense**	**2009**			**2009**		
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
kWh	Residential	4068	4716	53,033,179	$0.0071	376,536	51,388,434	$0.0071	364,858
kWh	General Service <50 kW	4068	4716	29,450,950	$0.0065	191,431	29,687,570	$0.0065	192,969
kW	General Service >50 Kw	4068	4716	332,681	$2.5532	849,401	332,681	$2.5532	849,401
kW	Street Lighting	4068	4716	3,052	$1.9738	6,024	3,052	$1.9738	6,024
kW	Sentinel Lighting	4068	4716	44	$2.0150	89	44	$2.0150	89
kWh	Unmetered Scattered Load	4068	4716	546,982	$0.0065	3,555	546,982	$0.0065	3,555
	TOTAL	0	0	**83,366,888**		**1,427,036**	**81,958,762**		**1,416,896**
Wholesale Market Service		**Revenue**	**Expense**	**2009**	*rate ($/kWh):*	**$0.00520**	**2009**	*rate ($/kWh):*	**$0.00520**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4062	4708	53,033,179		275,773	51,388,434		267,220
kWh	General Service <50 kW	4062	4708	29,450,950		153,145	29,687,570		154,375
kWh	General Service >50 Kw	4062	4708	148,504,837		772,225	148,504,837		772,225
kWh	Street Lighting	4062	4708	1,273,628		6,623	1,273,628		6,623
kWh	Sentinel Lighting	4062	4708	16,986		88	16,986		88
kWh	Unmetered Scattered Load	4062	4708	546,982		2,844	546,982		2,844
	TOTAL	0	0	**232,826,563**		**1,210,698**	**231,418,437**		**1,203,376**
Rural Rate Protection		**Revenue**	**Expense**	**2009**	*rate ($/kWh):*	**$0.00100**	**2009**	*rate ($/kWh):*	**$0.00100**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
kWh	Residential	4062	4730	52,872,087		52,872	51,737,634		51,738
kWh	General Service <50 kW	4062	4730	29,450,950		29,451	29,687,570		29,688
kWh	General Service >50 Kw	4062	4730	148,504,837		148,505	148,504,837		148,505
kWh	Street Lighting	4062	4730	1,273,628		1,274	1,273,628		1,274
kWh	Sentinel Lighting	4062	4730	16,986		17	16,986		17
kWh	Unmetered Scattered Load	4062	4730	546,982		547	546,982		547
	TOTAL	0	0	**232,665,471**		**232,665**	**231,767,638**		**231,768**
Debt Retirement Charge		**Revenue**	**Expense**	**2009**	*rate ($/kWh):*	**$0.00700**	**2009**	*rate ($/kWh):*	**$0.00700**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	TOTAL	0	0	**0**		**0**	**0**		**0**
Low Voltage Charges		**Revenue**	**Expense**	**2009**			**2009**		
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	TOTAL (Input amount)	4075	4750	**0**	339,515.32	**339,515**	**0**	339,515.32	**339,515**
GRAND TOTAL		0	0	**0**		**16,677,534**	**0**		**16,576,986**

- The table below reflects the working capital allowance based on the rate application projections ($2,815,595) and the new OEB Load Forecast projections ($2,800,513). The table further reflects the total rate base calculations based on the rate application projections ($12,318,654) and he new OEB Load Forecast projections ($12,303,571).

Working Capital Allowance & Total Rate Base

Working Capital Allowance

			Rate Application - 2009	**Revised Load Forecast - 2009**
Eligible Distribution Expenses:	*(1)*			
3500-Distribution Expenses - Operation			455,700	455,700
3550-Distribution Expenses - Maintenance			353,900	353,900
3650-Billing and Collecting			435,800	435,800
3700-Community Relations			5,600	5,600
3800-Administrative and General Expenses			807,900	807,900
3950-Taxes Other Than Income Taxes			34,200	34,200
Total Eligible Distribution Expenses			2,093,100	2,093,100
3350-Power Supply Expenses	(2)		16,677,534	16,576,986
Total Expenses for Working Capital			18,770,634	18,670,086
Working Capital Allowance		**15.0%**	**2,815,595**	**2,800,513**

TOTAL RATE BASE	**Rate Application - 2009**		**Revised Load Forecast - 2009**	
Net Fixed Assets in Service:				
Opening Balance	8,521,501		8,521,501	
Closing Balance	10,484,616		10,484,616	
Average Balance		9,503,058		9,503,058
		2,815,595		2,800,513
TOTAL RATE BASE		**12,318,654**		**12,303,571**

- The table below reflects Distribution Revenue Requirement based on the rate application projections ($3,582,721) and the new OEB Load Forecast projections ($3,581,765) for a variance of $956 which would represent an decrease in the revenue requirement.

	2009 Rate Application		OEB Load Forecast - 2009	
Rate Base				
2008 ending Net Fixed Assets	8,521,501		8,521,501	
2009 ending Net Fixed Assets	10,484,616		10,484,616	
Average Net Fixed Assets		9,503,058		9,503,058
Working Capital Allowance Base	18,770,634		18,670,086	
Working Capital Allowance	15%	2,815,595	15.00%	2,800,513
Rate Base		12,318,654		12,303,571
Return On Rate Base				
Deemed Short-Term Debt %	4.00%	492,746	4.00%	492,143
Deemed Long-Term Debt %	52.67%	6,487,824	52.67%	6,479,881
Deemed Equity %	43.33%	5,338,083	43.33%	5,331,548
Short-Term Interest	4.47%	22,026	4.47%	21,999
Long-Term Interest	4.64%	300,835	4.64%	300,466
Return On Equity	8.57%	457,474	8.57%	456,914
Return On Rate Base		780,334		779,379
Distribution Expenses & Taxes				
OM&A	2,093,100		2,093,100	
Amortization	735,424		735,424	
PILs/Taxes	204,993	3,033,517	204,993	3,033,517
Revenue Offsets		(231,131)		(231,131)
Distribution Revenue Requirement		3,582,721		3,581,765

35.

[Ex3/T2/S1/Pg9]

Preamble: With regards to the GS>50 KW forecast Midland states at Ex 3/T2/S1/page 9 that the non-weather sensitive class forecasts are “based on the trend of consumption over the past two historic years (2006 and 2007)….”

a. Please explain the rationale for using only two years of consumption data to develop the GS>50 load forecast when Midland has access to 5-years of customer data as presented in Table 7 (Ex 3/T2/S1/page 10).

b. What is the GS>50 kW rate class load forecast if 5-years of consumption data is used to develop the forecast?

c. Please also provide the impact on the proposed test year load and revenue forecast if this alternate load forecast were adopted.

RESPONSE:

a) Consumption in the GS>50 kW class has been declining for the past 2 years, as can be seen in Table 7 on page 10 of the ERA load forecast report. This trend appears to be continuing. Data for January to October 2008 indicate YTD consumption of 117,512,777 kWh in the GS>50 kW class, compared to 124,364,279 for the equivalent period in 2007, a decline of 5.5%.

b) If the average growth from 2003-2007 is used, the trend growth rate would be -0.1%. This would result in class kWh of 147,762,234 in 2008 and 147,591,063 in 2009. This appears to be unreasonable given the decline in consumption since 2006 and the YTD consumption that covers 10 months of the current year.

c) The test year load impact of using the above load forecast is summarized in the table below:

Impact on Test Year if forecast in 35 (b) adopted for GS >50 kW Class in 2009.						
ERA Forecast		Per Board Staff 35 (b)		Variance		% Variance
kWh	kW	kWh	kW	kWh	kW	kWh & kW
139,428,070	332,681	147,591,063	352,158	8,162,993	19,477	5.9%

In applying the above load forecast for the GS>50 customers, the resulting revenue impact will be an decrease in our revenue deficiency of $39,336. The calculations are as follows:

- The table below provides for the calculation of the Cost of Power projections based on the rate application projections ($16,677,534) and the new OEB Load Forecast projections ($17,282,632).

Cost of Power Projections

					Rate Application			OEB Revised Load Forecast		
Electricity (Commodity)		**Customer**	**Revenue**	**Expense**	**2009**	*rate ($/kWh):*	**$0.05450**	**2009**	*rate ($/kWh):*	**$0.05450**
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	kWh	Residential	4006	4705	53,033,179		2,890,308	53,033,179		2,890,308
	kWh	General Service <50 kW	4035	4705	29,450,950		1,605,077	29,450,950		1,605,077
	kWh	General Service >50 Kw	4035	4705	148,504,837		8,093,514	157,199,241		8,567,359
	kWh	Street Lighting	4025	4705	1,273,628		69,413	1,273,628		69,413
	kWh	Sentinel Lighting	4030	4705	16,986		926	16,986		926
	kWh	Unmetered Scattered Load	4035	4705	546,982		29,811	546,982		29,811
		TOTAL	0	0	**232,826,563**		**12,689,048**	**241,520,967**		**13,162,893**
Transmission - Network		**Customer**	**Revenue**	**Expense**		**2009**			**2009**	
		Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
	kWh	Residential	4066	4714	53,033,179	$0.0038	201,526	53,033,179	$0.0038	201,526
	kWh	General Service <50 kW	4066	4714	29,450,950	$0.0034	100,133	29,450,950	$0.0034	100,133
	kW	General Service >50 Kw	4066	4714	332,681	$1.4180	471,742	352,158	$1.4180	499,360
	kW	Street Lighting	4066	4714	3,052	$1.0694	3,264	3,052	$1.0694	3,264
	kW	Sentinel Lighting	4066	4714	44	$1.0749	47	44	$1.0749	47
	kWh	Unmetered Scattered Load	4066	4714	546,982	$0.0034	1,860	546,982	$0.0034	1,860
		TOTAL	0	0	**83,366,888**		**778,572**	**83,386,365**		**806,190**
Transmission - Connection		**Customer**	**Revenue**	**Expense**		**2009**			**2009**	
		Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**	**Volume**	**Rate**	**Amount**
	kWh	Residential	4068	4716	53,033,179	$0.0071	376,536	53,033,179	$0.0071	376,536
	kWh	General Service <50 kW	4068	4716	29,450,950	$0.0065	191,431	29,450,950	$0.0065	191,431
	kW	General Service >50 Kw	4068	4716	332,681	$2.5532	849,401	352,158	$2.5532	899,130
	kW	Street Lighting	4068	4716	3,052	$1.9738	6,024	3,052	$1.9738	6,024
	kW	Sentinel Lighting	4068	4716	44	$2.0150	89	44	$2.0150	89
	kWh	Unmetered Scattered Load	4068	4716	546,982	$0.0065	3,555	546,982	$0.0065	3,555
		TOTAL	0	0	**83,366,888**		**1,427,036**	**83,386,365**		**1,476,765**
Wholesale Market Service		**Customer**	**Revenue**	**Expense**	**2009**	*rate ($/kWh):*	**$0.00520**	**2009**	*rate ($/kWh):*	**$0.00520**
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	kWh	Residential	4062	4708	53,033,179		275,773	53,033,179		275,773
	kWh	General Service <50 kW	4062	4708	29,450,950		153,145	29,450,950		153,145
	kWh	General Service >50 Kw	4062	4708	148,504,837		772,225	157,199,241		817,436
	kWh	Street Lighting	4062	4708	1,273,628		6,623	1,273,628		6,623
	kWh	Sentinel Lighting	4062	4708	16,986		88	16,986		88
	kWh	Unmetered Scattered Load	4062	4708	546,982		2,844	546,982		2,844
		TOTAL	0	0	**232,826,563**		**1,210,698**	**241,520,967**		**1,255,909**
Rural Rate Protection		**Customer**	**Revenue**	**Expense**	**2009**	*rate ($/kWh):*	**$0.00100**	**2009**	*rate ($/kWh):*	**$0.00100**
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
	kWh	Residential	4062	4730	52,872,087		52,872	52,872,087		52,872
	kWh	General Service <50 kW	4062	4730	29,450,950		29,451	29,450,950		29,451
	kWh	General Service >50 Kw	4062	4730	148,504,837		148,505	157,199,241		157,199
	kWh	Street Lighting	4062	4730	1,273,628		1,274	1,273,628		1,274
	kWh	Sentinel Lighting	4062	4730	16,986		17	16,986		17
	kWh	Unmetered Scattered Load	4062	4730	546,982		547	546,982		547
		TOTAL	0	0	**232,665,471**		**232,665**	**241,359,875**		**241,360**
Debt Retirement Charge		**Customer**	**Revenue**	**Expense**	**2009**	*rate ($/kWh):*	**$0.00700**	**2009**	*rate ($/kWh):*	**$0.00700**
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
		TOTAL	0	0	**0**		**0**	**0**		**0**
Low Voltage Charges		**Customer**	**Revenue**	**Expense**		**2009**			**2009**	
		Class Name	**USA #**	**USA #**	**Volume**		**Amount**	**Volume**		**Amount**
		TOTAL (Input amount)	4075	4750	**0**	339,515.32	**339,515**	**0**	339,515.32	**339,515**
GRAND TOTAL			0	0	**0**		**16,677,534**	**0**		**17,282,632**

- The table below reflects the working capital allowance based on the rate application projections ($2,815,595) and the new OEB Load Forecast projections ($2,906,360). The table further reflects the total rate base calculations based on the rate application projections ($12,318,654) and he new OEB Load Forecast projections ($12,409,418).

Working Capital Allowance & Total Rate Base

Working Capital Allowance

		Rate Application - 2009	Revised Load Forecast - 2009
Eligible Distribution Expenses:	*(1)*		
3500-Distribution Expenses - Operation		455,700	455,700
3550-Distribution Expenses - Maintenance		353,900	353,900
3650-Billing and Collecting		435,800	435,800
3700-Community Relations		5,600	5,600
3800-Administrative and General Expenses		807,900	807,900
3950-Taxes Other Than Income Taxes		34,200	34,200
Total Eligible Distribution Expenses		2,093,100	2,093,100
3350-Power Supply Expenses	(2)	16,677,534	17,282,632
Total Expenses for Working Capital		18,770,634	19,375,732
Working Capital Allowance	**15.0%**	**2,815,595**	**2,906,360**

TOTAL RATE BASE	Rate Application - 2009		Revised Load Forecast - 2009	
Net Fixed Assets in Service:				
Opening Balance	8,521,501		8,521,501	
Closing Balance	10,484,616		10,484,616	
Average Balance		9,503,058		9,503,058
		2,815,595		2,906,360
TOTAL RATE BASE		**12,318,654**		**12,409,418**

- The table below reflects Distribution Revenue Requirement based on the rate application projections ($3,582,721) and the new OEB Load Forecast projections ($3,588,470) for a variance of $5,749 which would represent an increase in the revenue requirement.

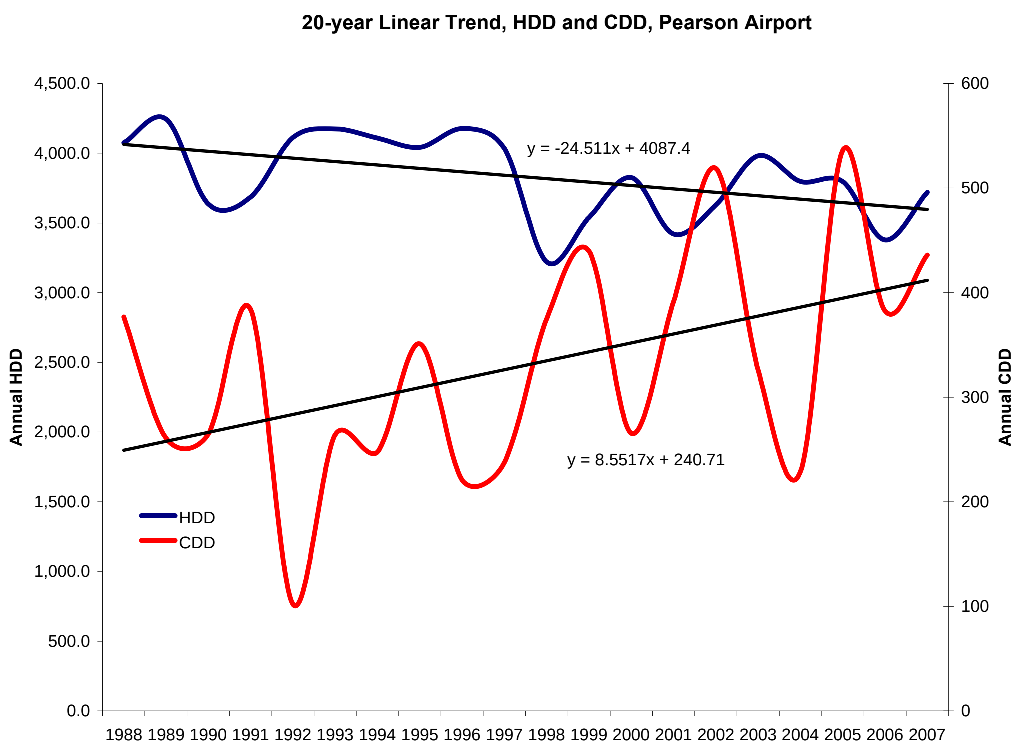
	2009 Rate Application		OEB Load Forecast - 2009	
Rate Base				
2008 ending Net Fixed Assets	8,521,501		8,521,501	
2009 ending Net Fixed Assets	10,484,616		10,484,616	
Average Net Fixed Assets		9,503,058		9,503,058
Working Capital Allowance Base	18,770,634		19,375,732	
Working Capital Allowance	15%	2,815,595	15.00%	2,906,360
Rate Base		12,318,654		12,409,418
Return On Rate Base				
Deemed Short-Term Debt %	4.00%	492,746	4.00%	496,377
Deemed Long-Term Debt %	52.67%	6,487,824	52.67%	6,535,627
Deemed Equity %	43.33%	5,338,083	43.33%	5,377,415
Short-Term Interest	4.47%	22,026	4.47%	22,188
Long-Term Interest	4.64%	300,835	4.64%	303,051
Return On Equity	8.57%	457,474	8.57%	460,844
Return On Rate Base		780,334		786,084
Distribution Expenses & Taxes				
OM&A	2,093,100		2,093,100	
Amortization	735,424		735,424	
PILs/Taxes	204,993	3,033,517	204,993	3,033,517
Revenue Offsets		(231,131)		(231,131)
Distribution Revenue Requirement		3,582,721		3,588,470

36.

Please prepare a weather normal for test year 2009 using a liner trend method based on 20 years of historical weather data. Please also prepare a load and revenue forecast using the methodology proposed in this application, for test year 2009 using this weather normal.

RESPONSE:

Below, we have fitted a linear trend to 20 years of historical weather data (HDD and CDD from 1988 to 2007) for Toronto Pearson International Airport.



Based on the estimated trend equations, HDD and CDD have been projected for 2003 up to and including the 2009 test year. These values are summarized in the table below:

Actual and Projected (Trend) HDD and CDD for Pearson International Airport, based on 1988-2007

Year	Actual HDD	Trend HDD	Actual CDD	Trend CDD
2003	3,981.5	3,695.2	325.6	377.5
2004	3,797.9	3,670.7	228.9	386.1
2005	3,796.8	3,646.2	536.2	394.6
2006	3,378.5	3,621.7	382.5	403.2
2007	3,719.4	3,597.2	436	411.7
2008		3,572.7		420.3
2009		3,548.2		428.8

Please note that the resulting trend is not a weather normal in the sense of a climatological long term average. Rather, it is a projection of actual degree days using a simple linear trend based on the actual annual degree over the latest 20 years available.

The ERA weather normalization/load forecast model was developed for use with monthly degree day data, month-to-month changes in full-time employment, and monthly peak days. It is not possible to develop a load forecast using the above annual trended degree days using the current ERA model.

37.

Please provide the impact on the proposed test year distribution load and revenue forecast, of the following:

a) 1% change in number of customers.

b) 1% change in the proposed weather normal.

RESPONSE:

(a) In response to VECC IR #2 (e), it was indicated that the test year forecast normalized average use per customer for the Residential Class is 8,274 kWh and for the GS<50 kW class is 37,946 kWh. A 1% change in Residential customers would result in approximately ± 60 customers or about ± 496,440 kWh per annum. A 1% change in GS<50 customers would result in approximately ± 7 customers or about ± 265,622 kWh per annum.

In applying the above load forecast for a ±1% change in both Residential and GS< 50 customer numbers, the revenue impact will be an increase of $544 on Midland's Distribution Revenue Requirement.

The table below summarizes the results of the changes in Working Capital Allowance, Total Rate Base, Regulated Return on Capital and the resulting Base Revenue Requirement for a +1% change in both Residential and GS<50 customer numbers and the resulting load.

Distribution Revenue Requirement

	2009 Rate Application		+1% Change in Residential and GS<50 Load	
Working Capital Allowance	$	2,815,595	$	2,824,191
Total Rate Base	$	12,318,654	$	12,327,249
Regulated Return on Capital	$	780,334	$	780,879
OM&A Expenses	$	2,093,100	$	2,093,100
3850-Amortization Expense	$	735,424	$	735,424
Total Distribution Expenses	$	2,828,524	$	2,828,524
Regulated Return On Capital	$	780,334	$	780,879
PILs (with gross-up)	$	204,993	$	204,993
Service Revenue Requirement	$	3,813,852	$	3,814,396
Less: Revenue Offsets	$	231,131	$	231,131
Base Revenue Requirement	$	3,582,721	$	3,583,265

Alternatively, applying the above load forecast for a -1% change in both the Residential and GS< 50 customer numbers and the resulting load, the revenue impact will be a decrease of $544 on Midland's Distribution Revenue Requirement.

(b) A change of ± 1% to weather normal HDD implies a ± 79,304 kWh per annum change for Residential Class consumption and a ± 43,387 kWh per annum change for GS<50 kW Class consumption. A change of ± 1% to weather normal CDD implies a ± 54,508 kWh per annum change for Residential Class consumption and a ± 31,036 kWh per annum change for GS<50 kW Class consumption.

In applying the above load forecast for a +1% change to weather normal HDD and CDD for both Residential and GS< 50 classes, the revenue impact will be an increase of $88 and $61 respectively on Midland's Distribution Revenue Requirement

The table below summarizes the results of the changes in Working Capital Allowance, Total Rate Base, Regulated Return on Capital and the resulting Base Revenue Requirement for a +1% change to weather normal HDD and CDD for both Residential and GS<50 customers.

Distribution Revenue Requirement

	2009 Rate Application	+1% Change in Residential and GS<50 HDD	-1% Change in Residential and GS<50 HDD	+1% Change in Residential and GS<50 CDD	-1% Change in Residential and GS<50 CDD
Working Capital Allowance	$ 2,815,595	$ 2,816,979	$ 2,814,211	$ 2,816,560	$ 2,814,630
Total Rate Base	$ 12,318,654	$ 12,320,037	$ 12,317,270	$ 12,319,618	$ 12,317,689
Regulated Return on Capital	$ 780,334	$ 780,422	$ 780,247	$ 780,395	$ 780,273
OM&A Expenses	$ 2,093,100	$ 2,093,100	$ 2,093,100	$ 2,093,100	$ 2,093,100
3850-Amortization Expense	$ 735,424	$ 735,424	$ 735,424	$ 735,424	$ 735,424
Total Distribution Expenses	$ 2,828,524	$ 2,828,524	$ 2,828,524	$ 2,828,524	$ 2,828,524
Regulated Return On Capital	$ 780,334	$ 780,422	$ 780,247	$ 780,395	$ 780,273
PILs (with gross-up)	$ 204,993	$ 204,993	$ 204,993	$ 204,993	$ 204,993
Service Revenue Requirement	$ 3,813,852	$ 3,813,939	$ 3,813,764	$ 3,813,913	$ 3,813,790
Less: Revenue Offsets	$ 231,131	$ 231,131	$ 231,131	$ 231,131	$ 231,131
Base Revenue Requirement	$ 3,582,721	$ 3,582,808	$ 3,582,633	$ 3,582,782	$ 3,582,660

Alternatively, applying the above load forecast for a -1% change to weather normal HDD and CDD for both the Residential and GS< 50 customer class, the revenue impact will be a decrease of $88 and $61 respectively on Midland's Distribution Revenue Requirement.

RATE BASE / CAPITAL EXPENDITURES

38.

[Ex2/T1/S1]

The pre-filed evidence of MPUC indicates significant increases in capital expenditures in 2008 and 2009. The Company proposes to replace one substation in each of the years from 2007 to 2010. Rondar Engineering completed an assessment of the substation infrastructure in 2006 and recommended replacement of the substation infrastructure. The application also indicates that Rondar has been completing the maintenance on MPUC substations over the past 10 years. Please answer the following questions with respect to this evidence:

a) What process did the Company follow with respect to awarding contracts to outside vendors? Please provide details and file any RFQs or RFPs that were distributed to third parties.
b) Was Rondar Engineering awarded any contracts or performed any work on the substations that they identified for replacement or upgrade? If "Yes", please provide details on the contracts awarded or work performed including cost details.
c) What impact will the replacement of the substations have on the reliability of the distribution system? How will these replacements impact the reliability statistics? Please provide forecasts where appropriate.

RESPONSE:

a) Upon completion of the substation study, Midland met with Rondar to discuss the overall substation plan in conjunction with Midland's capital plan. It was determined that the Scott Street substation would be the first to be updated in 2007. Midland contracted with Rondar to oversee the upgrade and installation of the equipment, based on their expertise with Midland's distribution system. Three quotes for the supply and installation of the breakers were obtained from Wesco, Areva and ABB. Areva was selected based on references and the ability to comply with Midland's specifications. The decision to use the switch gear at the Scott Street substation set a precedent for the supply of Areva switch gear and Schweitzer relays for subsequent substation upgrades. The rationale for this is to provide consistent materials in all substations.

As experience was gained from Rondar, Midland undertook this role in planning for 2008. Midland requested quotes from three engineering firms for the installation of the new Brandon substation – Tiltran, State Electric and R&B Construction. Tiltran was awarded the contract based on price, investigation of references and ability to comply with Midland's specifications. Areva was selected to supply the switch gear and relays as indicated above.

Attached to this document are copies of the quotes received from Wesco, Areva, ABB, Tiltran, State Electric and R&B Construction.

b) As indicated above, Rondar was contracted by Midland for the 2007 Scott Street upgrade to oversee the construction of the substation. Rondar did not provide any transformer, switch gear or relay materials.

c) As indicated in our Rate Application, Midland's substations are 50 years old. The substation upgrades are not only done to ensure the safety and reliability of our distribution system, but also to meet existing and future load demands and will allow backfeeding in the event of a catastrophic failure of a substation. The replacement of the old dysfunctional breakers and relays with new digital technology will provide improved power restoration in the event of a fault. Reliability statistics should be improved, however, Midland cannot forecast when power outages will occur.

39.

[Ex2/T4/S3/Att1]

In the Cost of Power worksheet volumes shown for the Residential class and General Service less than 50 kW do not reconcile with the numbers used in the load forecast (Exh3/Tab2/Sc3/Table 27). Please explain the variance.

RESPONSE:

The volumes shown for the Residential, General Service less than 50kW, and Unmetered Scattered Load class in the load forecast E3/T2/S3/Table 27 have not been uplifted by the loss factor of 1.0651. When we apply the loss factor, the volumes agree to the Cost of Power Projections found in E2/T4/S3/Att 1.

The table below reconciles the differences.

Customer Class	2009 Normalized E3/T2/S3/Table 27	Loss Factor	Cost of Power Projections E2/T4/S3/Att 1
Residential	49,791,737	1.0651	53,033,179
General Service <50 kW	27,650,878	1.0651	29,450,950
Unmetered Scattered Load	513,550	1.0651	546,982

INCOME TAX

40.

[Ex4/T3/S1/Att6]

Please answer the following questions with respect to income tax calculations:

a) The table showing the detailed tax calculations for PILs does not include 2007 information. Please provide a revised table for the years 2006 through to 2009, including the 2007 information.

b) Please show the calculation of the line item "Income before PILs/Taxes" of $644,773 for the 2009 test year. Please also show the calculation of the 2009 test year regulatory income before taxes based on the following calculation: rate base multiplied by the equity thickness multiplied by the return on equity percentage. Please explain why there is a difference.

c) An amount of $61,437 and $163,561 representing Actual Debt Interest for the years 2008 and 2009 respectively has been added to determine the PILs amount. Please explain why these charges, which are not deductible for tax purposes, should true up to the ratepayers. The pre-tax income used as the starting point for regulatory tax calculation allows for the deduction of deemed interest.

RESPONSE:

a) Midland has revised Attachment #6 to include the detailed tax calculations for PILs for 2006 to 2009. This schedule is attached below.

Midland Power Utility Corporation (ED-2002-0541)
PILs Calculations for 2009 EDR Application (EB-2008-0236)
July 31, 2008

Taxable Income Calculation - P6

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2006 Actual Total Entity	2006 Actual Less: Non-Distribution Portion	2006 Actual Utility Only	2007 Actual Total Entity	2007 Actual Less: Non-Distribution Portion	2007 Actual Utility Only	2008 Projection	2009 @ existing rates	2009 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		756,491		756,491	778,718		778,718	831,968		831,968	364,769	-47,556	644,773
Additions:													
Interest and penalties on taxes	103			0			0			0			0
Amortization of tangible assets	104	427,256		427,256	497,831		497,831	523,913		523,913	622,181	735,424	735,424
Amortization of intangible assets	106			0			0			0			0
Recapture of capital cost allowance from Schedule 8	107			0			0			0			0
Gain on sale of eligible capital property from Schedule 10	108			0			0			0			0
Income or loss for tax purposes- joint ventures or partnerships	109			0			0			0			0
Loss in equity of subsidiaries and affiliates	110			0			0			0			0
Loss on disposal of assets	111			0			0			0			0
Charitable donations	112			0			0			0			0
Taxable Capital Gains	113			0			0	4,617		4,617			0
Political Donations	114			0			0			0			0
Deferred and prepaid expenses	116			0			0			0			0
Scientific research expenditures deducted on financial statements	118			0			0			0			0
Capitalized interest	119			0			0			0			0
Non-deductible club dues and fees	120			0			0			0			0
Non-deductible meals and entertainment expense	121			0			0			0			0
Non-deductible automobile expenses	122			0			0			0			0
Non-deductible life insurance premiums	123			0			0			0			0
Non-deductible company pension plans	124			0			0			0			0
Tax reserves beginning of year	125	76,272		76,272	40,000		40,000	80,000		80,000	80,000	80,000	80,000
Reserves from financial statements- balance at end of year	126	77,241		77,241	80,000		80,000	80,000		80,000	80,000	80,000	80,000
Soft costs on construction and renovation of buildings	127			0			0			0			0
Book loss on joint ventures or partnerships	205			0			0			0			0
Capital items expensed	206			0			0			0			0
Debt issue expense	208			0			0			0			0
Development expenses claimed in current year	212			0			0			0			0
Financing fees deducted in books	216			0			0			0			0
Gain on settlement of debt	220			0			0			0			0
Non-deductible advertising	226			0			0			0			0
Non-deductible interest	227			0			0			0			0
Non-deductible legal and accounting fees	228			0			0			0			0
Recapture of SR&ED expenditures	231			0			0			0			0
Share issue expense	235			0			0			0			0
Write down of capital property	236			0			0			0			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0			0			0			0
Actual Debt Interest				0			0			0	61,437	163,561	163,561
Pensions		3,653		3,653	10,370		10,370			0			0
Recovery of Regulatory Assets Written Off		372,959		372,959	765,974		765,974	972,015		972,015			0
Income from Enerconnect Limited Partnership				0	2,556		2,556			0			0
				0			0			0			0
				0			0			0			0
Total Additions		**957,381**	**0**	**957,381**	**1,396,731**	**0**	**1,396,731**	**1,660,545**	**0**	**1,660,545**	**843,618**	**1,058,985**	**1,058,985**

Deductions:													
Gain on disposal of assets per financial statements	401			0			0	36,734		36,734			0
Dividends not taxable under section 83	402			0			0			0			0
Capital cost allowance from Schedule 8	403	369,383		369,383	403,866		403,866	569,567		569,567	674,299	806,480	806,480
Terminal loss from Schedule 8	404			0			0			0			0
Cumulative eligible capital deduction from Schedule 10 CEC	405	2,731		2,731	2,362		2,362	2,196		2,196	2,043	1,900	1,900
Allowable business investment loss	406			0			0			0			0
Deferred and prepaid expenses	409			0			0			0			0
Scientific research expenses claimed in year	411			0			0			0			0
Tax reserves end of year	413	77,241		77,241	80,000		80,000	80,000		80,000	80,000	80,000	80,000
Reserves from financial statements - balance at beginning of year	414	76,272		76,272	40,000		40,000	80,000		80,000	80,000	80,000	80,000
Contributions to deferred income plans	416			0			0			0			0
Book income of joint venture or partnership	305			0			0			0			0
Equity in income from subsidiary or affiliates	306			0			0			0			0
Deemed Debt Interest				0			0			0	249,129	322,861	322,861
Revenues from Non-Utility Operations - net				0			0			0	52,895	28,000	28,000
Regulatory Assets Capitalized for Accounting		550,432		550,432			0			0			0
Ontario Capital tax included in income				0	4,000		4,000			0			0
Pensions				0			0	3,684		3,684			0
				0			0			0			0
				0			0			0			0
Total Deductions		**1,076,059**	**0**	**1,076,059**	**530,228**	**0**	**530,228**	**772,181**	**0**	**772,181**	**1,138,366**	**1,319,241**	**1,319,241**
NET INCOME (LOSS) FOR TAX PURPOSES		**637,813**	**0**	**637,813**	**1,645,221**	**0**	**1,645,221**	**1,720,332**	**0**	**1,720,332**	**70,021**	**-307,812**	**384,517**
Charitable donations from Schedule 2				0			0			0			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)				0			0			0			0
Non-capital losses of preceding taxation years from Schedule 4		0	0	0	209,827	0	209,827	0	0	0	0	0	0
Net-capital losses of preceding taxation years from Schedule 4		0	0	0	0	0	0	0	0	0	0	0	0
Limited partnership losses of preceding taxation years from Schedule 4				0			0			0			0
				0			0			0			0
				0			0			0			0
				0			0			0			0
TAXABLE INCOME (LOSS)		**637,813**	**0**	**637,813**	**1,435,394**	**0**	**1,435,394**	**1,720,332**	**0**	**1,720,332**	**70,021**	**-307,812**	**384,517**

b) The table below sets out the calculation of income before PILs/Taxes of $644,773 as set out in the Rate Application, for the 2009 test year.

2009 Statement of Income based on New Rates

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	2,890,308.26
4010-Commercial Energy Sales	-
4015-Industrial Energy Sales	-
4020-Energy Sales to Large Users	-
4025-Street Lighting Energy Sales	69,412.75
4030-Sentinel Lighting Energy Sales	925.75
4035-General Energy Sales	9,728,400.94
4050-Revenue Adjustment	-
4055-Energy Sales for Resale	-
4060-Interdepartmental Energy Sales	-
4062-Billed WMS	1,443,363.60
4066-Billed NW	778,571.81
4068-Billed CN	1,427,035.96
4075-Billed LV	339,515.32
3000-Sales of Electricity Total	**16,677,534.40**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	3,841,852
4082-Retail Services Revenues	-
4084-Service Transaction Requests (STR) Revenues	-
4090-Electric Services Incidental to Energy Sales	-
3050-Revenues From Services - Distirbution Total	**3,841,852**
3100-Other Operating Revenues	
4210-Rent from Electric Property	82,480.80
4220-Other Electric Revenues	-
4225-Late Payment Charges	10,000.00
4230-Sales of Water and Water Power	-
4235-Miscellaneous Service Revenues	91,625.00
3100-Other Operating Revenues Total	**184,105.80**
3150-Other Income & Deductions	
4325-Revenues from Merchandise, Jobbing, Etc.	82,000.00
4330-Costs and Expenses of Merchandising, Jobbing, Etc.	(60,800.00)
4355-Gain on Disposition of Utility and Other Property	-
4375-Revenue of Non-Utility Operations	49,000.00
4380-Expenses of Non-Utility Operations	(21,000.00)
4390-Miscellaneous Non-Operating Income	-
4398-Foreign Exchange Gains and Losses, Including Amortization	-
3150-Other Income & Deductions Total	**49,200.00**
3200-Investment Income	
4405-Interest and Dividend Income	10,000.00
3200-Investment Income Total	**10,000.00**
3350-Power Supply Expenses	
4705-Power Purchased	12,689,047.70
4708-Charges-WMS	1,210,698.13
4710-Cost of Power Adjustments	-
4714-Charges-NW	778,571.81

Account Description	Total
4715-System Control and Load Dispatching	-
4716-Charges-CN	1,427,035.96
4730-Rural Rate Assistance Expense	232,665.47
4750-LV Charges	339,515.32
3350-Power Supply Expenses Total	**16,677,534.40**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	314,900.00
5010-Load Dispatching	16,000.00
5012-Station Buildings and Fixtures Expense	64,000.00
5014-Transformer Station Equipment - Operation Labour	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-
5016-Distribution Station Equipment - Operation Labour	8,200.00
5017-Distribution Station Equipment - Operation Supplies and Expenses	17,000.00
5020-Overhead Distribution Lines and Feeders - Operation Labour	-
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	-
5030-Overhead Subtransmission Feeders - Operation	-
5035-Overhead Distribution Transformers- Operation	-
5040-Underground Distribution Lines and Feeders - Operation Labour	-
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	-
5055-Underground Distribution Transformers - Operation	-
5065-Meter Expense	11,400.00
5070-Customer Premises - Operation Labour	22,100.00
5075-Customer Premises - Materials and Expenses	2,100.00
5085-Miscellaneous Distribution Expense	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-
5096-Other Rent	-
3500-Distribution Expenses - Operation Total	**455,700.00**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	77,200.00
5110-Maintenance of Buildings and Fixtures - Distribution Stations	13,400.00
5114-Maintenance of Distribution Station Equipment	1,600.00
5120-Maintenance of Poles, Towers and Fixtures	6,600.00
5125-Maintenance of Overhead Conductors and Devices	95,900.00
5130-Maintenance of Overhead Services	-
5135-Overhead Distribution Lines and Feeders - Right of Way	29,300.00
5145-Maintenance of Underground Conduit	-
5150-Maintenance of Underground Conductors and Devices	33,800.00
5155-Maintenance of Underground Services	-
5160-Maintenance of Line Transformers	9,900.00
5175-Maintenance of Meters	86,200.00
3550-Distribution Expenses - Maintenance Total	**353,900.00**
3650-Billing and Collecting	
5305-Supervision	-
5310-Meter Reading Expense	96,000.00
5315-Customer Billing	190,300.00
5320-Collecting	68,700.00
5325-Collecting- Cash Over and Short	200.00
5330-Collection Charges	600.00
5335-Bad Debt Expense	80,000.00
5340-Miscellaneous Customer Accounts Expenses	-
3650-Billing and Collecting Total	**435,800.00**
3700-Community Relations	
5405-Supervision	-

Account Description	Total
5410-Community Relations - Sundry	5,600.00
5415-Energy Conservation	-
5420-Community Safety Program	-
5425-Miscellaneous customer accounts expenses	-
5510-Demonstrating and Selling Expense	-
5515-Advertising Expense	-
5520-Miscellaneous Sales Expense	-
3700-Community Relations Total	**5,600.00**
3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	27,600.00
5610-Management Salaries and Expenses	285,900.00
5615-General Administrative Salaries and Expenses	70,400.00
5620-Office Supplies and Expenses	107,800.00
5625-Administrative Expense Transferred Credit	-
5630-Outside Services Employed	75,400.00
5635-Property Insurance	21,600.00
5640-Injuries and Damages	21,700.00
5645-Employee Pensions and Benefits	-
5655-Regulatory Expenses	73,700.00
5660-General Advertising Expenses	-
5665-Miscellaneous General Expenses	28,500.00
5670-Rent	-
5675-Maintenance of General Plant	90,600.00
5680-ESA Fees	4,700.00
3800-Administrative and General Expenses Total	**807,900.00**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant, and Equipment	735,424.31
3850-Amortization Expense Total	**735,424.31**
3900-Interest Expense	
6005-Interest on Long Term Debt	144,788.52
6030-Interest on Debt to Associated Companies	-
6035-Other Interest Expense	18,772.84
6042-Allowance For Other Funds Used During Construction	
3900-Interest Expense Total	**163,561.36**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	34,200.00
3950-Taxes Other Than Income Taxes Total	**34,200.00**
4000-Income Taxes	
6110-Income Taxes	204,993
6115-Provision for Future Income Taxes	
4000-Income Taxes Total	**204,993**
4100-Extraordinary & Other Items	
6205-Donations	-
6215-Penalties	-
5706-Amortization Street Lighting	-
6310-Extraordinary Deductions	
4100-Extraordinary & Other Items Total	**-**
(Net Income)/Loss	**644,773**

The table below provides for a calculation of the 2009 Test Year regulatory income.

Ratebase		12,318,654
Deemed Portion		43.33%
Effective Rate		8.57%
Deemed Return on Equity	$	457,474

Income Before PILS/Taxes	$	644,773
Add: Actual Interest Expense	$	163,561
Less: Deemed Interest Expense	$	322,861
Less: Non-Utility Net Income	$	28,000
Deemed Return on Equity	$	457,473

As noted above, the Deemed Return on Equity totals $457,473 vs. actual income of $644,773. The difference between these two amounts is the Non-Utility Net Income (Revenue from Non-Utility Operations (Acct #4375) of $49,000 less Expenses from Non-Utility Operations (Acct #4380) of -$21,000 provides for a net income from Non-Utility Operations) of $28,000; and, the difference between actual interest expense and deemed interest expense.

c) Midland's income tax calculation has been revised to deduct the deemed interest of $322,861 as shown above (a) on P6 Taxable Income for the 2009 new distribution rates. The resulting income tax calculation is set out on P8 Total PILs Expense table below.

P8 Total PILs Expense

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Projection	2009 Projection [1]	2009 Test [1]
Regulatory Taxable Income/(Loss)	637,813	1,435,394	1,720,332	70,021	-307,812	384,517
Combined Income Tax Rate				16.50%	0.00%	16.50%
Total Income Taxes	0	431,044	586,015	11,553	0	63,445
Investment & Miscellaneous Tax Credits						0
Income Tax Payable	0	**431,044**	**586,015**	**11,553**	**0**	63,445
Large Corporations Tax (LCT)	0	0	0	0	0	0
Ontario Capital Tax (OCT)	0	1,906	0	0	0	0
Grossed-up Income Tax	0					80,822
Grossed-up LCT	0					0
Total PILs Expense	**0**	**432,950**	**586,015**	**11,553**	**0**	**80,822**

When final rates are determined, this item will be reflected in those rates.

SMART METERS

41.

[Ex9/T1/S3]

MPUC is requesting a rate rider of $1.00 per customer per month to fund smart metering activities. The evidence indicates that MPUC will be scheduled for full installation of Smart Meters in 2009 in a process expected to take less than two months. Please answer the following questions with respect to smart metering activities:

a) How many smart meters do you expect to install in the 2009 Test Year?

b) What is the estimated cost per installed meter? Please provide a breakdown of the costs of these installations.

c) What will be the total estimated costs of smart metering activities in 2009?

d) Has MPUC purchased or does it expect to purchase Smart Meters or advanced metering infrastructure ("AMI") whose functionality exceeds the minimum functionality adopted in Ontario Regulation 425/06? If "Yes", please provide details of how the functionality exceeds the minimum functionality.

RESPONSE:

a) Midland expects to install approximately 6,700 smart meters in the 2009 Test Year.

b) The estimated cost per installed meter is $190.02 ($106.40 +$22.43+$25.65+$35.53 from table below)

Rate Filing	Category	2008	2009	2010	2011	2012	2013	TOTAL
Smart Meter Unit Costs	A	$0.00	$688,603.82	$7,853.13	$7,853.13	$7,853.13	$7,853.13	$106.40
Smart Meter Other Unit Costs	B	$56,700.00	$74,066.21	$21,000.00	$0.00	$0.00	$0.00	$22.43
Smart Meter Installation Costs Per Unit	C	$0.00	$173,600.61	$0.00	$0.00	$0.00	$0.00	$25.65
Smart Meter Other Costs Per Unit	D	$2,211.30	$238,238.22	$0.00	$0.00	$0.00	$0.00	$35.53
AMI Computer Hardware Costs	F	$0.00	$65,772.00	$0.00	$0.00	$0.00	$0.00	
AMI Computer Software Costs	G	$0.00	$12,208.35	$0.00	$0.00	$0.00	$0.00	
Other Computer Hardware Costs	H	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Other Computer Software Costs	I	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Incremental AMI O&M Expenses	J	$0.00	$100,971.36	$133,201.23	$100,971.36	$100,971.36	$100,971.36	
Incremental AMI Admin Expenses	K	$0.00	$0.00	$3,402.00	$0.00	$0.00	$0.00	
Incremental Other O&M Expenses	L	$0.00	$0.00	$22,680.00	$22,680.00	$22,680.00	$22,680.00	
Incremental Other Admin Expenses	M	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Utility Safety & Maintenance Capital Budget	2	$17,266.00	$17,266.00	$0.00	$0.00	$0.00	$0.00	
TOU Billing Budget	3	$0.00	$106,014.12	$90,336.93	$39,112.69	$36,177.12	$36,706.06	
	Grand Total	$76,177.30	$1,476,740.69	$278,473.29	$170,617.18	$167,681.61	$168,210.55	
	Difference From Above	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	

c) Midland projects the smart metering initiative to total $1,476,740.69 in 2009. These costs are budget figures only. Midland is in negotiation process as prescribed by the Fairness Commissioner through the London RFP process and is unable at this point, to provide exact costing on the AMI. Once the negotiation process has been completed Midland will be entering into contracts which will in turn, provide more precise cost estimates.

d) Midland does not expect to install smart metering infrastructure that exceeds the minimum requirements pursuant to Ontario Regulation 425/06.

Attachments:

1. IR# 6 a) Continuity Schedule

2. IR #28 Stats Canada – Midland information

3. IR#38 a) Substation Quotes:

   Wesco

   Areva

   ABB

   Tiltran

   State Electric

   R&B Construction

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY Midland Power Utility Corporation
Application ID NUMBER EB-2008-0236

Date 12-Dec-08

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

Account Description	Account Number	2005 Opening Principal Amounts as of Jan-1-05 [1]	Transactions (additions) during 2005, excluding interest and adjustments [5]	Transactions (reductions) during 2005, excluding interest and adjustments [5]	Adjustments during 2005 - instructed by Board [2]	Adjustments during 2005 - other [3]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec31-05	Closing Interest Amounts as of Dec-31-05
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 6,470	$ 12,613				$ 19,083	$ 87	$ 524	$ 611
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ 47,094				$ 47,094	$ -	$ 761	$ 761
Other Regulatory Assets - Sub-Account - Other [6] Rate Rider	1508	$ (6,707)					$ (6,707)			$ -
Other Regulatory Assets - Sub-Account - Other [6] Transition Costs	1508	$ (28,743)					$ (28,743)	$ (3,409)	$ (2,087)	$ (5,496)
Other Regulatory Assets - Sub-Account - Other [6] Hydro One	1508	$ -			$ 33,243		$ 33,243			$ -
Retail Cost Variance Account - Retail	1518	$ 50,718		$ (2,788)			$ 47,930			$ -
Misc. Deferred Debits	1525	$ 35,893		$ (10,553)			$ 25,340			$ -
Retail Cost Variance Account - STR	1548						$ -			$ -
Qualifying Transition Costs [4]	1570	$ 420,898	n/a	n/a	$ (19,523)	$ (15,941)	$ 385,435	$ 86,663	$ (86,663)	$ 0
Pre-Market Opening Energy Variances Total [4]	1571	$ 547,697	n/a	n/a			$ 547,697	$ 105,888	$ 39,708	$ 145,596
Extra-Ordinary Event Costs	1572						$ -			$ -
Deferred Rate Impact Amounts	1574						$ -			$ -
RSVA -- One-time Wholesale Market Service	1582	$ 51,471	$ 12,681				$ 64,153	$ 4,750	$ 4,099	$ 8,849
2006 PILs & Taxes Variance	1592	n/a	n/a	n/a	n/a	n/a		n/a	n/a	
Other Deferred Credits	2425	$ (532,000)		$ (223,388)			$ (755,388)	$ -		$ -
Sub-Total		$ 545,698	$ 72,389	$ (236,729)	$ 13,720	$ (15,941)	$ 379,137	$ 193,979	$ (43,657)	$ 150,321
Smart Meter Capital and Recovery Offset	1555									
Smart Meter Operaqtion, Maintenance and Administration	1556									
Deferred Payments in Lieu of Taxes	1562	$ (233,595)		$ (176,550)			$ (410,145)	$ (534)	$ (21,936)	$ (22,471)
Deferred PILs Contra Account [8]	1563	$ 233,595	$ 176,550				$ 410,145	$ 534	$ 21,936	$ 22,470
CDM Expenditirues and Recoveries	1565	$ 4,569		$ (127,560)			$ (122,990)	$ 27	$ 66	$ 92
CDM Contra Account	1566	$ -	$ 122,990				$ 122,990	$ -		$ -
Recovery of Regulatory Asset Balances	1590	$ (372,959)		$ (530,932)			$ (903,891)	$ (7,776)	$ (44,657)	$ (52,433)
No sub-total										
Low Voltage Variance Account	1550						$ -			$ -
RSVA - Wholesale Market Service Charge	1580	$ 295,095	$ 167,705				$ 462,799	$ 51,826	$ 24,192	$ 76,018
RSVA - Retail Transmission Network Charge	1584	$ (79,642)	$ (23,571)				$ (103,214)	$ 3,420	$ 535	$ 3,955
RSVA - Retail Transmission Connection Charge	1586	$ 713,728	$ 198,840				$ 912,568	$ 957	$ 4,415	$ 5,372
RSVA - Power (including Global Adjustment)	1588	$ 54,296	$ 542,121				$ 596,418	$ 17,016	$ 5,602	$ 22,618
RSVA - Power - Sub-Account - Global Adjustment	1588	$ -	$ (644,025)				$ (644,025)	$ -	$ (13,668)	$ (13,668)
Sub-Total		$ 983,477	$ 885,094	$ -	$ -	$ -	$ 1,868,571	$ 73,219	$ 34,743	$ 107,962

Footnotes

1 As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis

2 Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
- (a) $33,243 - Adjustment for Hydro One Charges (applicable from Jan 1/04 - Apr 30/06) - per Regulatory Asset Model RP-2005-0020, EB-2005-0390
- (b) $-19,523 Adjustment for the write off of transition costs - the lesser of 10% or $60 per customer

3 Provide supporting statement indicating nature of this adjustments and periods they relate to
- (a) $-19,541 Removal of non-qualifying transition costs from account #1570
- (b) $ - 55 Adjustment for Hydro One Charges (applicable from Jan 1/04 - Apr 30/06)

4 Closed April 30, 2002

5 For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.

6 Please describe "other" components of 1508 and add more component lines if necessary.

7 Interest projected on December 31, 2007 closing principal balance.

8 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY Midland Power Utility Corporation
Application ID NUMBER EB-2008-0236

Date 12-Dec-08

		2006										
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-06**	**Transactions (additions) during 2006, excluding interest and adjustments[5]**	**Transactions (reductions) during 2006, excluding interest and adjustments[5]**	**Adjustments during 2006 - instructed by Board[2]**	**Adjustments during 2006 - other[3]**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Principal Balance as of Dec-31-06**	**Opening Interest Amounts as of Jan-1-06**	**Interest Jan-1 to Dec31-06**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-06**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 19,083	$ 1,428				$ (6,470)	$ 14,041	$ 611	$ 472	$ (712)	$ 371
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 47,094	$ 16,650					$ 63,744	$ 761	$ 2,509		$ 3,270
Other Regulatory Assets - Sub-Account - Other[6] Rate Rider	1508	$ (6,707)					$ 6,707	$ (0)	$ -			$ -
Other Regulatory Assets - Sub-Account - Other[6] Transition Costs	1508	$ (28,743)						$ (28,743)	$ (5,496)	$ (1,553)		$ (7,049)
Other Regulatory Assets - Sub-Account - Other[6] Hydro One	1508	$ 33,243					$ (33,243)	$ -	$ -			$ -
Retail Cost Variance Account - Retail	1518	$ 47,930		$ (4,581)			$ (50,718)	$ (7,370)	$ -	$ 5,455	$ (5,833)	$ (378)
Misc. Deferred Debits	1525	$ 25,340					$ (25,340)	$ 0	$ -			$ -
Retail Cost Variance Account - STR	1548	$ -						$ -	$ -			$ -
Qualifying Transition Costs[4]	1570	$ 385,435	n/a	n/a		$ (55)	$ (385,380)	$ (0)	$ 0			$ 0
Pre-Market Opening Energy Variances Total[4]	1571	$ 547,697	n/a	n/a			$ (547,697)	$ -	$ 145,596	$ 13,236	$ (158,832)	$ -
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
RSVA -- One-time Wholesale Market Service	1582	$ 64,153	$ 925				$ (51,471)	$ 13,606	$ 8,849	$ 1,951	$ (9,726)	$ 1,074
2006 PILs & Taxes Variance	1592	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ (755,388)	$ 203,184					$ (552,204)	$ -			$ -
Sub-Total		$ 379,137	$ 222,187	$ (4,581)	$ -	$ (55)	$ (1,093,612)	$ (496,925)	$ 150,321	$ 22,070	$ (175,103)	$ (2,712)
Smart Meter Capital and Recovery Offset	1555		$ 485	$ (11,643)				$ (11,158)		$ (38)		$ (38)
Smart Meter Operaqtion, Maintenance and Administration	1556											
Deferred Payments in Lieu of Taxes	1562	$ (410,145)	$ 68,916					$ (341,229)	$ (22,471)	$ (29,980)		$ (52,450)
Deferred PILs Contra Account[8]	1563	$ 410,145		$ (68,916)				$ 341,229	$ 22,470	$ 29,980		$ 52,450
CDM Expenditirues and Recoveries	1565	$ (122,990)	$ 113,422					$ (9,568)	$ 92			$ 92
CDM Contra Account	1566	$ 122,990		$ (113,422)				$ 9,568	$ -			$ -
Recovery of Regulatory Asset Balances	1590	$ (903,891)		$ (684,042)			$ 2,556,966	$ 969,033	$ (52,433)	$ 79,645		$ 27,212
No sub-total												
Low Voltage Variance Account	1550	$ -	$ 6,619					$ 6,619	$ -	$ (89)		$ (89)
RSVA - Wholesale Market Service Charge	1580	$ 462,799	$ (280,034)				$ (295,095)	$ (112,330)	$ 76,018	$ 11,710	$ (80,351)	$ 7,377
RSVA - Retail Transmission Network Charge	1584	$ (103,214)	$ (30,959)				$ 115,970	$ (18,202)	$ 3,955	$ (2,785)	$ 326	$ 1,496
RSVA - Retail Transmission Connection Charge	1586	$ 912,568	$ (443,759)				$ (915,789)	$ (446,980)	$ 5,372	$ 25,270	$ (35,368)	$ (4,726)
RSVA - Power (including Global Adjustment)	1588	$ 596,418	$ (467,655)				$ (54,296)	$ 74,467	$ 22,618	$ 20,908	$ (22,264)	$ 21,262
RSVA - Power - Sub-Account - Global Adjustment	1588	$ (644,025)	$ 253,296					$ (390,729)	$ (13,668)	$ (38,947)		$ (52,616)
Sub-Total		$ 1,868,571	$ (1,215,788)	$ -	$ -	$ -	$ (1,149,210)	$ (496,427)	$ 107,962	$ 55,014	$ (137,657)	$ 25,319

Footnotes

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Midland Power Utility Corporation
Application ID NUMBER	EB-2008-0236
Date	**12-Dec-08**

Account Description	**Account Number**	**2007** Opening Principal Amounts as of Jan-1-07	Transactions (additions) during 2007, excluding interest and adjustments[5]	Transactions (reductions) during 2007, excluding interest and adjustments [5]	Adjustments during 2007 - instructed by Board [2]	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec31-07	Closing Interest Amounts as of Dec-31-07
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	**1508**	$ 14,041					$ 14,041	$ 371	$ 664	$ 1,034
Other Regulatory Assets - Sub-Account - Pension Contributions	**1508**	$ 63,744					$ 63,744	$ 3,270	$ 3,014	$ 6,283
Other Regulatory Assets - Sub-Account - Other [6] Rate Rider	**1508**	$ (0)					$ (0)	$ -		$ -
Other Regulatory Assets - Sub-Account - Other [6] Transition Costs	**1508**	$ (28,743)					$ (28,743)	$ (7,049)	$ (1,359)	$ (8,408)
Other Regulatory Assets - Sub-Account - Other [6] Hydro One	**1508**	$ -					$ -	$ -		$ -
Retail Cost Variance Account - Retail	**1518**	$ (7,370)	$ (303)				$ (7,673)	$ (378)	$ (296)	$ (675)
Misc. Deferred Debits	**1525**	$ 0					$ 0	$ -		$ -
Retail Cost Variance Account - STR	**1548**	$ -					$ -	$ -		$ -
Qualifying Transition Costs [4]	**1570**	$ (0)	n/a	n/a			$ (0)	$ 0		$ 0
Pre-Market Opening Energy Variances Total [4]	**1571**	$ -	n/a	n/a			$ -	$ -		$ -
Extra-Ordinary Event Costs	**1572**	$ -					$ -	$ -		$ -
Deferred Rate Impact Amounts	**1574**	$ -					$ -	$ -		$ -
RSVA -- One-time Wholesale Market Service	**1582**	$ 13,606					$ 13,606	$ 1,074	$ 656	$ 1,730
2006 PILs & Taxes Variance	**1592**	$ -					$ -	$ -		$ -
Other Deferred Credits	**2425**	$ (552,204)	$ 249,660				$ (302,544)	$ -		$ -
Sub-Total		$ (496,925)	$ 249,357	$ -	$ -	$ -	$ (247,568)	$ (2,712)	$ 2,678	$ (34)
Smart Meter Capital and Recovery Offset	**1555**	$ (11,158)	$ 18,766	$ (21,040)			$ (13,432)	$ (38)	$ (1,145)	$ (1,183)
Smart Meter Operaqtion, Maintenance and Administration	**1556**									
Deferred Payments in Lieu of Taxes	**1562**	$ (341,229)		$ (20,897)			$ (362,126)	$ (52,450)	$ (17,601)	$ (70,052)
Deferred PILs Contra Account [8]	**1563**	$ 341,229		$ 20,897			$ 362,126	$ 52,450	$ 17,601	$ 70,051
CDM Expenditirues and Recoveries	**1565**	$ (9,568)	$ 9,568				$ (0)	$ 92		$ 92
CDM Contra Account	**1566**	$ 9,568		$ (9,568)			$ 0	$ -		$ -
Recovery of Regulatory Asset Balances	**1590**	$ 969,033		$ (690,497)			$ 278,536	$ 27,212	$ 30,084	$ 57,296
No sub-total										
Low Voltage Variance Account	**1550**	$ 6,619	$ 107,007				$ 113,626	$ (89)	$ 2,870	$ 2,780
RSVA - Wholesale Market Service Charge	**1580**	$ (112,330)	$ (261,779)				$ (374,109)	$ 7,377	$ (10,115)	$ (2,738)
RSVA - Retail Transmission Network Charge	**1584**	$ (18,202)	$ 276,529				$ 258,327	$ 1,496	$ 7,284	$ 8,780
RSVA - Retail Transmission Connection Charge	**1586**	$ (446,980)	$ (498,635)				$ (945,615)	$ (4,726)	$ (31,150)	$ (35,876)
RSVA - Power (including Global Adjustment)	**1588**	$ 74,467	$ 525,585				$ 600,052	$ 21,262	$ 21,558	$ 42,819
RSVA - Power - Sub-Account - Global Adjustment	**1588**	$ (390,729)	$ 427,984				$ 37,255	$ (52,616)	$ (9,810)	$ (62,426)
Sub-Total		$ (496,427)	$ 148,707	$ -	$ -	$ -	$ (347,719)	$ 25,319	$ (9,554)	$ 15,766

Footnotes

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY	Midland Power Utility Corporation
Application ID NUMBER	EB-2008-0236
Date	**12-Dec-08**

Account Description		**Account Number**	**Projected Interest on Dec 31 -07 balance from Jan 1, 2008 to Dec 31, 2008** [7]	**Projected Interest on Dec 31 -07 balance from Jan 1, 2009 to April 30, 2009** [7]	**Balance before Forecasted Transactions**	**Forecasted Transactions, Excluding Interest from Jan 1, 2008 to Dec 31, 2008**	**Forecasted Transactions, Excluding Interest from Jan 1, 2009 to April 30, 2009**	**Projected Interest from Jan 1, 2008 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to December 31, 2008**	**Projected Interest from Jan 1, 2009 to April 30, 2009 on Forecasted Transx (Excl Interest) from Jan 1, 2009 to April 30, 2009**	**Balance**
Other Regulatory Assets - Sub-Account - OEB Cost Assessments		**1508**	$ 559	$ 157	$ 15,791					$ 15,791
Other Regulatory Assets - Sub-Account - Pension Contributions		**1508**	$ 2,537	$ 712	$ 73,277					$ 73,277
Other Regulatory Assets - Sub-Account - Other [6]	Rate Rider	**1508**			$ (0)					$ (0)
Other Regulatory Assets - Sub-Account - Other [6]	Transition Costs	**1508**	$ (1,144)	$ (321)	$ (38,615)					$ (38,615)
Other Regulatory Assets - Sub-Account - Other [6]	Hydro One	**1508**			$ -					$ -
Retail Cost Variance Account - Retail		**1518**	$ (305)	$ (86)	$ (8,739)					$ (8,739)
Misc. Deferred Debits		**1525**			$ 0					$ 0
Retail Cost Variance Account - STR		**1548**			$ -					$ -
Qualifying Transition Costs [4]		**1570**			$ 0					$ 0
Pre-Market Opening Energy Variances Total [4]		**1571**			$ -					$ -
Extra-Ordinary Event Costs		**1572**			$ -					$ -
Deferred Rate Impact Amounts		**1574**			$ -					$ -
RSVA -- One-time Wholesale Market Service		**1582**	$ 552	$ 43	$ 15,930	$ -	$ -	$ -	$ -	$ 15,930
2006 PILs & Taxes Variance		**1592**			$ -					$ -
Other Deferred Credits		**2425**			$ (302,544)					$ (302,544)
	Sub-Total		$ 2,198	$ 505	$ (244,900)	$ -	$ -	$ -	$ -	$ (244,900)
Smart Meter Capital and Recovery Offset		**1555**	$ (1,301)	$ (365)	$ (16,280)					
Smart Meter Operaqtion, Maintenance and Administration		**1556**								
Deferred Payments in Lieu of Taxes		**1562**	$ (14,413)	$ (4,044)	$ (450,634)					$ (450,634)
Deferred PILs Contra Account [8]		**1563**	$ 14,413	$ 4,044	$ 450,634					$ 450,634
CDM Expenditirues and Recoveries		**1565**	$ -	$ -						$ -
CDM Contra Account		**1566**								$ -
Recovery of Regulatory Asset Balances		**1590**	$ 11,086	$ 3,068	$ 349,985					$ 349,985
	No sub-total									
Low Voltage Variance Account		**1550**	$ 4,522	$ 1,251	$ 122,180					$ 122,180
RSVA - Wholesale Market Service Charge		**1580**	$ (14,975)	$ (4,120)	$ (395,943)					$ (395,943)
RSVA - Retail Transmission Network Charge		**1584**	$ 10,281	$ 2,845	$ 280,233					$ 280,233
RSVA - Retail Transmission Connection Charge		**1586**	$ (37,974)	$ (10,415)	$ (1,029,880)					$ (1,029,880)
RSVA - Power (including Global Adjustment)		**1588**	$ 23,450	$ 6,609	$ 672,930					$ 672,930
RSVA - Power - Sub-Account - Global Adjustment		**1588**	$ 1,051	$ 410	$ (23,709)					$ (23,709)
	Sub-Total		$ (13,645)	$ (3,419)	$ (350,479)	$ -	$ -	$ -	$ -	$ (350,479)

Footnotes

All Data

	Midland Ontario (Town) SELECT ANOTHER REGION			Ontario (Province) SELECT ANOTHER REGION		
Population and Dwelling Counts	Midland, Town			Ontario		
	Total	Male	Female	Total	Male	Female
Population in 2001 (1)	16,214			11,410,046†		
Population in 1996 (2)	16,347A			10,753,573†		
1996 to 2001 population change (%)	- 0.8			6.1		
Total private dwellings	6,872			4,556,240		
Population density per square kilometre	557.4			12.6		
Land area (square km)	29.09			907,655.59		

Age Characteristics of the Population	Midland, Town			Ontario		
	Total	Male	Female	Total	Male	Female
Total - All persons (3)	16,210	7,610	8,605	11,410,050	5,577,055	5,832,990
Age 0-4	775	400	370	671,250	343,340	327,905
Age 5-14	2,195	1,115	1,080	1,561,500	801,355	760,145
Age 15-19	1,155	565	590	769,420	394,915	374,500
Age 20-24	880	425	455	718,420	359,645	358,775
Age 25-44	4,100	1,940	2,160	3,518,010	1,724,535	1,793,480
Age 45-54	2,355	1,130	1,230	1,635,280	801,540	833,740
Age 55-64	1,680	780	900	1,064,000	520,565	543,430
Age 65-74	1,505	705	795	818,165	383,625	434,545
Age 75-84	1,190	450	745	503,930	202,265	301,665
Age 85 and over	380	95	285	150,075	45,260	104,810
Median age of the population	41.1	39.6	42.4	37.2	36.4	38.0
% of the population ages 15 and over	81.7	80.1	83.1	80.4	79.5	81.3

Common-law Status	Midland, Town			Ontario		
	Total	Male	Female	Total	Male	Female
Total - Population 15 years and over (4)	13,250	6,090	7,150	9,177,300	4,432,360	4,744,935
Not in a common-law relationship	12,085	5,515	6,570	8,592,795	4,138,645	4,454,140
In a common-law relationship	1,160	580	580	584,505	293,715	290,790

Legal Marital Status	Midland, Town			Ontario		
	Total	Male	Female	Total	Male	Female
Total - Population 15 years and over (5)	13,245	6,095	7,150	9,177,300	4,432,365	4,744,935
Single (6)	3,660	1,915	1,745	2,793,080	1,490,270	1,302,805
Married (7)	6,430	3,210	3,220	4,897,095	2,450,975	2,446,125
Separated (8)	615	245	370	311,380	136,075	175,305
Divorced (9)	1,215	495	720	597,595	249,825	347,770
Widowed (10)	1,325	230	1,095	578,145	105,215	472,935

Search for another place

Search

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2001 Census Aboriginal Population Profiles

Midland (T)

Map

Geographic Hierarchy

Additional Data

Data Quality Note(s)

Ontario

Geographic Hierarchy

Data Quality Note(s)

Select a view

All data | Aboriginal peoples | Education | Families and households | Immigration and citizenship | Income and earnings | Labour | Language | Language of work | Mobility and migration | Place of work | Population | Visible minority | Or Build your own

Search for another place

Search

Help/FAQs

Print-friendly format

Download file

Midland (T)

Map

Geographic hierarchy

Data quality note(s)

Ontario

Map

Geographic hierarchy

Data quality note(s)

All data

Midland Ontario (Town) Select another region

Ontario (Province) Select another region

Population and dwelling counts	Midland, Town Total	Male	Female	Ontario Total	Male	Female
Population in 2006[1]	16,300[E]			12,160,282[†]		
Population in 2001[1]	16,214			11,410,046[†]		
2001 to 2006 population change (%)	0.5			6.6		
Total private dwellings[2]	7,248			4,972,869		
Private dwellings occupied by usual residents[3]	6,897			4,554,251		
Population density per square kilometre	560.3			13.4		
Land area (square km)	29.09			907,573.82		

Figure

Age characteristics	Midland, Town Total	Male	Female	Ontario Total	Male	Female
Total population[4]	16,300	7,640	8,660	12,160,285	5,930,700	6,229,580
0 to 4 years	700	335	365	670,770	343,475	327,290
5 to 9 years	815	400	410	721,590	369,670	351,920
10 to 14 years	1,020	505	515	818,445	420,705	397,740
15 to 19 years	1,165	605	555	833,115	427,185	405,925
20 to 24 years	935	475	460	797,255	400,445	396,815
25 to 29 years	770	385	390	743,695	360,525	383,170
30 to 34 years	775	360	415	791,955	382,030	409,925
35 to 39 years	870	435	435	883,990	430,220	453,770
40 to 44 years	1,250	595	660	1,032,415	507,130	525,280
45 to 49 years	1,335	605	730	991,970	486,390	505,585
50 to 54 years	1,270	600	670	869,400	423,345	446,060
55 to 59 years	1,185	575	615	774,530	378,530	395,995
60 to 64 years	975	445	525	581,985	283,545	298,440
65 to 69 years	795	360	440	466,240	222,640	243,600
70 to 74 years	755	350	405	401,950	187,510	214,445
75 to 79 years	640	275	365	338,910	149,585	189,325
80 to 84 years	605	215	390	250,270	97,240	153,035
85 years and over	435	130	305	191,810	60,555	131,260
Median age of the population[5]	44.4	42.9	45.7	39.0	38.1	39.9
% of the population aged 15 and over	84.5	83.8	85.1	81.8	80.9	82.7

Figure

Common-law status characteristics	Midland, Town Total	Male	Female	Ontario Total	Male	Female
Total population 15 years and over[6]	13,765	6,400	7,365	9,949,485	4,796,850	5,152,630

Wesco Distribution / Eaton Electrical

Neg# T39402081702 Alt# 0000 & 0001

Job Name: TC60217 Midland PUC – Scott Street Switchgear Replacement

Commercial Summary

February 9, 2007 – Distributor Cost TNIP

Price Summary

The following pricing is based on the bill of material, comments and clarifications accompanying this proposal and is valid for receipt of the complete order. Unit prices, if provided, are for accounting purposes only.

Option #1 Base proposal with SEL-315S relay

Qty	BASE PROPOSAL Product Name	Designations	Unit Price CAD$	Total Price CAD$
1	4.16kV Medium Voltage Arc Resistant Type 2, Switchgear, Indoor NEMA 1 with drip proof cover, 2000A, 3-Ph., 3-W per attached BOM's	Scott SWGR w-SEL-351S	**$ 295,000.00**	**$295,000.00**
1	Spare 50 VCP-W 250, 1200A vacuum breaker	Spare Breaker	**Included**	**Included**
1	Spare Primary & Secondary Potential Transformer fuses (3 each)	Spare Fuses	**Included**	**Included**
1	P4500 Stationary battery charger	P4500 Series Primax	**Included**	**Included**
1	Spare parts list as per list attached (Metal-Clad Switchgear assemblies recommended spare parts	50VCP-W250	**Included**	**Included**
1	Installation of new switchgear Scope: Install new switchgear / Battery bank / connect DC Feeds / Ground switchgear to existing grounds / labour and equipment.	Installation by Canadian Power Systems. James Barfield.	**Included**	**Included**

Option #2 Alternate with Cutler Hammer Relay FP-5000

Qty	BASE PROPOSAL Product Name	Designations	Unit Price CAD$	Total Price CAD$
1	4.16kV Medium Voltage Arc Resistant Type 2, Switchgear, Indoor NEMA 1 with drip proof cover, 2000A, 3-Ph., 3-W per attached BOM's	Scott SWGR w-FP-5000 relay	**$ 280,000.00**	**$280,000.00**
1	Spare 50 VCP-W 250, 1200A vacuum breaker	Spare Breaker	**Included**	**Included**
1	Spare Primary & Secondary Potential Transformer fuses (3 each)	Spare Fuses	**Included**	**Included**
1	P4500 Stationary battery charger	P4500 Series Primax	**Included**	**Included**
1	Spare parts list as per list attached (Metal-Clad Switchgear assemblies recommended spare parts	50VCP-W250	**Included**	**Included**
1	Installation of new switchgear Scope: Install new switchgear / Battery bank / connect DC Feeds / Ground switchgear to existing grounds / labour and equipment.	Installation by Canadian Power Systems. James Barfield.	**Included**	**Included**

Notes

1. Power systems studies, coordination studies, installation supervision, field installation, acceptance testing, commissioning, start-up and training, are not included in this proposal.

Wesco Distribution / Eaton Electrical
Neg# T3940208I702 Alt# 0000 & 0001
Job Name: TC60217 Midland PUC – Scott Street Switchgear Replacement
Commercial Summary

Terms and Conditions

See Wesco Terms and Conditions attached.

Taxes:	Excluded.
Price Validity:	60 days for acceptance and firm for quoted shipment, unless extended or terminated in writing by an authorized representative of Eaton Electrical .
Freight:	FOB Factory freight pre-paid and allowed to first Canadian destination. Customs formalities are included. Unloading is not included. Equipment is shipped via Eaton Electrical selected carrier including factory standard commercial packaging.
Warranty:	Per Eaton Electrical Selling Policy 25000-C. 18 months from shipment or 12 months from start-up, whichever occurs first. An extra one-year warranty on Cutler-Hammer brand products is available at no extra charge when Eaton Electrical Services & Systems (EESS) is selected to complete all power systems studies, installation supervision, acceptance testing, start up and commissioning. Refer to EESS rate schedule in the Appendix.

COMMERCIAL COMMENTS AND CLARIFICATIONS

Pricing is per the attached quotation letter for the stated scope of supply, bills of material, drawings, comments and clarifications only. Any customer requested additions or deletions to the bill of material will be reviewed by Cutler-Hammer and may result in a price adjustment. Taxes are not included.

The price is valid for 60 days and firm through quoted shipment.

Cutler-Hammer Engineering Services and Systems (CHESS) is not included in the scope of supply or price quotation. CHESS services are available at additional cost for start-up and commissioning as outlined in the attached rate schedule. If CHESS commissioning is ordered along with and at the same time as the equipment the warranty period will be extended by 12 months.

Coordination studies, testing services, field installation, training, and/or field testing services are not included in this proposal.

QUALITY SYSTEM CERTIFICATION

Eaton Electrical's Medium Voltage Switchgear is manufactured in Greenwood, SC, USA in an ISO9001 registered facility. Certificate copy is available upon customer request.

DRAWINGS and SHIPMENT SCHEDULE Medium Voltage Switchgear:

The following is our standard lead times for this product. Lead time is negotiable and subject to available space.

Order based on the following:	APPROVAL DRAWINGS	FINAL DRAWINGS	QUOTED SHIPMENT
♦ No drawing approval -- equipment released for immediate manufacture:	WAIVED*	16-18 Weeks ARO	22-24 Weeks ARO
• On-board drawing approval:	10 Weeks ARO	16-18 Weeks ARA	22-24 Weeks ARA
♦ Drawings for approval issued:	10 Weeks ARO	16-18 Weeks ARA	22-24 Weeks ARA

- *For orders with final drawings (no approval), all engineering information must be received at time of order. Delays in receipt of critical information will affect the schedule.
- ARO = After Receipt of Order with complete information.
- ARA = After Return of Approval drawings with release.
- Instruction manuals are supplied 2 weeks prior to shipment.
- Customer witness test, if requested, will delay shipment by a minimum of one (1) business day upon completion.

This proposal includes standard (C-H) submittals. Drawings for approval will include:

STANDARD DRAWINGS LIST:

The following is a list of standard drawings provided by Cutler-Hammer, once for approval and once for installation. Wiring diagrams and instruction books are supplied for record/reference and not for approval.

A. Electrical three-line diagrams.

B. Electrical control schematic diagrams.

C. Mechanical primary one line (bus arrangement)

D. Bills of material.

E. Front elevation.

F. Nameplate data sheets.

AREVA

Table of contents

AREVA

1. Commercial Presentation

1.1. Contacts

Commercial contact
Gerry Decastro
Area Manager Ontario Eastern Region
Phone : (905) 333-2051
gerry.decastro@areva-td.com

1.2. Price and general conditions

Following your request for quotation, AREVA T&D Canada is pleased to submit our Firm offer. Scope of supply, material and arrangement shall be as per shown in this document. This letter is part of our offer.

Prices:

5kV Switchgear

ITEM #1 - 3 Cells 5 kV 2000A 25kA Type 2 with SEL 351S..........$ 220 565.00

Alternative

~~ITEM #1 - 3 Cells 5 kV 2000A 25kA Type 2 with AREVA Relay ...... $ 213 000.00~~

ITEM #2 - Battery and Charger ....$ 13 900.00

ITEM #3 - 1 Spare breaker HVX 5-25-12E......................................$ 9 550.00

All prices in **Canadian dollars TNIP**

Miscellaneous

Installation...(see details in page 9)..$ 16 100.00

Special tool list ...(Section 7)..$ 4 286.00

Recommended Spare Part List (Section 6)..$ 2 270.00

Delivery : EXW, AREVA T&D Inc. Plant , Montreal , Quebec.

$266,671.00

Validity : 30 Days

AREVA

Terms and conditions :As per AREVA T&D Canada Terms and conditions

Production time The offered production cycle time would be 18-to 20 working weeks. This production cycle is based on the information we have in hands. Shorter production cycle may be available and can be confirmed later based on your requirements, factory loading and backlog at time of purchase order.

Quality: As per our ISO9001 internal quality program.

We would like to have the opportunity to discuss and answer any questions you might have on our proposal and features of our design. Do not hesitate to contact us should you have any questions.

Regards,

Amir Ibrahim
Technical Sales Reprehensive

T&D
Medium Voltage Switchgear , 5845 Couture Blvd, Saint-Leonard (Qc), Canada H1P 1A8
Tel.: (514) 329-3912
Fax: (514) 329-3911

GENERAL
2007 SERVICE RATE
CANADA

Field technicians, supervisors and engineers are available to provide technical assistance and technical direction for the installation, commissioning, expertise, inspection repair and maintenance, of apparatus sponsored and sold by the Company and/or its associates.

The following rates are based on an eight-hour workday (excluding lunch period) for service within Canada.
For large contracts, please contact us to see if a reduced rate is applicable.

SERVICE RATES

SUPERVISOR or FIELD TECHNICIAN (M.V Apparatus – P&C)

Monday through Friday	**$112.00/per hour**
Weekday overtime	**$134.00/per hour**
Week-end and observed holiday rates	**$150.00/per hour**
Travelling time (week days)	**$98.00/per hour**
Travelling time (week-end and observed holidays)	**$118.00/per hour**

SUPERVISOR (H.V Apparatus) or P&C COMMISSIONING ENGINEER

Monday through Friday	**$127.00/per hour**
Weekday overtime	**$165.00/per hour**
Week-end and observed holiday rates	**$203.00/per hour**
Travelling time (week days)	**$112.00/per hour**
Travelling time (week-end and observed holidays)	**$134.00/per hour**

ENGINEER, SENIOR P&C COMMISSIONING SPECIALIST or GIS SPECIALIST(*)

Monday through Friday	**$175.00/per hour**
Weekday overtime	**$234.00/per hour**
Week-end and observed holiday rates	**$292.00/per hour**
Travelling time (week days)	**$155.00/per hour**
Travelling time (week-end and observed holidays)	**$186.00/per hour**

(*) GIS SPECIALIST
The above rates apply for Canadian specialist. If a foreign specialist has to be mobilised from Europe due the specificity of the project or the unavailability of a Canadian specialist different rates will apply.

AREVA

2007 SERVICE RATE - TERMS & CONDITIONS

1. HOURLY RATES

Hourly rate is based on standard workweek of five eight-hour days, Monday through Friday. Weekday overtime, Monday through Friday, is based on all time worked after the first eight (8) hours of the day, even though the work may continue into the following day.
All time worked and/or traveled on weekend and observed holiday will be billed at the rate listed in the previous page.

Hourly rates exclude travelling and living expenses, airfare, freight and local transportation (refer to article 3 & 4)

2. TRAVELLING TIME

Travelling time will be billed from the time the serviceman leaves the plant to the time of arrival to site and vice-versa. Local travelling time will be billed in the same fashion.

3. TRAVELLING EXPENSES

Airfare & Freight expenses will be billed at cost plus 15% administration fees.
The service man shall have a vehicle available at all times.

- The rate for the use of a personal or company vehicle is 0.90$ per kilometre.
- Rental car will be billed at cost (rental fee + insurance + gasoline) plus 15% administration fees.

4. LIVING EXPENSES

Living expenses for food and lodging will be charged at a rate of $ 236.00 per calendar day.

A lump sum of 86.00$ per day will be charged when the service man is lodged and nourished by the customer or when the work to be done requires more than four hours but does not exceed one day. The same amount is applicable when the site location does not generate lodging expenses.

The lodging and living conditions on site have to be approved by the service man and the administrator of the project. The service man shall always have the choice of lodging either in existing hotels or the customer's accommodation.

5. NOTES

1. The Service Rates do not include any tax and are firm for the year of 2007.
2. Actual invoicing rates will be those in effect at the time the work is carried out.
3. A supervisor is not a foreman for the contractor. Under no circumstances will he and/or AREVA Canada inc. be held responsible for faults in the erection of the equipment, as this is the sole responsibility of the CONTRACTOR.
4. Delays caused by bad weather, union conflicts, etc. are not AREVA Canada inc.'s responsibility, and waiting time will be charged at the same rate as hours worked.
5. Cost incurred because of delays due to equipment failure or other problems (cranes, men, etc.) cannot be imputed to AREVA Canada inc.
6. AREVA Canada inc. will do the utmost to complete the work limiting the travelling to one return trip from the plant to site. However, it is not always possible due to the nature of the work, availability of test equipment and personnel, and if another return trip becomes necessary, the additional costs are then entirely the responsibility of the customer.
7. The choice to use a car or plane to get to the customer's site will be AREVA'S decision.
8. Rates are based on average lodging cost. AREVA reserve the right to revise those rates when judged appropriate.
9. Where unusual job circumstances exist requiring more than normal travelling and/or exceptional Living Expenses a request should be made to the company for appropriate rates.

ABB

Jan 26 2007

Midland PUC
16984 Hwy 12
PO Box 820
Midland , Ontario
L4R 4P4

Attn: Mr. Wayne Dupuis

Quote # S07SN 070126

Subject: **4.16 kV Arc Proof Metalclad Switchgear**
Midland PUC

Thank you for your interest in our products and services. In response to your request for a quotation, we are pleased to submit the following proposal.

Scope of Work

Includes the supply only , witness testing and factory acceptance tests in ABB Plant and packing for local transport to Midland

Switchgear

- Includes ABB Unigear switchgear rated type C arc resistant.
- Includes one incoming breaker position , four outgoing feeder positions, one PT set as per drawing MID-06-01
- Main Bus 2000A copper bus.
- Includes one ABB breaker rated 2000A, 4.16 kV, 3 phase, 60 Hz, 31.5kA, 125 VDC.
- Includes Four 4 ABB breakers rated 1200A, 4.16 kV, 3 phase, 60 Hz, 31.5kA, 125 VDC.
- Includes 5(five) SEL 351A protection relays rated 125VDC, c/w LCD panel, 5A rated phase and neutral elements, 120V AC ph-ph voltage elements, min 6 input/output elements. Relay is fully programmable with configurable inputs and outputs.
- Includes breaker control push buttons on front of SEL relay
- Includes local / remote switch.
- Includes three CT's rated 2000/5A for the main incoming.

ABB

Switchgear Cont'

- Includes 12 --CT's rated 1200/800/5A for the feeder breakers.
- Includes three fused PT's, single phase, 2 winding, 2450/70V 500VA, 60 BIL, and accuracy 0.3Z.
- Arc resistant switchgear chimney system will be vented upwards as depicted on the drawing.

Price .... $ 255, 000. 00 Taxes Extra

Option I

Switchgear

- Includes ABB Unigear switchgear rated type C arc resistant.
- Includes one incoming breaker position , four outgoing feeder positions, one PT set as per drawing MID-06-01
- Main Bus 2000A copper bus.
- Includes one ABB breaker rated 2000A, 4.16 kV, 3 phase, 60 Hz, 31.5kA, 125 VDC.3 cy operating time
- Includes Four (4) ABB breakers rated 1200A, 4.16 kV, 3 phase, 60 Hz, 31.5kA, 125 VDC. 3 cy operating time
- Includes 5 (five) ABB REF 541 protection relays rated 125VDC, c/w LCD panel, 5A rated phase and neutral elements, 120V AC ph-ph voltage elements, min 6 input/output elements. Relay is fully programmable with configurable inputs and outputs.
- Includes breaker control push buttons on front of REF relay
- Includes local / remote switch.
- Includes three CT's rated 2000/5A for the main incoming.
- Includes 12 CT's rated 1200/5A for the feeder breakers.
- Includes three fused PT's, single phase, 2 winding, 2450/70V 500VA, 60 BIL, and accuracy 0.3Z.
- Arc resistant switchgear chimney system will be vented upwards as depicted on the drawing.

ABB

- Includes ARC Flash Protection for 6 cells using one REA 101 and 4 REA 105 to reduce trip signal to breakers to 2.5 ms in case of fault or 50 ms total trip time
- Includes all fiber optic sensors
- Arc resistant switchgear chimney system will be vented upwards as depicted on the drawing.

Price .... $ 268, 000. 00 Taxes Extra

Installation option

Option includes delivery to site, unloading, installation including :placing in position, reassembly and bolting down of one complete metalclad switchgear assembly Removal and disposal of old existing switchgear can be also done if we have some data about it

- ABB Power Technology Service will supply, unload, place in position, reassemble where necessary and bolt down to channel sills one single bus, single breaker, air insulated switchgear assembly as outlined in your technical specification.
- Connect DC and function test all equipment , provide training for Midland PUC and commissioning company before they start commissioning .

Price .... $ 24, 000. 00 Taxes Extra

Delivery Drawings: 12 to 14 Weeks
Warranty: Standard Two Year
Separate Payments Required for
Ready to Ship for Substation (option 1 and 2)
Installation of Substation if selected
Delivery: Subject to Prior Sales
Terms & Conditions: Terms & Conditions ABB Inc.

ABB

FAT Testing

The following are tests will be included and performed on the equipment supplied by ABB Inc.

1. Dielectric Tests
2. Impulse Withstand Tests
3. Power Frequency Withstand Tests
4. Partial discharge (Corona) Tests
5. Functional tests
6. Inspection of 4.165 kV bus joints.

Not Included

1. Any Arc Resistant Testing.
2. Internal Arching Tests.
3. ABB Inc. will submit factory laboratory test reports.

Spare Parts – not included in switchgear price

• Electronic controller	Part # 7004902R0113	$ 800. 00
• Key support c/w membrane switches	Part # 7004907R0106	$ 200. 00
• Spare vacuum bottle		$ 700. 00
• Auxiliary switches	Part # GEC 7002397R0119	$ 200. 00
• Lighting Tubes /Box	60W, 8 ft, 120V- Box of 12	$ 150. 00
• Indicating light Bulbs Each	LED, 120VDC, Long life	$ 12. 50
• Fuses for SS TX Each	15A, 4160V	$ 250. 00 x 3
• PT fuses Each	0.5A, 4160V	$ 200. 00 x 3
• Spare breaker Each	VM1 121231	$ 12, 000.00

$14,512.50

ABB

Comments & Exceptions

- ABB Inc. takes exception to any arc resistant testing and Internal Arcing tests.
- ABB will provide the factory test results for arc resistance provided by the ABB switchgear manufacturing plant.

ABB Service will like to do a presentation about ABB UNIGEAR products , Arc flash Protection REA relays , Ars flash Hazard control Strategies and more .

We thank you for the opportunity to provide this review for you. If you have any questions concerning this proposal, please do not hesitate to contact me at (905) 460-3000 ext. 3204.

Yours Truly 26. JAN 07

ABB Inc. per
Sever Bodea

Julie Brisebois

ABB Inc.
Power Technology Service Division
201 Westcreek Blvd.
Brampton, Ontario
L6T 5S6

ABB

The following additional terms and conditions also apply.

All prices are net and firm for 30 days, subject to credit approval, with all applicable taxes extra.

All travelling time, mileage, and expenses are is included in the quoted price.

Invoicing will be progressive on a monthly basis as charges accumulate, if applicable.

Excessive delays due to circumstances beyond our control (such as customer requirements, weather, local utility, etc.) may be charged as an extra to the quoted price at the applicable hourly rate.

Customer initiated job rescheduling may result in extra charges to the quoted price.

Any charges (and scheduling) for isolation and grounding by the local utility will be the responsibility of the customer unless otherwise arranged.

Any costs incurred to satisfy local union requirements would be charged as an extra to the quoted price.

Any costs incurred to satisfy safety-training requirements would be charged as an extra to the quoted price.

ABB Service standard tests and testing procedures will be used (if applicable) which adhere to our ISO 9001 QMI standards.

All work will be performed by **ABB** Service personnel and/or **ABB** authorized subcontractors.

The customer will be responsible for providing any temporary power that may be required during the course of this project.

Prior to the start of any work, the customer will be required to provide free and easy access to the proposed work areas. This includes the removal of all materials stored around the proposed work areas.

The customer will limit access to the work areas to authorized personnel only.

The customer will be responsible for all media and third party inquiries.

Certification of Insurance and WSIB will be issued upon request and after receipt of a purchase order, if required.

TILTRAN SERVICES

Division of Carroll Electric (1982) Limited

ELECTRICAL POWER SYSTEMS SPECIALISTS

September 18, 2007

Midland Power Utility Corporation
16984 Highway 12
P.O. Box 820
Midland, ON
L4R 4P4

Attention: **Mr. Glenn McCurdy, B.Sc.**
Assistant Manager of Operations

RE: Budgetary Estimate for Brandon Substation - Midland
Quotation 0709-4209

Dear Glenn:

Tiltran Services has reviewed the information discussed during our September 6, 2007 meeting and offers the following for your consideration. Unfortunately due to the compressed timelines there are some features we have not been able to incorporate and these have been identified below.

Our proposal allows for:

1. Concrete terminal pole and base to allow free standing option c/w
    a. 46 kv fused load break switch
    b. 46 kv station class arresters on pole
2. Concrete pad for transformer – frost free and stamped
3. Concrete encased duct bank from terminal pole to transformer pad
4. Primary cables and terminations (cold shrink) – 4/0 AL, 46 KV concentric neutral cable, trench allowance of 30 metres included Cu
5. Placement of Utility supplied transformer – assumed manufacturer delivered to site
6. Secondary Distribution Equipment – see options below
7. Underground cable and conduit between transformer and secondary equipment – allowance for 15 KV copper cable, based on 10MVA secondary current capacity
8. Underground conduits (4 circuits) for distribution to utility placed poles – allowance for 40 m trench lengths
9. Cables for three (3) of the above circuits c/w surge arresters on the concentric neutrals – including separate neutrals quantity two (2) – terminations (cold shrink included)

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10. Energization assistance and follow-up monitoring of transformer condition (oil samples) during manufacturers warranty period of one (1) year
11. Coordination Study covering primary supply and each of three circuits to the largest downstream device
12. Pre-service testing and commissioning allowed
13. Tie in to existing SCADA system allowed
14. Additional fencing allowed to reduce overall yard size including stone coverage

Secondary Equipment

Due to compressed time frame we have only been able to obtain one quote on the secondary gear – this is from Schneider Canada. Equipment consists of a four cell section of gear with four (4) breakers – vacuum style VR-05025-12 breaker, battery package and charger, test equipment – cabinet, cables, lift truck, ground truck. Also included is a house service panel to allow for heat, lights and receptacles. All breakers are set up for 600 amps maximum circuit ratings – adjustable up to maximum – equipped with a SEL 351-6 protective relay. System consists of four feeder breakers (No main device) with each breaker separately equipped with the SEL relay

(JUST BREAKER)

Option #1

Secondary equipment housed in a prefab (Butler style) building

Price .... $ 709,550.00 PST included

Option #2

Secondary equipment housed in a out door walk in enclosure – on separate pad

Price .... $ 682,875.00 PST included

NOTES:

INCLUDE IN PRICE

- $20,000 allowance to remove existing concrete pads – existing surplus plus pads for active gear
- $ 4,500 allowance for Soil Bearing testing
- Ground Grid Soil Resistivity Testing
- Tamper-proofing Customer supplied top bushing mounted Transformer

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NOT IN PRICE

- oil containment system
    - compressed timeframe has not allowed for responses on oil containment systems
- Ground Grid needed to meet conditions after above study completed
- Cables routing up all poles by Utility – including guards/supports
- Building permits/fees
- No allowance for overtime charges
- **MATERIAL ESCALATION CHARGES – ALL PRICES ARE BASED ON SEPTEMBER 2007 RATES/COSTS**

There are other possible options to consider such as padmounted Reclosers with Form 6 protection relays. These devices do allow communication via SCADA systems and MAY prove cost effective. This was to be an option we were going to explore – it is different then the station we visited yet if cost effective may be of interest.

Other options available – fully enclose the transformer within a bungalow structure – using the "garage area" as the transformer enclosure and the house as the distribution area – this provides a low profile, subdivision style appearance.

We would appreciate the opportunity to review this proposal with you and your operating group.

We look forward to being of assistance.

Regards
TILTRAN SERVICES

J. Paul Krupicz, P.Eng. MBA
Engineering Manager

Equipment deliveries – 18-20 weeks ARO

With transformer already on order, to meet a mid September 2008 energization the distribution equipment would need to be ordered by mid March 2008.
Based on our estimate, we would have staff on site for a period of 8 weeks – available spring 2008 to start

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The State Group Inc.

3206 Orlando Drive, Mississauga, Ontario L4V 1R5
Tel: (905) 672-2772
Fax: (905) 672-1919

ISO 9001:2000
Registered

November 9, 2007

To: Midland Power Utility Corporation
16984 Highway 12
Midland, ON L4R 4P4

Attn. Mr. Wayne Dupuis, C. Tech.
Manager of Operations

Re: Budget price for Brandon Substation (44/4.16kV) turn key project

We thank you for the opportunity to provide for your consideration our budget price for the above mentioned project.
Our Budget price is **$1,151,300.00 + GST**, and includes the following, for a complete operational turn key substation:

✓ 1-Areva arc proof Type 2 switchgear, complete with 3 cells, 5kV, 2000A, 25kA, with SEL 351S relays, including one 2000A main breaker, four 1200A feeder breakers, PT's and CT's .
✓ 2-Batteries and charger as required.
✓ 3-Prefabricated building for the above switchgear, complete with necessary lighting, heating, etc.
✓ 4-Installation only of the free issued by PUC, Northern transformer (7.5/10MVA, 44/4.16kV).
Al. Cu? — 5-5kV Bus Duct or U/G cables and terminations, from the transformer to the switchgear.
6-44kV terminal pole, outside the substation yard, c/w fused LBS switch (S&C), arrestors, and accessories.
7-Overhead wires to existing 44kV line across the road (connection to existing by PUC).
8-Aproximate 25m of duct bank (4-4"PVC) and 44kV cables from the terminal pole to the transformer (require HV side mounted bushings), or overhead wires to top mounted bushings (as shown on Northern Transformer drawing).
✓ 9-Secondary 5kV feeders duct bank (8-4"PVC), approximate 80m total, for four feeders (3+1 spare).
✓ 10-5kV feeder cables (1c#500MCM/phase) for three feeders (approximate 50m long each), from the switchgear to wood poles (supplied and installed by PUC).
✓ 11-Concrete foundations (floating pads) for switchgear building and transformer.
✓ 12-Chain link fence 50' x 110'.
✓ 13-6" of 3/4" crushed stones inside the yard.
14-Station grounding based on a 5' x 5' grid (if calculation done after the soil resistivity test will require more grounding, this will be extra).
15-ESA drawing revision and field inspection included.
16-Commissioning and coordination study included.
17-Engineering for civil and electrical work included.

18-Quotation for civil work did not take in consideration adverse soil conditions. Geotechnical study is required in order to finalize the design, and is not included in our price.
19-SCADA system is existing.
20-Removal of the old station is not included.

We are confident that providing that the geotechnical and grounding study do not bring unexpected challenges, we will be able to improve our quote, once the engineering is finalized.

We are looking to work with you in finding solutions for a mutual advantage.

Please do not hesitate to contact us if you have any questions regarding the above.

Yours truly,

Mike Petrovici, Project Manager
The State Group Inc.

R&B CONSTRUCTION SERVICES INC.

January 17, 2008

Midland Power Utility Corporation
16984 Highway 12
P.O. Box 820
Midland ON L4R 4P4

Attention: Mr. Wayne Dupuis, C. Tech.
Manager of Operations

Re: Brandon St. Substation Replacement, Midland ON

For the sum of one million two hundred ten thousand dollars ($1,210,00.00) plus G.S.T. R&B Construction Services Inc. will supply and install replacement equipment, associated building enclosure, foundations, duct banks and cabling for the existing Brandon Street Substation.

The equipment will generally comprise of four bays of 5KV switchgear complete with breakers, and one 44KV dip pole complete with load break switch, fuses and hardware for the pole. (The transformer is to be provided by Midland PUC.) The switchgear will be set on a concrete foundation and enclosed in a prefabricated building specifically designed for this application. A precast concrete foundation will be provided outside the building for the transformer and a cast-in-place foundation provided for the dip pole. Duct banks will be provided between the dip pole and transformer, transformer and switchgear, and switchgear and hydro poles, and the overall layout will be generally as shown on the attached drawing labelled Brandon St. Substation, Midland ON dated Nov 22, 2007, Revision 2.

We will supply and install three runs of 44KV cable from the dip pole to the transformer complete with terminations. We will supply and install 5KV cables between transformer and switchgear, and three runs of 5KV cables from switchgear to existing hydro poles, complete with all terminations except those at existing hydro poles. We will install the hydro supplied transformer on its foundation and connect this to the existing ground grid. Provision of a ground grid study, layout and coordination study, and commissioning of all newly installed equipment is included.

Once the new substation is up and running we will remove the existing equipment and turn this over to Midland PUC, except if this involves the handling of PCBs. We can make arrangements for the latter but the costs for PCB removal are not included in the above price.

13845 27th Side Road, Terra Cotta, ON L7C 1N8 • Phone: 1-888-846-6215 • Fax: 905-877-6818 • rbcon@rbconstruction.on.ca

Please note that the above price is based on the switchgear specifications as provided at the meeting on September 10, 2007, which were the specifications for Scott Street Substation – Switchgear Replacement. If the final agreed upon specifications result in changes it will be necessary to adjust the price accordingly.

Specifically not included in the above price are: handling of PCBs; disposal of existing equipment other than by turning over to Midland PUC; demolition and removal of existing foundations; repair or replacement of existing substation ground grid; repair or replacement of existing substation fence; connection of new 5KV cables at existing hydro poles; supply and installation of 44KV overhead cables to new dip pole; submissions to Electrical Safety Authority (if required); local hydro costs associated with the work; work on premium time; and work in winter conditions.

Please note that the delivery time for switchgear will range from 28 – 40 weeks depending on the exact specifications for the equipment and the date when the order is placed.

Thank you for the opportunity to submit this proposal.

Yours truly,
R&B Construction Services Inc.

Jeremy Cook, P.Eng.
Project Manager

/Attachments
- Drawing: Brandon St. Substation, Midland ON dated Nov 22, 2007, Revision 2
- R&B quote sheet