EB-2014-0055

Ontario Energy Board

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Algoma Power Inc. for an order approving or just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015.

ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")
CROSS-EXAMINATION COMPENDIUM

Table 11 Calculation of the 2015 RRRP Funding Amount

Determination of Residential R1 & R2 2015 Electricity Distribution Rates and RRRP Funding

2015 Distribution Base Rate Determination											
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8496	105,791,701		13.6%	86.4%	22.24	0.1356	2,267,699	14,349,470	16,617,169
Residential - R2	kW	50		198,901	12.0%	88.0%	820.21	18.1276	492,124	3,605,601	4,097,725
									2,759,823	**17,955,071**	**20,714,894**
2015 Application of Rate Indexing Methodology											
Delivery Charges Indexed by Simple Average of Other LDC Increases in Current Year											
Simple Average Increase in Delivery Charge for 2015 using the 2014 Board Approved RRRP Adjustment Factor											**0.79%**
			Billing Determinant		F/V Split		Distribution Rates		Revenues		
Customer Class	Metric	Average # of Customers	kWh	kW	Fixed Allocation	Variable Allocation	Monthly Service Charge	Variable Charge	Fixed	Variable	Total Revenue
Residential - R1	kWh	8496	105,791,701		40.7%	59.3%	23.34	0.0328	2,379,862	3,465,392	5,845,254
Residential - R2	kW	50		198,901	36.8%	63.2%	600.83	3.1131	360,498	619,199	979,696
Hold Residential - R2 Fixed Charge at $596.12					36.5%	63.5%	596.12	3.1273	357,672	622,024	979,696
Transformer Ownership Allowance - Allocated to the Residential - R2 class										74,096	74,096
									2,737,534	**4,087,417**	**6,824,951**
The Rural and Remote Rate Protection Amount Required for 2015											**$13,964,040**

ii. Do the impacts of any rate change require mitigation?

Status: Complete Settlement

Supporting Parties: API, Energy Probe, VECC, and the Algoma Coalition

Evidence: Exhibit 8, Tab 2, Schedule 12

Table 12 below has been determined on the basis of the rate design accompanying this Proposed Settlement Agreement. There are no total impacts which exceed 10 percent and therefore API is not proposing rate mitigation.

Table 12 Summary of Bill Impacts

Summary of Bill Impacts						
Customer Class	Type	Usage kWh	Demand kW	Total Bill		
				Includes OCEB (if applicable)		
				Current	Proposed	%
Residential - R1	RPP-TOU	250		63.04	61.55	-2.38%
		800		147.58	138.19	-6.36%
		1,500		255.18	235.76	-7.61%
		2,000		332.03	305.43	-8.01%
		5,000		793.16	723.52	-8.78%
		10,000		1,561.71	1,420.33	-9.05%
		15,000		2,330.26	2,117.16	-9.15%
Residential - R2	Non-RPP	30,000	50	4,694.57	4,858.65	3.49%
		81,000	160	11,753.29	12,269.77	4.39%
		90,000	225	13,406.62	14,119.30	5.32%
		4,100,000	6,000	542,714.15	562,688.13	3.68%
R2, Interval	Non-RPP	90,000	225	13,502.27	14,119.30	4.57%
Seasonal	RPP-TOU	287		110.14	109.78	-0.33%
		1,000		292.68	297.47	1.63%
Street Lighting	Non-RPP	150	1	50.17	54.75	9.12%
		19,056	62	6,364.05	6,937.78	9.02%

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Ontario Energy Board

Filing Requirements For Electricity Distribution Rate Applications - 2014 Edition for 2015 Rates Applications -

Chapter 2

Cost of Service

July 18, 2014

application concerning class revenue requirements in Appendix 2-P, on the basis of the proposed customer classes to provide continuity of information.

2.10.2 Class Revenue Requirements

Appendix 2-P shows the format for filing cost allocation information and includes four tables.

The first table in Appendix 2-P is a format for showing the test year class revenue requirements, which is produced in output sheet O-1 of the Board model. This table also includes a comparison to the most recent study previously filed with the Board.

The Board has established ranges for revenue-to-cost ratios. Rate re-balancing is the process of changing rates by different percentage amounts for different customer rate classes. To support a proposal to re-balance rates, the distributor must provide information on the revenue by class that would pertain if all rates were changed by a uniform percentage. These ratios must be compared with the ratios that will result from the rates being proposed by the distributor.

The second table in Appendix 2-P shows three revenue scenarios, by rate class. Each scenario is based on the forecast of class billing quantities. The scenarios are, respectively, the forecast quantities multiplied by: a) existing rates, b) prorated existing rates that would yield the test year Base Revenue Requirement, and c) proposed class revenues. The table also shows the allocation of Miscellaneous Revenue to the rate classes, which is an output from the cost allocation model.

2.10.3 Revenue-to-Cost Ratios

The range of acceptable ratios is in the Board's March 31, 2011 Report, on Cost Allocation, section 2.9.4.

The third table in Appendix 2-P combines information from the previous two tables in the form of revenue-to-cost ratios and includes the following information for each class:

- The previously approved ratios most recently implemented by the distributor;
- The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model; and
- The ratios that are proposed for the test year, which are the proposed class revenues, together with the updated cost allocation model.

Results flowing from the updated cost allocation model may show some ratios being outside of the Board-approved ranges. In these cases, distributors must ensure that their cost allocation proposals include adjustments to bring them into the Board-approved ranges. In making any such adjustments, distributors should address potential mitigation measures if the impact of the adjustments on the rate burden of any particular class or classes is significant.

If the distributor proposes to continue re-balancing after the test year, the ratios proposed for subsequent year(s) must be provided. The fourth table in Appendix 2-P provides a format for presentation. In particular, if the proposed ratios are outside the Board's policy range in the test year, the distributor must show the proposed ratios in subsequent years that would move the ratios into the policy range.

If using a cost allocation model other than the Board model, the distributor must ensure that costs exclude LV costs and deferral and variance accounts such as Smart Meter costs and that revenues exclude rate riders, rate adders and the Smart Metering Entity charge. The distributor must also ensure that information relevant to microFIT unit costs and revenue is consistent with the output from the Board's model.

2.11 Exhibit 8: Rate Design

The following areas are discussed in this exhibit:

1) Fixed/Variable Proportion;
2) Rate Design Policy Consultation
3) Retail Transmission Service Rates (RTSRs);
4) Retail Service Charges;
5) Wholesale Market Service Rate;
6) Smart Metering Charge;
7) Specific Service Charges;
8) Low Voltage Service Rates (where applicable);
9) Loss Adjustment Factors;
10) Tariff of Rates and Charges;
11) Revenue Reconciliation;
12) Bill Impact Information; and
13) Rate Mitigation (where applicable).

Please note that monthly fixed charges must be shown to two decimal places while variable charges must be shown to four places. Distributors wishing to depart from this approach must provide a full explanation as to why they believe it is necessary.

2.11.1 Fixed/Variable Proportion

The applicant must provide the following information related to the fixed/variable proportion of its proposed rates:

- Current fixed/variable proportion for each rate class, along with supporting information;
- Proposed fixed/variable proportion for each rate class, including an explanation for any changes from current proportions; and
- A table comparing current and proposed monthly fixed charges with the floor and ceiling as calculated in the cost allocation study.

If a distributor's current fixed charge is higher than the calculated ceiling, there is no requirement to lower the fixed charge to the ceiling, nor are distributors expected to raise the fixed charge further above the ceiling.

The fixed/variable analysis must be net of (i.e. exclude) rate adders, funding adders and rate riders (i.e. Low Voltage, smart meter rate riders, GEA and smart grid rate riders, deferral/variance account disposition, etc.).

2.11.2 Rate Design Policy Consultation

On April 3, 2014, the Board released its *Draft Report on Rate Design for Electricity Distributors (EB-2012-0410)* which proposed implementing a fixed monthly charge for distribution service. While the policy consultation is still ongoing, distributors can propose a fixed monthly charge within their applications based on the proposed policy options as applicable, for the Board's consideration. In proposing a fixed monthly service charge to recover distribution service costs, the distributor must provide an explanation of the method used to design the fixed charge.

2.11.3 Retail Transmission Service Rates ("RTSRs")

In preparing its application, the distributor must reference the Board's *Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates,* October 22, 2008, and subsequent updates to the Uniform Transmission Rates ("UTRs"). A completed version of the RTSR model must be filed in pdf and live Microsoft Excel.

The distributor must ensure that the information provided in this section is consistent with that provided in the working capital allowance calculation provided in Section 2.5.1.3, as it relates to rates such as RTSRs, or provide explanations for any differences.

File Number:	0
Exhibit:	
Tab:	
Schedule:	
Page:	
Date:	

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	**%**
Residential - R1	$ 12,066,293	63.75%	$ 15,148,651	65.00%
Residential - R2	$ 4,569,290	24.14%	$ 3,735,935	16.03%
Seasonal	$ 1,995,675	10.54%	$ 3,722,892	15.97%
Street Lighting	$ 296,807	1.57%	$ 697,035	2.99%
Total	$ 18,928,065	100.00%	$ 23,304,513	100.00%

Notes

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated cost and revenue of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

Classes (same as previous table)	**Column 7B**	**Column 7C**	**Column 7D**	**Column 7E**
	Load Forecast (LF) X current approved equivalent rates	**L.F. X current approved equivalent rates X (1 + d)**	**LF X proposed equivalent rates**	**Miscellaneous Revenue**
Residential - R1	$ 14,900,660	$ 16,617,169	$ 16,617,169	$ 292,845
Residential - R2	$ 3,674,441	$ 4,097,725	$ 4,097,725	$ 75,827
Seasonal	$ 1,763,879	$ 1,967,072	$ 1,967,072	$ 79,308
Street Lighting	$ 139,697	$ 155,789	$ 155,789	$ 18,778
Total	$ 20,478,677	$ 22,837,755	$ 22,837,755	$ 466,758

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate riders.

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential - R1	114.10	111.63	111.63	85 - 115
Residential - R2	59.80	111.71	111.71	80 - 120
Seasonal	115.00	54.97	54.97	80 - 115
Street Lighting	43.00	25.04	25.04	70 - 120

Notes

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1. Status Quo means

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2015	2016	2017	
	%	%	%	%
Residential - R1	111.63	111.63	111.63	85 - 115
Residential - R2	111.71	111.71	111.71	80 - 120
Seasonal	54.97	54.97	54.97	80 - 115
Street Lighting	25.04	25.04	25.04	70 - 120

Note

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2013 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2013. In 2014 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2014 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Appendix 2-V
Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
								kWh	kW					
Residential - R1	Customers	8,432.00	8,559.00	8,495.50	105,791,701		$ 23.34	$ 0.0328		$ 5,849,387.43	$ 16,617,169		$ 16,617,169	$ 10,767,782
Residential - R2	Customers	50.00	50.00	50.00	83,288,188	198,901	$ 596.12		$ 3.1273	$ 979,695.10	$ 4,097,725		$ 4,097,725	$ 3,118,030
Seasonal	Customers	3,191.00	3,084.00	3,137.50	7,731,414		$ 26.75	$ 0.1241		$ 1,966,605.98	$ 1,967,072		$ 1,967,072	$ 466
Street Lighting	Connections	1,018.00	1,018.00	1,018.00	804,705	2,380	$ 0.98	$ 0.1787		$ 155,772.46	$ 155,789		$ 155,789	$ 17
RRRP Funding (Net of Stranded Meter Allocation and Transformer Ownership Credit)										$ 13,889,944.00	$ -		$ -	-$ 13,889,944
Sub-Total A										$ 22,841,404.97	$ 22,837,755		$ 22,837,755	-$ 3,650
Residential - R1 Stranded Meter Allocation										$ -	$ -		$ -	$ -
Residential - R2 Transformer Ownership Credit										$ 74,096.00		$ 74,096	$ 74,096	$ -
Total		12,691.00	12,711.00	12,701.00	197,616,008	201,281				$ 22,915,500.97	$ 22,837,755	$ 74,096	$ 22,911,851	-$ 3,650

2014 Cost Allocation Model

EB-2013-0055

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

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	7	12
	R1	**R2**	**Street Light**	**Seasonal**
Customer Unit Cost per month - Avoided Cost	$13.48	$18.77	$0.42	$12.59
Customer Unit Cost per month - Directly Related	$20.59	$50.01	$0.89	$19.19
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$60.80	$344.53	$39.90	$91.03
Existing Approved Fixed Charge	$20.96	$612.10	$0.00	$24.64

RRRP 2002 – 2007 FUNDING VARIANCE

In its last cost of service application, EB-2009-0278, specifically Exhibit 9, Tab 1, Schedule 6, API sought relief of a funding variance in its RRRP funding account for the period of 2002 to 2007. However, the matter was not raised as part of the Settlement Agreement in the matter of EB-2009-0278. In this Application, API is requesting specific relief of the amount of $173,543 associated with the 2002 to 2007 variance.

In 2003, the government announced plans to extend the RRRP funding to all of Great Lakes Power's (API's predecessor) customers. The relief was in the form of RRRP payments from Hydro One and was determined to be $2,333,808 annually ($194,484 per month). This amount was equated to a monthly credit of $28.50 per residential customer; 6,824 customer times $28.50 per customer per month equals $2,333,808 per annum.

The variance recorded by API relates to a billing system allocation of the monthly $28.50 credit per customer that existed for RRRP funding in that same time frame. The billing system allocated the monthly credit on a 30 day basis, which left the utility short since more funding was credited to the customer than what was received by API (or GLP at the time). Therefore, for a 31 day billing period the billing system would allocate a benefit of $29.45 per customer (31/30 * $28.50 = $29.45). Over a year for 6,824 customers this is a shortfall of approximately $30,000 per year.

Additionally, the funding regime did address the variability in customer counts. As the number of eligible customers changed from 6,824 in 2002 to 6,797 in 2007, the RRRP funding did not keep pace.

API had an accrued balance of $235,653 related to this account at the end of 2008, but determined through an accounting review and comparison to OEB Rate Order Decision EB-2007-0744, that this variability in funding was satisfied as a result of that Decision. Therefore, API is seeking $173,534 according to the following schedule.

Table 9.8.1.1 below summarizes the calculation of the RRRP funding adjustment that is required to address the variance.

Table 9.8.1.1

	Days	RRRP Payments from HONI		Days	# Cust	RRRP Credits to Customers	Variance
2002	245	$1,555,872		245	6,845	$1,593,145	$37,273
2003	365	$2,333,808		365	6,866	$2,380,612	$46,804
2004	366	$2,333,808		366	6,820	$2,371,430	$37,622
2005	365	$2,333,808		365	6,789	$2,354,144	$20,336
2006	365	$2,333,808		365	6,784	$2,352,208	$18,400
2007	243	$1,555,872		243	6,797	$1,568,972	$13,100
		$12,446,976				**$12,620,510**	**$173,534**

API has included the original rate order describing the $28.50 per customer and the annual filings as an Appendix A to this Schedule.

API had been funded previously through a RRRP regime from 2002 – September 2007. The current RRRP regime was implemented in February 2009. There was a variance of $173,534 that related to the 2002-2007 funding which has been recorded as a receivable on the balance sheet of API and should be relieved through an additional payment from the RRRP funding pool administered by Hydro One.

Appendix A

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Ontario Energy Board

Commission de l'Ènergie de l'Ontario

Ontario

RP-2003-0149 1

IN THE MATTER OF the *Ontario Energy Board* Act, 1998, S.O. 1998, c. 15, Schedule B; of the Energy Competition Act, 1998; 2

AND IN THE MATTER OF section 79.8 of the *Ontario Energy Board* Act, 1998, S.O. 1998, c. 15. 3

Before: 4

Paul Vlahos
Vice Chair and Presiding Member 5

Robert Betts
Member 6

RATE ORDER 7

On June 27, 2003, pursuant to section 79.8 of the Ontario Energy Board Act, 1998, the Minister of Energy directed the Ontario Energy Board (the "Board") to amend the Distribution Rate Order of Great Lakes Power Limited ("GLPL"). Regulation 262/03 extended Rural and Remote Rate Protection to the residential customers served by GLPL. The amended rate schedule is based on a total revenue requirement of $9.8 million including Rural and Remote Rate Protection of $2.3 million. 8

GLPL's current distribution rate order (RP-2002-0109/EB-2002-0249/EB-2002-0277) was approved by the Board on an interim basis on May 13, 2002, effective May 1, 2002. The interim rate order was made final with the passage of Bill 210. 9

THE BOARD THEREFORE ORDERS THAT: 10

1 Great Lakes Power Limited's current distribution rate order is amended by revoking page 1 of the Schedule of Monthly Rates and Charges and replacing it with the document set out in Appendix "A" [oeb:12R15-0:13]of this Order effective May 1, 2002. 11

DATED at Toronto, July 11, 2003.

ONTARIO ENERGY BOARD

Peter H. O'Dell
Assistant Board Secretary

APPENDIX "A" RP-2003-0149 13
Great Lakes Power Limited- Distribution Division
Schedule of Rates and Charges
Dated June 27, 2003
Effective May 1, 2002

14

RESIDENTIAL			
	Monthly Service Charge	(per month)	$ 19.97
	Distribution Volumetric Rate	(per kWh)	$ 0.0200
SEASONAL			
	Monthly Service Charge	(per month)	$ 22.63
	Distribution Volumetric Rate	(per kWh)	$ 0.0400
GENERAL SERVICE < 50 KW			
	Monthly Service Charge	(per month)	$ 26.09
	Distribution Volumetric Rate	(per kWh)	$ 0.0360
GENERAL SERVICE > 50 KW			
	Monthly Service Charge	(per month)	$ 583.29
	Distribution Volumetric Rate	(per kW)	$ 2.00
SENTINEL LIGHTING/STREET LIGHTING			
	Distribution Volumetric Rate	(per kWh)	$ 0.0327
LARGE CUSTOMER A			
	Monthly Service Charge	(per month)	$ 557.42
	Distribution Volumetric Rate	(per kW)	$ 8.50
LARGE CUSTOMER B			
	Monthly Service Charge	(per month)	$ 2,792.67
	Distribution Volumetric Rate	(per kW)	$ 8.50

Note: Under the Ontario Energy Board Act and associated Regulations, year-round residential customers are eligible to receive Rural and Remote Rate Protection. Distribution Charges already reflect the appropriate discount of $28.50/month under this program. 15

This is page 1 only... Specific Service Charges appear on Page 2 of (pre Bill 210) Interim Schedule. 16

UNDERTAKING NO. J1.4: TO PROVIDE A MORE DETAILED CALCULATION ON THE VARIANCE, SHOWING THE VARIABILITY WITH RESPECT TO CUSTOMER NUMBERS AND THE AMOUNT DUE TO THE BIMONTHLY BILLING ISSUE.

RESPONSE:

A Live Excel file, Undertaking_No_J1_4_20140821.xslx, accompanies these responses to the Undertakings arising from the Technical Conference.

This file details the derivation of the variability with respect to the customer numbers and the amount due to the bi-monthly billing issue.

	Days	RRRP Payments from HONI	Days	# Cust	RRRP Credits to Customers	Variance	Initial # Cust	RRRP Credits to Customers	Days Pro-rated Variance	Change in # Cust	Customer Count Variance
2002	245	$1,555,872	245	6,845	$1,593,145	$37,273	6,824	1,588,286	32,414	21	4,859
2003	365	$2,333,808	365	6,866	$2,380,612	$46,804	6,824	2,366,222	32,414	42	14,390
2004	366	$2,333,808	366	6,820	$2,371,430	$37,622	6,824	2,372,705	38,897	(4)	(1,275)
2005	365	$2,333,808	365	6,789	$2,354,144	$20,336	6,824	2,366,222	32,414	(35)	(12,078)
2006	365	$2,333,808	365	6,784	$2,352,208	$18,400	6,824	2,366,222	32,414	(40)	(14,014)
2007	243	$1,555,872	243	6,797	$1,568,972	$13,100	6,824	1,575,320	19,448	(28)	(6,348)
		$12,446,976			**$12,620,510**	**$173,534**			**$188,001**		**($14,467)**

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Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2014-0055**

VOLUME: **Technical Conference**

DATE: **August 20, 2014**

understand your concern. I am not looking for a detailed justification about the law.

Mr. Taylor, where I was really going to was the interrogatory itself responds by saying API does not propose to adjust the historic discounts. So to your point, I think maybe if you explain why that is, maybe that's where I am losing the train of logic that you have. And I think that's where I'm really going.

MR. TAYLOR: The historic discounts were -- you are talking about the $28.50 per kilowatt-hour -- sorry, per customer per month, we are not proposing to change that.

The rural and remote rate protection subsidy that was provided to API's customers, we don't dispute that that amount was incorrect. We think that the 28.50 was correct, and that is why we are not proposing to change that rate in any way whatsoever.

MR. GARNER: So maybe now, if you have no objection, to let API respond.

MR. TAYLOR: Okay.

MR. LAVOIE: So if I were -- the triple-R regime that was first announced in 2003 and applicable to the API distribution utility, Great Lakes Lower at the time, was determined on a formula that is used in Hydro One rural scenarios, situations, which is, as Mr. Taylor mentioned, $28.50 per month. And it was derived using the $28.50 per month multiplied by -- our average customer count at the time was 6,824, over the course of a year, which equated to a fixed sum of 2,333,808.

Now, implied within the calculation is inherent variability; there are customers that Algoma Power had taken on from the period 2003 to 2007 when the relief of subsidy changed, the formula changed, and in that period of time there was no true-up to what the actual customer count was, and those credits that were appropriately given to the customers over that period of time. So there is a variability with respect to customers.

And the second variance that existed was how the credit was applied. And Algoma Power had a bimonthly billing system that it applied to its residential customers, and inherent in a 28.50 per month -- it sounds simple, but the months don't have the same number of days. And therefore over a bimonthly period, you have to make a billing assumption within that calculation.

And we had done so very similar -- identical, actually, to the fixed monthly charges that are applied as part of our rate structure, applied on a 30-day month basis.

So those two variances that occurred over a period -- actually 2002 to 2007, had accumulated within an account that we are now seeking to recover.

So we feel that this type of variability has to be occurring within the Hydro One system and would be trued up at some periodic basis. You could never be trued up on that number.

So we believe we are asking for the mechanical -- the relief of that mechanical nature of the relief mechanism that was in place at the time.

MR. GARNER: Okay. Thank you. And also that helps me understand what Mr. Taylor was indicating about the 28.50.

Is there a way for you to allocate or distinguish between the amounts of the two variabilities? You said basically there is customer numbers and there is the billing problem, so that 173,000 is a combination of those two variances; is that correct?

And I guess the next question is: Can you break those out?

MR. LAVOIE: We provided a table of the payments and credits in table 9.8.1.1, but we don't have that --

MR. GARNER: I'm not at this stage, but what dawns on me when we review this is there may be an argument for one part of that and not the other part. And therefore would you be able to create -- or know that difference?

I am not going to say I am going to make that argument; it just dawns on me it could be...

MR. LAVOIE: I am not 100 percent certain that we have it in the format that you are asking for, but we do have a calculation for the number, so --

MR. GARNER: Could you undertake to provide that number?

MR. LAVOIE: Yeah. Yes, we will do that.

MS. DJURDJEVIC: Okay. That will be undertaking J1.4, and can we just get that stated on the record?

UNDERTAKING NO. J1.4: TO PROVIDE A MORE DETAILED CALCULATION ON THE VARIANCE, SHOWING THE VARIABILITY