Northern Ontario Wires Inc.
153 Sixth Avenue
P.O. Box 640
Cochrane, ON
P0L 1C0

December 18, 2012

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

Re: Cost of Service Application EB-2012-0153

Dear Ms. Walli:

Northern Ontario Wires Inc. hereby submits a revised COS Application for 2013 rates. This revision is made in accordance with the Boards letter dated December 10, 2012.

The following outlines the revisions made to the original application dated November 16, 2012.

Exh	Tab	Sch	Att	Num	Revision	Title	Note
1	2	3			1	Budget Directives and Assumptions	Forecast Preparation and Approval
3	1	3			1	Approach to Weather Normalized Load Forecast	Reference to data set
3	1	3	1	2	1	Load Forecast Data Set	Added Load Forecast Data set
4	6	1			1	Purchases from Suppliers	Non Affiliates updated discussion
4	6	1	1	1	1	Table of Purchases by Supplier	Non Affiliates updated table
4	8	3			1	Allowance for PILs	Explain difference between 2013 Capital Additions and UCC
7	1	1			1	Overview of Cost Allocation	Discuss weighting factors
7	1	1	1	3	1	Cost Allocation Sheet I-6	Added sheet per Ack Letter
7	1	1	1	4	1	Cost Allocation Sheet I-8	Added sheet per Ack Letter
7	1	1	1	5	1	Cost Allocation Sheet O-1	Added sheet per Ack Letter
7	1	1	1	6	1	Cost Allocation Sheet O-2	Added sheet per Ack Letter
7	2	1	1	2	1	Revenue-to-Cost Ratios	Matched Table 2 to App2P
8	3	5			1	Low Voltage Charges	Support for Forecast LV
8	3	6			1	Loss Adjustment Factors	Loss Factor Discussion
9	5	1			1	LRAMVA Process	LRAMVA Disposition
9	5	1	1	1	1	NOW Inc. 2011 LRAM LRAMVA	LRAM LRAMVA Calculation

An electronic copy has been submitted to the Board through the RESS system, and two hard copies of revisions will be delivered to the OEB office.

This document is being filed pursuant to the Board’s e-Filing Services.

Yours Truly,

NORTHERN ONTARIO WIRES INC.

Geoffrey Sutton, CA

Chief Financial Officer

Northern Ontario Wires Inc.

2013 COS Rate Rebasing

Revised Application #1

EB-2012-0153

Rates Effective: May 1, 2013

Date Filed: November 16, 2012

Date Revised: December 18, 2012

Northern Ontario Wires Inc.

153 Sixth Avenue

P.O. Box 640

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Budget Directives and Assumptions

NOW Inc. compiles budget information for three major components of the budgeting process: revenue forecasts, operation, maintenance and administration forecasts and capital forecast. Budget information was prepared for both the Bridge and Test Years. 2012BY forecasts were updated based on actual 2011 results, and the 2013TY projections were also reviewed in light of 2011 results.

NOW Inc. completed the operating and capital budgets with senior management throughout the spring and summer of 2012. The final budgets that are the basis for this application were approved by senior management at the August 2012 management meeting.

Revenue Forecast

The revenue budget includes three components: energy revenue, distribution revenue and other revenue.

The energy revenue for 2013 was forecast using the weather normalized load forecast prepared by Elenchus Research Associates ("ERA") as presented in E3/T1/S2/Att1. Rates for energy pass-through charges are described in E3/T1/S3.

Distribution revenue was forecast using the weather normalized volumes multiplied by both current approved distribution rates and by proposed rates in order to project revenue for the 2013TY. Other revenues were reviewed on an item by item basis with each account projection being determined based on the most reliable historical indicator.

Operations, Maintenance and Expense Forecast

The OM&A expenses for the 2012BY and 2013TY were forecast using work plans, approved pay grid progression, capital budgets and prior years historical costs. The expenditures were submitted to NOW Inc.'s Board of Directors for approval and reflected the following assumptions:

Wages:

- Union Wages reflect settlement of the collective agreement on October 24, 2012.
- Salaries reflect movement of the individual currently in the position along the existing salary grid with assumed cost of living adjustments of 3%.
- The impact of the transfer pricing study on the allocation charge of indirect labour has been reflected.
- Other changes in staffing levels to occur include retirement of a lineman in 2014 for which an apprentice was hired in 2011 to cover this deficiency.

Fleet:

- Assumed Fleet rates will increase by 2.5%.
- Assumed change in fleet levels will be required as part of fleet replacement program.

Operating and Maintenance, Billing and Collecting, General Administration

- Costs other than labour and fleet have assumed to increase 2.5%.

Regulatory Costs:

- 2013 Cost of Service application assumed to cost $100,000 plus $15,000 in intervenor costs. Assumed full recovery through rates from May 2013 to April 2016.
- Assumed OEB Annual assessments of $17,000 and $900 in other cost awards.
- Assumed Annual distributor license fee of $800
- Assumed Annual Regulatory consulting cost of $7,500 plus publishing costs of $2,500 for each year for IRM and other application requirements
- Assumed $4,000 per year in Low-Income Energy Assistance Program (LEAP) funding.

Amortization:

- 2013 Amortization on an MIFRS basis.

PILS:

- Regulatory PILS as per Board model.

Capital Budget

The capital budget is formulated on a project by project basis. The maintenance program is relied on to identify any assets that must or should be removed from service and replaced in order to maintain secure and reliable supply. Projects are prioritized by location and asset condition.

Capital spending to replace existing aging infrastructure is required in order to maintain safe and reliable delivery of electricity to NOW Inc.'s customers.

Additional information on NOW Inc.'s approach to investment planning is included in E2/T4/S4.

Approach to Weather Normalized Load Forecast

The approach to the weather normalized load forecast is in the Elenchus Research Associates Report at E3/T1/S2/Att1.1

The data set used to calculate the Load Forecast is shown at E3/T1/S2/Att1.2

Purchases from Suppliers

NOW Inc. purchases supplies and services from third parties in order to distribute electricity to its customers. E4/T6/S1/Att1 lists NOW Inc.'s expenditures on purchased products and services in 2011 in excess of $50,000 from any single supplier. While spending projections are not prepared on this basis, NOW Inc. expects its pattern of expenditures to remain generally consistent with recent history, except for material variances in expenses for Operations, Maintenance and Administration.

NOW Inc.'s procurement policy appears as E4/T6/S1/Att2 to this schedule. NOW Inc. purchases equipment, materials and services in a cost effective manner with full consideration given to price as well as product quality, the ability to deliver on time, reliability, compliance with engineering specifications and quality of services. Vendors are screened to ensure knowledge, reputation, and the capability to meet NOW Inc.'s needs. The procurement of goods and services for NOW Inc. is carried out with the highest of ethical standards and consideration to the public nature of the expenditures.

NOW Inc. is currently involved in a number of partnerships in order to reduce costs and improve efficiencies:

- North-east District Buying Consortium: NOW Inc. is a member of this group, which consists of seven (7) LDCs. The Buying Consortium negotiates prices based on volume, therefore reducing costs of materials.
- Utilities Standards Forum: As NOW Inc. is a relatively small LDC, it has joined the USF Group, which provides the technical and engineered specifications needed in order to meet Distribution Code requirements.

- ESA Audits: NOW Inc. participates annually in Electrical Safety Authority audits as required under Ontario Regulation 22/04, which identifies safety deficiencies. This is done in conjunction with other Northeast utilities for cost savings.
- Services Agreement with CTS: NOW Inc.'s affiliate, Cochrane Telecom Services, provides the necessary human resources and facilities in order to maximize efficiencies

Allowance for PILs

The OEB's Income Tax/PILs workform was used to calculate the PILs amount 2013TY of $26,245 (E4/T8/S3/Att1) on a MIFRS basis.

2013 Capital additions vs 2013 UCC

NOW Inc. is proposing new capital additions for the year 2013 in the amount of $725,029. This is discussed in E2/T3/S3. For the purposes of PIL's calculation this amount has been reported sheet "O. Schedule 8 CCA Test Year" of the OEB PILs model. However total capital additions for 2013 are being reported as $1,799,761. This is caused by the inclusion of smart meters being moved into rate base at their 2013 net book value. For purposes of clarity NOW Inc. would like to make mention that the smart meter assets have been included in the opening 2012 UCC balance as the assets were reported in 2011 and previous year tax filings.

2013 Test Year Capital Projects	
Iroquois Falls 12kV extension from Picadilly to New Circle	$ 77,920
Cochrane 4th/5th St. and 5th/6th St. laneways reconstruction	$ 92,598
Cochrane 5th/6th St. laneway reconstruction	$ 79,980
Kapuskasing 5kV to 25kV conversion/upgrade/extension from Nipigon to Ottawa	$ 101,351
Cochrane Pole Changes	$ 53,560
Kapuskasing Pole Changes	$ 53,560
Iroquois Falls Pole Changes	$ 53,560
Tools and Equipment	$ 12,875
Transportation Equipment	$ 176,500
Computer Equipment Hardware	$ 10,300
Computer Software	$ 5,150
Miscellaneous Equipment	$ 7,725
2013 Test Year Capital Projects	$ 725,079
Smart Meter Assets NBV @ Jan 1, 2013	
Smart Meters	$ 1,036,720
Computer Hardware	$ 20,669
Computer Software	$ 16,743
Tools And Equipment	$ -
Other Equipment	$ 751
	$ 1,074,882
Total 2013 Additions	$ 1,799,961

Overview of Cost Allocation

NOW Inc. retained Elenchus Research Associates ("Elenchus") to complete its cost allocation study for this application. The report prepared by Elenchus with respect to the cost allocation study for the 2013TY is at E7/T1/S1/Att1. The relevant input and output sheet of the cost allocation model are filed under E7/T1/S1/Att2.

Weighting Factors

Services

	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Insert Weighting Factor for Services	1.0	1.2	10.1	1.0	1.0

Billing and Collecting

	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Insert Weighting Factor for Billing and Collecting	1.0	2.0	7.0	1.0	5.0

NOWI review of their assets, and identified average costs of services recorded to 1855 for the Residential, General Service less than 50kW, and General Service 50 to 4,999 kW. No information was available for Street Lighting and Unmetered Scattered Load, although it is believed that these accounts have costs recorded to 1855. In light of the information available, NOWI used calculated weighting factors where possible, and relied on default weighting factors for the remaining unmetered classes.

NOWI does not track the time costs associated with preparing bills, mailing, and receiving payment and recording revenue at a level of detail sufficient to produce appropriate weighting factors. Therefore, the most appropriate information available at this time is the default weighting factors.

2013 Cost Allocation Model

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	118,115,776
Total kWs from Load Forecast	182,246
Deficiency from RRWF	- 454,824
Miscellaneous Revenue	240,798

			1	2	3	7	9
Billing Data	**ID**	**Total**	**Residential**	**General Service less than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Unmetered Scattered Load**
Forecast kWh	**CEN**	118,115,776	41,735,131	19,541,272	55,101,173	1,610,563	127,637
Forecast kW	**CDEM**	182,246			177,931	4,315	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		66,500			66,500		
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-					
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	118,115,776	41,735,131	19,541,272	55,101,173	1,610,563	127,637

kWh - 30 year weather normalized amount		118,115,776	41,735,131	19,541,272	55,101,173	1,610,563	127,637
Existing Monthly Charge			$17.83	$23.90	$181.61	$5.27	$12.23
Existing Distribution kWh Rate			$0.0135	$0.0134			$0.0134
Existing Distribution kW Rate					$0.6880	$6.2108	
Existing TFOA Rate					$0.60		
Additional Charges							
Distribution Revenue from Rates		$2,573,502	$1,687,784	$481,829	$274,969	$124,569	$4,352
Transformer Ownership Allowance		$39,900	$0	$0	$39,900	$0	$0
Net Class Revenue	**CREV**	$2,533,602	$1,687,784	$481,829	$235,069	$124,569	$4,352
Data Mismatch Analysis							
Revenue with 30 year weather normalized kWh		2,533,602	1,687,784	481,829	235,069	124,569	4,352

Weather Normalized Data from Hydro One

	Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
kWh - 30 year weather normalized amount	124,600,332	44026389.69	20614087.83	58126227.4	1698982.909	134644.2713
Loss Factor		**1.0549**	**1.0549**	**1.0549**	**1.0549**	**1.0549**

2013 Cost Allocation Model

Sheet I6.2 Customer Data Worksheet -

	ID	Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
Billing Data							
Bad Debt 3 Year Historical Average	BDHA	$60,770	$31,184	$29,586	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$97,121	$48,748	$27,981	$20,392		
Number of Bills	CNB	73,200	63,060	9,204.00	840.00	36.00	60.00
Number of Devices						1,546	
Number of Connections (Unmetered)	CCON	1,564				1,546	18
Total Number of Customers	CCA	6,100	5,255	767	70	3	5
Bulk Customer Base	CCB	6,100	5,255	767	70	3	5
Primary Customer Base	CCP	6,100	5,255	767	70	3	5
Line Transformer Customer Base	CCLT	6,030	5,255	767		3	5
Secondary Customer Base	CCS	6,030	5,255	767		3	5
Weighted - Services	CWCS	8,434	5,255	905	710	1,546	18
Weighted Meter -Capital	CWMC	570,478	367,062	122,417	81,000	-	-
Weighted Meter Reading	CWMR	83,866	63,060	15,788	5,017	-	-
Weighted Bills	CWNB	87,684	63,060	18,408	5,880	36	300

Bad Debt Data

		Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Historic Year:	2002	81,278	31,467	49,811			
Historic Year:	2003	52,277	34,527	17,750			
Historic Year:	2004	48,755	27,557	21,198			
Three-year average		**60,770**	**31,184**	**29,586**	**-**	**-**	**-**

2013 Cost Allocation Model

Sheet I8 Demand Data Worksheet -

This is an input sheet for demand allocators.

CP TEST RESULTS	12 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

			1	2	3	7	9
Customer Classes		Total	Residential	General Service less than 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
CO-INCIDENT PEAK							
1 CP							
Transformation CP	TCP1	21,466	10,480	3,136	7,462	374	14
Bulk Delivery CP	BCP1	21,466	10,480	3,136	7,462	374	14
Total Sytem CP	DCP1	21,466	10,480	3,136	7,462	374	14
4 CP							
Transformation CP	TCP4	82,460	36,389	12,964	31,865	1,183	59
Bulk Delivery CP	BCP4	82,460	36,389	12,964	31,865	1,183	59
Total Sytem CP	DCP4	82,460	36,389	12,964	31,865	1,183	59
12 CP							
Transformation CP	TCP12	215,564	80,936	36,185	96,463	1,806	174
Bulk Delivery CP	BCP12	215,564	80,936	36,185	96,463	1,806	174
Total Sytem CP	DCP12	215,564	80,936	36,185	96,463	1,806	174
NON CO_INCIDENT PEAK							
1 NCP							
Classification NCP from Load Data Provider	DNCP1	25,535	11,869	4,197	9,080	374	15
Primary NCP	PNCP1	25,535	11,869	4,197	9,080	374	15
Line Transformer NCP	LTNCP1	16,455	11,869	4,197		374	15
Secondary NCP	SNCP1	16,455	11,869	4,197	-	374	15
4 NCP							
Classification NCP from Load Data Provider	DNCP4	93,456	39,899	16,255	35,747	1,495	60
Primary NCP	PNCP4	93,456	39,899	16,255	35,747	1,495	60
Line Transformer NCP	LTNCP4	57,709	39,899	16,255		1,495	60
Secondary NCP	SNCP4	57,709	39,899	16,255	-	1,495	60
12 NCP							
Classification NCP from Load Data Provider	DNCP12	238,104	87,559	43,390	102,497	4,484	174
Primary NCP	PNCP12	238,104	87,559	43,390	102,497	4,484	174
Line Transformer NCP	LTNCP12	135,607	87,559	43,390		4,484	174
Secondary NCP	SNCP12	135,607	87,559	43,390	-	4,484	174

2013 Cost Allocation Model

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$2,533,602	$1,687,784	$481,829	$235,069	$124,569	$4,352
mi	Miscellaneous Revenue (mi)	$240,798	$142,976	$44,971	$34,400	$18,090	$360
			Miscellaneous Revenue Input equals Output				
	Total Revenue at Existing Rates	**$2,774,400**	**$1,830,760**	**$526,800**	**$269,469**	**$142,659**	**$4,712**
	Factor required to recover deficiency (1 + D)	1.1795					
	Distribution Revenue at Status Quo Rates	$2,988,426	$1,990,769	$568,325	$277,268	$146,931	$5,133
	Miscellaneous Revenue (mi)	$240,798	$142,976	$44,971	$34,400	$18,090	$360
	Total Revenue at Status Quo Rates	**$3,229,224**	**$2,133,746**	**$613,296**	**$311,668**	**$165,021**	**$5,493**
	Expenses						
di	Distribution Costs (di)	$835,277	$506,770	$126,298	$96,637	$104,202	$1,370
cu	Customer Related Costs (cu)	$877,868	$628,042	$174,242	$50,908	$22,605	$2,071
ad	General and Administration (ad)	$771,226	$507,660	$134,908	$69,427	$57,710	$1,521
dep	Depreciation and Amortization (dep)	$285,259	$169,231	$51,702	$47,330	$16,750	$246
INPUT	PILs (INPUT)	$26,245	$15,217	$4,341	$4,289	$2,364	$34
INT	Interest	$164,801	$95,553	$27,258	$26,933	$14,844	$213
	Total Expenses	**$2,960,676**	**$1,922,473**	**$518,749**	**$295,524**	**$218,475**	**$5,455**
	Direct Allocation	$0	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$268,548	$155,707	$44,418	$43,888	$24,188	$347
	Revenue Requirement (includes NI)	$3,229,224	$2,078,180	$563,166	$339,411	$242,663	$5,802
		Revenue Requirement Input equals Output					
			64.36%	17.44%	10.51%	7.51%	0.18%
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$4,818,760	$2,794,177	$799,576	$790,532	$428,318	$6,158
gp	General Plant - Gross	$1,436,164	$832,704	$237,541	$234,707	$129,355	$1,857
accum dep	Accumulated Depreciation	($633,777)	($367,678)	($107,380)	($106,596)	($51,377)	($746)
co	Capital Contribution	$0	$0	$0	$0	$0	$0
	Total Net Plant	**$5,621,147**	**$3,259,203**	**$929,738**	**$918,642**	**$506,296**	**$7,269**
	Directly Allocated Net Fixed Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$12,342,221	$4,361,011	$2,041,918	$5,757,663	$168,292	$13,337
	OM&A Expenses	$2,484,371	$1,642,472	$435,448	$216,972	$184,517	$4,962
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	***$14,826,592***	***$6,003,483***	***$2,477,366***	***$5,974,635***	***$352,809***	***$18,299***
	Working Capital	$1,927,457	**$780,453**	**$322,058**	**$776,703**	**$45,865**	**$2,379**
	Total Rate Base	**$7,548,604**	**$4,039,656**	**$1,251,795**	**$1,695,344**	**$552,161**	**$9,648**
		Rate Base Input Does Not Equal Output					
	Equity Component of Rate Base	$3,774,302	**$2,019,828**	**$625,898**	**$847,672**	**$276,080**	**$4,824**
	Net Income on Allocated Assets	$268,548	**$211,272**	**$94,548**	**$16,144**	**($53,455)**	**$39**
	Net Income on Direct Allocation Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$268,548**	**$211,272**	**$94,548**	**$16,144**	**($53,455)**	**$39**

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 General Service less than 50 kW	3 General Service 50 to 4,999 kW	7 Street Lighting	9 Unmetered Scattered Load
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**102.67%**	**108.90%**	**91.83%**	**68.00%**	**94.68%**
	EXISTING REVENUE MINUS ALLOCATED COSTS	**($454,823)**	($247,420)	($36,366)	($69,942)	($100,005)	($1,090)
		Deficiency Input equals Output					
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	**($0)**	$55,565	$50,130	($27,743)	($77,643)	($309)
	RETURN ON EQUITY COMPONENT OF RATE BASE	7.12%	10.46%	15.11%	1.90%	-19.36%	0.80%

2013 Cost Allocation Model

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

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	9
Summary	**Residential**	**General Service less than 50 kW**	**General Service 50 to 4,999 kW**	**Street Lighting**	**Unmetered Scattered Load**
Customer Unit Cost per month - Avoided Cost	$9.51	$16.73	$60.63	$1.16	$7.94
Customer Unit Cost per month - Directly Related	$13.55	$24.06	$88.12	$1.71	$11.51
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$25.47	$39.34	$120.91	$12.98	$23.70
Existing Approved Fixed Charge	$17.83	$23.90	$181.61	$5.27	$12.23

Revenue-to-Cost Ratios

PREVIOUS REVENUE TO COST RATIOS

NOW Inc.'s Revenue-to-Cost ratios from the 2009 EDR Approved results (EB-2008-0238) were considered final in that decision. Table 1 shows the last Board approved Revenue-to-Cost ratios.

Table 1: R/C Ratios for 2009 Approved Final

Rate Class	2009 EDR Approved	OEB Range
Residential	1.0276	0.85 - 1.15
GS< 50	1.0276	0.80 - 1.20
GS> 50	1.0276	0.80 - 1.20
Street Light	0.7000	0.70 - 1.20
USL	1.0276	0.80 - 1.20

No Revenue to Cost Ratio adjustments were required during the 2010 to 2012 IRM period for NOW Inc.

PROPOSED REVENUE TO COST RATIOS

For 2013, NOW Inc. is proposing the following revenue to cost ratios in table 2 below.

Table 2: 2013 Revenue to Cost Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2009	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	102.76	102.67	102.67	85 - 115
GS < 50 kW	102.76	108.90	108.04	80 - 120
GS > 50 kW	102.76	91.83	91.83	80 - 120
Street Lighting	70.00	68.00	70.00	70 - 120
Unmetered Scattered Load (USL)	102.76	94.68	94.68	80 - 120

Low Voltage Charges

NOW Inc. is an embedded distributor with Hydro One Networks Inc. ("HONI") and therefore pays and charges a Low Voltage Service Rate.

NOW Inc. has experienced an increase in Low Voltage charges over the last three years where Hydro One's LV rates have escalated from $1.66/kW in 2009 to $3.60/kW in 2011.

	2009	2010	2011
January	$ 18,538	$ 7,891	$ 12,077
February	$ 7,997	$ 7,423	$ 12,903
March	$ 7,006	$ 6,857	$ 11,687
April	$ 6,736	$ 6,156	$ 10,382
May	$ 5,935	$ 6,413	$ 10,554
June	$ 5,326	$ 10,839	$ 12,791
July	$ 6,837	$ 10,101	$ 13,224
August	$ 5,658	$ 9,324	$ 14,056
September	$ 6,377	$ 10,834	$ 12,860
October	$ 5,881	$ 8,519	$ 12,741
November	$ 6,405	$ 9,508	$ 13,271
December	$ 6,994	$ 10,989	$ 15,923
	$ 89,690	$ 104,852	$ 152,469

Therefore NOW Inc. has forecasted annual Low Voltage payments to HONI of $162,000 for 2013 and has used estimated RTSR connection revenues to allocate the charges to the various rate classes.

NOW Inc. is proposing the new low voltage charges as calculated in E8/T3/S5/Att1 shown in Table1 below.

Table 1: Current and Proposed Low Voltage Rates

	2012 Low Voltage Rates		**2013 Low Voltage Rates**	
Customer Class Name	Rate	per	Rate	per
Residential	$0.0011	kWh	$0.0013	kWh
General Service < 50 kW	$0.0006	kWh	$0.0012	kWh
General Service > 50 to 4999 kW	$0.3342	kW	$0.4554	kW
Unmetered Scattered Load	$0.0006	kWh	$0.0012	kWh
Street Lighting	$0.2454	kW	$0.3520	kW

Loss Adjustment Factors

NOW Inc. applies a loss adjustment factor to customers' metered consumption for billing purposes in order to bill for consumption that reflects the amount of electricity NOW Inc. has to purchase in order to meet customers' requirements when taking into account the distribution losses.

NOW Inc. is partially embedded in Hydro One's system, and approximately 19.3% of the delivered load to our system is from Hydro One.

The total loss factor ("TLF") is calculated by multiplying the Distribution System Loss Factor ("DLF") by the Supply Facilities Loss Factor ("SFLF").

SFLF

NOW Inc. has calculated a specific SFLF by weighting the losses attributed by Hydro One and the losses attributed by the IESO. The majority of the electricity is supplied through the IESO controlled grid, and we have utilized the standard SFLF of 1.0045 for this load. Hydro One applies a loss factor of 1.034 to the load supplied by them; therefore NOW Inc. has calculated the following SFLF to be used in calculating the TLF.

Table 1 – Calculation of SFLF

	SFLF	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	Average
IESO		115,646,246	105,897,970	105,470,644	105,402,416	96,684,590	105,820,373
HONI		25,037,645	25,126,780	25,512,666	25,476,018	25,627,863	25,356,194
Wholesale kWh delivered to distributor		140,683,891	131,024,749	130,983,310	130,878,434	122,312,453	131,176,567
IESO		82.2%	80.8%	80.5%	80.5%	79.0%	80.7%
HONI		17.8%	19.2%	19.5%	19.5%	21.0%	19.3%
Wholesale kWh delivered to distributor		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
IESO	1.0045	0.8257	0.8119	0.8088	0.8090	0.7940	0.8103
HONI	1.0340	0.1840	0.1983	0.2014	0.2013	0.2167	0.1999
Weighted SFLF		1.0098	1.0102	1.0102	1.0102	1.0107	1.0102

DLF

The distribution loss factor is calculated by taking the total energy purchased over a year and dividing it by the total energy that was billed to customers during the same year.

Table 2 – Calculation of DLF

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual
"Wholesale" kWh delivered to distributor (higher value)	140,683,891	131,024,749	130,983,310	130,878,434	122,312,453
"Wholesale" kWh delivered to distributor (lower value)	140,683,891	131,024,749	130,983,310	130,878,434	122,312,453
Portion of "Wholesale" kWh delivered to distributor for Large User Customer(s)					
Net "Wholesale" kWh delivered to distributor (A2)-(B)	**140,683,891**	**131,024,749**	**130,983,310**	**130,878,434**	**122,312,453**
"Retail" kWh delivered by distributor	134,694,227	120,863,495	123,574,673	123,364,740	115,981,280
Portion of "Retail' kWh delivered by distributor for Large Use Customer(s)					
Net "Retail" kWh delivered by distributor (D)-(E)	**134,694,227**	**120,863,495**	**123,574,673**	**123,364,740**	**115,981,280**
Loss Factor in distributor's system [C/F]	1.0445	1.0841	1.0600	1.0609	1.0546

Distribution losses since 2007 have been greater than 5% in each subsequent year. This increase has been attributed to a change in wholesale meters in the Iroquois Falls distribution area. This area is embedded in with Hydro One Networks Inc. and has a higher loss factor applied. The five year average Total Loss Factor is proposed to be 1.0716. The details supporting this figure are found in the E8/T3/S6/Att2 to this schedule.

TLF

The TLF is derived by multiplying the DLF by the SLF. Table 3 details the total loss factors proposed for the primary and secondary metered customers.

Table 3 – Current and Proposed Loss Factors

	Current	Proposed
Supply Facilities Loss Factor	1.0060	1.0102
Distribution Loss Factor - Secondary Metered Customer < 5,000 kW	1.0386	1.0608
Distribution Loss Factor - Primary Metered Customer < 5,000 kW	1.0282	1.0502
Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0448	1.0716
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0344	1.0609

NOW Inc. notes that its proposed distribution loss factor is greater than 5%. As required by the filing guidelines NOW hereby details actions currently planned, and actions taken to reduce losses in previous five years and results.

With respect to operation and maintenance activities aimed at reducing line losses, NOW has recently ordered a thermal imaging camera which we will start utilising in our regular monthly line patrol therefore any “ hot spots” can be immediately identified then prioritized and repaired as soon as possible which will reduce line loses from hot connection points. Historically NOW addressed line losses via visual line patrols and evaluation of line losses with metering information.

NOW Inc. has identified the reduction of line losses to be a key component of its asset management plan (see E2/T4/S5/Att1.1). Excerpts from the plan as submitted with the NOW Cost of Service Application are reproduced below. Please refer to the NOW Asset Management Plan, in particular the System Optimization Pilot Study included as Appendix B to the Asset Management Plan, for more detail.

2.2 Asset Strategy

The guiding principles for NOW Inc.'s asset strategy are:

- *Maintain awareness of safety around electricity for employees, customers and the general public.*
- *Convert all existing 2.4 kV lines to 12.4 kV and 25 kV in order to improve reliability and reduce electrical losses.*
- *Upgrade distribution system with the intent of reducing electrical losses, thus resulting in the elimination of two (2) substations (MSB and Millgate).*
- *Improve customer reliability through effective maintenance plans and planned replacement of assets at the end of their life cycle.*
- *Maintain quality by updating the CGIS system as required.*

7.2 Asset Condition Assessment

Prior to the implementation of the CGIS system in 2010, assets were kept in paper or spreadsheet form, wherein detail, attributes and their condition were poorly documented or unknown. With the evolution of the GIS and various database projects, data collection and retention has improved dramatically.

In 2006, NOW Inc. participated in a System Optimization Pilot Study (Appendix B), which identified system loss and capacity improvement opportunities. The resulting recommendations of this study were integrated into future capital projects, most of which are outlined in this AMP.

Yearly gas and oil analysis and monthly visual checks of our distribution station transformers are in fairly good condition.

LRAMVA Process

NOW Inc. participates in the OPA's CD&M programs. In NOW Inc.'s 2012 Rate Application (EB-2011-0188) the LRAM claim approved related to the fiscal year 2010. In that decision Board staff noted that NOW had last rebased in 2009, and that CDM savings for the 2009 rebasing year, as well as savings from 2006, 2007 and 2008 persisting from 2009 to 2012 had been included in the LRAM request. The Board did not approve LRAM relating to 2009 CDM programs in 2009 and persistence from 2006, 2007, 2008, 2009 CDM programs in 2009, 2010, 2011 or 2012, as these effects should have been reflected in the new 2009 load forecast.

For purposes of the 2011 disposition and claim NOW Inc. determines that it would be entitled to collect LRAM for the 2010 persistence and 2011 LRAMVA.

E9/T5/S1/Att1.1 shows the calculation of NOW Inc.'s 2011 LRAM/LRAMVA. NOW Inc.'s LRAM (2010 programs 2011 persistence) calculations are based on the final evaluation results for 2006 to 2010 OPA-Contracted Province-Wide CDM Programs ("OPA Programs"). NOW Inc.'s LRAMVA calculations that are based on the final evaluation results for 2011 OPA-Contracted Province-Wide CDM Programs ("OPA Programs").

The LRAMVA calculations are determined by calculating the energy or demand savings by customer class and valuing those energy or demand savings using the distributor's Board-approved variable distribution charge appropriate to the class. The calculation includes applicable carrying charges.

The following table shows that for 2011 NOW Inc. LRAM/LRAMVA amount totals $11,668.

2010 LRAM and 2011 LRAMVA

Rate Class	Savings	Amount	Interest *	Total
Residential	**0.1 GWh**	$ 1,677	$ 46	$ 1,723
General Service Less Than 50 kW	**0.7 GWh**	$ 9,664	$ 266	$ 9,930
General Service Greater Than 50 kW	**0.0 MW**	$ 14	$ 0	$ 14
Total		**$ 11,355**	**$ 313**	**$ 11,668**

* Carrying Costs to April 30, 2013

The following table shows that for 2011 NOW Inc. LRAM/LRAMVA Rate Rider calculation.

2010 LRAM and 2011 LRAMVA Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2014

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 1,723	41,735,131	kWh	$ 0.00004
General Service Less Than 50 kW	$ 9,930	19,541,272	kWh	$ 0.00051
General Service Greater Than 50 kW	$ 14	177,931	kW	$ 0.00008
Total	**$ 11,668**			

As stated in Section 13.4 of the Board's Guidelines for Electricity Distributor Conservation and Demand Management, April 26, 2012 (EB-2012-0003) and section 2.7.10 – CDM Costs, LRAMVA, Pages 36-37 of the Filing Requirements, at a minimum, distributors must apply for the disposition of the balance in the LRAMVA as part of their COS applications. As indicated above NOW Inc. calculated annual rate riders are immaterial. NOW Inc. therefore is not requesting disposition of Account 1568 in this application, but will consider it for future applications or would consider alternative Board direction.

The OPA's 2011 Final Annual Report Data is provided at E9/T5/S1/Att1.2

2010 LRAM and 2011 LRAMVA Rate Rider Calculation

Effective: May 1, 2013 to April 30, 2014

Rate Class	Total	Billing Determinant		Rate Rider
Residential	$ 1,723	41,735,131	kWh	$ 0.00004
General Service Less Than 50 kW	$ 9,930	19,541,272	kWh	$ 0.00051
General Service Greater Than 50 kW	$ 14	177,931	kW	$ 0.00008
Total	**$ 11,668**			

Output Table Three
2010 LRAM and 2011 LRAMVA

Rate Class	Savings	Amount	Interest *	Total
Residential	**0.1 GWh**	$ 1,677	$ 46	$ 1,723
General Service Less Than 50 kW	**0.7 GWh**	$ 9,664	$ 266	$ 9,930
General Service Greater Than 50 kW	**0.0 MW**	$ 14	$ 0	$ 14
Total		**$ 11,355**	**$ 313**	**$ 11,668**

* Carrying Costs to April 30, 2013

Output Table Two
Calculated Carrying Costs to April 30, 2013

Month	OEB Prescribed Annual Rate	Days in Month	Monthly Interest Rate	LRAM LRAMVA Residential	LRAM LRAMVA GS LT 50	LRAM LRAMVA GS GT 50	Allocated Carrying Costs Residential	Allocated Carrying Costs GS LT 50	Allocated Carrying Costs GS GT 50
Jan-2011	1.47%	31	0.12%	$ 140	$ 805	$ 1	$ 0.17	$ 1.01	$ 0.00
Feb-2011	1.47%	28	0.11%	$ 280	$ 1,611	$ 2	$ 0.32	$ 1.82	$ 0.00
Mar-2011	1.47%	31	0.12%	$ 419	$ 2,416	$ 3	$ 0.52	$ 3.02	$ 0.00
Apr-2011	1.47%	30	0.12%	$ 559	$ 3,221	$ 5	$ 0.68	$ 3.89	$ 0.01
May-2011	1.47%	31	0.12%	$ 699	$ 4,027	$ 6	$ 0.87	$ 5.03	$ 0.01
Jun-2011	1.47%	30	0.12%	$ 839	$ 4,832	$ 7	$ 1.01	$ 5.84	$ 0.01
Jul-2011	1.47%	31	0.12%	$ 978	$ 5,637	$ 8	$ 1.22	$ 7.04	$ 0.01
Aug-2011	1.47%	31	0.12%	$ 1,118	$ 6,443	$ 9	$ 1.40	$ 8.04	$ 0.01
Sep-2011	1.47%	30	0.12%	$ 1,258	$ 7,248	$ 10	$ 1.52	$ 8.76	$ 0.01
Oct-2011	1.47%	31	0.12%	$ 1,398	$ 8,053	$ 12	$ 1.74	$ 10.05	$ 0.01
Nov-2011	1.47%	30	0.12%	$ 1,537	$ 8,859	$ 13	$ 1.86	$ 10.70	$ 0.02
Dec-2011	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.07	$ 0.02
Jan-2012	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.03	$ 0.02
Feb-2012	1.47%	29	0.12%	$ 1,677	$ 9,664	$ 14	$ 1.95	$ 11.26	$ 0.02
Mar-2012	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.03	$ 0.02
Apr-2012	1.47%	30	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.02	$ 11.64	$ 0.02
May-2012	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.03	$ 0.02
Jun-2012	1.47%	30	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.02	$ 11.64	$ 0.02
Jul-2012	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.03	$ 0.02
Aug-2012	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.03	$ 0.02
Sep-2012	1.47%	30	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.02	$ 11.64	$ 0.02
Oct-2012	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.03	$ 0.02
Nov-2012	1.47%	30	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.02	$ 11.64	$ 0.02
Dec-2012	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.03	$ 0.02
Jan-2013	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.07	$ 0.02
Feb-2013	1.47%	28	0.11%	$ 1,677	$ 9,664	$ 14	$ 1.89	$ 10.90	$ 0.02
Mar-2013	1.47%	31	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.09	$ 12.07	$ 0.02
Apr-2013	1.47%	30	0.12%	$ 1,677	$ 9,664	$ 14	$ 2.03	$ 11.68	$ 0.02
							$ 46.17	$ 266.02	$ 0.38

NOWI 2010 LRAM and 2011 LRAMVA

2010								
2011 Persistence		kWh	2011 Rate	Amount	Total	RES	GSLT 50	GSGT50
	RES	42,522	0.0135	$ 574		$ 574		
	GSLT 50	321,545	0.0134	$ 4,309			$ 4,309	
				$ 4,883				
		kW	2011 Rate	Amount				
	GSGT50	3	3.5306	$ 11.11				$ 11
					$ 4,894			
2011 Preliminary								
2011 Programs		kWh	2011 Rate	Amount				
	RES	81,712	0.0135	$ 1,103		$ 1,103		
	GSLT 50	399,653	0.0134	$ 5,355			$ 5,355	
				$ 6,458				
		kW	2011 Rate	Amount				
	GSGT50	1	3.5306	$ 2.81				$ 3
					$ 6,461			
				2011 LRAM/LRAMVA	**$ 11,355**	**$ 1,677**	**$ 9,664**	**$ 14**

Residential 2010 Programs
2011 Persistence (kWh)

Amount	2011
2010	
Cool Savings Rebate	413
Every Kilowatt Counts Power Savings Event	17,257
Great Refrigerator Roundup	24,851
2010 Total	**42,522**
Grand Total	**42,522**

GSLT50 2010 Programs
2011 Persistence (kWh)

Amount	2011
2010	
High Performance New Construction	30,433
Power Savings Blitz	291,111
2010 Total	**321,545**
Grand Total	**321,545**

GSGT50 2006 to 2010 Programs
2011 Persistence (kW)

Amount	2011
2010	
Multi-Family Energy Efficiency Rebates	3
2010 Total	**3**
Grand Total	**3**

2011 Programs
(kWh)

	kWh
RES	
Appliance Exchange	824
Appliance Retirement	28,618
Bi-Annual Retailer Event	31,192
Conservation Instant Coupon Booklet	20,258
HVAC Incentives	819
RES Total	**81,712**
GSLT50	
Direct Install Lighting	121,356
Efficiency: Equipment Replacement	278,297
GSLT50 Total	**399,653**
Grand Total	**481,365**

2011 Programs
(kW)

	kW	Months	Extended kW
GSGT50			
High Performance New Construction	0	12	1
GSGT50 Total	**0**	**12**	**1**
Grand Total	**0**	**12**	**1**