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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

January 19, 2009

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2008-0232 – Hydro One Remote Communities 2009 Distribution Rate Application – Responses to Interrogatory Question

I have attached three (3) copies of Hydro One Networks' responses to Interrogatory questions.

An electronic copy of the complete application, including the attached updates, has been filed using the Board's Regulatory Electronic Submission System (RESS) and the proof of successful submission slip is attached.

Hydro One Networks will post electronic copies of the update on the Hydro One Networks' website for public access. In addition, one copy is being provided for public access at each of the following Hydro One Remote Communities Office –

Hydro One Remote Communities Office, 8th Floor, South Tower, 483 Bay Street, Toronto, Ontario

Hydro One Remote Communities Office, 680 Beaverhall Place, Thunder Bay, Ontario

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

c. EB-2008-0232 Intervenors

Ontario Energy Board (Board Staff) INTERROGATORY #1 List 1

Interrogatory

RATE BASE / CAPITAL EXPENDITURES

1. Ref: Ex D2 / Tab 3 / Sch 1

Please explain the variance between column (b) titled "Additions" in Exhibit D2/Tab3/Sch 1 and column (b) titled "Capital Expenditures" in Exhibit D2/Tab3/Sch 3.

Response

In Exhibit D2, Tab3, Schedule 1, "Additions" (column b) refers to assets that have been placed into service during the year. In any particular year, capital additions consist of those programs and projects begun and finished in that year, as well as those started in previous years, accumulated as Work in Progress over the years, and completed in the year under consideration resulting in the multi-year accumulated costs being placed in-service, capitalized and added to Rate Base.

In Exhibit D2, Tab3, Schedule 3, "Capital Expenditures" (column b) refers to dollars spent on capital projects during the year. Some of these programs and projects will be completed in the same year as the expenditure while others will be completed in future years.

Please note that the "Additions" (column b) in Exhibit D2, Tab3, Schedule 1 are equal to "Transfers to Plant" (column c) in Exhibit D2, Tab3, Schedule 3.

Ontario Energy Board (Board Staff) INTERROGATORY #2 List 1

Interrogatory

RATE BASE / CAPITAL EXPENDITURES

2. Ref: Ex D2 / Tab 2 / Sch 3

In Exhibit D2/Tab2/Sch 3/G1, Remotes indicates that it will be overhauling or replacing components on 60 diesel engines. Please answer the following questions with respect to this initiative:

a. How many engines will be overhauled in 2009?

b. What is the total cost of overhauling or replacing engines in 2009?

c. How many engines will be replaced with new units? Please provide details.

Response

(a) The business plan includes the overhaul of 4 diesel engines in 2009.

(b) The total cost of overhauling and replacing the diesel engines is estimated to be $1.4 million.

(c) Five new engines, noted as replacements in the table below, will be installed. Further details on both planned engine replacements and overhauls are presented in this table.

Overhaul / Replacement Work

Unit	Rating (kW)	Model	Month	Hours	Cost Estimate (000s)	Notes
Biscotasing A	100	Cat 3304B	January	20k	$ 70	Overhaul
Fort Severn A	600	Cat 3512	April	42k	$ 200	Overhaul
Kasabonika C	600	Cat 3412	March	82k	$ 215	Replacement, radiator, installation.
Kingfisher C	250	Detroit	March	20k	$ 85	Overhaul
Lansdowne A	250	Cat 3406B	June	60k	$ 40	Replace with new unit (acquired 2008). Installation cost only.
Weagamow A	600	Cat 3512	May	65k	$ 233	Replacement
Fort Severn B	455	Cat 3412	Fall	48k	$ 185	Replacement, radiator, installation.
Kingfisher A	455	Cat 3412	Summer	70k	$ 210	Replacement, radiator, installation.
Wapekeka A	820	Cat 3508B	Fall	20k	$ 180	Overhaul
					$ 1,418	

Ontario Energy Board (Board Staff) INTERROGATORY #3 List 1

Interrogatory

RATE BASE / CAPITAL EXPENDITURES

3. Ref: Ex D2 / Tab 2 / Sch 3 / Pg 5

Remotes indicates that it plans to test catalytic reactor technology at its Armstrong station at a cost of $358,368. Please answer the following questions with respect to this initiative:

a. Has the company conducted any cost/benefit analysis with respect to this initiative? If "Yes", please provide details.

b. Does Remotes plan to extend this initiative to other gensets? If "Yes", please provide details and cost estimates.

c. Should Remotes decide to expand this initiative and use the catalytic reactor technology on all or majority of its gensets, what will be the additional cost to implement this initiative?

d. Remotes has indicated the possibility of adopting a zero emissions strategy. Has Remotes forecast the cost of such a strategy? If so, what would be the additional cost to the utility?

Response

a. No. This is a pilot project aimed at providing quantitative and qualitative information that will help determine the possible cost/benefit of this approach. Diesel engine manufacturers are incorporating catalytic reactor technology that will be standard in 2014 with the implementation of Tier 3 requirements by the US Environmental Protection Agency (EPA). There is uncertainty on how the new technology will be adapted to a diesel generating station. This pilot project is planned to accomplish 3 things:
   - to determine the impact and cost/benefit of this technology on our operations
   - measure the reduction in emissions and mitigate risks associated with regulation
   - determine how to implement the future changes in engines to our plants

b. That has not yet been determined, and will depend in part on the results of the initial pilot project.

c. Detailed cost information is not yet available. The pilot project will provide useful information on costs/benefits that will aid in determining if there is a business case for broader application of this technology.

d. That has not yet been determined. The "zero emissions" strategy referenced in the evidence is specifically tied to the Armstrong single-unit catalytic reactor pilot project. It is not planned or expected that Remotes would be able to achieve zero emissions across its entire fleet, and Remotes is not proposing that a zero-emissions strategy be adopted in all locations. Remotes has an active emissions reduction program which lays out several initiatives aimed at minimizing the emissions associated with our operation. An emission reduction action plan is submitted to the CSA Climate Change Registry on an annual basis. The Armstrong pilot project is one component of that plan.

Ontario Energy Board (Board Staff) INTERROGATORY #4 List 1

Interrogatory

RATE BASE / CAPITAL EXPENDITURES

4. Ref: Ex D2 / Tab 4 / Sch 1

Please provide a table similar to the one in Exhibit D2/Tab4/Sch 1 for the years 2006 to 2009.

Response

Please see the table below. The 2009 column is the pre-filed version as the change in working capital using updated 2009 expenses is not material.

HYDRO ONE REMOTE COMMUNITIES INC.

Statement of Working Capital
2006 - 2009
(000's)

Line No.	Particulars	2006	2007	2008	2009
	OM&A Expenses				
1	Generation	$ 26,421	$ 27,386	$ 31,699	$ 32,291
2	Distribution	1,540	1,241	1,757	1,666
3	Billing and Collecting	4,394	1,874	1,637	1,805
4	Community Relations	214	413	577	599
5	Administrative & General	1,026	877	983	981
6	External Costs	64	49	83	90
7	Total Eligible OM&A	$ 33,660	$ 31,840	$ 36,736	$ 37,432
8	Working Capital Factor	15%	15%	15%	15%
9	Working Capital Allowance	$ 5,049	$ 4,776	$ 5,510	$ 5,615

Ontario Energy Board (Board Staff) INTERROGATORY #5 List 1

Interrogatory

RATE BASE / CAPITAL EXPENDITURES

5. Ref: Ex D1 / Tab 2 / Sch 1

Remotes has updated Table 1 showing annual capital investments. Total capital expenditures for 2008 have reduced from $4.1 million to $3.1 million, a drop of approximately 25%. Proposed expenditures for 2009 have dropped from $5.4 million to $5.1 million or by 5% from that previously forecast. Please answer the following questions with respect to the revision:

a. Please provide a list of completed, pending and cancelled projects in 2008 including costs.

b. Capital expenditures for 2008 have declined significantly as a result of the update as compared to 2009 expenditures. Please provide reasons for the significant drop in 2008.

c. Will remotes be able to complete all planned expenditures for 2009? If no, please provide a list of projects that may not be completed.

d. Considering that some of the 2008 projects will flow to the 2009 Test Year, does Remotes still plan to complete all the 2009 scheduled projects on schedule?

Response

a. Generation Capital

2008 ($000s)	Update (November 28, 2008)	Status
Replacement of Diesel Engines	775	Completed
Emergency System Breakdowns	534	Completed
Sandy Lake Upgrade	430	Completed
Replacement of Auxiliary Equipment	130	Completed
Protection Upgrade	120	Pending
Lansdowne House Tank Farm Improvements Ph 2	0	Pending
Gull Bay Upgrade Project	0	Pending

Road Site Replacements (Oba) Ph 1	27	Pending
SCADA & PLC Upgrades	15	Pending
TOTAL	**$2,031**	

Distribution Capital

2008 ($000s)	**Update (November 28, 2008)**	**Status**
Deer Lake Joint Use	25	Partially Completed
Sandy Lake Line Improvements	35	Pending
Fort Severn Line Improvements	65	Pending
Distribution System Improvements	0	Partially Completed
Metering & Minor Storm Damage*	95	Completed
Damage Claims & Small External Demand Requests*	32	Completed
TOTAL	**$252**	

* Consists of a number of small projects in various communities

Facilities

Facilities capital projects are illustrated in the table below:

2008 ($000s)	**Update (November 28, 2008)**	**Status**
Weagamow Staff House	379	Completed
Truck garages, Line Shed Refurbishments, Hillsport Facilities Trailer	300	Partially Completed
TOTAL	**$679**	

b. The Tables below illustrate the change in 2008 capital project spend between the prefiled evidence filed on August 29, 2008 and that filed on November 28, 2008. Minor fixed assets did not change between the 2 filings.

Generation Projects - 2008

($000s)	Update (November 28, 2008)	Prefiled (August 29, 2008)	Variance	Explanation
Replacement of Diesel Engines	775	775	0	
Emergency System Breakdowns	534	534	0	
Sandy Lake Upgrade	430	430	0	
Replacement of Auxiliary Equipment	130	130	0	
Protection Upgrade	120	270	(150)	Project delayed due to engineering resource limitations
Lansdowne House Tank Farm Improvements Phase 2	0	295	(295)	Project deferred to complete work at Sandy Lake
Gull Bay Upgrade Project	0	151	($151)	Project delay(s) due to equipment/material unavailability resulted in Remotes work being re-scheduled.
Road Site Replacements (Oba) Ph 1	27	27	0	
SCADA & PLC Upgrades	15	111	(96)	Project deferred due to engineering resource limitations
TOTAL	**$2,031**	**$2,723**	**($692)**	

Distribution Projects – 2008

Demand work associated with the new customer connections at Sandy Lake has resulted in delays in the distribution system improvements and work associated with Joint Use, due to resource limitation. At the demand work in Sandy Lake is recoverable the delay in the distribution system improvements has resulted in reduced capital spending for Remotes in 2008.

($000s)	Update (November 28, 2008)	Prefiled (August 29, 2008)	Variance	Explanation

Deer Lake Joint Use	25	25	0	
Sandy Lake Line Improvements	35	35		
Fort Severn Line Improvements	65	65		
Distribution System Improvements	0	193	(193)	Small projects in various communities not complete due to delay in Asset Condition Assessments
Metering & Minor Storm Damage	95	95		
Damage Claims & Small External Demand Requests	32	32		
TOTAL	**$252**	**$445**	**($193)**	

Facilities Projects - 2008

$000s	**Update (November 28, 2008)**	**Prefiled (August 29, 2008)**	**Variance**	**Explanation**
Weagamow Staff House	378	378	0	
Truck garages, Line Shed Refurbishments, Hillsport facilities trailer	300	432	(132)	Resources required to complete facilities maintenance work
TOTAL	**$679**	**$811**	**($132)**	

c. Yes, Remotes expects to complete all planned expenditures in 2009. The resource limitations experienced in 2008 that resulted in project delays have been addressed by the addition of 3 fulltime engineering positions in the 2009 business plan, of which 2 have already been filled.

d. The updated evidence regarding 2008 and 2009 capital budget and programs reflects Remotes latest information regarding project schedules. Remotes plans to spend all of the 2009 requested capital in the projects identified, however the composition of expenditures may alter with business needs.

Ontario Energy Board (Board Staff) INTERROGATORY #6 List 1

Interrogatory

RATE BASE / CAPITAL EXPENDITURES

6. Ref: Ex C1 / Tab 4 / Sch 1

Table 1 in Exhibit C / Tab 4/ Schedule 1 shows the depreciation expense from 2005 to 2009. Although Remotes has updated capital expenditures for 2008 and 2009 with significant reductions, depreciation and other related expenses have not changed as a result of the update. Please provide an updated schedule with the appropriate revisions.

Response

In updating the pre-filed evidence, Remotes has used the Board's materiality threshold of 1% of Net Fixed Assets ($230K for 2007) to determine areas of the evidence to update. Thus, depreciation expense and accumulated depreciation were not updated as they did not meet this materiality threshold.

The revised forecast for capital expenditures for 2008 and 2009 has minimal impact on depreciation expense as the majority of depreciation is related to existing assets. Depreciation expense on new assets is negligible in comparison.

Below is an updated Table 1 which includes the immaterial depreciation adjustments resulting from the updated evidence regarding changes for assets to be placed into service during 2008 and 2009. Any difference in depreciation expense will be captured in the RRRP variance account.

Table 1
Depreciation Expense
$ Thousand

	Historic			Bridge		Test	
Description	**2005**	**2006**	**2007**	**2008 (filed)**	**2008 (IR Response)**	**2009 (filed)**	**2009 (IR response)**
Depreciation on Fixed Assets	2,343	2,550	2,486	2,554	2,549	2,762	2,743
Asset Removal Costs	122	186	204	106	106	207	207
Losses/Gains	-	-	-	(6)	(6)	-	-
Total	**2,465**	**2,736**	**2,690**	**2,654**	**2,649**	**2,969**	**2,950**

Ontario Energy Board (Board Staff) INTERROGATORY #7 List 1

Interrogatory

INCOME TAX

7. Ref: Ex C2 / Tab 6 / Sch 1 / Att A (Updated Nov 28, 2008)

The Company has recalculated the Regulatory Net Income to $223,000. Remotes does not have any equity and therefore cannot earn a return on equity based on the Board's methodology. Please provide details as to how Remotes has calculated the Regulatory Net Income.

Response

Regulatory Net Income of $223,000 arises due to differences between amounts recognized for regulatory purposes and those recognized for income tax purposes. The differences between income tax and regulatory reported items are for such things as capital cost allowance/depreciation and capitalized overheads, among others. See Exhibit C1, Tab 5, Schedule 1 for a description of the Book to Tax Adjustments and Exhibit C2, Tab 6, Schedule 1 for a list of adjustments for the 2009 Test Year. For Remotes, the total of the 2009 Book to Tax Adjustments give rise to an overall income tax payable. Revenue must be collected from ratepayers for this payable, leading to a net income requirement of $223,000. The specifics of the calculation of this net income requirement are outlined below.

The first step is to calculate the income tax provision. Although Remotes is 100% debt-financed with no return on equity (and hence there is no gross-up for income tax on equity return required), there are various Book to Tax Adjustments to Regulatory Income Before Tax that are made in determining taxable income (see above).

Using the total of the Book to Tax Adjustments from Exhibit C2, Tab 6, Schedule 1, the table below shows the derivation of the income tax payable associated with those adjustments. Line 3 in the table shows that an income tax provision of $223 thousand is required.

Calculation of Required Income Taxes
2009 Test Year
$000

Line No.		
1	Total Book to Tax Adjustments per C2-T6-S1	453
2	Gross-Up for Income Tax [Line 1 / (1-33%]	676
3	Income Tax Requirement [Line 2 * 33%]	223
4	= Income before Tax required for breakeven {Line 3]	223
	Income Tax Rates per C2-T6-S1:	
	Federal Tax	19%
	Provincial Tax	14%
	Total Federal and ON Tax rate	33%

The second step is to determine the regulatory income before tax required for a breakeven result. This amount is the same as the income tax payable. That is, $223 thousand in regulatory income before tax less $223 thousand in income tax equals zero net income. Line 4 in the table shows the Income before Tax.

Ontario Energy Board (Board Staff) INTERROGATORY #8 List 1

Interrogatory

INCOME TAX

8. Ref: Ex C2 / Tab 6 / Sch 1 / Att C

In Exhibit C2-6-1, Attachment C, the taxable loss (line 34) for 2007 is $1.1 million. However, the 2007 tax return indicates a taxable loss of $1.9 million (2007 Tax Return, Schedule CT23, page 14 of 20). Please explain the variance.

Response

Please see revised Exhibit C2, Tab 6, Schedule 2, Attachment A Federal and Ontario Income Tax Return which was filed to the CRA.

The net loss for income tax purposes per the 2007 Federal Tax Return Schedule 1 is $1,110,237. This is the same as the loss on line 600 Schedule CT23, page 14 of 20 and line 690 Schedule CT23, page 15 of 20.

The revised exhibit now reconciles with the loss of $1.1 million reflected on line 34 Exhibit C2, Tab 6, Schedule 1, Attachment C.

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec, Ontario, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax services office or tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the *T2 Corporation – Income Tax Guide* (T4012).

Identification

Business Number (BN) 001 87083 6269 RC0001

Corporation's name

002 Hydro One Remote Communities Inc.

Has the corporation changed its name since the last time you filed your T2 return? 003 1 Yes [ ] 2 No [X]

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** . . . . . 004 1 Yes [ ] 2 No [ ]

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . 010 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018)

011 483 Bay Street, 8th Floor

012 South Tower

City: 015 Toronto

Province, territory, or state: 016 ON

Country (other than Canada): 017

Postal code/Zip code: 018 M5G 2P5

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . 020 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028)

021 c/o

022

023

City: 025

Province, territory, or state: 026

Country (other than Canada): 027

Postal code/Zip code: 028

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? . . . . 030 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038)

031 483 Bay Street, 8th Floor

032 South Tower

City: 035 Toronto

Province, territory, or state: 036 ON

Country (other than Canada): 037

Postal code/Zip code: 038 M5G 2P5

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. 043 ____ YYYY MM DD

To which tax year does this return apply?

Tax year start: 060 2007-01-01 (YYYY MM DD)

Tax year-end: 061 2007-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . 063 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . 065 ____ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . 066 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . 067 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . 070 1 Yes [ ] 2 No [X]

Amalgamation? . . . . 071 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . 072 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . 076 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . 078 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and **complete and attach** Schedule 97.

081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . 082 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	092	093	094	095	096
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203		3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Was the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233		———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234		———
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177

Attachments – continued from page 2

		Yes	Schedule
Is the corporation subject to Part XIII.1 tax?	255		92 *
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265		55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

*** We do not print this schedule.**

Additional information

Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? (Only complete if **yes** was entered at line 281) 282 ______

If the major business activity involves the resale of goods, show whether it is wholesale or retail 283 1 Wholesale ☐ 2 Retail ☐

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Gen & distb electric	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.			300	-1,110,237 A
Deduct: Charitable donations from Schedule 2	311			
Gifts to Canada, a province, or a territory from Schedule 2	312			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction *	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Subtotal			►	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360	
Income exempt under paragraph 149(1)(t)			370	
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** ______ A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . **405** ______ B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000	x	Number of days in the tax year in 2005 and in 2006 / Number of days in the tax year	/ 365	=	1
400,000	x	Number of days in the tax year after 2006 / Number of days in the tax year	365 / 365	= 400,000	2

Add amounts at lines 1 and 2 400,000 4

Business limit (see notes 1 and 2 below) . . . . . **410** ______ C

Notes: 1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.

2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x **415** *** ______ D / 11,250 = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** ______ F

Small business deduction

Amount A, B, C, or F whichever is the least	______	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	16 %	= ______ 5
Amount A, B, C, or F whichever is the least	______	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	17 %	= ______ 6
Amount A, B, C, or F whichever is the least	______	x	Number of days in the tax year after December 31, 2008 / Number of days in the tax year	/ 365	x	17 %	= ______ 7

Total of amounts 5, 6, and 7 – enter on line 9 **430** ______ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] . . . . . **435** ______ H

Amount H	______	x	Number of days in the tax year in 2005 / Number of days in the tax year	/ 365	x	3 %	= ______ I
Amount H	______	x	Number of days in the tax year in 2006 / Number of days in the tax year	/ 365	x	5 %	= ______ J
Amount H	______	x	Number of days in the tax year in 2007 / Number of days in the tax year	365 / 365	x	7 %	= ______ K

Resource deduction – total of amounts I, J and K . . . . . **438** ______ L

Enter amount L on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360			A
Amount Z1 from Part 9 of Schedule 27		B	
Amount QQ from Part 13 of Schedule 27		C	
Taxable resource income from line 435		D	
Amount used to calculate the credit union deduction (from Schedule 17)		E	
Amount from line 400, 405, 410, or 425, whichever is the least		F	
Aggregate investment income from line 440		G	
Total of amounts B, C, D, E, F, and G		►	H
Amount A **minus** amount H (if negative, enter "0")			I

Amount I	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 %	=	J
Amount I	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	K
Amount I	x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	K1
Amount I	x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	K2

General tax reduction for Canadian-controlled private corporations – total of amounts J, K, K1, and K2 . . . L

Enter amount L on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)			M
Amount Z1 from Part 9 of Schedule 27		N	
Amount QQ from Part 13 of Schedule 27		O	
Taxable resource income from line 435		P	
Amount used to calculate the credit union deduction (from Schedule 17)		Q	
Total of amounts N, O, P, and Q		►	R
Amount M **minus** amount R (if negative, enter "0")			S

Amount S	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	365 / 365	x	7 %	=	T
Amount S	x	Number of days in the tax year after December 31, 2007 and before January 1, 2009 / Number of days in the tax year	/ 365	x	8.5 %	=	U
Amount S	x	Number of days in the tax year after December 31, 2008 and before January 1, 2010 / Number of days in the tax year	/ 365	x	9 %	=	U1
Amount S	x	Number of days in the tax year after December 31, 2009 and before January 1, 2011 / Number of days in the tax year	/ 365	x	10 %	=	U2

General tax reduction – total of amounts T, U, U1, and U2 . . . V

Enter amount V on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income (from Schedule 7) . . . . **440** ______ x 26 2 / 3 % = ... ______ A

Foreign non-business income tax credit from line 632 . . . . ______

Deduct:
Foreign investment income (from Schedule 7) . . . . **445** ______ x 9 1 / 3 % = ______
(if negative, enter "0") ______ ▶ ______ B

Amount A **minus** amount B (if negative, enter "0") . . . . ______ C

Taxable income from line 360 . . . . ______

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . . ______

Foreign non-business income tax credit from line 632 . . . . ______ x 25 / 9 = ______

Foreign business income tax credit from line 636 . . . . ______ x 3 = ______

______ ▶ ______

x 26 2 / 3 % = ______ D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) . . . . ______

Deduct: Corporate surtax from line 600 . . . . ______

Net amount . . . . ______ ▶ ______ E

Refundable portion of Part I tax – Amount C, D, or E, whichever is the least . . . . **450** ______ F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year . . . . **460** ______

Deduct: Dividend refund for the previous tax year . . . . **465** ______

______ ▶ ______ G

Add the total of:

Refundable portion of Part I tax from line 450 above . . . . ______

Total Part IV tax payable from Schedule 3 . . . . ______

Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation . . . . **480** ______

______ ▶ ______ H

Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H . . . . **485** ______

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3 . . . . ______ x 1 / 3 ______ I

Refundable dividend tax on hand at the end of the tax year from line 485 above . . . . ______ J

Dividend refund – Amount I or J, whichever is less (enter this amount on line 784) . . . . ______

Part I tax

Base amount of Part I tax – taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . **550** ______ A

Corporate surtax calculation

Base amount from line A above		1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)		2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360		a	
28.00 % of taxed capital gains		b	6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c	

Total of lines 2 to 6		7
Net amount (line 1 **minus** line 7)		8

Corporate surtax*

Line 8 ______ x $\frac{\text{Number of days in the tax year before January 1, 2008} \quad 365}{\text{Number of days in the tax year} \quad 365}$ x 4 % = **600** ______ B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . **602** ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360			
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount		▶	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . **604** ______ D

Subtotal (**add** lines A, B, C, and D) ______ E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608		
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
(taxed capital gains 624 ______)			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount L	638		
General tax reduction from amount V	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644		
Federal political contributions 646 ______			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		▶	F

Part I tax payable – Line E **minus** line F . . . . ______ G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Québec, Ontario, and Alberta)	760	
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765	
Total tax payable	770	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Canadian film or video production tax credit refund (Form T1131)	796	
Film or video production services tax credit refund (Form T1177)	797	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	
Total credits	890	B

Refund code 894 Overpayment

Balance (line A **minus** line B)

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.
Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid

Enclosed payment 898

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information

910 Branch number

914 Institution number

918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 1 Yes ☐ 2 No X

Certification

I, 950 ALICANDRI (Last name in block letters) 951 VINCENT (First name in block letters) 954 Vice President, Corporate Tax (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2008-12-09 Date (yyyy/mm/dd) — Signature of the authorized signing officer of the corporation — 956 (416) 345-6778 Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☐ 2 No X

958 BRIAN SOARES Name in block letters — 959 (416) 345-6782 Telephone number

Language of correspondence – Langue de correspondance

990 Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français.

1 English / Anglais X 2 Français / French ☐

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 141

NOTES CHECKLIST

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2007-12-31

- This schedule should be completed from the perspective of the person who prepared or reported on the **financial statements**. This person is referred to as the "accounting practitioner", in this schedule.
- For more information, see RC4088, *Guide to the General Index of Financial Information (GIFI) for Corporations* and T4012, *T2 Corporation – Income Tax Guide*.
- Attach a copy of this schedule, along with any Notes to the financial statements, to the GIFI.

Part 1 – Accounting practitioner information

Does the accounting practitioner have a professional designation? . . . . . **095** 1 Yes [X] 2 No [ ]

Is the accounting practitioner connected* with the corporation? . . . . . **097** 1 Yes [ ] 2 No [X]

* A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Note
If the accounting practitioner does not have a professional designation **or** is connected with the corporation, you do not have to complete Parts 2 and 3 of this schedule. However, you do have to complete Part 4.

Part 2 – Type of involvement

Choose the option that represents the highest level of involvement of the accounting practitioner: **198**

Completed an auditor's report . . . . . 1 [X]

Completed a review engagement report . . . . . 2 [ ]

Conducted a compilation engagement . . . . . 3 [ ]

Part 3 – Reservations

If you selected option "1" or "2" under **Type of involvement** above, answer the following question:

Has the accounting practitioner expressed a reservation? . . . . . **099** 1 Yes [ ] 2 No [X]

Part 4 – Other information

Were notes to the financial statements prepared? . . . . . **101** 1 Yes [X] 2 No [ ]

If *Yes*, complete lines 102 to 107 below:

Are any values presented at other than cost? . . . . . **102** 1 Yes [ ] 2 No [X]

Has there been a change in accounting policies since the last return? . . . . . **103** 1 Yes [ ] 2 No [X]

Are subsequent events mentioned in the notes? . . . . . **104** 1 Yes [ ] 2 No [X]

Is re-evaluation of asset information mentioned in the notes? . . . . . **105** 1 Yes [ ] 2 No [X]

Is contingent liability information mentioned in the notes? . . . . . **106** 1 Yes [X] 2 No [ ]

Is information regarding commitments mentioned in the notes? . . . . . **107** 1 Yes [ ] 2 No [X]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** 1 Yes [ ] 2 No [X]

If *Yes*, complete line 109 below:

Are you filing financial statements of the joint venture(s) or partnership(s)? . . . . . **109** 1 Yes [ ] 2 No [ ]

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2007-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements				0 A
Add:				
Provision for income taxes – current		101	-427,187	
Interest and penalties on taxes		103	543	
Amortization of tangible assets		104	4,002,371	
Non-deductible meals and entertainment expenses		121	105,175	
Reserves from financial statements – balance at the end of the year		126	17,678,581	
Subtotal of additions			21,359,483 ▶	21,359,483
Other additions:				
Debt issue expense		208	11,503	
Miscellaneous other additions:				
600 Capital tax expensed		290	114,800	
601 Computer software expensed		291	16,965	
Subtotal of other additions		199	143,268 ▶	143,268
Total additions		500	21,502,751 ▶	21,502,751
Deduct:				
Capital cost allowance from Schedule 8		403	1,966,299	
Reserves from financial statements – balance at the beginning of the year		414	16,934,226	
Subtotal of deductions			18,900,525 ▶	18,900,525
Other deductions:				
Miscellaneous other deductions:				
700 Capitalized interest		390	113,467	
701 WSIB gain included in income		391	3,108	
702 Capitalized overhead		392	208,710	
703 Removal expense added back via depreciation		393	203,811	
704.1 Other deductions	3,072,355			
704.2 Capital tax deduction	111,012			
Total	3,183,367	394	3,183,367	
Subtotal of other deductions		499	3,712,463 ▶	3,712,463
Total deductions		510	22,612,988 ▶	22,612,988
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				-1,110,237

* For reference purposes only

Attached Schedule with Total

FDONE.Ttwone52

Title Schedule 1 Other deductions (line 394)

Description	Amount	
Capital tax expense per CT23		
Underwriting fees 20(1)(e)		
OPEB Capitalized offset on schedule 13		
Enviromental deduction re:b/s int adjustment included in income via sch 13		
Enviromental deduction re:b/s adjustment included in income via sch 13		
Total		

Attached Schedule with Total

Line 208 – Debt issue expense

Title

Description	Amount	
Amortization underwriting fee (761780)	1,632	00
Amortization of Hedge loss (761770)	9,430	00
Bond Discount (761120,761130)	441	00
Total	11,503	00

Attached Schedule with Total

Line 704 – Amount

Title Line 704 – Amount

Description	Amount	
Opeb capitalized	203,876	00
Enviromental expense payments not reflected on T2S-13	2,868,479	00
Total	3,072,355	00

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 4

CORPORATION LOSS CONTINUITY AND APPLICATION

Name of corporation	Business Number	Tax year-end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2007-12-31

- This form is used to determine the continuity and use of available losses; to determine the current-year non-capital loss, farm loss, restricted farm loss, and limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that may be applied in a year; and to request a loss carryback to previous years.
- The corporation can choose whether or not to deduct an available loss from income in a tax year. It can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the *Income Tax Act*, when control has been acquired, no amount of capital loss incurred for a tax year ending (TYE) before that time is deductible in computing taxable income in a TYE after that time **and** no amount of capital loss incurred in a TYE after that time is deductible in computing taxable income of a TYE before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the *T2 Corporation – Income Tax Guide*.
- File one completed copy of this schedule with the T2 return, or send it by itself to the tax centre where the return is filed.
- Parts, sections, subsections, paragraphs, and subparagraphs mentioned in this schedule refer to the *Income Tax Act*.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes		-1,110,237
Deduct: (increase a loss)		
Net capital losses deducted in the year (enter as a positive amount)		
Taxable dividends deductible under sections 112, 113, or subsection 138(6)		
Amount of Part VI.1 tax deductible		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		
Subtotal (if positive, enter "0")		-1,110,237
Deduct: (increase a loss)		
Section 110.5 and/or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions		
Subtotal		-1,110,237
Add: (decrease a loss)		
Current-year farm loss		
Current-year non-capital loss (if positive, enter "0")		-1,110,237

Continuity of non-capital losses and request for a carryback

	Line		
Non-capital loss at the end of the previous tax year			
Deduct: Non-capital loss expired *	100		
Non-capital losses at the beginning of the tax year	102		
Add: Non-capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	105		
Current-year non-capital loss (from calculation above)	110	1,110,237	1,110,237
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	150		
Section 80 – Adjustments for forgiven amounts	140		
Subsection 111(10) – Adjustments for fuel tax rebate			
Deduct:			
Amount applied against taxable income (enter on line 331 of the T2 return)	130		
Amount applied against taxable dividends subject to Part IV tax	135		
Subtotal			1,110,237
Deduct – Request to carry back non-capital loss to:			
First previous tax year to reduce taxable income	901		
Second previous tax year to reduce taxable income	902		
Third previous tax year to reduce taxable income	903	1,110,269	
First previous tax year to reduce taxable dividends subject to Part IV tax	911		
Second previous tax year to reduce taxable dividends subject to Part IV tax	912		
Third previous tax year to reduce taxable dividends subject to Part IV tax	913		1,110,269
Non-capital losses – Closing balance	180		

* A non-capital loss expires as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004, and before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

An allowable business investment loss becomes a net capital loss as follows:
- After **7** tax years if it arose in a tax year ending before March 23, 2004;
- After **10** tax years if it arose in a tax year ending after March 22, 2004.

Election under paragraph 88(1.1)(f)

Paragraph 88(1.1)(f) election indicator	190	Yes

Loss from a wholly owned subsidiary deemed to be a loss of the parent from its immediately previous tax year.

Part 2 - Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200			
Capital losses transferred on the amalgamation or the wind-up of a subsidiary corporation	205			
Deduct:				
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Add:			Subtotal	
Current-year capital loss (from the calculation on Schedule 6)			210	
Unused non-capital losses that expired in the tax year*			A	
Allowable business investment losses (ABIL) that expired as non-capital losses in the tax year**			B	
Enter amount from line A or B, whichever is less	215			
ABILs expired as non-capital loss: line 215 divided by the inclusion rate*** 75.0000 %			220	
			Subtotal	

Note: If there has been an amalgamation or a wind-up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary. Add all these amounts and enter the total at line 220 above.

Deduct: Amount applied against the current-year capital gain (see Note 1)			225	
			Subtotal	
Deduct – Request to carry back capital loss to (see Note 2):	Capital gain (100%)		Amount carried back (100%)	
First previous tax year		951		
Second previous tax year		952		
Third previous tax year		953		
Capital losses – Closing balance			280	

Note 1

Enter the amount from line 225 **multiplied** by 50% on line 332 of the T2 return.

Note 2

On lines 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, multiply this amount by the 50% inclusion rate.

* Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004, and before 2006. Enter the losses from the 21st previous tax year if the losses were incurred in a tax year ending after 2005. Enter the part that was not used in previous years and the current year on line A.

** Enter the losses from the 8th previous tax year if the losses were incurred in a tax year ending before March 23, 2004. Enter the losses from the 11th previous tax year if the losses were incurred in a tax year ending after March 22, 2004. Enter the full amount on line B.

*** This inclusion rate is the rate used to calculate your ABIL referred to at line B. Therefore, use one of the following inclusion rates, whichever applies:

- For ABILs incurred in the 1999 and previous tax years, use 0.75.
- For ABILs incurred in the 2000 and 2001 tax years, the inclusion rate is equal to amount M on Schedule 6 - version T2SCH6(01).
- For ABILs incurred in the 2002 and later tax years, use 0.50.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year			
Deduct: Farm loss expired *	300		
Farm losses at the beginning of the tax year	302		
Add: Farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	305		
Current-year farm loss	310		
Deduct:			
Other adjustments (includes adjustments for an acquisition of control)	350		
Section 80 – Adjustments for forgiven amounts	340		
Amount applied against taxable income (enter on line 334 of the T2 return)	330		
Amount applied against taxable dividends subject to Part IV tax	335		
Subtotal			
Deduct – Request to carry back farm loss to:			
First previous tax year to reduce taxable income	921		
Second previous tax year to reduce taxable income	922		
Third previous tax year to reduce taxable income	923		
First previous tax year to reduce taxable dividends subject to Part IV tax	931		
Second previous tax year to reduce taxable dividends subject to Part IV tax	932		
Third previous tax year to reduce taxable dividends subject to Part IV tax	933		
Farm losses – Closing balance	380		

* A farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business . . . . . 485 ______ C

Minus the deductible farm loss:

$2,500 plus D or E, whichever is less . . . $ 2,500

(Amount C above ______ – $2,500) divided by 2 = ______ D

$ 6,250 E . . . 2,500 F

Current-year restricted farm loss (amount C minus amount F) (enter this amount on line 410) . . . . . ______

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			
Deduct: Restricted farm loss expired *	400		
Restricted farm losses at the beginning of the tax year	402		
Add: Restricted farm losses transferred on the amalgamation or the wind-up of a subsidiary corporation	405		
Current-year restricted farm loss (enter on line 233 of Schedule 1)	410		
Deduct:			
Amount applied against farming income (enter on line 333 of the T2 return)	430		
Section 80 – Adjustments for forgiven amounts	440		
Other adjustments	450		
Subtotal			
Deduct – Request to carry back restricted farm loss to:			
First previous tax year to reduce farming income	941		
Second previous tax year to reduce farming income	942		
Third previous tax year to reduce farming income	943		
Restricted farm losses – Closing balance	480		

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

* A restricted farm loss expires as follows:
- After **10** tax years if it arose in a tax year ending before 2006; or
- After **20** tax years if it arose in a tax year ending after 2005.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year				
Deduct: Listed personal property loss expired after seven tax years			500	
Listed personal property losses at the beginning of the tax year			502	
Add: Current-year listed personal property loss (from Schedule 6)			510	
			Subtotal	
Deduct:				
Amount applied against listed personal property gains (enter on line 655 of Schedule 6)	530			
Other adjustments	550			
			Subtotal	
Deduct – Request to carry back listed personal property loss to:				
First previous tax year to reduce listed personal property gains	961			
Second previous tax year to reduce listed personal property gains	962			
Third previous tax year to reduce listed personal property gains	963			
Listed personal property losses – Closing balance			580	

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Corporation's share of limited partnership loss	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Current-year limited partnership losses (column 3 - 6)
600	602	604	606	608		620

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from prior tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership identifier	Fiscal period ending	Limited partnership losses at the end of the previous tax year	Corporation's at-risk amount	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year. (the lesser of columns 3 and 6)
630	632	634	636	638		650

Continuity of limited partnership losses that can be carried forward to future tax years

Partnership identifier	Limited partnership losses at the end of the previous tax year	Limited partnership losses transferred on an amalgamation or the wind-up of a subsidiary	Current-year limited partnership losses (from column 620)	Limited partnership losses applied (cannot exceed column 650)	Limited partnership losses closing balance (662 + 664 + 670 - 675)
660	662	664	670	675	680

Total (enter this amount on line 335 of the T2 return)

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A	1,110,237		1,110,237	N/A		
2006		N/A		N/A			
2005		N/A		N/A			
2004		N/A		N/A			
2003		N/A		N/A			
2002		N/A		N/A			
2001		N/A		N/A			
2000		N/A		N/A			*
Total		1,110,237		1,110,237			

Farm losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A				N/A		
2006		N/A		N/A			
2005		N/A		N/A			
2004		N/A		N/A			
2003		N/A		N/A			
2002		N/A		N/A			
2001		N/A		N/A			
2000		N/A		N/A			
1999		N/A		N/A			
1999		N/A		N/A			
1998		N/A		N/A			*
Total							

Restricted farm losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce: Taxable income	Applied to reduce: Part IV tax	Balance at end of year
Current	N/A				N/A	N/A	
2006		N/A		N/A		N/A	
2005		N/A		N/A		N/A	
2004		N/A		N/A		N/A	
2003		N/A		N/A		N/A	
2002		N/A		N/A		N/A	
2001		N/A		N/A		N/A	
2000		N/A		N/A		N/A	
1999		N/A		N/A		N/A	
1999		N/A		N/A		N/A	
1998		N/A		N/A		N/A	*
Total						N/A	

* **This balance expires this year and will not be available next year.**

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2007-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes ☐ 2 No ☒

	1 Class number (200)	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) (201)	3 Cost of acquisitions during the year (new property must be available for use)* (203)	4 Net adjustments** (205)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) (207)	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** (211)	7 Reduced undepreciated capital cost	8 CCA rate % (212)	9 Recapture of capital cost allowance (line 107 of Schedule 1) (213)	10 Terminal loss (line 404 of Schedule 1) (215)	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** (217)	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) (220)
2	1		17,275,395	108,308		0	54,154	17,329,549	4	0	0	693,182	16,690,521
3	2		758,822			0		758,822	6	0	0	45,529	713,293
4	3		13,216	972,045		0	486,023	499,238	5	0	0	24,962	960,299
5	6		3,034,575	380,718		0	190,359	3,224,934	10	0	0	322,493	3,092,800
6	8		1,541,572	10,899		0	5,450	1,547,021	20	0	0	309,404	1,243,067
7	10		128,568	45,645		0	22,823	151,390	30	0	0	45,417	128,796
8	12		716	16,672		0	8,336	9,052	100	0	0	9,052	8,336
9	13		7,382			0		7,382	N/A	0	0	1,845	5,537
10	17		4,782,209	926,100		0	463,050	5,245,259	8	0	0	419,621	5,288,688
11	43.1		5,218			0		5,218	30	0	0	1,565	3,653
12	45		12,708	22,377		0	11,189	23,896	45	0	0	10,753	24,332
13	47		515,594	464,650		0	232,325	747,919	8	0	0	59,834	920,410
14	50			82,335		0	41,168	41,167	55	0	0	22,642	59,693
		Total	28,075,975	3,029,749			1,514,877	29,590,847				1,966,299	29,139,425

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

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SCHEDULE 13

CONTINUITY OF RESERVES

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2007-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- References to parts, sections, subsections, paragraphs, and subparagraphs are from the federal *Income Tax Act*.
- File one completed copy of this schedule with the corporation's *T2 Corporation Income Tax Return*.
- For more information, see the *T2 Corporation Income Tax Guide*.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on amalgamation or wind-up of subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The total capital gains reserve at the beginning of the taxation year plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary should be entered on line 880, and the total capital gains reserve at the end of the taxation year, should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description		Balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add $	Deduct $	Balance at the end of the year $
Reserve for doubtful debts		110	115			120
Reserve for undelivered goods and services not rendered		130	135			140
Reserve for prepaid rent		150	155			160
Reserve for December 31, 1995 income		170	175			180
Reserve for refundable containers		190	195			200
Reserve for unpaid amounts		210	215			220
Insurance corporation policy reserves						
Bank reserves						
Other tax reserves		230	235			240
Totals		270	275			280

Enter "X" in the column above if the tax reserve has also been reported on the corporation's financial statements. This allows offsetting entries on Schedule 1, resulting in a zero effect on net income for tax purposes.

The amount from line 270 plus the amount from line 275 should be entered on line 125 of Schedule 1 as an addition.
The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on amalgamation or wind-up of subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB LT (a/c 453000-260)	5,302,449		626,662		5,929,111
2	OPEB Short Term (a/c 358000)	300,000				300,000
3	RRP Rev Deferral (a/c 427191	3,219,097			1,767,525	1,451,572
4	LT-Environ. Liab (a/c452054)	6,293,680		1,898,218		8,191,898
5	Current-Envir. Lia. (452017)	1,819,000			13,000	1,806,000
6						
	Reserves from Part 2 of Schedule 13					
	Totals	16,934,226		2,524,880	1,780,525	17,678,581

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
Hydro One Remote Communities Inc.	87083 6269 RC0001	2007-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Networks Inc.	483 Bay Street Toronto . ON CA M5G 2P5			1,587,322		

T2 SCH 14 (99)

Canada

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* ☐ Yes ☒ No

Corporation's Legal Name *(including punctuation)*
Hydro One Remote Communities Inc.

Ontario Corporations Tax Account No. (MOF)
1800030

This Return covers the Taxation Year
Start (year month day): 2007-01-01
End (year month day): 2007-12-31

Mailing Address
483 Bay Street, 8th Floor
South Tower
Toronto
ON CA M5G 2P5

Has the mailing address changed since last filed CT23 Return? ☐ Yes
Date of Change (year month day):

Date of Incorporation or Amalgamation (year month day): 1998-08-18

Registered/Head Office Address
483 Bay Street, 8th Floor
South Tower
Toronto
ON CA M5G 2P5

Ontario Corporation No. (MGS): 1310735

Location of Books and Records
483 Bay Street, 8th Floor
South Tower
Toronto
ON CA M5G 2P5

Canada Revenue Agency Business No.
If applicable, enter
87083 6269 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
BRIAN SOARES	(416) 345-6782	(416) 345-6978

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced (year month day):
Ceased (year month day):
☒ *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* ☒ *Not Applicable* (MGS)

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). No. of Schedule(s):

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). ☒ **No Change**

Preferred Language / *Langue de préférence*
☒ English *anglais* ☐ French *français*

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.
Name of Authorized Person *(Print clearly or type in full)*

Title D ☐ Director O ☐ Officer P ☒ Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) box(es) and complete required information.

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent) 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired year month day

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
	X	Was the corporation inactive throughout the taxation year?
X		Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
X		the Carry-back of a Loss?
	X	an Overpayment?
	X	a Specified Refundable Tax Credit?
	X	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

89954572

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

Generation & Distb.

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

		Line	Amount
Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	-1,110,237
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax ______ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses	–	From 704	
Net capital losses (page 16) From 715 ______ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	-1,110,237

Addition to taxable income for unused foreign tax deduction for federal purposes + 11 ______

Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11) = 20 ______

Number of Days in Taxation Year

Taxable Income

From 10 (or 20 if applicable) ______ x 30 100.0000 % Ontario Allocation x 12.5 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ______ ÷ Total Days: 73 365) = + 29 ______

From 10 (or 20 if applicable) ______ x 30 100.0000 % Ontario Allocation x 14 % x (Days after Dec. 31, 2003: 34 365 ÷ Total Days: 73 365) = + 32 ______

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 ______

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) ☐ Yes ☒ No

* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a)) 50 ______

Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b)) + 51 ______

Add: Losses of other years deducted for federal purposes (fed.s.111) + 52 ______

Subtract: Losses of other years deducted for Ontario purposes (s.34) – 53 ______

= ______ ▶ 54 ______

Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1) 55 ______

Ontario Business Limit Calculation

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004: 31 ______ ÷ ** 365) = + 46 ______

400,000 x (Days after Dec. 31, 2003: 34 365 ÷ ** 365) = + 47 400,000

Business Limit for Ontario purposes 46 + 47 = 44 400,000 x (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) 48 100.0000 % = 45 400,000

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 ______ (Least of 50 , 54 or 45) = 60 ______

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

	Rate		Days		Total Days		Box	Amount
Calculation of IDSBC Rate	7 %	x	31 Days after Dec. 31, 2002 and before Jan. 1, 2004:	÷	73 Total Days: 365	= +	89	.
	8.5 %	x	34 Days after Dec. 31, 2003: 365	÷	73 Total Days: 365	= +	90	8.5000
IDSBC Rate for Taxation Year 89 + 90						=	78	8.5000
Claim	From 60	x	From 78: 8.5000 %			=	70	

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 400,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** - From 10 (or 20 if applicable) + 80

If you are a member of an associated group (X) 81 **X** (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
See schedule			+ 82	
			+ 83	
			+ 84	
Aggregate Taxable Income 80 + 82 + 83 + 84, etc.			= 85	

Number of Days in Taxation Year

		Days		Total Days		Box	Amount
320,000	x	31 Days after Dec. 31, 2002 and before Jan. 1, 2004:	÷	73 Total Days: 365	= +	115	
400,000	x	34 Days after Dec. 31, 2003: 365	÷	73 Total Days: 365	= +	116	400,000
115 + 116					=		400,000

	Box	Amount
115 + 116	– 114	400,000
(If negative, enter nil)	= 86	

Number of Days in Taxation Year

	Rate		Days after Dec. 31, 2002		Total Days		Box	Amount
Calculation of Specified Rate for Surtax	4.6670 %	x	38: 365	÷	73: 365	= +	97	4.6670

From 86 x From 97 4.6670 % = 87

From 87 x From 60 ÷ From 114 400,000 = 88

Surtax Lesser of 70 or 88 = 100

**** Note: Short Taxation Years –*** Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

DOLLARS ONLY

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)*

110 ______

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits + 120 ______

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) – From 56 ______

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 ______ ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 ______

*Ontario Allocation

Lesser of 56 or 121 + 122 ______

120 – 56 + 122 = 130 ______

Taxable Income + From 10 -1,110,237

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) – From 56 ______

Add: Adjustments for Surtax on Canadian-controlled private corporations + From 122 ______

Subtract: Taxable Income 10 -1,110,237 X Allocation % to jurisdictions outside Canada – 140 ______

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses – 141 ______

10 – 56 + 122 – 140 – 141 = 142 ______

Claim

Number of Days in Taxation Year

143 ______ (Lesser of 130 or 142) x From 30 100.0000 % (Ontario Allocation) x 1.5 % x Days after Dec. 31, 2002 and before Jan. 1, 2004: 33 ______ ÷ Total Days 73 365 = + 154 ______

143 ______ (Lesser of 130 or 142) x From 30 100.0000 % (Ontario Allocation) x 2 % x Days after Dec. 31, 2003: 34 365 ÷ Total Days 73 365 = + 156 ______

M&P claim for taxation year 154 + 156 = 160 ______

***Note:** *Ontario Allocation for M&P Credit purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations

= 161 ______

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity

= 162 ______

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* 170 ______

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 ______ Credit Claimed 180 ______

Subtotal of Income Tax

40 – 70 + 100 – 110 – 160 – 161 – 162 – 170 – 180 = 190 ______

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.

Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* - - - - - - - - - - - - - - - + 191 .

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.

Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* - - - - - - - - - - - - - - - + 192 .

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)

Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. 204 Name of Production

Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* - + 193 .

Graduate Transitions Tax Credit (GTTC) (s.43.6) No. of Graduates From 6596

Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194

Eligible Credit From 6598 CT23 Schedule 115 (*Attach Schedule 115*) - - - - - - - - - - - - - - - + 195 .

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)

Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.

Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* - - + 196 .

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)

Applies to labour relating to computer animation and special effects on an eligible production.

Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* - + 197 .

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)

Applies to qualifying R&D expenditures under an eligible research institute contract.

Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* - - - - - - - - - - - - - - + 198 .

Ontario Production Services Tax Credit (OPSTC) (s.43.10)

Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.

Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* - + 199 .

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)

Applies to qualifying labour expenditures of eligible products for the taxation year.

Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* - + 200 .

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)

Applies to qualifying expenditures in respect of eligible Canadian sound recordings.

Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* - - + 201 .

Apprenticeship Training Tax Credit (ATTC) (s.43.13) No. of Apprentices From 5896

Applies to employment of eligible apprentices. 202

Eligible Credit From 5898 CT23 Schedule 114 (*Attach Schedule 114*) - - - - - - - - - - - - - - - + 203 .

Other (specify) - - - - - - - - - - - - - - - + 203.1 .

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220 .

Specified Tax Credits ***Applied to reduce Income Tax*** - - - - - - - - - - - - - - - - - - = 225 .

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* - - - - = 230 .

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation + 240 48,223,021

Total Revenue of the corporation + 241 36,672,725

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 ☐ (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End	Total Assets	Total Revenue
			+ 243	+ 244
			+ 245	+ 246
			+ 247	+ 248

Aggregate Total Assets 240 + 243 + 245 + 247 , etc. = 249 48,223,021

Aggregate Total Revenue 241 + 244 + 246 + 248 , etc. = 250 36,672,725

Determination of Applicability

Applies if ***either*** Total Assets 249 exceeds $5,000,000 ***or*** Total Revenue 250 exceeds $10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101**.

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - - CMT Base From Schedule 101 2136 (If negative, enter zero) x From 30 100.0000 % (Ontario Allocation) X 4 % = 276

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)* – 277

Subtract: Income Tax – From 190

Net CMT Payable (If negative, enter Nil on Page 17.) = 280

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 From 2333

Application of CMT Credit Carryovers

A. Income Tax (before deduction of specified credits) + From 190

Gross CMT Payable + From 276

Subtract: Foreign Tax Credit for CMT purposes – From 277

If 276 – 277 is negative, enter NIL in 290 = – 290

Income Tax eligible for CMT Credit = 300

B. Income Tax (after deduction of specified credits) + From 230

Subtract: CMT credit used to reduce income taxes – 310

Income Tax = 320

Transfer to page 17

If A & B apply, 310 ***cannot exceed the lesser of*** 230 **,** 300 ***and your CMT credit carryover available*** 2333 **.**

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333 **.**

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 *and* 430 *on page 10 then proceed to page 13.*

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 *and* 430 *are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in* 550 *on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.*

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

		Line	Amount
Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	25,956,758
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	17,678,581
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	6,205,991
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	49,841,330
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	49,841,330
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	–	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	–	382	
Net Paid-up Capital	=	390	49,841,330

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

		Line	Amount
Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	

continued on Page 10

Total Assets (Int.B. 3015R)

DOLLARS ONLY

Total Assets per balance sheet	+	420	48,223,021
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	48,223,021
Amounts in 360 and 361 (if deducted from assets)	+	440	6,408,816
Subtract: Amounts in 371 , 372 and 381	–	441	
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	54,631,837

Investment Allowance (410 ÷ 450) x 390 — **Not to exceed** 410	=	460	
Taxable Capital 390 – 460	=	470	49,841,330

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	36,672,725
Total Assets (as adjusted)	From 430	48,223,021

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

					Total Days				
7,500,000	x	Days after Dec. 31, 2004 and before Jan. 1, 2006: 36	÷	73	365	=	+	501	
10,000,000	x	Days after Dec. 31, 2005 and before Jan. 1, 2007: 37	÷	73	365	=	+	502	
12,500,000	x	Days after Dec. 31, 2006 and before Jan. 1, 2008: 38 365	÷	73	365	=	+	504	12,500,000
15,000,000	x	Days after Dec. 31, 2007: 39	÷	73	365	=	+	505	
Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505						=		503	12,500,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

					Total Days				
0.3 %	x	Days before Jan. 1, 2007: 556	÷	73	365	=	+	511	%
0.225 %	x	Days after Dec. 31, 2006 and before Jan. 1, 2009: 557 365	÷	73	365	=	+	512	0.2250 %
Capital Tax Rate 511 + 512						=		516	0.2250 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+ From 470 ________
– From 503 ________
= 471 ________ x From 30 100.0000 % Ontario Allocation x From 516 0.2250 % Capital Tax Rate x Days in taxation year 555 365 / 365 (366 if leap year) = + 523 ________

If floating taxation year, refer to Guide.

Transfer to 543 on page 12 and complete the return from that point

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. ☐ 509 (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. X 524 (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation

Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - - - + From 470 49,841,330

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
See schedule			+ 531	1,138,979,784
			+ 532	
			+ 533	

Aggregate Taxable Capital 470 + 531 + 532 + 533 , etc. - - - = 540 1,188,821,114

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E below, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From 470 49,841,330 ÷ From 540 1,188,821,114 x From 503 12,500,000 = 541 502,632

Transfer to 542 in Section E below

Ss.69(2.1) Election Filed

591 (X if applicable) **Election filed**. *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

+ From 470 49,841,330
– 542 502,632
= 471 49,338,698 x From 30 100.0000 % (Ontario Allocation) x From 516 0.2250 % (Capital Tax Rate) x 555 365 (Days in taxation year) / * 365 (366 if leap year) = + 523 111,012 (**Total Capital Tax for the taxation year**)

Transfer to 543 and complete the return from that point

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From 470 x From 30 100.0000 % (Ontario Allocation) x From 516 0.2250 % (Capital Tax Rate) - - - = + 561

– Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - – From 995

= 562

Capital Tax - - - 562 x 555 365 (Days in taxation year) / * 365 (366 if leap year) - - - = 563 (**Total Capital Tax for the taxation year**)

Transfer to 543 and complete the return from that point

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits - - - = 543 111,012

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - – 546

Capital Tax 543 – 546 *(amount cannot be negative)* - - - = 550 111,012

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes 565 and 570. Do not submit with this tax return.)

565 ______ x 567 ______% x From 30 100.0000 % Ontario Allocation x 555 365 (Days in taxation year) / * 365 (366 if leap year) = + 569 ______

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1 | Capital Tax Rate (1) *(Refer to Guide)*

570 ______ x 571 ______% x From 30 100.0000 % Ontario Allocation x 555 365 (Days in taxation year) / * 365 (366 if leap year) = + 574 ______

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount | Capital Tax Rate (2) *(Refer to Guide)*

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) 569 + 574 = 575 ______

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments – 585 ______

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions 575 – 585 = 586 ______

Transfer to 543 on Page 12

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements 587 ______ x 2 % = 588 ______

Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in 588 and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in 588.)

Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – 589 ______

Premium Tax 588 – 589 = 590 ______

Transfer to page 17

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1	± 600	-1,110,237
		Transfer to Page 15

Add:

Federal capital cost allowance	+ 601	1,966,299
Federal cumulative eligible capital deduction	+ 602	
Ontario taxable capital gain	+ 603	
Federal non-allowable reserves. Balance beginning of year	+ 604	16,934,226
Federal allowable reserves. Balance end of year	+ 605	
Ontario non-allowable reserves. Balance end of year	+ 606	17,678,581
Ontario allowable reserves. Balance beginning of year	+ 607	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+ 608	
Federal resource allowance *(Refer to Guide)*	+ 609	
Federal depletion allowance	+ 610	
Federal foreign exploration and development expenses	+ 611	
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+ 617	

Management fees, rents, royalties and similar payments to non-arms' length non-residents

Number of Days in Taxation Year

612	x 5 / 12.5 x	Days after Dec. 31, 2002 and before Jan. 1, 2004: 33	÷ 73	Total Days: 365	= + 633	
612	x 5 / 14 x	Days after Dec. 31, 2003: 34 365	÷ 73	Total Days: 365	= + 634	

Total add-back amount for Management fees, etc. 633 + 634 =	+ 613	
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	+ 615	
Add any negative amount in 473 from Ont. CT23 Schedule 161	+ 616	
Federal allowable business investment loss	+ 620	
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	+ 614	
Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614 =	36,579,106	640 36,579,106
		Transfer to Page 15

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+ 650	1,966,299
Ontario cumulative eligible capital deduction	+ 651	
Federal taxable capital gain	+ 652	
Ontario non-allowable reserves. Balance beginning of year	+ 653	16,934,226
Ontario allowable reserves. Balance end of year	+ 654	
Federal non-allowable reserves. Balance end of year	+ 655	17,678,581
Federal allowable reserves. Balance beginning of year	+ 656	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+ 657	
Ontario depletion allowance	+ 658	
Ontario resource allowance *(Refer to Guide)*	+ 659	
Ontario current cost adjustment *(Attach schedule)*	+ 661	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+ 675	
Subtotal of deductions for this page 650 to 659 + 661 + 675	681	36,579,106
		Transfer to Page 15

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1	From ±	600	-1,110,237
Total of Additions on page 14	From =	640	36,579,106
Sub Total of deductions on page 14	From =	681	36,579,106

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year 662 ______

ONTTI Gross-up deduction calculation:

Gross-up of CCA

[From 662 ______ x 100 / From 30 100.0000 Ontario Allocation] – From 662 ______ = 663 ______

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [665 ______ x 30 % x 100 / From 30 100.0000 Ontario allocation] = 666 ______

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [667 ______ x 100 % x 100 / From 30 100.0000 Ontario allocation] = 668 ______

Number of Employees accommodated 669 ______

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: [670 ______ x 30 % x 100 / From 30 100.0000 Ontario allocation] = 671 ______

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [672 ______ x 15 % x 100 / From 30 100.0000 Ontario allocation] = 673 ______

Ontario allowable business investment loss	+	678	
Ontario Scientific Research Expenses claimed in year in 477 **from Ont. CT23 Schedule 161**	+	679	
Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003)	+	677	
Total of other deductions allowed by Ontario *(Attach schedule)*	+	664	

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 36,579,106 ▶ 680 36,579,106

Net income (loss) for Ontario Purposes 600 + 640 – 680 = 690 -1,110,237

Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	720 (2)	730	740	750
Add:	Current year's losses (7)	701 1,110,237	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703 1,110,237	713	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17 1,110,237	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707 1,110,237	717	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day	Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800 9th preceding taxation year 1999-03-31	817 (9)	860 (9)		850	870
801 8th preceding taxation year 1999-12-31	818 (9)	861 (9)		851	871
802 7th preceding taxation year 2000-12-31	819 (9)	862 (9)		852	872
803 6th preceding taxation year 2001-12-31	820	830	840	853	873
804 5th preceding taxation year 2002-12-31	821	831	841	854	874
805 4th preceding taxation year 2003-12-31	822	832	842	855	875
806 3rd preceding taxation year 2004-12-31	823	833	843	856	876
807 2nd preceding taxation year 2005-12-31	824	834	844	857	877
808 1st preceding taxation year 2006-12-31	825	835	845	858	878
809 Current taxation year 2007-12-31	826	836	846	859	879
Total	829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance**.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910 1,110,237	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding	901	2004-12-31	911 1,110,269	921	931	941
ii) 2nd preceding	902	2005-12-31	912	922	932	942
iii) 1st preceding	903	2006-12-31	913	923	933	943
Total loss to be carried back			From 706 1,110,237	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

Income Tax	+	From 230 or 320	
Corporate Minimum Tax	+	From 280	
Capital Tax	+	From 550	111,012
Premium Tax	+	From 590	
Total Tax Payable	=	950	111,012
Subtract: Payments	–	960	141,219
Capital Gains Refund (s.48)	–	965	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	–	985	
Specified Tax Credits *(Refer to Guide)*	–	955	
Other, specify	–		
Balance	=	970	-30,207
If payment due	Enclosed *	990	
If overpayment: Refund *(Refer to Guide)*	=	975	
Apply to (year month day)		980	30,207

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*

VINCENT ALICANDRI

Title

Vice President, Corporate Tax

Full Residence Address

c/o 483 Bay Street
South Tower, 8th floor
Toronto
ON CA M5G 2P5

Signature

Date 2008-12-09

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Attached Schedule with Total

Other reserves not allowed as deductions for income tax purposes (Attach schedule) (Int.B. 3012R)

Title Amounts deducted for tax in excess of amounts booked for accounting

Description	Amount	
NBV	-25,498,268	00
UCC	29,139,425	00
CIP	2,517,467	00
NBV adjustment	47,367	00
Total	6,205,991	00

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Remote Communities Inc.	1800030	2007-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Primary debt net of unamortized discounts and premiums (302000)	+	22,859,961
I/C loan (356100)	+	1,474,194
Customer deposits (390000)	+	329,592
Deposits held in trust (428000)	+	
Unamortized wsib gain (451070)	+	12,383
Deposits for construction (392000)	+	1,280,628
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	25,956,758

Non-Capital Loss Continuity Workchart – Ontario

Non-capital losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A	1,110,237		1,110,237	N/A	
2006		N/A		N/A		
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		
2000		N/A		N/A		*
Total		1,110,237		1,110,237		

Farm losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2006		N/A		N/A		
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		
2000		N/A		N/A		
1999		N/A		N/A		
1999		N/A		N/A		
1998		N/A		N/A		*
Total						

Restricted farm losses

Year	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce taxable income	Balance at end of year
Current	N/A				N/A	
2006		N/A		N/A		
2005		N/A		N/A		
2004		N/A		N/A		
2003		N/A		N/A		
2002		N/A		N/A		
2001		N/A		N/A		
2000		N/A		N/A		
1999		N/A		N/A		
1999		N/A		N/A		
1998		N/A		N/A		*
Total						

* **This balance expires this year and will not be available next year.**

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Remote Communities Inc.	1800030	2007-12-31

Is the corporation electing under regulation 1101(5q)? 1 [ ] Yes 2 [X] No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	17,275,395	108,308		0	17,383,703	54,154	17,329,549	4	0	0	693,182	16,690,521
2	758,822			0	758,822		758,822	6	0	0	45,529	713,293
3	13,216	972,045		0	985,261	486,023	499,238	5	0	0	24,962	960,299
6	3,034,575	380,718		0	3,415,293	190,359	3,224,934	10	0	0	322,493	3,092,800
8	1,541,572	10,899		0	1,552,471	5,450	1,547,021	20	0	0	309,404	1,243,067
10	128,568	45,645		0	174,213	22,823	151,390	30	0	0	45,417	128,796
12	716	16,672		0	17,388	8,336	9,052	100	0	0	9,052	8,336
13	7,382			0	7,382		7,382	N/A	0	0	1,845	5,537
See schedule	5,315,729	1,495,462			6,811,191	747,732	6,063,459				514,415	6,296,776
Totals	28,075,975	3,029,749			31,105,724	1,514,877	29,590,847				1,966,299	29,139,425

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Remote Communities Inc.	1800030	2007-12-31

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
17	4,782,209	926,100		0	5,708,309	463,050	5,245,259	8	0	0	419,621	5,288,688
43.1	5,218			0	5,218		5,218	30	0	0	1,565	3,653
45	12,708	22,377		0	35,085	11,189	23,896	45	0	0	10,753	24,332
47	515,594	464,650		0	980,244	232,325	747,919	8	0	0	59,834	920,410
50		82,335		0	82,335	41,168	41,167	55	0	0	22,642	59,693
Totals	5,315,729	1,495,462			6,811,191	747,732	6,063,459				514,415	6,296,776

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Remote Communities Inc.	1800030	2007-12-31

For use by a corporation to provide a continuity of all reserves claimed which are allowed for tax purposes.

Part 1 – Capital gains reserves

Description of property	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
1					
Totals	A	B			C

The total capital gains reserve at the beginning of the taxation year **A** plus the total capital gains reserve transfer on amalgamation or wind-up of subsidiary **B**, should be entered on Schedule 6; and the total capital gains reserve at the end of the taxation year **C**, should also be entered on Schedule 6.

Part 2 – Other reserves

Description	Ontario balance at the beginning of the year $	Transfer on amalgamation or wind-up of subsidiary $	Add	Deduct	Ontario balance at the end of the year $
Reserve for doubtful debts					
Reserve for undelivered goods and services not rendered					
Reserve for prepaid rent					
Reserve for December 31, 1995 income					
Reserve for refundable containers					
Reserve for unpaid amounts					
Other tax reserves					
Totals	D	E			F

The amount from **D** plus the amount from **E** should be entered in 607 of the CT23.
The amount from **F** should be entered in 654 of the CT23.

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
OPEB LT (a/c 453000-260)	5,302,449		626,662			5,929,111
OPEB Short Term (a/c 358000)	300,000					300,000
RRP Rev Deferral (a/c 427191	3,219,097			1,767,525		1,451,572
See schedule	8,112,680		1,898,218	13,000		9,997,898
Reserves from Part 2						
Totals	16,934,226		2,524,880	1,780,525		17,678,581

Enter in box 653 *of the CT23* *Enter in box* 606 *of the CT23*

Ontario Continuity of Reserves
Schedule 13

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Hydro One Remote Communities Inc.	1800030	2007-12-31

Part 3 – Continuity of non-deductible reserves

Reserve	Ontario opening balance	Transfers	Ontario additions	Ontario deductions	Other adjustments	Ontario closing balance
LT-Environ. Liab (a/c452054)	6,293,680		1,898,218			8,191,898
Current-Envir. Lia. (452017)	1,819,000			13,000		1,806,000
Totals	8,112,680		1,898,218	13,000		9,997,898

Ontario Energy Board (Board Staff) INTERROGATORY #9 List 1

Interrogatory

INCOME TAX

9. Ref: Ex C2 / Tab 6 / Sch 1 / Att C

In Exhibit C2-6-1, Attachment C, the taxable loss for 2006 is $2.8 million. Please confirm whether the loss has been carried forward to 2007. If "Yes", please provide details and if "No", please provide the reasons for not carrying forward losses from previous years.

Response

The taxable loss for 2006 of $2.8 million was carried back and applied to the 2004 and 2005 taxation years. The recovery of payments in lieu of corporate income taxes is recorded in the Statement of Operations and thus would be accounted for in the RRRP variance account. As the RRRPVA has not been cleared since its establishment in 2003, the current balance reflects the tax loss carry-back to 2004 and 2005.

Ontario Energy Board (Board Staff) INTERROGATORY #10 List 1

Interrogatory

INCOME TAX

10. Ref: Ex C2 / Tab 6 / Sch 1 / Att C

If Remotes were to carry forward losses from previous years to 2008 and 2009, is it possible that Remotes may not realize a profit for the 2009 Test Year? If "yes", please provide a table with the related calculation.

Response

See response to Exhibit H, Tab 1, Schedule 9 regarding loss application for 2006.

The loss for 2007 of $1.1 million was carried back and applied to 2004.

See revised Exhibit C2, Tab 6, Schedule 2, Attachment A, CT23 page 17 of 20.

Ontario Energy Board (Board Staff) INTERROGATORY #11 List 1

Interrogatory

SMART METERS

11\.

In Schedule B of the attached report, Remotes noted that the smart metering plan was developed with three primary objectives: to assist customers in reducing usage during peak periods on the grid, to support customer billing based on a fluctuating price for electricity, and to offer customers better information on their usage. Remotes also noted that the first two objectives do not apply in an off-grid context and the third objective – to offer customers better, more timely information is appropriate to its business with significant potential benefits for its customers and its business. Accordingly, Remotes planned to pilot alternative smart meter technologies. Please answer the following questions with respect to this evidence:

a. What alternative smart meter technologies have been considered by Remotes and how different are they as compared to smart metering implemented by other distributors? Please provide a detailed explanation.

b. In the 2009 Rate Application, Remotes has indicated its intention to deploy smart meter technology. Is this technology different from the alternative technologies referred to in the August 4, 2006 document? Please clarify and provide a detailed response.

c. Remotes has noted three primary objectives for implementing smart metering technology. Of these, the Company has indicated that a utility like Remotes would only benefit from the third objective. Since there seems to be a limited benefit from implementing smart metering technology, has Remotes conducted a cost/benefit analysis? If so, please provide details of the analysis.

d. The evidence notes that Remotes plans to pilot alternative smart meter technologies. Has remotes conducted the pilot? If “yes”, please provide details including the result of the pilot. If “not”, when will Remotes conduct the pilot?

Response

a. Remotes does not intend to use TOU rates in our communities and the meters we will install will be outside of the provincial Smart Meter regime. New metering will be installed to accomplish the following:
    a. To ensure Remotes will have access to a meter product that is supportable in Ontario post-Smart Metering implementation
    b. To look for enhancements in new technology that will reduce operating costs or reduce customer reconnection response time and allow reduced load limiting costs.
    c. To reduce billing errors associated with manual meter reading.

   Remotes has deployed some PowerCost Monitors through its CDM program. These monitors give customers real time information about their electrical consumption and support one of the objectives outlined in the Smart Metering plan filed in August of 2006. Remotes plans to provide these monitors to every customer by 2011.

b. The technology is consistent with the goals identified in the August 2006 Response to Board Directives (see Attachment). However, the technology does not support a “pre-paid” option. Remotes’ investigated meters with pre-payment functionality, but was not successful in attracting a supplier able to support the implementation of the technology (see part d below for more information).

c. No, Remotes has not conducted a cost/benefit analysis at present. A detailed cost-benefit analysis will be completed when more information is available when the design is completed in 2009.

d. No pilot was undertaken. Remotes attempted to pilot a pre-paid meter project during 2006 and 2007. Because pre-paid meters are not generally compatible with provincial requirements for smart meters, the pre-paid meter supplier Remotes was working with closed down its business. No alternative supplier has been identified and Remotes’ therefore does not plan to proceed with a pilot.

Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
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Fax: (416) 345-5870
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Susan.E.Frank@HydroOne.com

Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

August 04, 2006

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2005-0511 – Hydro One Remote Communities – Response to Board Directives

Attached are Hydro One Remote Communities ("Remotes") responses to the Directives contained in the Ontario Energy Board's May 10, 2006 Decision in the above matter.

On page 3 of the Decision, the Board directed Remotes to complete and file the full TRC testing results for its Conservation and Demand Management program. Remotes has completed an analysis using TRC benefits and costs of its 2006 program spending based on projected costs and on the expected uptake for the program. The results of this analysis showing a Benefit to Cost ratio of 1.47 is attached as Schedule A.

On page 6 of the Decision, the Board noted that Remotes faces special challenges in implementing a smart metering program, and required Remotes to file a report on the feasibility of smart meters in its service territory and its plans for smart metering. This Report is attached as Schedule B.

Sincerely,

Susan Frank

Susan Frank

Customer Education Program

The Customer Education Program consists of community workshops/meetings to discuss energy conservation. The workshops will be held jointly sponsored with the Ontario Power Authority.

The workshops will offer conservation tips and hands on demonstrations, and will feature exchanges for energy efficient equipment, mainly light bulbs, Christmas lighting and motion detectors.

The TRC value for this program is based on calculating the net present value of the investment (by each technology) using Remotes' avoided costs as filed, and the assumptions in the Board's assumptions and measures guide.

Pilot Program

The pilot program is focussed on 4 communities and is done in conjunction with Pathfinders (INAC and NRCan) and the local band council. To date, the program has focussed on baseline energy studies and getting community buy in. Home visits, including the installation of energy efficient equipment, are planned for the fall. Equipment exchanges currently planned include lights and motion detectors, though other equipment may be used depending on the community.

TRC Program Benefits

	Customer Education	Pilot Program	Total
Number of Customers Reached	99	700	799
Number of light bulbs	297	3,359	3,656
TRC benefit	$14,800	$223,205	$238,005
Number of motion detectors	99	653	752
TRC benefit	$23,374	$168,392	$191,766
Number of Christmas lights	500	500	1,000
TRC benefit	$5,491	$5,491	$10,982
Savings in year (kWh)	13,149	110,851	124,000
Savings over life of technology (kWh)	420,916	2,609,513	3,030,429
Total TRC benefit of Program	$43,665	$397,088	$440,753

Name of the Programs: Community Pilot & Education Schedule A

Description of the program (including intent, design, delivery, partnerships and evaluation):

Remotes' customer education program and its pilot project involve the distribution of CFLs, Motion Detectors and Xmas lights. Programs are in partnership with INAC (Pathfinders) and the OPA's aboriginal program. Costs include educational components

	Lightbulbs	Motion Detectors	50% mini
Base case technology:	139 kWh	696 kWh	13.5
Efficient technology:	35 kWh	487 kWh	1
Number of participants or units deli	3656	752	1000
Measure life (years):	4	10	20

TRC Results:

TRC Benefits ($):	$	*440,753.39*
TRC Costs ($):	$	*300,000.00*
Utility program cost (less incentives):	$	300,000.00
Participant cost:	$	-
Total TRC costs:	$	300,000.00
Net TRC (in year CDN $):	$	300,000.00

Benefit to Cost Ratio (TRC Benefits/TRC Costs): 1.47

Note: cost includes educational & promotional components of programs

Results: (one or more category may apply)

Conservation Programs:

Pilot communities with lighting exchanges and motion detectors.

	lifecycle	*in year*
Energy saved (kWh):	*3,030,429*	124,001
Other resources saved :		
Natural Gas (m3):		
Other (specify):		

Background Summary

Hydro One Remote Communities (Remotes) is an integrated generation and distribution company, and is licensed to serve 20 isolated, off-grid, communities in Northern Ontario. The company is 100% debt financed and is operated on a break-even basis. The federal and provincial governments both have programs in place to support the high cost of generating electricity in the far north. As a result, most of remotes customers pay electricity rates that are below the cost of service.

Remotes does not believe that the Smart Meter systems recommended for grid connected customers are appropriate to its service territory. Remotes notes that the smart metering plan was developed with three primary objectives, to assist customers in reducing usage during peak periods on the grid, to support customer billing based on a fluctuating price for electricity, and to offer customers better information on their usage.

Remotes believes that the first two objectives do not apply in an off-grid context, and that implementing a technology to meet them would pose significant challenges, as outlined in more detail below. Remotes does, however, believe that the third objective—to offer customers better, more timely information—is appropriate to its business, with significant potential benefits for its customers and its business. Remotes therefore plans to pilot alternative "smart meter" technologies that would meet the objective of improving customer information to help customers reduce their energy usage by improving the information available to them.

Load Shifting in Remote Communities

Remotes owns and operates 18 diesel generating stations, with 59 diesel generators in service. The generating systems were designed to match a single generating unit to the community load, and to operate that unit at its optimal capacity. This approach maximizes fuel efficiency, as the amount of electricity generated is the amount required. It also reduces maintenance costs, because maintenance on generating units is required based on the number of hours each unit runs. Operating two units at a time effectively doubles the maintenance costs. The generating systems do not incorporate peaking units.

Remotes does not believe that encouraging customers to use electricity in off-peak hours would reduce the cost of generation in its service territory, as its system is not designed to incorporate peaking units. Moreover, as the peak load is primarily related to seasonality rather than time of day, customers may not be able to change the time of use easily.

Required Smart Metering System Service and Information Flow

The Board's Smart Meter Implementation Plan requires that distributors provide daily feedback to customers on their previous day's energy usage. This communications infrastructure is required to support Time of Use and Critical Peak Pricing.

Remotes notes that the communications infrastructure required to support these information flows does not exist in its service territory and would be costly to create. Remotes notes that an investment in radio technology and a regional repository would be required in each community to gather the meter information. Phone service and satellite communications to and from the communities have been unreliable in the past. Remotes does not, therefore, believe the reliable transfer of data from the communities to a centralized collection computer and to Remotes' customer information system would be feasible. As noted above, Remotes does not plan expect to implement an hourly pricing regime, as its costs do not vary by hour and because, by Regulation, its customers do not pay rates based on the cost of service.

The Benefits of Improved Information to Customers

Remotes expects that its customers would benefit from improved information about their usage, and notes that Hydro One's recent Real Time Monitoring pilot project supports this view. Hydro One's pilot tested four hundred participants and control customers over a 2.5 year period. The study isolated the effect of the provision of more frequent feedback with no further advice or consultation about possible conservation activities.

Overall, the average reduction in energy consumption across the study sample was 6.5%. The customer satisfaction surveys performed along with the study showed very positive attitudes to the real-time monitors. The study also predicted that an overall average reduction of between 7% and 10% would be feasible if other conservation and price measures were combined with the real time monitor. The report also pointed to another pilot project that showed electricity savings in the range of 20% when a real time monitor was used in conjunction with a smartcard meter for prepayment of electricity.

Alternative Metering Technologies Pilot Project

Remotes plans to implement a pilot project to test alternative smart meter technologies that offer customers information that will allow them to adjust their consumption.

Remotes also anticipates that piloting meter technologies with an in-home display, prepaid cards or automatic disconnection features could have a collateral benefit of lessening other issues associated with bill collections and customer arrears.

Ontario Energy Board (Board Staff) INTERROGATORY #12 List 1

Interrogatory

SMART METERS

12. Ref: Ex A / Tab 12 / Sch 1 / Pg 5

Remotes has indicated that it plans to begin deploying smart meter technology in 2009 after other distribution companies have deployed smart meters to rural communities. Please answer the following questions:

a. How many smart meters does Remotes intend to install?

b. Will the smart meters be installed in all communities? If no, please provide details.

c. What will be the approximate cost of each installed smart meter?

d. Will Remotes be filing a separate Smart Meter application? If yes, when?

e. What will be the procuring process for the smart meters?

f. What is total estimated cost of Remotes Smart Meter Implementation Plan?

g. Will Remotes be asking for a smart meter rate adder in this or in a subsequent application? If "yes", please provide details.

h. Has Remotes incurred any expenditures related to the Smart Meter implementation initiative? If "yes", please provide details including the account in which they are included.

Response

a. Remotes intends to deploy new enhanced meters to all customers (approx. 3400) in 2010 and 2011. The design for Remotes implementation will be based on the evaluation of the provincial Smart Meter implementation program.

b. Yes.

c. Detailed cost analysis is not available at this time. Remotes intends to leverage the Networks contracts and procurement process as much as possible in the acquisition of equipment. Remotes expects the costs to be similar to the costs associated with Hydro One Networks' implementation in rural Northern Ontario. Information about Hydro One Networks' costs will be available after its Northern rural installations/ pilot project is initiated. At this time, without having completed the design (which is not expected until the end of 2009), Remotes expects that the costs for implementing and installing the enhanced metering system will be approximately $200 per customer. This is a rough estimate.

d. No. Remotes' is not planning to make a separate Smart Meter application due to the limited purpose, scope and technology of Remotes' smart meter plan. See Exhibit H, Tab 1, Schedule 11 for more information. As such, Remotes' smart meter plan is more akin to a meter replacement program and it accordingly falls outside the provincial Smart Meter regime.

e. Remotes' intends to leverage the Hydro One Networks contracts and procurement process as much as possible. This technology will continue to be supported in Ontario.

f. Remotes will prepare a design and finalize the estimate for implementation in 2009. A detailed cost estimate is unavailable at this time. Based on the approximate cost of $200/customer noted in the response to part (c), the total cost of implementation is anticipated to be $700 thousand ($200/customer x 3400 customers).

g. No. A Smart Meter rate adder is not considered necessary due to the relatively minor amount of the costs for Remotes' smart meter plan, compared with those of other utilities.

h. No.

Ontario Energy Board (Board Staff) INTERROGATORY #13 List 1

Interrogatory

SMART METERS

13. Ref: Ex D1 / Tab 2 / Sch 1 / Pg 8

Remotes has indicated some initial investments in smart meter technologies amounting to $32,000. Please provide answers to the following questions with respect to this expenditure:

a. When was this expenditure incurred?

b. Please provide details and a breakdown of this expenditure.

c. Has this expenditure been included as part of the capital programs and added to rate base? If "yes", to which year's rate base has this expenditure been added?

Response

a. It is planned for 2009.

b. It is program initiation costs associated with planning and determining available infrastructure and modifications for implementation. Details are:
   - Installation of Meters $8,000
   - Travel $14,000
   - Meters and software $10,000

c. Yes, $32,000 has been included in the capital program with 50% of it included in 2009 rate base.

Ontario Energy Board (Board Staff) INTERROGATORY #14 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

14. Ref: Ex C1 /Tab 2/ Sch 1 / page 2

Please provide a table showing the actual OM&A expense for each of the years 2003 through 2007, 2008 (Bridge) and 2009 (Test). Please include in the table a breakdown of the OM&A by the following expense categories:

- o Generation
- o Distribution
- o Customer Care
- o Community Relations
- o Administrative, General and Other

Response

Please see the table below.

Summary of OM&A Actual and Budget ($000's)

	Actual	Actual	Actual	Actual	Actual	Updated Forecast	Updated Forecast
Description	**2003**	**2004**	**2005**	**2006**	**2007**	**Bridge 2008**	**Test 2009**
Generation	22,497	19,970	22,184	26,421	27,386	31,699	30,897
Distribution	1,035	1,055	1,461	1,540	1,241	1,757	1,648
Customer Care	1,174	1,680	3,394	4,394	1,874	1,637	1,800
Community Relations	16	34	238	214	413	577	599
Administration and Other OM&A	112	576	794	1,026	877	983	981
External Costs	201	119	43	64	49	83	90
TOTAL	25,035	23,434	28,114	33,659	31,840	36,736	36,016

Ontario Energy Board (Board Staff) INTERROGATORY #15 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

15. Ref: Ex C1 /Tab 2/ Sch 2 / page 8

Remotes notes that fuel costs are affected by three main factors: price, delivery and volume. Does Remotes have a variance account to track fuel price variances? If so, please describe the operation of this variance account and show the entries into the account for 2008 year-to-date, and provide the current balances in the account. When does Remotes' expect to dispose of the balances in the account?

Response

No, Remotes does not use a fuel variance account.

As a result of Remotes' break-even business model, cost and revenue differences between forecast and actuals do not result in a profit or loss to Remotes, but are offset by the Rural and Remote Rate Protection Variance Account. Recording to the RRRP variance account is done for total profit or loss not account by account.

On an operational basis, fuel variances are identified and analyzed monthly by comparing budget to actual in terms of volume/fuel efficiency and price.

Ontario Energy Board (Board Staff) INTERROGATORY #16 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

16. Ref: Ex C1 /Tab 2/ Sch 2

The market price of diesel fuel has declined since the time that the original Remotes application was filed (August) and Remotes has since provided an Update (November 28, 2008). Please provide the average 2009 diesel fuel price used to prepare the 2009 application. Please describe the process that Remotes used to forecast diesel fuel prices for the budget year 2009. Does Remotes forecast diesel fuel prices for the IRM years subsequent to 2009 (i.e. 2010 and 2011)? What is the price forecast that will be used for the years 2010 and 2011 and what is the basis of the forecast (e.g., is it based on NEB or EIA forecasts)?

Response

The average delivered fuel prices used are provided below, in C$/litre. These prices reflect commodity and delivery costs:

Original 2009 Submission (August)	Updated 2009 Submission (November)
$ 1.45	$ 1.39

Commodity
As there is no Canadian forecast for diesel fuel commodity prices, commodity pricing is confirmed through a high level analysis of futures contracts, which is the same methodology used by the NEB for its seasonal "outlook" on prices.

Delivery
Given that cost of delivery accounts for about 45% of the delivered price of fuel, delivery supplier contract data is critical in developing the forecast price. The delivery cost is forecast on the basis of expected supplier contracts and CPI data as provided by Global Insight. The long term nature of the supplier fuel contracts adds some stability to the cost of fuel transportation. Expected fuel costs are also impacted by the available storage in each community.

For business planning purposes we normally forecast on a five year rolling basis. The same fuel pricing methodology above is used for future years (beyond current and next, in this case beyond 2009 and 2010) but on a less detailed basis. Fuel pricing is forecasted on the basis of expected supplier contracts and CPI data as provided by Global Insight. Given the cost of delivery in relation to overall pricing, supplier contract data is critical in developing the pricing used, making NEB or EIA forecasts less relevant to our business. The long term nature of the supplier fuel contracts adds stability to the delivery component of the fuel price. Additionally, the current supplier fuel contracts are based on the previous month's fuel benchmarks, to avoid constant spot price variability.

The costing of the August original submission was largely based on March actual supplier prices and YTD costs incurred. The fuel pricing of the original submission was done prior to the summer 2008 fuel price spike.

The costing of the November revised submission was largely based on November actual supplier prices and YTD costs incurred. The fuel pricing of the revised submission was done after the summer 2008 fuel price spike and dramatic price fall.

Ontario Energy Board (Board Staff) INTERROGATORY #17 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

17. Ref: Ex C1 /Tab 2/ Sch 2 / page 8

Remotes notes that fuel costs are affected by three main factors: price, delivery and volume.

a) Does Remotes use any price risk mitigation strategies such as forward contracting or hedging?

b) Does Remotes have a fuel price hedging policy in place?

c) If the answers to the above questions are yes, please explain the strategies/policies in place.

d) If the answers to the above questions are no, please explain why not.

Response

a) No, Remotes does not use forward contracting or hedging strategies to mitigate price risk.

b) No, since Remotes does not hedge.

c) N/A

d) The complexity and costs of introducing a fuel hedging price risk mitigation strategy outweigh its benefits. In order to support hedging activities, Remotes would need a significant investment in risk management, monitoring and control procedures as well as extensive accounting disclosure and recording. Operational infrastructure and additional financing would need to be established and additional expert resources would need to be utilized.

It should also be noted that economic theory suggests that over the long-run a hedging program can do no better than to break even in terms of commodity price savings relative to the market price. That is, the savings achieved in those periods when hedged prices are less than the market price will over the long-run be offset by the opportunity losses incurred in those periods when the hedged price is greater than the market price, since to do otherwise would imply an ability to beat the market through forecasting skill. Thus, there is no net price benefit to hedging over the long-run and the reduction in fuel price volatility that a hedging program can provide comes with the added costs of administration and hedge purchase costs, which ratepayers would end up bearing.

As a result, in Remotes' view there is no ratepayer benefit to be gained from pursuing a hedging strategy given the costs involved and the lack of long-term benefits.

In an effort to create pricing stability Remotes has negotiated long term contracts with multiple suppliers via a competitive RFP process (see Exhibit H, Tab 1, Schedule 18). Current contract pricing is based on the average benchmark for the previous month, thus avoiding day to day spot market variability. Additionally, Remotes has mitigated some impact of rising fuel costs through First Nation fuel purchases and winter road maximization.

Ontario Energy Board (Board Staff) INTERROGATORY #18 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

18. Ref: Ex C1 /Tab 2/ Sch 2 / page 8

Remotes' evidence mentions that it has negotiated long term fuel delivery contracts with: multiple suppliers; directly with First Nations communities; and finally, that it has maximized winter roads deliveries among other measures. Please describe the nature of the contracts and indicate what savings or other benefits are expected from these contracts and the winter roads delivery strategy? In answering the question please discuss the costs of fuel delivery (i.e. transportation) separately from the costs of the commodity itself.

Response

Air delivery typically constitutes about 70% of fuel delivered to Remotes' communities, followed by year-round delivery at 13%, winter road delivery at 12% and First Nations (tank farms) at about 5%.

This mix of delivery modes with air delivery as the pre-dominant type reflects the relative lack of year-round road access, a short winter road season and the Remote Communities' load shape (heaviest during the winter months). Air delivery costs are 30 to 60 cents per litre greater than road delivery. The long-term fuel supply contracts are structured to establish delivery costs over a 2-3 year contract term and maximize quantity delivered to air-access communities during the critical winter road delivery season.

In 2007, a comprehensive tender process was used to establish contracts for supply of diesel and bio-diesel fuel and delivery over the winter road, all-season road and by air to a total of 18 Remote Community generating stations; air & winter road delivery for 12 sites; and all-season road delivery for 6 sites. The RFP was posted on Hydro One's website and advertised in the "Globe & Mail" and "Thunder Bay Chronicle Journal". Five proponents responded: Wasaya Airways, Morgan Fuels, Imperial Oil, Central Canada Fuels and Wilderness North Air. Following evaluation of the responses to the RFP, a primary and two secondary fuel suppliers for air delivery were selected along with a separate primary fuel supplier for road delivery and two primary suppliers for winter road delivery. The long term contracts consist of both commodity and delivery components. The commodity fuel costs fluctuate with market prices. The contracts stabilize the delivery component of the diesel fuel cost over the life of the contract with a variable fuel cost component.

The selection/utilisation of two suppliers for winter road supply has proven to provide an increase in winter road volume delivery to the community sites. As noted above, winter road delivery is preferable due to its lower costs per litre, arrived at through cheaper transportation, larger loads and less handling. Having secondary air-delivery suppliers in place served to enhance the competitive supply market in the region and contributed to capacity development of the new suppliers.

In 2008, Remotes as a result was positioned to take advantage of the best winter road network in recent years and was able to road-deliver fuel to 11 of our 12 air-access communities. Over 3 million litres of diesel fuel was delivered, a 35% increase over the previous 5 year average. This additional volume of just over 1 million litres, resulted in savings of approximately $450k, based on the lower cost of winter-road delivery and using the 45 cent mid-point of the range of per-litre savings noted above.

The success of winter road deliveries is largely contingent on cold weather, active road construction and external funding. The construction of a winter road involves packing snow and ice over various kinds of terrain including water, in an effort to achieve a drive-able trail. These roads are critical to community development since supplies for construction projects are brought in during this time. The key is to have enough ice to support the weight of the vehicle. Normally, the winter road season lasts only approximately 4-7 weeks for fuel delivery due to the heavy vehicle weight.

In addition to the increased winter-road delivery in 2008, local fuel supply contracts for 3.4 million litres of winter road fuel from First Nation tank farms were negotiated, representing a 25% increase over the previous highest quantity. The delivered price of winter road fuel, obtained from local tank farms, is approximately 30 cents per litre less than fuel supplied by air delivery. The estimated savings from the purchase of fuel from First Nation tank farms exceeded $1.0 million (3.4 million litres x 30 cents/ litre = $1 million), compared with air delivery.

Ontario Energy Board (Board Staff) INTERROGATORY #19 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

19. Ref: Ex C1 /Tab 2/ Sch 2 / page 3 and 4

With respect to the Renewable Energy Partnerships budgeted at $253,000 for 2009 please provide more specific details of the spending proposals, and the timetable of future work that may be forthcoming as a result of the studies. Please explain:

a) Are these one-time costs or would there be an on-going budget in the subsequent years of the IRM period?
b) When would the projects begin generating power?
c) Why was the funding moved from capital to operating expense?

Response

a. Remotes expects these costs will continue past 2009. Remotes facilitates and participates in the development of renewable energy projects with First Nation and First Nation partnerships for two reasons:
   - To reduce the amount of greenhouse gas emissions associated with supply of electricity to remote communities
   - To reduce long term operating costs through the initiation of projects that create economic development and capacity building in remote communities.

b. The estimated start-up date is Fall of 2010; however, this date is subject to various project milestones being met and is accordingly subject to change.

c. The original classification as capital was an oversight. Remotes' does not intend at this time to enter into an ownership relationship for these assets. Therefore, the costs were moved to expense.

Ontario Energy Board (Board Staff) INTERROGATORY #20 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

20. Ref: Ex C1 /Tab 2/ Sch 2 / page 3 and 4

With respect to the Renewable Energy Partnerships, Remotes mentions that it proposes to enter into Power Purchase Agreements with the First Nations and others and would buy electricity at a price based on the avoided cost of diesel fuel. Do the Power Purchase Agreements require Board approval? If so, when would Remotes expect to be filing the agreements?

Response

Remotes does not believe that Power Purchase Agreements ("PPA") entered into by Remotes would require Board approval, as in Remotes' view such approval is beyond the scope of the regulatory framework contemplated under the relevant legislation (the *Electricity Act* and the *OEB Act*). There are no provisions in either of those *Acts* that require Board approval of PPA. Accordingly, Remotes does not propose to file such agreements.

Instead, similar to the costs of diesel fuel and other generation-related costs, Remotes suggests that the prudence of the company's PPA procurement practices and the cost consequences of specific PPAs would be subject to the Board's review as part of a Remotes rates application, following the signing of a PPA.

Although there is currently no grid connection or generation plan within the Ontario Power Authority's Integrated Power System Plan for off-grid communities, there is a great deal of interest in developing renewable projects in remote off-grid communities, and the OPA has begun a consultation with First Nations on potential ways an OPA Standard Offer program could support renewable energy development in the 32 remote communities in the north. These projects will be higher cost than similar projects in the south due to transportation and access challenges. Therefore, incremental funding will be required to develop and construct these projects. In order to make these projects sustainable a higher cost for the energy produced is required. Remotes believes that short term (5 year) PPAs at or near the cost of diesel generation will help to facilitate these projects and drive down the consumption of diesel fuel. As grid connections are expanded, the OPA may wish to roll these PPAs into their portfolio of supply contracts at a lower, but sustainable rate.

Ontario Energy Board (Board Staff) INTERROGATORY #21 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

21. Ref: Ex C1 /Tab 2 / Sch 5 / page 1

With respect to the funding of the CDM programs,

a) What is the involvement of the OPA in terms of funding the programs?
b) What percentage of Remotes CDM costs are devoted to OPA funded CDM?
c) Are there any OPA funded CDM activities that Remotes is recovering through distribution rate revenues in 2009? If so, please provide the program and the associated cost.

Response

a) The OPA has not been involved to-date in funding Remotes' CDM programs as the OPA's legislated mandate is the integrated power system (i.e., on-grid), and all of Remotes' service territory is off-grid. Nonetheless, in 2006 the OPA engaged a consultant to develop a framework for electricity conservation programs in all First Nation communities across Ontario, including the off-grid communities in Remotes' service territory. Remotes collaborated with the OPA in developing this framework in Remote communities, including assisting in a pilot project in 2007. The OPA is compiling the research results, and our understanding is that the OPA plans to launch a program in 2009. Remotes plans to participate in this program if it is suitable for off-grid applications; however, details are not yet available. Once these details are available, a decision on whether to participate and apply for funding will be made.

b) None of the test year CDM costs are devoted to OPA-funded CDM, as the details related to the OPA program are not yet available. As noted above, Remotes' worked with the OPA in the delivery of their pilot project in 2007.

   Remotes' has assisted the OPA in the delivery of CDM material to Remote communities using available cargo space on aircraft. Remotes' has also used the OPA's CDM material in the delivery of conservation education in the schools.

c) No.

Ontario Energy Board (Board Staff) INTERROGATORY #22 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

22. Ref: Ex C1 /Tab 2/ Sch 5 / page 3

The evidence mentions that conservation programs helped customers save over one million kWh of electricity and 300,000 liters of diesel fuel during the last year. Please describe the elements of these programs and what each element contributes in terms of savings, including financial savings to customers. What are the expected savings of these programs for 2009 and have these savings been built into the budget?

Response

The table below shows the 2007 savings by program element.

Item	Number of Units	Estimated 2007 kWh Savings per Unit	Estimated 2007 Annual kWh Savings	2007 Estimated Diesel Savings (litres)
27 W CFL Lighting Exchanges	1,023	174	178,002	50,878
15 W CFL Lighting Exchanges	800	139	111,200	31,771
Xmas LED Lighting Exchanges	250	13	3,250	929
Outside light Motion Detectors	279	209	58,311	16,660
Block Heater Timers	140	810	113,400	32,400
Low flow shower heads	968	545	527,560	150,731
Faucet Aerator	400	34	13,600	3,886
Hot Water Pipe Insulation 10”	400	76	30,400	8,686
PowerCost Monitors	175	195	34,125	9,750
Total		2,097.5	1,069,848	305,671

The program elements were targeted at residential consumers, based on the assumption that most consumers use electricity in the first block and pay 7.75 cents per kWh, Remotes estimates that residential consumers saved a total of $82,913.22 as a result of this program

The 2009 Test Year program and forecast is shown below.

Item	Number of Units	2009 kWh Savings per Unit	2009 Annual kWh Savings	2009 Estimated Diesel Savings (litres)
27 W CFL Lighting Exchanges	150	174	26,100	7,457
Xmas LED Lighting Exchanges	75	13	975	279
Outside light Motion Detectors	75	209	15,675	4,479
Block Heater Timers	75	810	60,750	17,357
Refrigerator Replacement	81	760	61,560	17,589
Hot Water Tank Wrap	1,034	270	279,180	79,766
PowerCost Monitors	40	195	7,800	2,228
Total		2,097.5	452,040	129,154

Conservation initiatives are factored into the load forecast model through reduced average usages based on lower historical data. Efficiency improvements are realized in the load forecast model through improved operating efficiency ratios, reducing the litres burnt. The reduction in litres burnt is in turn reflected in the budget through reduced diesel fuel costs.

Ontario Energy Board (Board Staff) INTERROGATORY #23 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

23. Ref: Ex C2 / Tab 3 / Sch 1

Please provide a table showing the percentage increases in base salary and total compensation (salary wages and benefits) budgeted for 2009 (versus 2008) broken down by major employee grouping (e.g., executive, management, non-union and unionized workers).

Response

Please see the table below for the percentage increases in Base Salary and Total Compensation from 2008 Bridge to 2009 Test. As indicated in the pre-filed evidence at Exhibit C1, Tab 3, Schedule 1, the increase in compensation costs is driven largely by the increase in headcount to 41 full-time staff from 38. On a cost-per-employee basis, 2009 Test Year pay costs are budgeted to remain flat except for a 3% inflationary adjustment.

	col. (a)	col. (b)	col. (c)	col. (d)
Line No.	**Particulars**	**2008**	**2009**	**Increase**
	Base Salary			
1	MCP (Executive)	$ 578,712	$ 596,073	3%
2	PWU (Unionized)	1,881,300	2,099,217	12%
3	Society (Management	782,000	894,955	14%
4	Total	3,242,012	3,590,245	11%
	Total Compensation			
5	MCP (Executive)	677,212	697,523	3%
6	PWU (Unionized)	2,359,140	2,632,406	12%
7	Society (Management	830,500	950,510	14%
	Total	3,866,852	4,280,439	11%
	Headcount			
8	MCP (Executive)	5	5	0
9	PWU (Unionized)	24	26	2
10	Society (Management	9	10	1
11	Total	38	41	3

Ontario Energy Board (Board Staff) INTERROGATORY #24 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

24. Ref: Ex C1 /Tab 2 / Sch 1

Please list the productivity or cost efficiency programs at the utility that are either in place now or are contemplated to be in place at some future time. Please describe the nature of any such program and the scope, timing and benefits expected. What is the amount of cost savings that have been achieved so far?

Response

Remotes has focused on trying to attain efficiencies in the following areas of its operations:

- Fuel transportation and fuel contracting
- Generation automation and remote controls SCADA
- Improved Diesel Station Efficiency Standards
- Conservation and Demand Management Program
- Productivity Improvements

Fuel Transportation

Fuel is Remotes' largest single cost, and is affected by three main factors: price, delivery and volume. Because the commodity price for diesel fuel is outside of Remotes' control, Remotes has focused on controlling delivery costs and the volume of fuel required. As discussed in detail in H-1-18, savings related to improvements in the transportation, supply and storage of fuel were about $1.45 million in 2008 due to the increased use of winter road delivery for fuel and due to contracts with First Nations for fuel from First Nations' tank farms.

Generation automation and remote controls SCADA

Generation automation, the introduction of remote controls and the introduction of a SCADA system improved fuel efficiency. Prior to the automation of our generating stations, fuel efficiency averaged 3.03 kWh generated per litre of fuel. It now stands at about 3.55 kWh generated per litre of fuel, an efficiency gain of 17%. Based on the 2009 forecast, this improvement is expected to reduce annual fuel volumes by about 2.6 million litres, or about $3.7M. As the technology currently being used is coming to the end of life, renewal is planned in 2009. This project is discussed in Exhibit D1-02-1, page 5, lines 20-27.

Improved Diesel Station Efficiency Standards

Improvements to diesel station efficiency standards are ongoing. Two projects at road sites are planned in 2009 and are expected to save over 10,000 litres of diesel fuel annually or about $9 thousand per year, based on an average road site price of $0.92 per litre. Remotes' continues to examine changes in technology that reduce the station service loads in our generation stations. Changes to the Generation Design Guidelines include the use of variable frequency drives, use of secondary heating in staff housing and lighting efficiency improvements. This work will continue.

Conservation and Demand Management Program

Remotes' customer CDM program is expected to save approximately 129,154 litres of fuel in 2009. Based on average fuel prices, this will save approximately $180 thousand in diesel fuel costs in 2009, based on a delivered fuel price of $1.39 per litre. The CDM activities are expected to last for a number of years, so savings are expected to continue for as long as the specific CDM measure or technology is in use. This program is ongoing and is discussed in detail in Exhibit C1-2-5.

Productivity Improvements

Remotes has initiated an ongoing centralized schedule process for utilization of flights for personnel and cargo. To-date in 2008, this has led to 60 fewer flights than when the program was initiated, or a savings of about $294 thousand. Over the next several years, an initiative to store tools at generation stations is underway with the expectation that this will reduce cargo on aircraft and will allow for more employees per flight. This is expected to reduce the number of annual flights.

Remotes has also improved the results and efficiency of its collection process through the introduction of 2 collection trips to each community annually. This has reduced the amount of receivables from $1.7M in 2003 to $0.7M in 2008 and reduced collection trip costs due to fewer customers in arrears. This reduction of $1 million in fly-in community receivables results in approximately $60 thousand in annual carrying cost savings ($1M x approximate 6% cost of debt), as well as bad debt expense. Although difficult to quantify the savings in bad debts, it is reasonable to assume that timely action taken on accounts in arrears leads to a greater prospect of recovery and avoidance of a future bad debt.

This program has also resulted in reducing the average arrears per customer and the number of customer disconnections.

Ontario Energy Board (Board Staff) INTERROGATORY #25 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

25. Ref: Ex C1 /Tab 2/ Sch 1

For any extra Regulatory Expenses associated with this application (the 2009 COS rate case costs), please provide a breakdown by expense category of the amount requested for 2009. Is the amount proposed to be amortized over a 3-year time period?

Response

$100,000 is budgeted in 2009 for regulatory/hearing expenses. This budgeted amount includes estimated external legal costs, intervenor funding, and hearing costs. The regulatory expenses associated with this application are included under "Administrative and Other OM&A" expense category. The amount has not been proposed to be amortized over a 3-year period. Remotes' includes in its budget an amount of this size to cover program expenditures that may occur in any year that are not annual occurrences. Any over or under-spending in a given year relative to the base-year budget is effectively captured in the RRRP variance account, so that ratepayers are held harmless.

Ontario Energy Board (Board Staff) INTERROGATORY #26 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

26. Ref: Ex C1 /Tab 2/ Sch 1

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

As discussed in Exhibit H, Tab 1, Schedule 25, Remotes has budgeted for regulatory expenses but does not feel it is appropriate to amortize these costs over a period of more than a single year as each year Remotes does incur miscellaneous project costs. Additionally as noted in Exhibit H, Tab 1, Schedule 25, the RRRP variance account serves to hold ratepayers harmless from the impacts of overages or underages in actual expenses relative to the base-year budget.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #27 List 1</u>

<u>Interrogatory</u>

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

27. <u>Ref: Ex C1 /Tab 2 / Sch 1</u>

Please confirm that the utility 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.

<u>Response</u>

Remotes confirms that there are no one-time expenses in 2008 that have been inadvertently carried over into the 2009 budget. Expenses in 2008 include the costs associated with the clean up, investigation and monitoring of the fuel spill in Kingfisher, which was a one-time event. Due to the method of remediation that will be used for this spill, it is expected that these costs will be ongoing for a number of years. As a result, additional funds have been included in 2009 to carry on with the monitoring of the Kingfisher spill.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #28 List 1</u>

<u>Interrogatory</u>

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

28. <u>Ref: Ex C1 /Tab 2 / Sch 1</u>

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.

<u>Response</u>

Remotes' confirms that charitable donations are not included in the revenue requirement, and are not included in revenues sought from utility ratepayers.

Ontario Energy Board (Board Staff) INTERROGATORY #29 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

29. Ref: Ex C1 /Tab 2 / Sch 1

Please identify and explain any costs in the Remotes' 2009 budget associated with the implementation of the new International Financial Reporting Standards.

Response

As a publicly accountable enterprise (PAE), Hydro One is required to comply with IFRS commencing 2011. The overall IFRS conversion project is managed by Hydro One Networks' Corporate Finance group, with Remotes' share of costs reflected in the Corporate Common Functions and Services cost allocation. In addition, Remotes Finance staff will be participating in the conversion and the additional workload associated with this initiative will be managed with temporary resources in 2009 at an estimated cost of $40,000. At this time it is unknown what the long-term effect will be on resourcing at Remotes.

Ontario Energy Board (Board Staff) INTERROGATORY #30 List 1

Interrogatory

OPERATIONS, MAINTENANCE & ADMINISTRATIVE EXPENSES

30. Ref: Ex C1 /Tab 2 / Sch 1

Please identify any costs in the Remotes' 2009 budget associated with the Winter Warmth Program or any other special assistance programs to low income customers.

Response

No costs associated with the Winter Warmth Program are included in Remotes' 2009 budget as Remotes does not participate in this program. Remotes does not disconnect residential electrical services for non-payment during the winter months.

Remotes believes that the majority of its customers are low income and therefore it does not have any special assistance programs designed to help specific groups of its low income customers. Based on the 2005 Statistics Canada information that is available for the First Nation communities in Remotes' service territory, the median after-tax income for all families in Remotes' service territory ranges from $25,024 to $37,683 compared to $59,377 for all families in Ontario. Remotes' collection practices are therefore designed to assist all residential customers in paying their bills. For example, Remotes negotiates payment plans with residential customers who fall behind on their bills, and offers advice to customers on how to avoid high bills.

In Remotes' service territory, where as noted above customers tend to have lower incomes and where paying the full cost for electricity would result in higher bills, the Rural and Remote Rate Protection program ("RRRP"), although technically not based on income qualification, provides a benefit to low income customers and could be considered an assistance program.

Ontario Energy Board (Board Staff) INTERROGATORY #31 List 1

Interrogatory

LOAD & REVENUE FORECAST

31. Ref: Customer Forecast (Ex G/T1/S2/ page 3)

a. Remotes' is forecasting 3,411 customers in test year 2009 (Ex G1/T1/S2/page 3, Table 1). Please explain the methodology used to forecast number of customers in the test year.
b. Please provide historical customer numbers, by rate class for the period 2003 to 2008.
c. Please provide the 2006 Board approved customer forecast. Please identify and explain the reasons for a variance (if any) between the 2006 Board approved customer forecast and actual number of customers in 2006.
d. Please explain if Remotes' test year customer count forecast is consistent with one or more external forecasts (such as Housing Outlook reports from CMHC or the chartered banks). Please provide the references to the reports/forecasts used and explain how these forecasts support Remotes' projections for customer additions in the test year. If the external reports/forecasts do not support Remotes' proposed customer forecast, then please explain the reasons for any variances.

Response

a. In the evidence update, filed November 28, 2008, Remotes has updated the 2009 customer numbers to be 3,480. Forecast customer counts are largely based on historical data. Feedback is solicited from communities about upcoming construction or community programs that may impact future loads or customer counts. Annual planning meetings with INAC also help to identify community changes. Information from field employees who regularly work in these remote locations is also solicited to form an overall customer count.

b. As provided in the table below:

CUSTOMER COUNT SUMMARY	Act 2003	Act 2004	Act 2005	Act 2006	Act 2007	Fcast 2008
Residential - Year Round - Non Std. 'A'	2,566	2,487	2,486	2,463	2,440	2,426
Residential - Seasonal	121	131	126	127	139	139
General Service 1-Phase - Non Std. 'A'	285	279	280	283	286	286
General Service 3-Phase - Non Std. 'A'	26	26	26	26	26	26
Street Lighting	6	6	6	6	6	5
Residential - Road Access - Std. 'A'	16	18	18	18	18	18
Residential - Air Access - Std. 'A"	108	113	112	112	107	107
General Service - Road Access - Std. 'A'	33	31	28	25	25	25
General Service - Air Access - Std. 'A'	274	280	284	283	285	284
TOTAL SUMMARY	3,435	3,371	3,366	3,343	3,332	3,316

c. The Board did not approve a forecast for customer numbers in 2006. The methodology set out in the EDR model required the use of a historic year to determine customer numbers. The 2006 Board-approved customer forecast is the actual number of customers in 2004. Small changes in the number of customers each year are normal. Explanations for significant variances are provided in the Notes column. Residential declines are largely related to increased collection activity.

CUSTOMER COUNT SUMMARY	2006 Board-approved (= 2004 actual)	2006 Actual	Variance	Notes
Residential - Year Round - Non Std. 'A'	2487	2463	-24	The majority of the decline is due to increased collection activity.
Residential - Seasonal	131	127	-4	
General Service 1-Phase - Non Std. 'A'	279	283	4	
General Service 3-Phase - Non Std. 'A'	26	26	0	
Street Lighting	6	6	0	
Residential - Road Access - Std. 'A'	18	18	0	
Residential - Air Access - Std. 'A"	113	112	-1	
General Service - Road Access - Std. 'A'	31	25	-6	
General Service - Air Access - Std. 'A'	280	283	3	
TOTAL SUMMARY	3371	3343	-28	

d. External or third party reports (CMHC or chartered banks) and outlook are not relevant because they are not specific to the Remote communities we service. Forecast customer counts are largely based on historical data. Feedback is solicited from communities about upcoming construction or community programs that may impact future loads or customer counts. Annual planning meetings with INAC also help to identify community changes. Information from field employees who regularly work in these remote locations is also solicited, to form an overall customer count.

Ontario Energy Board (Board Staff) INTERROGATORY #32 List 1

Interrogatory

LOAD & REVENUE FORECAST

32. Ref: Customer Forecast

Please prepare a test year customer forecast by rate class using a simple trend method based on historical customer data from 2003 to 2007.

Response

Please see Table 1 and Table 2 below. The percentage annual change for the five year period was used to forecast 2008 and 2009 customers by class on a trended basis (Table 1), and the trended forecast is compared against the 2008 and 2009 updated submission (Table 2).

Remotes feels that a simple trend method is inappropriate for a number of reasons. For example, it does not properly reflect one-time anomalies, such as the 2007 spike in the Residential – Seasonal class (see Table 1). This spike is not expected to carry over into 2008 or 2009, but its effect is implicitly included in the forecast in the simple trending approach. The trending method also exaggerates the impact of a decline in customers in the Commercial Service – Road Access class that occurred in 2004 and 2005. This decline was stabilized in 2006 and 2007, as the data in Table 1 indicate, yet the trending method forecasts a continuing decline into 2008 and 2009.

Overall, the trended method forecasts a larger decline in customers than the Remotes submission for 2008 (see Table 2) and as such it does not reflect the more recent years' stability in customer numbers. Finally, the trended approach does not reflect in the 2009 forecast the expected 70 residential connections in Sandy Lake, due to the recent expansion of generator capacity in that community, and the 138 Marten Falls customers expected to be added as a result of that community's inclusion in Remotes' service territory.

Table 1 – Trended 2008 and 2009 Customer Forecast

CUSTOMER COUNT SUMMARY	Actual 2003	Actual 2004	Actual 2005	Actual 2006	Actual 2007	2003-2007 Annual % Change	(1) Trended 2008	(2) Trended 2009
Residential - Year Round - Non Std. 'A'	2566	2487	2486	2463	2440	-1.2%	2410	2380
Residential – Seasonal	121	131	126	127	139	3.7%	144	150
General Service 1-Phase - Non Std. 'A'	285	279	280	283	286	0.1%	286	287
General Service 3-Phase - Non Std. 'A'	26	26	26	26	26	0.0%	26	26
Street Lighting	6	6	6	6	6	0.0%	6	6
Residential - Road Access - Std. 'A'	16	18	18	18	18	3.1%	19	19
Residential - Air Access - Std. 'A"	108	113	112	112	107	-0.2%	107	107
General Service – Road Access - Std. 'A'	33	31	28	25	25	-6.1%	23	22
General Service - Air Access – Std. 'A'	274	280	284	283	285	1.0%	288	291
TOTAL SUMMARY	3435	3371	3366	3343	3332	-0.7%	3309	3287

Note (1,2): Trended 2008 = Actual 2007 x 2003-2007 Annual % Change; Trended 2009 = Trended 2008 x 2003-2007 Annual % Change

Table 2 – Comparison of Trended 2008/2009 Customer Forecast with Updated Submission

CUSTOMER COUNT SUMMARY	2008 Simple Trended Method	2008 Updated Submission	2009 Simple Trended Method	2009 Updated Submission (including Marten Falls)
Residential - Year Round - Non Std. 'A'	2410	2426	2380	2632
Residential - Seasonal	144	139	150	139
General Service 1-Phase - Non Std. 'A'	286	286	287	294
General Service 3-Phase - Non Std. 'A'	26	26	26	28
Street Lighting	6	5	6	5
Residential - Road Access - Std. 'A'	19	18	19	18
Residential - Air Access - Std. 'A"	107	107	107	118
General Service - Road Access - Std. 'A'	23	25	22	26
General Service - Air Access - Std. 'A'	288	284	291	310
TOTAL SUMMARY	3309	3316	3287	3570

Ontario Energy Board (Board Staff) INTERROGATORY #33 List 1

Interrogatory

LOAD & REVENUE FORECAST

33. Ref: Load Forecast

a. In addition to the description provided at Ex G1/T1/S2/page 2, please explain the load forecast methodology (by rate class, if the methodology varies by rate class) adopted by Remotes for forecasting test year load. If the load forecast was developed using regression analysis, then please provide the statistical results of the regression equations and identify the independent variables used to forecast load.

b. Please describe and quantify any 'adjustments' made to the base line data (Ex G1/T1/S2/page 2, lines 11 to 13) and the reasons for these adjustments.

c. Is the load forecast methodology adopted in this application similar to the methodology approved by the Board in Remotes' last rate case (2006)? If the proposed forecasting methodology is different from what was previously approved by the Board, then please identify the differences and explain the reasons for the revisions to the Board approved methodology.

Response

a. The load forecast is compiled using actual historical data on energy usage by community, customer class, and time period. This historical data provides the baseline starting point for forecasting total usage (KWH sold). Average customer usage by block and month is also determined based on historical data, and customer count is factored in. Remotes does not use regression analysis in preparing the load forecast. The methodology used is identical for all rate classes.

b. Adjustments are made to this baseline data on a go-forward basis for items such as average usage growth, expected customer changes and impacts of conservation programs. Feedback is solicited from communities about upcoming construction or community programs that may impact future loads. Annual planning meetings with INAC also help to identify community changes. Information from field employees who regularly work in these remote locations is also solicited, to form an overall forecast.

The two significant adjustments in the planning period are:

- The addition of approximately 70 Sandy Lake residential customers. A new plant has recently been commissioned in the community, resulting in the lifting of connection restrictions. At the start of the 2008 planning period, the work was expected to occur in early 2008, but has since been delayed until Q4 2008 and Q1/Q2 2009.

- The addition of Marten Falls as a service area (expected 138 customers), based on a community of similar population.

c. The load forecast methodology adopted in this application is similar to the methodology approved by the Board in Remotes' last rate case (2006). Average usage by customer type, and customer counts, remain as key variables. The methodology used considers a longer historical period, has more detailed community, tier, and monthly trend information and is more suitable for the management of the company's operations.

Ontario Energy Board (Board Staff) INTERROGATORY #34 List 1

Interrogatory

LOAD & REVENUE FORECAST

34. Ref: Load Forecast

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

a. What was the forecast 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

Please see the table below for the load variance for the requested years.

KWH's Sold	2004	2005	2006	2007	YTD August 2008
KWH's Sold	50,414,300	49,417,000	49,680,300	50,618,800	36,858,500
Projection	52,155,869	51,233,127	52,052,138	52,170,061	35,806,658
	(1,741,569)	(1,816,127)	(2,371,838)	(1,551,261)	1,051,842
	-3%	-4%	-5%	-3%	3%

The negative variances in the years 2004 to 2007 were primarily the result of ongoing and unpredictable delays in new customer growth in the Sandy Lake community, based on a delay in a scheduled generation upgrade (funded by INAC and managed by the First Nations community). As a result of the delay in the upgrade, a restriction on new connections was in place in the community. In 2008 the positive variance is primarily the result of higher-than-anticipated customer growth in Sandy Lake, after the upgrade was installed and the restriction on new connections lifted.

As noted in the Exhibit H, Tab 1, Schedule 33, in developing the load forecast Remotes consults with INAC and its communities to determine the likely timing and volume of customer additions; however, the accuracy of the forecast is dependent on third-party funding and other commitments being realized.

Ontario Energy Board (Board Staff) INTERROGATORY #35 List 1

Interrogatory

LOAD & REVENUE FORECAST

35. Ref: Weather Forecast

a. Of the proposed nine rate classes (Ex G1/T1/S2/page 3/ Table 1), please identify the rate classes whose load is weather sensitive?
b. Please explain if weather is used as an input variable in developing the test year load forecast for the weather sensitive rate classes?
c. Is the test year 2009 load forecast based on normal weather? If the load forecast is based on normal weather, then please explain how was the test year weather normal derived and utilized in the load forecast. If the load forecast is not based on normal weather, then please explain the rationale for this approach.

Response

a. All rate classes are weather-sensitive. Given that other utility services are not widely available in these Remote locations, electricity is used as a primary or secondary heating method by the majority of our customers, making all customers weather-sensitive.

b. Weather data is not an input variable. Given the wide territory covered and communities serviced reliable weather data is not available. To compensate, load data from 1999-onward is used in the load forecast, to create a natural smoothing of weather impacts.

c. 2009 forecast assumes that the weather will be similar to previous years.

Ontario Energy Board (Board Staff) INTERROGATORY #36 List 1

Interrogatory

INCLUSION OF MARTEN FALLS IN SERVICE TERRITORY

36. Ref: Ex A/T1/S1/P2; Ex A/T2/S1/P2; Ex C1/T2/S2/P7

Preamble: Remotes indicated in its application that it had filed for its revenue requirement on the basis that the community of Marten Falls would be included in its service territory. Remotes has not received approval for the inclusion of this community, but has stated that it is in final discussions with Indian and Northern Affairs Canada (“INAC”) to finalize this agreement. On November 28, 2008, Remotes filed an update indicating that given its current schedule, inclusion of Marten Falls in its service territory will not be effected until July 1, 2009.

The table at ExA/T2/S1/P2 indicates that the cost to serve Marten Falls increases revenue requirement by $666,000 for the 2009 rate year. Please indicate if this amount covers the cost to serve Marten Falls from July 1, 2009 forward, or if it includes some or all of the costs to serve Marten Falls during the period from May 1, 2009 to June 30, 2009 as well.

Response

The increase to revenue requirement related to Marten Falls covers the cost to serve from July 1, 2009 forward.

Ontario Energy Board (Board Staff) INTERROGATORY #37 List 1

Interrogatory

COST ALLOCATION AND RATE DESIGN

37. Ref: Ex A/T2/S1/P3

Preamble: Remotes has requested an increase to the final block rate of 25% (the block affecting highest use customers). Remotes received approval for, and has implemented the increases to, the other blocks, in its previous rates proceeding, EB-2005-0511. The implementation of the final block rate remains an implementation matter from its previous rates proceeding.

Remotes discussed, but did not file evidence to suggest that the changes to the block structure have had a positive effect on energy conservation.

Has Remotes prepared studies or collected data which indicates the conservation effects of the changes to block rate structure? If so, please provide a copy of these materials. If such studies have not been prepared please explain why not.

Response

Remotes has not prepared such studies. Remotes feels that in general higher prices discourage use, but Remotes does not know the strength of the relationship. However, comparing the residential average monthly kWh usage levels between 2004 and 2007, introduction of the blocks and their 2006 rates does not appear to have had a large effect.

Remotes notes that one of the purposes of a more expensive third tier is to discourage the increased use of electricity as primary heating in its service territory, as the use of electrical heat leads to higher operating costs and the need for more frequent generation upgrades. Given that there are heating alternatives available in the communities such as wood and propane, the higher block rate is also a means to encourage fuel substitution by customers. Until 1989, the use of electrical heat was discouraged through restrictions on service size. However, service size restrictions were ineffective and difficult to enforce. In 2003, Manitoba Hydro implemented tiered rates and began charging customers at cost for each kWh over 2,000 kWh per month to reduce this problem. Quebec Hydro (900 kWh per month) and the Northwest Territories (700 kWh per month) already limited the amount of subsidized electricity to discourage electrical heating use. Based on customer survey results, 24% of Remotes' customers relied on electrical heat in 2003. This increased to 27% in 2005 but levelled off in 2007. In working with customers connecting to the distribution system, Remotes has been able to discourage the installation of electrical heat by citing the tiered rate structure. As noted in the evidence at Exhibit G1, Tab 1, Schedule 1, Remotes expects to raise the rate in the third block over time to reflect actual costs which will assist in this regard.

Ontario Energy Board (Board Staff) INTERROGATORY #38 List 1

Interrogatory

COST ALLOCATION AND RATE DESIGN

38. Ref:: Ex G1/T2/S1/P4-5

Preamble: Remotes has provided the average impact to customers in each of the classes affected by changes to the inclining block rate. The increase to the final block rate, discussed above, results in bill impacts that range from 9.5% to 12.7% increases for certain customer profiles in G1 and G3 classes, as provided by Remotes.

a. Please indicate the rate impacts on and number of Residential Year Round (R2) customers, and other accounts, where the bill increases are greater than the 12.7% increase discussed above. Please indicate the percentage, and total number of R2 customers affected by increases to their rates in excess of 15%, year-over-year from 2008 to 2009.
b. Does Remotes believe that the R2 customers affected by this increase are able to make further conservation gains? Please explain.

Response

a. 25 Residential Year Round (R2) customers are forecast to have impacts greater than 12.7%. These forecast individual-customer impacts average 15.7%, and range from 12.8% to 20.2%. While these 25 customers represent approximately 1% of the total number of customers in the Residential Year Round (R2) class, they represent 2.7% of the class kWh.

   Of the 25 R2 customers with impacts above 12.7%, 14 Residential Year Round (R2) customers are forecast to have impacts greater than 15%. These forecast individual-customer impacts average 17.4%, and range from 15.2% to 20.2%. While these 14 customers represent approximately 0.6% of the total number of customers in the Residential Year Round (R2) class, they represent 1.5% of the class kWh.

b. An average Residential customer in Remotes' service territory uses 1,157 kWh per month, as compared to the customers in part (a) above, who use an average of over 2,600 kWh per month. The customer in part (a) with the highest average monthly use has a monthly average use of over 5,700 kWh. In light of the very high usage of the customers who would face increases greater than 12.7%, Remotes believes conservation opportunities are available.

Ontario Energy Board (Board Staff) INTERROGATORY #39 List 1

Interrogatory

DEFERRAL AND VARIANCE ACCOUNTS

39. Ref: EB-2005-0511/Decision/P4

Preamble: In its Decision setting rates for 2006 (the "2006 Decision), Remotes was allowed a stabilization fund as part of the Rural and Remote Rate Protection Variance Account ("RRRP") variance account for the mitigation of certain "ongoing risks". The two risks discussed were increased diesel fuel costs, and the potential inclusion of new communities in its service territory.

a. Please provide a complete list of items that the Board has explicitly indicated can be recorded in the RRRP variance account for future rebate or recovery.
b. Please indicate what regulatory precedent Remotes relies upon for recording a provision for bad debt in a variance account.
c. Please indicate the regulatory precedent that Remotes relies upon for provision of bad debt in the RRRP variance account, in light of the Board's findings in the 2006 Decision.
d. What is Remotes approved policy on Bad Debt Expense? In what manner does this policy find applicability to the RRRP account?

Response

a. The 2006 Application indicated that the RRRP Variance Account was established in order to track differences between Remotes' revenues and costs. Through an Interrogatory response (Exhibit J, Tab 1, Schedule 3, included as Attachment 1 to this response) Remotes indicated that the difference between the revenues and costs of the business are posted to the RRRP Variance account, and listed the following types of revenue and cost involved:

   Energy revenue
   Late payment charge revenue
   External revenue

   Fuel expense
   Operations, maintenance and administrative expense
   Depreciation
   Asset removal expense
   OPEB amortization
   Amortization of environmental regulatory assets (LAR)

Financing charges
Capital tax

In addition to a discussion of the risks related to diesel fuel costs and the potential inclusion of new communities, the 2006 Decision stated that "The Board is satisfied with the approach taken by Remotes in the application of this account, and notes this account will be reviewed for disposition by the Board on an ongoing basis."

b. The RRRP variance account is used to track differences between Remotes' revenues and costs. The intent of the account is to serve as a tool to achieve a breakeven result over time. This approach is consistent with the operation of the Remotes business on a full cost-recovery basis with no equity return and 100% debt financing. With no opportunity for the shareholder to earn a return, business risks such as a variance in bad debt costs or in all other costs are to the ratepayers' account. Remotes is not aware of any regulatory precedents for this type of variance account; however, it is consistent with standard cost-recovery principles. The variance account balance reflects the total cumulative difference between the Board-approved bad debt expense and the actual bad debt expense. It should be emphasized, however, that recording to the RRRP Variance Account is done for total profit or loss, not account by account.

c. Remotes interprets the Board's findings quoted above related to the application of the account to mean that the Board is satisfied with Remotes' use of the account as a tool to achieve a break even result over time.

d. Please see Exhibit H, Tab 1, Schedule 40 for details regarding Remotes' policy on Bad Debt Expense. See the response to part (b) above for its applicability to the RRRP variance account.

RP-2005-0020/EB-2005-0511 Exhibit J, Tab 1, Schedule 3

Ontario Energy Board (Board Staff) INTERROGATORY #3 List 1

Interrogatory

Summary of Application (Exhibit A)

Tab 2, Schedule 1, page 2, starting at line 26 identifies that "In 2003, Remotes established a balance sheet revenue variance account to track differences between its revenues and costs."

What formed the basis for the approval of this account? What revenues and what costs go into the determination of the variance? Was the establishment of this account approved by the OEB? If so, please provide the approval. Please confirm that this variance account is the same as the account referenced on page 3 starting at line 20 identified as "the Rural and Remote Rate Protection Variance Account" and also the "RRRP Variance Account" referenced in Exhibit C, Tab 2, Schedule 2.

Response

a) The variance account was established pursuant to O. Reg. 442/01.

On December 18, 2002, Remotes received a letter from the OEB relating to customer rates and Rural and Remote Rate Protection. That letter established Rural and Remote Rate Protection at $21.1M for 2002.

Since 2003, Remotes has reported the quarterly balance in the account to the OEB. The RRRP level for Remotes has been set at $21.1M for 2002, 2003, 2004 and 2005.

b) The difference between the revenues and costs of the business are posted to the Revenue Variance account. The following lists the types of revenue and cost involved:

Energy revenue
Late payment charge revenue
External revenue

Fuel expense
Operations, maintenance and administrative expense
Depreciation

Asset removal expense
OPEB amortization
Amortization of environmental regulatory assets (LAR)
Financing charges
Capital tax

The variance account referenced on page 3, line 20, is the same as the "Rural and Remote Rate Protection Variance Account" and the "RRRP Variance Account" referenced in Exhibit C, Tab 2, Schedule 2.

Ontario Energy Board (Board Staff) INTERROGATORY #40 List 1

Interrogatory

DEFERRAL AND VARIANCE ACCOUNTS

40. Ref: Ex C1/T2/S4/P1-3

Preamble: Further details around Remotes practices for recording bad debt could be clarified. Please answer the following:

a. Please provide a continuity schedule from 2005-2009 which provides the following:
   - o Bad debt expense
   - o Allowances for doubtful accounts
   - o Accounts receivable
   - o RRRP variance account

The continuity schedule should indicate the opening and closing balances, additions, subtractions, and any interest accrued for each category listed above, and any other major category not listed here.

b. For the line item in part (a), "RRRP variance account" (Account 2320), please provide a specific breakdown outlining the main drivers which compose the balance in this account, i.e. fuel costs, bad debt, expansion of service territory, etc. If there are other major contributing categories, please add them to the table and make use of relevant descriptors.

c. Please provide the journal entries for bad debts recorded in the RRRP variance account from 2006 to present, clearly indicating the matching credit and debit accounts for each entry, and including how the bad debt variances were calculated.

d. Remotes cites in its application at ExC1/T2/S4/P3 that there was a "change in understanding" with INAC regarding backstopping of bad debts. Please provide a copy of the agreement with INAC regarding backstopping of bad debts. Please comment on how this agreement gave rise to "higher than plan[ned]" bad debt costs totalling $2.758M specifically explaining in detail any changes to Management's policy to recognize bad debts.

Response

a. Continuity schedules for the requested balance sheet accounts are provided below:

Allowance for Doubtful Accounts - Energy (Includes Long-Term Portion)

	2005	2006	2007	2008	2009
Opening Balance	(788)	(2,746)	(5,894)	(5,532)	(5,135)
Provision	(1,958)	(3,148)	362	397	(205)
Ending Balance	(2,746)	(5,894)	(5,532)	(5,135)	(5,340)

Gross Account Receivable

	2005	2006	2007	2008	2009
Beginning Balance	12,760	14,173	16,235	14,290	11,899
Activity	1,413	2,062	(1,945)	(2,391)	3,055
Ending Balance	14,173	16,235	14,290	11,899	14,954

Remote Rate Protection Revenue Variance - Liability

	2005	2006	2007	2008	2009*
Opening Balance	(6,349)	(6,840)	(3,219)	(1,464)	4,013
Operating Costs	32,305	37,775	35,957	41,164	40,557
Financing Charges	1,917	1,329	1,142	1,628	1,720
PILS	189	(584)	(427)	(2,250)	223
Customer Rates Revenue	(13,794)	(13,797)	(13,820)	(13,968)	(18,668)
Revenue from RRRP	(21,108)	(21,102)	(21,097)	(21,097)	(27,845)
RRRP Variance amount	(491)	3,621	1,755	5,477	(4,013)
Ending Balance	(6,840)	(3,219)	(1,464)	4,013	(0)

*2009 Assumes historical RRRP recovery and no variance for year

Note that Bad Debt is an Income Statement item which continuity schedules are not applicable to. Components of bad debt over time are however shown in the table below:

Bad Debt Expense

	2005	2006	2007	2008	2009
Bad Debt Write-off and Recovery	235	59	1,134	128	780
Provision	1,958	3,148	(362)	397	(205)
Energy Related Bad Debts	2,193	3,207	872	525	575

b. As a result of Remotes' break-even business model, any difference between customer rate revenue, RRRP revenue and expenses incurred are booked to the Rural and Remote Rate Protection Variance Account (RRRPVA). Recording to the RRRPVA is done on a consolidated basis for total profit or loss not account by account. See Exhibit F1, Tab 1, Schedule 1 for further details.

c. As discussed above bad debt entries are not directly journalized to the RRRP account. Bad Debt is included in the Operations, Maintenance and Administration line in the Statement of Operations on the Financial Statements and in detail in Exhibit C1, Tab 2, Schedule 4. The RRRP entries reflect the amounts required to achieve a Net Income of $0.

d. Remotes' does not have a formal agreement with INAC with respect to the backstopping of First Nation (Standard A) arrears or bad debts. In practice, however, Remotes always worked closely with INAC to collect outstanding balances. INAC funds essential services on reserves, and can intervene if a First Nation does not meet the terms of a funding agreement, including the payment of associated bills. In 2005, Remotes learned that INAC had changed its approach to allow for more First Nation autonomy in these matters. As a result, Remotes is less confident about its ability to collect these outstanding balances

Following the meeting Remotes decided to review its allowance for doubtful accounts.

Upon review of the allowance, it was management's opinion that the allowance was not adequate so the allowance rates were updated for each aged receivable category as follows:

2 years past due and greater	100%
1 year past due and <2 years	30%
240 days past due and <1 year	25%
120 days past due and <240 days	20%
60 days past due and <120 days	15%
<60 days and adjustments	0%

As with the previous methods, the allowance continues to be reviewed and adjusted for specific large or unusual receivable balances using management judgment.

Ontario Energy Board (Board Staff) INTERROGATORY #41 List 1

Interrogatory

DEFERRAL AND VARIANCE ACCOUNTS

41. Ref: Ex F1/T1/S1/P1; Ex A-9-1/Attachment 3

In Ex F1/T1/S1/P1, for 2007, Hydro One Remote Communities reports the following amounts:

-$1,464,000 for RRRP Variance Account (USoA 2320) and this agrees to Note 7 of the 2007 Audited Financial Statements (Ex A-9-1/Attachment 3, Note 7)

For this account please provide the following:

a. State the amount reported to the Board for the account in Hydro One Remote Communities' 2007 annual filing pursuant to RRR 2.1.7.
b. Identify the components of any difference between the amount in a) and the amount reported in ExF1/T1/S1/P1.
c. Explain each component of any difference identified in b). Please include an explanation of which other accounts now contain any such difference by component.
d. State where the amount in a) above has been reflected in Hydro One Remote Communities' 2007 audited financial statements and identify the line item in the audited financial statements.
e. State which value should be relied upon in this proceeding, and, if different from the value reported in the 2007 audited financial statements, explain why the Board should rely on such different value

Response

a) The amount reported to the Board in Remotes' 2007 annual filing as USofA 1508 was ($1,451,572).

b) The amount reported to the Board and the amount of ($1,464,080) reported in the audited financial statements differs by ($12,508). The difference between the amount reported in the January deferral account filing and the trial balance that ties to the audited financial statements exists due to post-filing adjustments made when preparing the audited financial statements.

c) The difference identified in b) relates to timing of reporting and is related to fuel accruals.

d) The amount of ($1,451,572) that was reported to the Board in January 2008 is not reflected in the financial statements. The financial statements reflect the post-filing adjustment made when preparing the audited statements.

e) The amount reported in the audited financial statements ($1,464,080) is the correct value.

Ontario Energy Board (Board Staff) INTERROGATORY #42 List 1

Interrogatory

DEFERRAL AND VARIANCE ACCOUNTS

42. Ref: ExC1/T2/S4/P1/Table 1

Preamble: Remotes provided an overview of Remotes' historical bad debt expense. That table is reproduced below for ease of reference.

Table 1
Customer Care OM&A
($ Thousands)

Category	Historic			Bridge	Test
	2005	2006	2007	2008	2009
Customer Care	1,201	1,187	1,002	1,147	1,230
Bad Debt	2,193	3,207	872	525	575
Total	3,394	4,394	1,874	1,672	1,805

a. Board staff notes at Ex C1/T2/S4/P1/Table 1 that bad debt is $3.207M and $0.872M for 2006 and 2007 respectively. Please explain whether these amounts were reduced by the bad debt amounts recorded in the RRRP variance account. If not, please explain.

b. Bad debt expenses are $0.525M and $0.575M for 2008 and 2009, respectively. Please explain the reasons for the bad debt reductions in these years as compared to 2006 and 2007, noted in (a) above, reduced significantly from the 2006 level (Table 1, Customer Care OM&A).

c. Usual practice in the electricity sector is to use audited numbers for the last fiscal years as the basis for balances in the deferral and variance accounts for disposition, with interest forecasted up to the start of the new rate year.

   I. Please provide the regulatory precedent for principal transactions being forecasted beyond December 31, 2007 for accounts requested for disposition.

   II. Please recalculate the amount requested for recovery through revenue requirement on the basis of the usual practice outlined above.

Response

a. Bad Debts amounts are not directly recorded in the RRRP Variance account. As a result of Remotes' break-even business model, cost and revenue differences between Board approved rates and actuals are offset by the Rural and Remote Rate Protection Variance Account. Recording to the RRRP is done on a consolidated basis for total profit or loss not account by account. Any profit or loss, including the bad debts amounts listed above, are included in the Remote Rate Protection Variance Account.

b. Bad debt amounts between 2005-2007 should be considered unusual, given the change in bad debt allowance provision related to Standard A arrears as discussed in Exhibit C1, Tab 2, Schedule 3. It is expected that bad debts will return to lower amounts more similar to levels pre-2005. The large allowance changes noted in 2005-2007 were required for significantly aged outstanding arrears. Since the provision has already been established for these historical arrears, any significant repayment will have a positive impact to the business, through the lowering of Accounts Receivable and the recovery of provision amounts. Payment plans will continue to be important in the upcoming years.

c. Remotes is the view that the RRRP Variance account should follow a similar approach as the Rural and Remote Rate Protection Account established under O.Reg 442/01. O.Reg 442/01, s. 4(2) says that:

> *"For each year, the Board shall calculate the amount by which Hydro One Remote Communities Inc.'s forecasted revenue requirement for the year, as approved by the Board, exceeds Hydro One Remote Communities Inc.'s forecasted consumer revenues for the year."*

Remotes believes the amount of Remotes' forecast RRRP subsidy as determined above should be included in the annual RRRP re-set, consistent with this regulation, and then trued-up the following year consistent with s. 5(13). Subsection 5(13) of O.Reg 442/01 says:

> *"If the amount collected under subsection (5) in a year is less than the total amount of rate protection available for eligible consumers […], the difference […] shall be added to the amount necessary to compensate distributors who are entitled to compensation under subsection 79(3) of the Act for the following year."*

I. In Remotes' case, the true-up of its RRRP variance account would include the balance in that account up to the new rate year. For that reason, Remotes believes that it is appropriate to include in the amount requested for disposition the forecast balance in its RRRP variance account up to December 31, 2008. This approach is consistent with the intent and operation of the Regulation. It should be noted that an audited actual balance for the account as at Dec. 31, 2008 will be available by the time a decision is rendered in this case and it could be included in a revised revenue requirement at that time in place of the current forecast, if the Board considers it advisable.

II. The following schedule shows the actual December 31, 2007 balance of the deferral account. No interest is applied to the RRRPVA given that the intent of the account is to serve as a tool to achieve a breakeven operating result. Adding interest would itself impact that year's operating result, causing a revision to the amount added to or withdrawn from the RRRPVA :

in $000's	**Dec. 31, 2007**
RRRP Variance Account	1,464

As noted in the part (a) response, an audited actual balance for the account to Dec. 31, 2008 will be available by the time a decision is rendered in this case.

Ontario Energy Board (Board Staff) INTERROGATORY #43 List 1

Interrogatory

DEFERRAL AND VARIANCE ACCOUNTS

43. Ref: Ex G1/T1/S2/P6; Ex C/T2/S4/P4/Table 1

Preamble: Remotes has requested clearance of the RRRP variance account, which is forecast to be in a deficit position of $4.013M by the end of 2008. Remotes has requested recovery from the RRRP variance account be added to the amount to be recovered through RRRP rates, and in turn revenue requirement.

a. Please indicate why Remotes has chosen to request recovery through revenue requirement rather than disposition through a rate rider.
b. Please provide a table of rate classes and the accompanying rate riders that would result if the Board were to authorize the recovery of the requested accounts over a period of one, two, or three years;

Response

a. Disposition through a rate rider would require that a rider be applied to RRRP rates, not to Remotes' customer rates, given that RRRP is used to fund the costs of providing service to remote communities in excess of amounts recovered through customer rates. Therefore, the Remotes' RRRP variance account must be cleared to RRRP and the 2008 deficit balance in Remotes RRRPVA must be collected through RRRP revenues. Currently there is no rate rider applied on RRRP rates and no mechanism to do so. For that reason, Remotes is requesting recovery of the deficit position of the RRRP variance account through revenue requirement and hence from RRRP.

b. Not applicable, as there is no mechanism to establish a rate rider on the RRRP rate. Please see the response in part (a) above.

Ontario Energy Board (Board Staff) INTERROGATORY #44 List 1

Interrogatory

DEFERRAL AND VARIANCE ACCOUNTS: RRRP AND DIESEL FUEL COSTS

44. Ref: ExF1/T1/S1/P1; ExC1/T2/S4/P1/Table 1; ExA/T3/S1/P6; ExC1/T2/S2/P8 (updated evidence)

Remotes has updated the table at ExF1/T1/S1/P1 indicating that the deficit position for the 2008 bridge year had increased from $2.577M to $4.013M, an increase of $1.436M. Remotes provided no update to the passage, "due primarily to increases in the cost of diesel fuel ($5M) and the need to create an adequate provision for bad debts ($4M)."

The table at ExC1/T2/S4/P1/Table 1, Customer Care OM&A, indicates that bad debt expense remained unchanged in the application.

a. Please provide an update to the 'passage' above, indicating the individual contributions of diesel fuel and of bad debt costs to the RRRP variance account.
b. At ExA/T3/S1/P4, Remotes indicates that it typically consumes between 14 and 17 million litres of diesel fuel per year in its operations. Please indicate what figure Remotes has used for its diesel usage forecast for 2008 and for 2009, the corresponding price for both the original and updated application evidence, used to determine the RRRP balance attributable to increased diesel fuel costs.
c. Please provide the underlying data for the table in the section "Challenges and Opportunities Facing Remotes" presented at ExA/T3/S1/P6, for both the original and updated application.
d. Please indicate why Remotes believes the level of its diesel fuel usage forecast is appropriate, especially in light of conservation initiatives and efficiency capital projects that Remotes cites in evidence.
e. What input data did Remotes consider in preparation of its original "cost of diesel fuel" forecast? (Filed August 29, 2008)
f. What input data did Remotes consider in preparation of its updated "cost of diesel fuel" forecast? (Filed November 28, 2008)
g. Retail diesel prices reached approximately 4.70USD/gallon in July 2008, and are now at approximately 2.60USD/gallon.[1] The price of diesel fuel is now at price levels comparable to 2005 levels. If the price of diesel fuel stays at current price levels, does Remotes foresee a significant credit contribution from diesel fuel prices to the balance in RRRP variance for 2009, 2010, and for 2011? How would Remotes propose to dispose of a credit balance in the RRRP account?

[1] Energy Information Administration. On-Highway diesel fuel prices. www.eia.doe.gov

Response

a. The passage should read as follows:

> "Over the past three years, due primarily to increases in the cost of diesel fuel ($7M) and the need to create an adequate provision for bad debts ($3M), Remotes has drawn down the balance in the RRRP variance account."

Note that the variances are for 2006 to 2008 based on the 2006 EDR Board-approved amounts. The bad debts did not change as a result of the update; however, the amount has been corrected above from $4M to $3M due to an oversight in the pre-filing.

b.

	Original 2008	Update 2008	Original 2009	Update 2009
Fuel Expense - Remote Communities	$20,742,465	$22,981,066	$23,113,951	$21,649,003
Litres (Actual/Projection)	14,909,014	14,977,119	15,980,438	15,562,773
Average Per Litre	$ 1.39	$ 1.53	$ 1.45	$ 1.39

c. The underlying data for the table in Exhibit A, Tab 3, Schedule 1 on the delivered price of a litre of diesel fuel is shown below.

	Fuel Expense	Litres Burnt (Actual/Projection)	Average Cost Per Litre
2003	$ 15,312,842	16,342,407	$0.94
2004	$ 13,017,141	14,440,938	$0.90
2005	$ 15,288,936	14,157,441	$1.08
2006	$ 18,607,662	14,363,464	$1.30
2007	$ 19,319,045	14,781,296	$1.31
Original 2008	$ 20,742,465	14,909,014	$1.39
Update 2008	$ 22,981,066	14,977,119	$1.53
Original 2009	$ 23,113,951	15,980,438	$1.45
Update 2009	$ 21,649,003	15,562,773	$1.39

d. Remotes believes the level of its diesel fuel usage forecast is appropriate. Although conservation initiatives and generation efficiency capital projects do have an impact on fuel burnt, there remains an overall reliance on diesel fuel. Conservation initiatives have been extremely positive but only impact diesel litres used by about 2% (e.g., 300,000 litres from Exhibit C1,Tab 2, Schedule 5, page 3 divided by 15M litres = 2%). Large technological advances to improve generation efficiency are not expected.

Major improvements to technologies to enhance generation efficiency were implemented in prior years, similar to that of the auto industry.

e. Fuel prices are derived via existing vendor contracts and the outlook for fuel commodity prices. Commodity pricing is confirmed through high-level analysis of market trends based on futures contracts. The costing of the August original submission was largely based on March actual supplier prices and YTD costs incurred. The fuel pricing of the original submission was done prior to the summer 2008 fuel price spike.

f. Fuel prices are derived via existing vendor contracts and the outlook for fuel commodity prices. Commodity pricing is confirmed through high-level analysis of market trends based on futures contracts. The costing of the November updated submission was largely based on November actual supplier prices and YTD costs incurred. The fuel pricing of the revised submission was done after the summer 2008 fuel price volatility.

g. Although the US dollar fuel price quoted in the above has fallen dramatically, many savings are not realized given the corresponding fall in the Canadian dollar and the requirement for more expensive air delivery for the majority of litres currently consumed, notwithstanding the success of recent efforts to increase winter-road deliveries (as discussed in Exhibit H, Tab 1, Schedule 18). Remotes' believes that current fuel prices are volatile. Whether fuel prices will result in an overall credit balance in the RRRP variance account in 2009, 2010 and 2011 is a matter of speculation.

Any over or under collection captured in the RRRP variance account should be reviewed annually by the OEB, and the RRRP rates adjusted accordingly.

Ontario Energy Board (Board Staff) INTERROGATORY #45 List 1

Interrogatory

SPECIFIC SERVICE CHARGES (SSC)

45. Ref: Ex E3/T1/S1/P2

Preamble: In the application Remotes discusses negotiated payment plans in certain communities.

With respect to reduction of arrears please provide the following:

a. A list of the communities where negotiated payment plans have been arranged and the parties to the agreements; and
b. A copy of the agreement for one of Remotes' representative service territories.

Response

a. There are currently five communities with negotiated prepayment plans. The two parties involved in each case are Remotes and the respective Community Chief and Council.

b. A generic version of an agreement is attached as Attachment 1.

Letter of Understanding on First Nation Energy Arrears Payment Plan

Hydro One
Remote Communities Inc.
680 Beaverhall Place
Thunder Bay On P7E 6G9
www.HydroOne.com

Tel: (807) 474-2800
Fax: (807) 475-8123
Billing Toll Free: 1-(800) 465 5085
Operations Toll Free: 1(888) 825 8707

Letter of Understanding on First Nation Energy Arrears Payment Plan

This letter will document Hydro One Remote Communities Inc.'s ("Hydro One") and x First Nation's agreement on a payment plan (the "Plan") to assist the x First Nation in managing their energy arrears owing to Hydro One as of *date*. This Letter of Understanding applies to accounts listed in Attachment 1. The Plan is as follows:

- X First Nation currently owes Hydro One the sum of **$x** for outstanding First Nation energy arrears. A summary of the accounts is listed in Attachment "1" (the "Outstanding Arrears").
- First Nation will pay Hydro One the sum of **$x** on *date*
- X First Nation will pay current Hydro One bills on the accounts identified in Schedule 1, for *date(s)* by their due dates.
- X First Nation will pay Hydro One over the course of this agreement, **$x** (the "Arrears Payment") broken down on a monthly basis as indicated in Attachment "2" starting with the *date* billing and until such time as the outstanding arrears described in Attachment "1" (the "Outstanding Arrears") have been reduced to zero.
- X First Nation will also pay their regular monthly energy accounts identified in Schedule 1, to Hydro One, in addition to the payments specified in this payment plan as well as any new accounts opened over the course of this agreement.
- X First Nation payments must be received by the Hydro One Remotes Office in Thunder Bay by the date identified on the monthly bills.
- In recognition of x First Nation's efforts in paying the Outstanding Arrears, Remotes will waive future monthly interest charges on the Outstanding Arrears provided that the First Nation makes all Arrears Payments and pays its regular monthly bill;
- Failure to pay Hydro One any Arrears Payments or the x First Nation's regular monthly bill will result in the application of current and future interest on the Outstanding Arrears to the x First Nation's account, owing at the time of the default. Hydro One also maintains the right to disconnect any services, including Standard A accounts, as well as the right to restrict future service connections, in the event of non-payment for either current bills or arrears payments.
- Under this arrangement, the x First Nation is encouraged to, at its own discretion (respecting time and amount), and without any penalty, over the duration of the agreement make lump sum or balloon payments to Remotes that will be applied directly to and reduce the arrears owed to Remotes.
- Penalties will not be imposed when arrangements are made with Hydro One to provide time to resolve a billing discrepancy and/or if the payments are not received due to reasons beyond the x First Nation's control (ie. Program funding deposits from Indian and Northern Affairs Canada or gaming commission revenues are delayed).
- This agreement will be subject to a review in x years by Hydro One and First Nation in *date*.

This Letter may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

Hydro One
Remote Communities Inc.
680 Beaverhall Place
Thunder Bay On P7E 6G9
www.HydroOne.com

Tel: (807) 474-2800
Fax: (807) 475-8123
Billing Toll Free: 1-(800) 465 5085
Operations Toll Free: 1(888) 825 8707

The parties agree that this letter accurately reflects the understanding reached by Hydro One Remote Communities Inc. and x First Nation. The receipt and sufficiency of the consideration exchanged for this agreement is acknowledged and the intent of the parties to be bound by this agreement is confirmed by the signature of their duly authorized representatives below.

Hydro One Remote Communities Inc

____

I have the authority to bind the corporation.
Rick Rhodes
Director, Hydro One Remote Communities Inc.

x FIRST NATION by the Chief of the x First Nation and a majority of the Council of the x First Nation at the x Indian Reserve on this ___ day of _________, *year*.

Witness	Chief
Witness	Councillor
Witness	Councillor
Witness	Councillor
Witness	Councillor

Ontario Energy Board (Board Staff) INTERROGATORY #46 List 1

Interrogatory

LOSS FACTORS

Preamble: Remotes included no discussion of loss factors in its application. Remotes did indicate that it has sets of isolated distribution and transformation assets which it owns and operates. The following questions seek to gain an understanding of Remotes current operating situation, and guidance for future years with respect to system losses.

46. Ref: Loss Factors

Does Remotes have an estimate of its losses separated into technical losses (i.e. line and transformer) versus non-technical losses (i.e. theft, metering inaccuracies) for energy?

a. If so, what is the percentage difference in these quantities?
b. If not, does Remotes intend to measure the output from its generation in order to make this comparison in the future?
c. If the answer to b. is no, why not?

Response

No, Remotes does not have an estimate of its losses separated into technical and non-technical losses. Remotes does monitor non-technical losses (e.g. theft) through system inspections including community visits. It should be noted that the distribution systems in remote communities tend to be compact and therefore technical losses are small.

a) N/A.

b) Remotes measures losses through monitoring the difference between generator output and metered usage. The measurement of generator output does not allow the differentiation between line loss and theft of power. The typical community total loss factor using this measure is 1.3% (both technical and non-technical losses).

c) See part b response.

Ontario Energy Board (Board Staff) INTERROGATORY #47 List 1

Interrogatory

LOSS FACTORS

Preamble: Remotes included no discussion of loss factors in its application. Remotes did indicate that it has sets of isolated distribution and transformation assets which it owns and operates. The following questions seek to gain an understanding of Remotes current operating situation, and guidance for future years with respect to system losses.

47. Ref: Loss Factors

Does Remotes have an estimate of its losses separated into line losses versus "unaccounted for" energy?

a. If so, what are the percentage amounts for Remotes as a whole, or for typical locations?

b. If not, does Remotes intend to implement metering or other monitoring that would enable it to make such estimates in the future?

Response

a. As noted in the response to Board Staff Interrogatory # 46, Remotes measures the difference between generator output and metered usage. Typical numbers for this loss are 1.3%.

b. Not applicable.

Ontario Energy Board (Board Staff) INTERROGATORY #48 List 1

Interrogatory

INAC

48. Ref: Ex D1/T2/S1/P1

Remotes' refers to the "Electrification Agreements" it has with INAC. Please file a copy of the current "Electrification Agreement".

Response

Please see Attachment A for an example of a Hydro One Remote Communities Agreement for Electrical Services.

Attachment A

Example of a Hydro One Remote Communities

Agreement for Electrical Services

Ret. "P"
JUN 25 1990 00624

AGREEMENT FOR ELECTRICAL SERVICE

KINGFISHER COMMUNITY ELECTRIFICATION

THIS AGREEMENT made in triplicate this 23rd day of March 1987.

B E T W E E N:

HER MAJESTY THE QUEEN, in right of Canada, represented herein by the Minister of Indian and Northern Affairs Canada, hereinafter referred to as "I.N.A.C."

OF THE FIRST PART

- and -

ONTARIO HYDRO, a body corporate, continued by the Power Corporation Act, R.S.O. 1980, c.384,

hereinafter referred to as "Ontario Hydro"

OF THE SECOND PART

WHEREAS, I.N.A.C. has requested Ontario Hydro to undertake the provision of community services in the community of Kingfisher Lake, Ontario, according to the terms and conditions hereinafter set forth;

AND WHEREAS, by virtue of the Power Corporation Act, Ontario Hydro is authorized to supply electrical services to customers and premises in rural Ontario districts.

NOW THEREFORE and in consideration of the mutual promises and obligations contained in the Agreement, I.N.A.C. and Ontario Hydro convenant and agree as follows:

1. DEFINITIONS

(a) "Band", means a Band as defined in the Indian Act, R.S.C. 1970, C.1-6;

(b) "Customer", means a user of power supplied through systems constructed or acquired pursuant to this Agreement;

(c) "Indian" means a person who is an Indian within the meaning of the Indian Act (Canada) and includes any other persons who the parties agree is an Indian for the purposes of this Agreement; — page one

(d) "Indian commercial entity", means a sole proprietorship, partnership, company or corporation, carrying on business in Ontario, entirely owned by one or more Indians;

DEFINITIONS (Continued)

(e) "Indian community enterprise", means an undertaking, including a business undertaking, operated by a Band;

(f) "Indian residence", means a residence which consists of one or more housekeeping units in which every occupant is an Indian or a non-Indian who is a boarder or a lodger paying compensation to an Indian in respect of such occupation;

(g) "Minister", means the Minister of Indian and Northern Affairs Canada;

(h) "Work", means the work described and defined in Section 2 of this Agreement; and

(i) "System capacity charge", means a charge for the capital cost of generating or distributing plant.

(j) "Remote Community", means a community isolated from Ontario Hydro's electrical grid.

2. SCOPE OF WORK

Ontario Hydro shall undertake the following:

(a) Construct a diesel generator building (64' x 24').

(b) Construct a Ontario Hydro st ff house.

(c) Supply and install a diesel uel tank farm to meet Environment Canada standards.

(d) Supply and install three diesel generators.

(e) Supply and install controls and a programmed controller.

(f) Supply and install a distribution system substantially in accordance with Appendix 'C' drawing No. 525 consisting of:
- 6450 metres of 3 phase line;
- 750 metres of single phase line;
- 3500 metres of secondary complete with transformers and stree lighting;
- 98 service connections.

(g) Supply and install a heat energy distribution system consisting of:
- approximately 230 metres of 2-3" insulated underground piping;
- heat exchangers, control equipment piping and heat energy meters for the school, gymnasium and clinic/social services buildings.

3. BASIS OF PAYMENT

(a) I.N.A.C. shall pay to Ontario Hydro all direct and indirect costs incurred to supply and install the community services as defined in Section 2 of this Agreement and outlined in Appendix A "Expenditure Plan" and Appendix B "Cost Estimate".

(b) The total liability of I.N.A.C. in respect of this Agreement shall not exceed the sum of $2,230,000. A yearly cash flow shall be mutually agreed upon by the parties.

(c) If at any time during the progress of the Work it becomes apparent that the total costs will exceed the costs as shown in this Agreement, Ontario Hydro shall inform the Minister of this fact in writing.

(d) The payment of any money by I.N.A.C. or the Minister hereunder is subject to there being an appropriation for the particular service for the fiscal year in which any commitment hereunder would come in course of payment.

(e) Payment will be made on approved invoices.

(f) The Project Manager will be accountable for the application of the expenditures relative to the work in this Agreement.

(g) Ontario Hydro will repay I.N.A.C. any overpayment relating to unexpended balances and disallowed expenses.

4. PROJECT MANAGER

For The Work performed in accordance with clause 2 herein:

(a) the Project Manager representing the Minister of the Department of Indian and Northern Affairs Canada is appointed by the Regional Manager of Technical Services who will be responsible for each phase and/or the complete project as described and defined by this Agreement. The Project Manager's responsibility and accountability is as described in Chapter 148 of the Administrative Policy Manual, issued by Treasury Board of Canada, entitled "Cost Control of Project".

(b) The Project Manager is Mr. D.B. Morellato, P.Eng. at the time of execution of this Agreement, however the Ontario Regional Manager of Technical Services may assign other personnel to the position of Project Manager as circumstances may dictate without requirement of an Amending Agreement.

(c) The Regional Manager of Technical Services will advise Ontario Hydro in writing of any changes to the position of Project Manager when they occur.

TIME FRAME

(a) Notwithstanding the date on which this Agreement is signed, the effective date for completion of the work shall be March 31, 1993.

(b) This Agreement shall continue in force for a period of twenty years following the in-service date of the Work and from year to year thereafter until terminated by notice in writing by either party which notice shall fix the date of termination. This notice may not be given prior to the twentieth anniversary of the in-service date of the Work and the date fixed for termination shall not be less than 365 days after the date of the notice of termination.

6. SYSTEM CAPACITY CHARGES

(a) Ontario Hydro shall collect a system capacity charge from each Customer requesting service with the exception that no system capacity charge shall be made for service to:

i) an Indian commercial entity;
ii) an Indian community enterprise;
iii) an Indian residence;
iv) a school, teacherage or other property operated by the Minister; or
v) any premises specifically designated by the Minister.

(b) The system capacity charge payable by any Customer shall comprise:

i) a fair and reasonable charge, representing the Customer's share of the installed cost of the generating plant in the community, determined by multiplying the amount of power in kilowatts made available to the customer and a rate in dollars per kilowatt, to be determined by Ontario Hydro, plus

ii) a charge for distribution facilities, (lines, tranformers, services, and meters) installed by Ontario Hydro for the exclusive use of the Customer, or, where such facilities are used to supply more than one Customer, such portion of the actual costs as is determined by Ontario Hydro.

(c) Except for the provisions herein relating to the making of system capacity charges, all rates and charges for providing electrical service to any Customer (including I.N.A.C.) shall be payable by that Customer and shall be the rates and charges authorized from time to time by Ontario Hydro for the relevant classification of service.

(d) The interpretation of rates and conditions of service shall be governed by the rules made by Ontario Hydro from time to time covering supply to Remote Communities for diesel generation.

6. SYSTEM CAPACITY CHARGES (Continued)

(e) Where a system capacity charge, or any part thereof, duplicates an amount payable by I.N.A.C. for facilities installed, such charge or portion thereof collected from the Customer shall be applied as a credit to the amount payable by I.N.A.C.

(f) Notwithstanding anything contained in this clause 6 Ontario Hydro shall be entitled to collect from any Customer charges for establishing facilities to which I.N.A.C. has not paid the costs of establishing. Any charges collected shall belong to Ontario Hydro and shall not be applied as a credit to the account payable by I.N.A.C.

7. CHANGES TO SYSTEM

(a) Whenever, by reasons of increased electrical load, it becomes necessary to alter, add to, remove or transfer any of the components of that system, Ontario Hydro shall determine the capital portion of the cost of such a change and which portions shall be paid for by I.N.A.C. and other Customers.

(b) Notwithstanding any determination of costs, Ontario Hydro shall not be obliged to alter, add to, remove or transfer any of the components of the system prior to acceptance by I.N.A.C. and other Customers of the said apportionment of costs and an undertaking to pay the same.

8. OWNERSHIP

(a) The property comprising the community services constructed pursuant to this Agreement shall become the property of Ontario Hydro and Ontario Hydro shall be fully responsible for all operating personnel and for the entire direct and indirect operation and maintenance costs, including the renewal and/or replacement of the various system components.

9. NOTICES

(a) Notices required or provided for in this Agreement shall be forwarded by prepaid registered mail, telex, telegram or telephone facsimile addressed as follows:

If to I.N.A.C.:

Regional Director General
Indian and Northern Affairs Canada
25 St. Clair Avenue East
Toronto, Ontario M4T 1M2
Telephone Facsimile Number: 1-416-973-6472

If to Ontario Hydro:

The Secretary
Ontario Hydro
700 University Avenue
Toronto, Ontario M5G 1X6
Telephone Facsimile Number: 1-416-592-2086

10. INDEMNITY

a) Ontario Hydro shall indemnify and save harmless I.N.A.C. from and against all claims, losses, costs, damages, actions, suits or other proceedings by whomsoever made, brought or prosecuted in any manner based upon, arising out of, related to, occasioned by or attributable to their performance or purported performance of this Agreement by Ontario Hydro, its servants, agents, assigns, contractors and subcontractors in performing the Work.

11. RESERVE LANDS

I.N.A.C. will authorize Ontario Hydro, its servants, agents and contractors to enter upon, use and occupy any reserve lands, at no cost to Ontario Hydro for the purposes of the installation and maintenance of the community service, during the term of the Agreement, by permit made pursuant to and subject to the provisions of the Indian Act. Ontario Hydro shall not be required to perform its obligations under this Agreement prior to appropriate permit(s) being provided to Ontario Hydro.

AMENDMENTS

(a) Any change involving the terms of this Agreement may be implemented by a Change Order or Amending Agreement.

13. FORCE MAJEURE

(a) If the performance of this Agreement by either party hereto is delayed, interrupted or prevented by reason of any strike, lockout, injunction, coalition between workers or other labour trouble, accident, fire, explosion, flood, embargo, war, riot, Act of God, enemy action, blockade, any decision, order or restriction of any government or subdivision or agency thereof, while acting in its sovereign capacity, or for any other cause whether or not of the nature of the character specifically enumerated above, which is beyond the reasonable control to such party, such party shall not be held responsible for failure to perform during the period of and to the extent that such party is delayed by one or more of such causes, provided that performance of this Agreement shall be resumed as soon as practicable after such disability is remedied.

14. MEMBERS OF THE HOUSE OF COMMONS and FORMER CIVIL SERVANTS

(a) No member of the House of Commons shall be admitted to any share or part of this Agreement or to any benefit to arise therefrom.

(b) No former public office holder who is not in compliance with the post employment provisions of the conflict of interest and post employment code for public office holders shall derive a direct benefit from this Agreement.

15. ENURES TO BENEFIT

(a) This Agreement shall enure to the benefit of and be binding upon the parties hereto, their administrators, successors, executors and assigns, respectively.

16. FINANCIAL REPORTING REQUIREMENTS

(a) Ontario Hydro will provide a financial report and a progress report to I.N.A.C. on a quarterly basis, specifying year to date expenditures, forecasted total annual expenditures, progress to date and forecasted progress for those years in which Work is done. The detail of the financial and progress report will be the subject of negotiation between I.N.A.C. and Ontario Hydro.

(b) Ontario Hydro shall establish and maintain financial records, in accordance with generally accepted accounting principles and practices, to ensure the adequacy, accuracy, completeness and timeliness of reports and plans based upon these records.

(c) INAC may request Ontario Hydro to provide an annual Audit Report relating to the Work to I.N.A.C. by June 30th for the preceding Ontario Hydro fiscal year. Independent auditors may be appointed by I.N.A.C. or Ontario Hydro to review the financial records maintained by Ontario Hydro related to the Work and to ensure that the Work is being managed within the agreed arrangement, that only allowable expenditures have been charged against the arrangement and that generally accepted accounting principles and practices have been consistently applied in the maintenance of financial records.

IN WITNESS WHEREOF the parties hereto have duly executed these Presents as of the day and year first above written.

SIGNED, SEALED AND DELIVERED)
on behalf of HER MAJESTY the)
QUEEN IN RIGHT OF CANADA,)
represented by the MINISTER)
of INDIAN and NORTHERN)
AFFAIRS CANADA:

I certify that this Arrangement conforms to the financial requirements of Treasury Board.

Regional Director General Ontario Region	S. Batra 26/06/89 Finance Officer
Witness	June 26/89 Witness

Ontario Hydro

Vice-President, Regions

ONTARIO HYDRO
Mar 23 1989
March 29 1989
19...

APPENDIX 'A'
EXPENDITURE PLAN

1989/90	$ 750,000.00
1990/91	1,317,000.00
1991/92	163,000.00
TOTAL........................	$2,230,000.00

APPENDIX 'B'
COST ESTIMATE

CONSTRUCTION COSTS

1.	Generators	280,900.00
2.	Controls	200,000.00
3.	Building	275,000.00
4.	Tank Farm	334,100.00
5.	Heat Recovery	140,000.00
6.	Three Phase Line	510,000.00
7.	Single Phase	48,000.00
8.	Secondary, Transformers & Lighting	282,000.00
9.	Staff House	130,000.00
10.	Well	20,000.00
11.	Septic Field	10,000.00
	TOTAL..................	$2,230,000.00

APPENDIX 'C'

Attached Distribution System
Drawing No. 91655 K.R.D. - 525

APPENDIX 'A'
EXPENDITURE PLAN

expenditure
change only.
[illegible]

1989/90	$ 402,100.00
1990/91	1,664,900.00
1991/92	163,000.00
TOTAL........................	$2,230,000.00

John C. Mann — Mar. 30/90

John Mann — Date
Supt. Of Finance and Administration

APPENDIX 'B'
COST ESTIMATE

CONSTRUCTION COSTS

1.	Generators	280,900.00
2.	Controls	200,000.00
3.	Building	275,000.00
4.	Tank Farm	334,100.00
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8.	Secondary, Transformers & Lighting	282,000.00
9.	Staff House	130,000.00
10.	Well	20,000.00
11.	Septic Field	10,000.00
	TOTAL..................	$2,230,000.00

APPENDIX 'C'

Attached Distribution System
Drawing No. 91655 K.R.D. - 525

Energy Probe INTERROGATORY #1 List 1

Interrogatory

Ref: Exhibit A, Tab 3, Schedule 1, page 7

Starting at line 21, the schedule notes cost efficiency improvements including "improved the coordination of flights to transfer staff and equipment". Please provide details of air transport to remote communities as follows:

a) Are any of the remote communities served by regularly scheduled flights of commercial airlines? Does Remotes use these services if available?

b) Who provides air transportation to communities not served by regularly scheduled commercial airlines?

c) What does "improved coordination of flights" referred to in the excerpt consist of? How many flights have been saved annually by this initiative? How much money has this saved on an annual basis?

Response

a) There is scheduled air service to 12 of the Remote communities served by Hydro One. Remotes' has used scheduled service, on occasion, for single passenger, standard business type travel. Scheduled commercial service is not used for work crews as it does not provide the logistical support and/or meet the scheduling that is required by Remotes maintenance and construction work. The typical aircraft charter flight is used to transport 3 to 4 staff and all of the tools, materials and provisions required to live and work on site for a 4 day work week. The charter service is able to accommodate the work schedule using this configuration of passenger/freight flight, with standard Monday departure (a.m.) and Thursday (p.m.) returns and on-demand when emergency response is required. Scheduled commercial service is less frequent and would only accommodate passenger travel.

b) Charter air passenger service is provided by a variety of operators in the Northwest Region, to all of the remote communities.

c) Improved flight coordination refers to the application of the following guidelines when flight planning with a centralized flight scheduling process to support Remotes work program:

- Aircraft are used to their maximum payload (capacity), where practical and safe, before a second flight is booked for the same destination.

- Return aircraft are to be used wherever practical for personnel and/or material moves.
- Aircraft may be held at an intermediate site(s) on the way to their end destination to facilitate work at that site.
- Overnight aircraft hold-over may be used as an alternative to booking flights on consecutive days for relocation of staff, where practical. Given the distance and flight time back to the Thunder Bay service centre from many/most remote communities, holding over of aircraft and pilot is typically less expensive than making consecutive flights.
- Dedicated freight aircraft are to be used when passenger aircraft do not provide adequate payload capacity and/or provision for material movement.

Energy Probe INTERROGATORY #2 List 1

Interrogatory

Ref: Exhibit A, Tab 3, Schedule 1, page 7

Line 22 refers to cost efficiency obtained by "improved … use of winter roads". Please provide details as follows:

a) How has Remotes "improved" its use of winter roads?

b) How has this resulted in cost savings?

c) How much has been saved by this strategy?

d) Who builds and pays for winter roads?

e) What are typical travel times on winter roads to reach remote communities? How does this typical travel time compare to air transport travel times?

Response

a) Winter road use improvement relates primarily to an increased volume of fuel transported to Hydro One and First Nation owned tank farms during 2007 and 2008. This may be attributed, in part, to the use of two suppliers for winter road delivery during this period. Remotes' fuel supply contract structure provides for this flexibility. Regular communication and co-ordination with the fuel suppliers during the 4 – 7 weeks winter road access is available, has contributed to this improvement. Please refer to the response provided in Exhibit H, Tab 1, Schedule 18 for more details.

b) and c) Please refer to response provided in Exhibit H, Tab 1, Schedule 18

d) The winter road network in Ontario is constructed by the First Nation Communities it serves, working both individually to construct and maintain a section of the road network serving each First Nation and collectively through winter road corporations. The Asheweig Winter Road Corporation is an example of the collective approach. It is owned and operated by six First Nations, including Kasabonika Lake, Kingfisher Lake, Kitchenuhmaykoosib Inninuwug (Big Trout Lake), Wapekeka (Angling Lake), Wawakapewin (Long Dog), and Wunnumin Lake. Funding is provided directly by the Ontario provincial government and the First Nations, with support from the federal government. Non-First Nation users, including Hydro One, are subject to toll fees and thus contribute to paying for a portion of winter road costs.

e) Winter road travel time(s) for the large vehicles used for bulk transport of fuel and materials are typically 12 – 18 hours (one way) from Pickle Lake and/or Red Lake, the most northern communities with all-weather road access. Flying time (direct/one-way), from airports located in Red Lake and Pickle Lake, will range from 0.5 to 1.5 hours. Notwithstanding the longer time required for road delivery, the per litre transport cost of diesel fuel is approximately 40 cents/litre less using road than flight delivery, as noted in Exhibit H, Tab 1, Schedule 18.

Energy Probe INTERROGATORY #3 List 1

Interrogatory

Ref: Exhibit A, Tab 7, Schedule 1, pages 1 – 2

Page 1 of this schedule lists the communities served by remotes. Page 2 shows these communities on a map of the province along with other communities with Band Council operated electricity systems. Please explain:

a) Who makes the decision whether a remote First Nations community is served by Hydro One or by a Band owned system?

b) Are Band owned systems supported by the Rural and Remote Rate Protection Plan?

c) If not, are Band owned systems receiving either direct or indirect subsidies comparable to RRRP from government agencies?

d) If Band owned systems are subsidized by government, does this subsidy get transferred with the system when Remotes takes over responsibility for a Band owned system like Marten Falls? If yes, has this subsidy been included in the financial impact of acquiring Marten Falls?

Response

a) The decision about which communities are served by Remotes is ultimately the Provincial Government's, as Remotes' service territory is set by Regulation. There are, however, a series of decisions required before and after the Provincial Government makes this determination. The First Nation has to decide that it wants Remotes as its utility provider. The First Nation, INAC and Remotes have to sign an agreement outlining roles and responsibilities. The OEB decides whether to approve the licence addition and reviews the cost consequences of the service territory addition in a rates case, as in the current proceeding.

b) No.

c) No, we do not believe band owned systems receive funding comparable to RRRP. INAC funding is available to First Nation band councils whether they operate their own systems or are in Remotes service territory. This funding includes money for new distribution and generation capital, and an electrical energy cost subsidy to support the operation of specific INAC-funded assets.

d) Yes, funding from the federal government gets carried forward if the community enters Remotes' service territory. This funding has been reflected in the agreement with Marten Falls and is reflected in the costs and revenues included in Remotes' current rate application. Specifically, Remotes has not included the costs of new capital for Marten Falls in its capital programs, as capital funding is provided by INAC, and Remotes has included full revenues from Standard A customers in Marten Falls in its forecast of customer revenues. Standard A customers will receive the electrical energy cost subsidy from INAC referred to in part (c) above to assist in paying Standard A rates. This is the same approach used for any First Nation community in Remotes' service territory.

Energy Probe INTERROGATORY #4 List 1

Interrogatory

Ref: Exhibit A, Tab 1, Schedule 1, page 2

Lines 20-26 describe the planned acquisition of Marten Falls electricity system by Remotes. Please explain:

a) What is the process for Remotes to acquire a band council owned system like Marten Falls?

b) Is there a similar process for Band Councils to acquire Remote's systems?

c) Is Remotes required to purchase the existing generation and distribution system? If yes, how is the system valued?

d) Will Remotes be required to pay for bringing the systems up to its standards? If yes, how much does Remotes estimate this will cost?

e) Does Remotes have a policy to actively acquire Band owned systems?

f) Does Remotes have a policy to encourage Band Councils to take over responsibility for electricity systems in their communities?

Response

a) In this case, the First Nation wrote to then-Minister of Energy, Dwight Duncan requesting inclusion in Remotes service territory and in the RRRP program. As indicated in the Minister's letter in response (Exhibit A, Tab 6, Schedule 2) an agreement with Remotes and INAC is a necessary precondition to this request. Remotes plans to forward the agreement to the Minister and request the necessary Regulatory changes once the agreement is finalized. Once the Regulatory changes are made, Remotes would request approval for the licence change. The agreement is structured such that the required regulatory changes (to RRRP and the Service Territory), and Ontario Energy Board approval are a precondition of service.

b) Yes. Normally, if a local Band Council decided to acquire Remotes' system, an agreement to transfer the system would need to be negotiated among the First Nation, INAC and Remotes. This agreement would generally include the following matters: the legal transfer of ownership of the distribution and generation assets, including, where necessary, a requirement that the First Nation and INAC release OEFC from any obligations; the disposition of environmental liabilities (if any exist); an inspection of the distribution system by the Electrical Safety Authority to ensure it meets provincial standards; a requirement to obtain the necessary OEB approvals; and, an inspection of the Tank Farm and Generating Station prior to transfer.

First Nations also have the right to restrict entry to reserve lands, and can use this right to ask Remotes to stop serving the community.

c) No, the existing generation and distribution system is not being purchased. The agreement is based on an operating contract with an initial term of 5 years, which provides for an automatic renewal unless one of the parties gives 13 months notice or a shorter notice period if one of the parties is in default in the agreement.

d) There are three main categories of assets in the community: the tank farm and associated fuel transfer system ("Tank Farm"); the generating station, including the generators and auxiliary systems ("Generating Station"); and the distribution system ("Dx System"). The First Nation, with funding support from INAC, is currently replacing the Tank Farm at no cost to Remotes. A Technical Standards and Safety inspection of the new Tank Farm is required prior to the transfer, and the cost to correct any deficiencies is to be funded by INAC and the First Nation at no cost to Remotes. The agreement also requires that an Electrical Safety Authority inspection of the Distribution System be undertaken prior to transfer, and that any deficiencies be corrected and fully paid for by the First Nation supported by INAC. Remotes undertook an assessment of the Generating Station and identified deficiencies. The Agreement requires INAC and the First Nation to correct these deficiencies at no cost to Remotes.

e) No. Remotes responds to First Nation requests.

f) No. Remotes responds to First Nation requests.

Energy Probe INTERROGATORY #5 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, page 3

Lines 14 and 15 of the schedule refer to "environmental improvements associated with waste heat projects".

a) Please explain what the waste heat projects consist of.

b) Does Remotes have any combined heat and power projects?

c) Has Remotes considered waste heat recovery for space and/or domestic water heating in remote communities?

Response

a) Waste heat projects include the restoration and return to service of the waste heat transfer systems, originally constructed along with generating station upgrades to supply heat to schools in Wapekeka and Kingfisher Lake. The work will involve equipment repair, replacement and modification to enable the systems to efficiently transfer heat for use by the school. The environmental improvements are the resulting reduction in fuel oil required to heat each school and the associated reduction in CO_2 emissions. In addition to the above noted projects, a third waste heat recovery system is currently in-service to supply heat to the Fort Severn water pumping station. There is a minor amount ($1500) included in the 2009 budget for work on this system.

b) Remotes does not have any combined heat and power projects associated with existing generating stations.

c) Remotes has used waste heat recovery systems for space heating and domestic water heating of staff houses located in close proximity to the generating station. Maintenance and operational difficulties have resulted in 4 of the 6 staff house water heating systems and 2 space heating systems being removed from service and replaced with conventional fuel oil heating. There are no plans to restore these systems at this time.

   There have been informal discussions with interested parties in Fort Severn FN to expand the waste heat system in that community and extend it to the band office and other buildings. While challenges to the design and application of these systems are recognized, Remotes remains open to working with proponents of waste heat transfer for use in facilities near our stations. It should be noted the cost of any new application would be borne by the user.

Energy Probe INTERROGATORY #6 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, page 3

Lines 22 and 23 describe Remotes intention to purchase power from renewable sources "at a price based on the avoided cost of diesel fuel".

a) What would the avoided cost of diesel fuel per kWhr be for the most recent year that Remotes has the necessary data to calculate it?

b) How does this compare with the expected cost of production of renewable power projects?

c) Why does Remotes propose to pay for renewable power based on the avoided cost of diesel rather than on a negotiated price more related to the cost of production of the renewable power?

d) If First Nations groups develop renewable power projects, will they be responsible for operation and maintenance of the plants or will Remotes operate and maintain them?

Response

a) Remotes intends to enter into agreements for the purchase of renewable energy from First Nations based on the delivered cost of fuel to the community and the diesel generation station fuel efficiency in the community. Determination of the length of agreement, re-dress dates, and escalation/de-escalation clauses will be made on a site-by-site basis to ensure agreements are adaptable to specific community requirements. A range of the avoided cost of fuel is $0.2 - $0.65 per kWhr for 2007. Agreements would recognize that fuel cost may vary significantly from one year to the next.

b) There are few installations to make a confident determination of the cost of production of renewable energy in a remote isolated community. In addition to the standard factors for an installation in a less isolated location, the following factors must be considered:
- Transportation of equipment.
- Availability of local construction materials.
- Transportation and lodging of construction resources.
- Ongoing maintenance requirements including equipment and unavailable local skilled resources.
- Size of development is appropriate for the community load.

- Complex co-ordination and controls are required for large penetration renewable projects.

The price of diesel fuel may vary significantly from one year to the next.

Investigations of site potential need to be completed to determine feasibility based on the avoided cost of diesel for the particular community.

c) Remotes is subsidized through the RRRP and is operated on a break-even basis. Use of the avoided cost of diesel fuel is consistent with this break-even philosophy in that Remotes will not profit or lose from the agreement. The agreements will be negotiated to ensure the break-even requirement can be met while adapting to the specific needs of the renewable development and community. The benefit to Remotes' customers from this arrangement is a reduction in diesel plant emissions, as well as an increase in community economic activity which could have a beneficial impact on customer arrears. Please see Exhibit H1, Tab 1, Schedule 20 for further information.

d) Remotes expect the First Nation will be responsible for the operation and maintenance of the renewable energy plant. However, Remotes is prepared to provide operating and maintenance support to the First Nation for the facility on a contract basis, where reasonable to do so.

Energy Probe INTERROGATORY #7 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 2, pages 3 – 4

Lines 25-29 on page 3 and lines 1-4 on page 4 of this schedule describe potential hydro resources and Remotes intention to spend $253 K in 2009 for engineering and assessment studies of the sites.

a) Does Remotes intend to be an equity partner in these developments? If not, how does Remotes expect to recover its costs for helping develop these sites?

b) Is INAC providing any financial or technical support for development of renewable energy options?

c) Are other government agencies providing financial or technical support for development of renewable energy options?

Response

a) Remotes' policy with respect to equity or other partnership arrangements with First Nation communities for renewable generation facilities is currently under development.

If Remotes does not participate as an equity partner, Remotes would expect to recover as part of its revenue requirement its reasonable and prudent costs for helping to develop these sites. Remotes intends to facilitate the initiation of these developments by utilizing Remotes' expertise in power project development, knowledge of the area and relationships with the First Nation community. In requesting cost recovery, Remotes notes that these renewable energy developments are expected to provide ratepayer benefits and cost savings in three areas:

- Reduced emissions as per Remotes' Voluntary Emissions Reduction Strategy
- Reduced future energy arrears based on the increase in local employment and other income associated with the developments
- Increased local resource capacity being available to reduce Remotes' future cost of operations.

b) Yes, INAC has co-funded several RETScreen (Renewable Energy Technology Screen) studies in several communities and INAC has contributed to the construction costs associated with the Shoulderblade Falls hydroelectric development in the community of Deer Lake.

c) Remotes is presently working with the Ontario Centre of Excellence (OCE), the University of Waterloo and other public and private sector partners to develop and test technology combining small wind generators (less than 1 MW in size) and hydrogen storage for use in remote communities, who are providing primarily technical, equipment and in-kind (time) support. Remotes' contribution is to offer technical and logistical support for the project.

Energy Probe INTERROGATORY #8 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 3, pages 1 – 2

This schedule discusses Distribution OM&A.

a) Does Remotes employ local residents in these communities to perform any of the distribution maintenance work?

b) What opportunities exist to train and employ local residents to perform more of the distribution maintenance tasks?

Response

a) Yes, Remotes employs local residents in the clearing of brush under distribution lines, clearing snow for access to locations, providing and operating equipment for setting poles, and in switching and isolating circuits in emergency/fire conditions.

b) Tasks beyond the ones listed above are covered under Hydro One’s collective agreements. In accordance with those collective agreements, Remotes’ line apprenticeships and line trades are recruited through Hydro One Networks and the Power Workers Union. Local residents are free to apply.

Energy Probe INTERROGATORY #9 List 1

Interrogatory

Ref: Exhibit C1, Tab 2, Schedule 3, page 3

Lines 8-9 refer to Remotes plan to install Smart meters in remote communities starting in 2009. It is Energy Probe's understanding that Smart meters are intended to reduce demand at peak times by linking the cost of power to time of use thereby avoiding costs of increased peak generating capacity.

a) Does the same concept apply to remote communities? For example, does Remotes expect to reduce the number of generating units required in a community through the implementation of Smart meters?

b) Does Remotes intend to introduce time of use rates with Smart Meters?

c) Would there be any effect on the RRRP required to support remote communities?

Response

a) Please see Exhibit H, Tab 1, Schedule 11 (a).

b) Please see Exhibit H, Tab 1, Schedule 11 (a).

c) To the extent that the benefits from Remotes smart meter plan noted in Exhibit H, Tab 1, Schedule 11 are not realized, there would likely be an effect on RRRP, given that approximately two-thirds of Remotes' cost of service is recovered from RRRP and assuming that smart meter costs are treated in the same fashion as Remotes' other costs. The cost savings of Remotes smart meter plan are expected to be in the areas of reduced operating costs, reduced manual billing errors and reduced load limiting costs. The design costs are still being determined, as is the business case, for the smart meter plan.

Energy Probe INTERROGATORY #10 List 1

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, page 7

Starting at line 17, the following statement appears:

> "Line inspections will identify conditions that require capital work to bring the Distribution System up to current standards, as prescribed by Section 4.4 of the *Distribution System Code* and by the Electrical Safety Authority under O.Reg 22/04 made under the *Electricity Act, 1998*."

a) Please provide specific section references of the Distribution System Code and O.Reg.22/04 that require existing distribution systems to be brought "up to current standards".

b) Who is meant by "current standards"? Are these Remotes internal distribution standards or external standards?

Response

a) Remotes' maintains the distribution system to the standards identified by the Electrical Safety Authority per O.Reg 22/04 under the *Electricity Act*. Deficiencies identified through line inspections and joint use work will determine corrective work required to the existing distribution system. Remotes will ensure the required repairs are completed subject to current standards. Relevant sections from O.Reg 22/04 are set out below.

Safety standards

4. (1) All distribution systems and the electrical installations and electrical equipment forming part of such systems shall meet the primary safety standard set out in subsection (2) by meeting the safety standards set out in subsections (3), (4), (5) and (6). O. Reg. 22/04, s. 4 (1).

(2) All distribution systems and the electrical installations and electrical equipment forming part of such systems shall be designed, constructed, installed, protected, used, maintained, repaired, extended, connected and disconnected so as to reduce the probability of exposure to electrical safety hazards. O. Reg. 22/04, s. 4 (2).

(4) All overhead distribution lines, including secondary distribution lines, shall meet the following safety standards:

1. Operating electrical equipment shall be maintained in proper operating condition.
2. Adequate space shall be provided around electrical equipment for proper operation and maintenance.
3. Energized conductors and live parts shall be barriered such that vegetation, equipment or unauthorized persons do not come in contact with them or draw arcs under reasonably foreseeable circumstances.
4. Metal parts of the installation that are not intended to be energized and that are accessible to unauthorized persons shall be effectively grounded.
5. Structures supporting energized conductors and live parts shall have sufficient strength to withstand the loads imposed on the structure by electrical equipment and weather loadings. O. Reg. 22/04, s. 4 (4).

(5) All underground distribution lines, including secondary distribution lines, shall meet the following safety standards:

1. Operating electrical equipment shall be maintained in proper operating condition.
2. Adequate space shall be provided around electrical equipment for proper operation and maintenance.
3. Energized conductors and live parts shall be barriered such that equipment or unauthorized persons do not come into contact with them or draw arcs under reasonably foreseeable circumstances.
4. Metal parts of the installation that are not intended to be energized and that are accessible to unauthorized persons shall be effectively grounded.
5. Parts of the distribution system in proximity to the inside walls of a swimming pool shall be installed in such a way as to minimize the possibility of voltage gradients in the swimming pool.
6. Parts of a distribution system in proximity to propane tanks and natural gas pipelines shall be installed in such a way as to minimize the possibility of explosions under normal circumstances and operating conditions. O. Reg. 22/04, s. 4 (5).

(6) Distribution stations shall meet the following safety standards:

1. Operating electrical equipment shall be maintained in proper operating condition.
2. Adequate space shall be provided around electrical equipment for proper operation and maintenance.
3. Metal parts of the installation that are not intended to be energized and that are accessible to unauthorized persons shall be effectively grounded.

4. Energized conductors and live parts shall be barriered such that equipment or unauthorized persons do not contact them or draw arcs under reasonably foreseeable circumstances.

5. Structures supporting energized conductors and live parts shall have sufficient strength to withstand the loads imposed on the structure by equipment and weather loadings. O. Reg. 22/04, s. 4 (6).

(7) In this section,

"weather loadings" means loads due to temperature, ice or wind acting on conductors and structures. O. Reg. 22/04, s. 4 (7).

b) Remotes uses distribution standards that are used by Hydro One Networks.

Energy Probe INTERROGATORY #11 List 1

Interrogatory

Ref: Exhibit D1, Tab 2, Schedule 1, page 8

This page of the schedule describes Facilities Capital. Table 1 on page 2 of the schedule shows bridge year expenditure of $679 k and test year expenditure of $639 k for Facilities Capital:

a) How much of the capital expenditure in each of the bridge and test years is attributable to work on the Thunder Bay Service Centre?

b) How much is attributable to work on staff houses?

c) What comprises “outbuildings”? Are generator buildings included in this category?

Response

a) Approximately $ 10k of facility improvement capital work was performed at the Thunder Bay Service Center in 2008. There are no improvement projects planned for the service center in 2009.

b) Staff house capital work in 2008 involved the acquisition, transport and assembly of a modular home, to provide a new staff house in Weagamow Lake. The total cost of this project is projected to be $ 330K. The test year budget amount of $639K includes provision for refurbishment and renovation of one staff house for an approximate expenditure of $250K. The remainder of facilities capital in 2008 and 2009 is primarily for the construction of garage(s) for storage of the Hydro One vehicle used by crews working at the generating station and on the distribution system in the community. Three garages were completed in 2008 and two are planned for 2009.

c) Outbuilding(s) typically comprise material storage buildings located at the generating station sites. The generating station building itself is included in this category.

Nishnawbe Aski Nation (NAN) INTERROGATORY #1 List 1

Interrogatory

Ref: Exhibit A, Tab 2, Schedule 1, Pages 1 to 4

a) Given the shortage of skilled workers identified by the Applicant, and the high costs of having such workers travel to and from First Nation communities served by the Applicant, has the Applicant (or any of its affiliated organizations such as Ontario Power Generation, Hydro One, etc.) developed any training programs for Aboriginal persons living in such communities to have them operate and maintain diesel generators and related equipment?

b) If not, does the Applicant have any plans to institute such training programs for Aboriginal residents living in the communities served by the Applicant? If not, why not?

c) Has the Applicant done any cost/benefit analysis of having Aboriginal residents already living in First Nations communities help operate and maintain diesel generators and related equipment of the Applicant? If so, please provide a copy of such cost/benefit analysis.

d) Concerning "customer arrears" and the alleged cost pressures facing the Applicant as a result of such arrears, has the Applicant produced customer arrears data for each First Nation community served by the Applicant. If so, please provide the annual data for each First Nation community served by the Applicant for the years 2006, 2007, and 2008. Please also provide the total for all communities served by the Applicant for those three years.

e) Does the Applicant believe that increasing the rates to the average customer (whether residential, Standard A, or otherwise) by 4 to 5%, as proposed in the Application, will relieve or resolve the problem of customer arrears?

f) Does the Applicant agree that increasing rates, as proposed in the Application, will likely aggravate the problem of customer arrears in First Nations communities?

g) Has the Applicant conducted any studies which indicate that customer arrears are likely to increase if the proposed rate increases are approved? Alternatively, has the Applicant produced or commissioned any studies on the issue of customer arrears generally? If so, please produce a copy of any such studies.

h) Does the Applicant agree that the principal source of customer arrears in the communities served by the Applicant, especially First Nations communities, is the fact that these communities have limited funds to spend on the necessities such as electricity?

Response

a) Remotes' staffing strategy is discussed in more detail in Exhibit C1, Tab 3, Schedule 1. As noted in that exhibit, Remotes contracts with local band councils for station operators/agents. Remotes has an established and on-going training program to ensure that local agents, who are responsible for day to day operations, are qualified to perform their duties. In terms of skilled trades, Remotes participates in the Hydro One apprenticeship program. Hydro One's training program offers apprentices work placements across the province so that apprentices gain knowledge and experience in all facets of their trade. Hydro One has taken steps to increase the participation of First Nation people in its apprenticeship program, including those living in Remotes' service territory. In November 2007, Hydro One approached the Sioux Lookout Area Aboriginal Management Board (SLAAMB) to determine if SLAAMB would assist in finding First Nation candidates interested in participating in Hydro One Networks' apprenticeship program. SLAAMB services all of the Nishnawbe Aski Nation communities in Remotes' service territory. The project promoted two of Hydro One's apprenticeship programs: Power Line Technician Apprenticeships and Utility Arborist Apprenticeships, with the opportunity to seek employment with Hydro One. In June 2008, the project was expanded to include identifying persons interested in other apprenticeship programs offered by Hydro One, Ontario Power Generation, and Bruce Power. Hydro One provides funding to SLAAMB to hire a Hydro One Employment Coordinator to visit the remote First Nation communities that are serviced by SLAAMB, share information about the programs, identify interested candidates, coordinate their applications, and work with Hydro One to determine the project's next steps. Hydro One and the Power Workers' Union meet regularly with SLAAMB to review the program and develop and implement further staged steps to the project.

b) Remotes does not intend to implement its own apprenticeship training program for residents in remote communities. Apprentices in skilled trades are required to work a specific number of hours in a year under the guidance of journeyman trades people in order to qualify as a skilled trades person. For example, Arborists require 6,000 hours (4 x 1,500 hour terms); Lines require 8,000 hours (4 x 2,000 hour terms); Electricians require 9,000 hours (5 x 1,800 hour terms); and Mechanics require 8,000 hours (4 x 2,000 hour terms). An apprentice working from a single remote community would not get enough hours to qualify in a trade. Even if the apprentice were willing to travel to all of Remotes' service territory, the scope of work conducted in Remotes' business would not be broad enough to support the required experience to qualify an apprentice in a trade.

c) Remotes has agents within communities to help operate and maintain its diesel plants. Remotes has not conducted a cost benefit analysis of hiring skilled trades people who would reside in the communities. Trades staff are typically qualified in a single trade or discipline. Remotes does not have sufficient work in any single community to support a full time skilled trades person. If the tradesperson were located in a remote community, plane travel would continue to be required to perform work in other communities. Remotes notes that within its business, it has 1 certified civil tradesperson, 3 line maintainers, 3 electricians and 4 mechanics to service all 20 communities.

d) Each month, Remotes communicates with local First Nation band councils to inform them of the outstanding balances, including what is owed on current accounts. In order to protect the privacy of our customers, the community names have been excluded from the analysis below.

First Nation Standard A Arrears ($000)

Community	2006	2007	2008
A	$246.6	$159.4	$41.1
B	$1,122.3	$1,247.5	$736.8
C	$148.4	$278.8	$218.8
D	$250.6	$456.6	$698.4
E	$12.0	$12.4	$0.5
F	$478.4	$137.8	$42.9
G	$1,246.5	$855.3	$547.8
H	$31.7	$46.4	$29.3
I	$314.9	$20.4	$69.2
J	$4,927.5	$3,893.7	$3,263.3
K	$429.2	$340.3	$178.3
L	$47.7	$31.9	$5.9
M	$3,061.1	$3,287.1	$3,523.4
N	$3.8	$2.9	$2.9
Total (All Remotes)	$12,320.7	$10,770.5	$9,358.6

First Nation Residential Arrears ($000)

Community	2006	2007	2008
A	$37.5	$42.7	$29.8
B	$73.1	$87.9	$77.9
C	$78.8	$61.9	$54.3
D	$72.8	$43.2	$35.8
E	$92.7	$73.4	$14.2
F	$44.3	$51.7	$118.5
G	$27.7	$21.0	$17.9
H	$39.7	$21.8	$26.1
I	$79.4	$39.7	$48.3
J	$267.1	$220.1	$156.9
K	$25.1	$24.0	$14.0
L	$52.0	$48.2	$52.6
M	$58.5	$40.2	$41.4
N	$12.6	$6.6	$8.3
Total (All Remotes)	$961.3	$782.4	$699.1

e) Remotes does not expect that the proposed rate increase will have a significant effect, either positive or negative, on customer arrears.

f) Please see the response to part (e). Remotes does not believe that there is a direct link between customer arrears and rate increases. Remotes considers that changes in the level of arrears are driven by a number of factors including the strength of the customer relationship, the frequency and timing of customer contact regarding collections, customer knowledge of the consequences of non-payment, and customer financial circumstances.

g) No studies have been done regarding the impact on customer arrears of the proposed rate increase, nor have any studies been commissioned or produced on the issue of customer arrears generally. As noted above, Remotes does not believe there is a direct link between customer arrears and rate increases. After the most recent rate increase, in 2002, Standard A arrears decreased. In subsequent years when rates were not increased there was an increase in Standard A arrears. Recent collection activities have greatly reduced the amount of arrears in both residential and Standard A customers in that same period when rates did not increase.

h) Remotes is a regulated utility and must recover the cost to supply electricity to its customers. Remotes does not wish to speculate on what is the principal source of customer arrears in the communities it serves.

Nishnawbe Aski Nation (NAN) INTERROGATORY #2 List 1

Interrogatory

Exhibit A, Tab 3, Schedule 1, Pages 1 to 7

(a) Provide particulars to explain in more detail the statement that "Remotes is 100% debt-financed and operates as a break-even business".

(b) As between the Applicant and Indian and Northern Affairs Canada ("1NAC"), have there been any disputes as to what expenditures constitute "ongoing operation and maintenance of the system" on the one hand, and "funding capital related to system expansions and capital upgrades" on the other hand? Has either the Applicant or INAC prepared a list of items, activities, and equipment that identifies whether the item, activity, or equipment is considered to be part of ongoing operation and maintenance of the system as opposed to capital related to system expansions and upgrades? If so, please provide a copy of that list.

(c) Is there any dispute resolution process as between the Applicant and INAC to settle controversies over whether an expenditure is on account of operation and maintenance as opposed to on account of system expansion and capital upgrades? If so, what is that process?

(d) Given the recent and significant decline in diesel fuel prices, please provide an updated graph, based on current diesel fuel prices for 2008 and estimated fuel prices for 2009, for the graph on p.6.

(e) The Applicant has advised that its conservation program saved 300,000 litres of fuel in 2008. Does the Applicant have further conservation programs to introduce in 2009 and thereafter? If so, what reductions in litres of fuel (also expressed as a percentage of the total diesel fuel used by the Applicant on an annual basis) does the Applicant expect to realize from such further conservation programs in 2009, 2010, and thereafter?

Response

a) The statement "Remotes is 100% debt-financed and operates as a break-even business" refers to both the capital structure of the company (in which there is zero equity and hence zero equity return) and the use of the Rural and Remote Rate Protection Variance Account (RRRPVA) to recover variances from the OEB-approved budget in costs and revenues.

Remotes capital structure with 100% debt was approved by the OEB in RP-1998-0001. The argument made and accepted by the Board was that since Remotes' operations are subsidized by the RRRP, if Remotes was to earn a return on equity that return would also have to be subsidized. In light of this, Remotes capital structure is 100% debt, consisting of 4% deemed short term debt and 96% long term debt. Further details on Remotes capital structure can be found in Exhibit B1, Tab 1, Schedule 1.

Since Remotes does not earn a return on equity, the risk of variances in costs and revenues should not be borne by the shareholder. In 2003, Remotes established a balance sheet revenue variance account (RRRPVA) to track differences between Remotes' revenues and costs.

b) No, there have been no disputes between operating and maintenance expenditures and those for capital expansions and upgrades. Under the Electrification Agreements, the distinction between the categories is clear. Remotes does not pay for expansions of the distribution system or increases to generation capacity. Please see the response to Board Staff Interrogatory # 48 for a sample Electrification Agreement.

c) No, there is no dispute resolution process between Remotes and INAC regarding whether expenditures are either capital or operating and maintenance in nature.

d) Please see Exhibit A, Tab 3, Schedule 1 Page 6 of the evidence updated on Nov. 28, 2008.

e) Yes, Remotes plans to continue the conservation program. Note that detailed planning for this program is conducted annually so that potential savings beyond 2009 are not available. Please see Exhibit H, Tab 1, Schedule 22 for a table showing anticipated kWh savings and the savings in litres of fuel for 2009. The table below shows the planned savings in 2009, the total litres of fuel and the percentage savings.

Planned CDM Fuel Savings	Total Forecast litres	Percentage Savings
129,154	15,562,773	1%

Nishnawbe Aski Nation (NAN) INTERROGATORY #3 List 1

Interrogatory

Ref: Exhibit A, Tab 7, Schedule 1, Page 2 of 2

a) Has the Applicant had any discussions with Hydro One (or any other agency) relating to the extension of any of the transmission lines shown on the Map of Remotes' Service Territory to eliminate the need for diesel generation in any First Nation communities currently served by the Applicant? If so, provide particulars of such discussions, including any relevant documentation.

b) Has the Applicant prepared or commissioned any feasibility or cost/benefit study showing what the costs of maintaining existing off-grid diesel generation will be in the foreseeable future (i.e. over the next two decades) as compared to the overall costs of connecting at least some of the First Nation communities currently served by the Applicant to the transmission grid operated by Hydro One? If so, provide a copy of any such study.

Response

a) Remotes does not play an active role in discussions related to transmission planning because Remotes' mandate is limited to the distribution and generation of electricity in off-grid communities. As such, Remotes does not have relevant documentation about discussions in regard to planning grid extensions.

   When requested by project proponents, Remotes provides information about the communities it serves to help facilitate the development of these projects. This information is limited to the most recent year's cost information, current customer rates, and the kWh usage for the particular community or communities. In particular, Remotes has provided information to First Nations (or their representatives) and/or transmitters and/or government agencies (INAC, Ministry of Energy) regarding the following transmission projects: Five Nations, Cat Lake, Pikangikum, Windigo and the Nipigon Enabler line.

   When projects are underway, Remotes provides the project proponents with an asset inventory and the net book value of the assets.

   When the project is completed, Remotes works with the transmitter and the new distributor to connect the system to the grid, to transfer customer information to the new distributor and to receive required approvals for the transfer of the assets and associated land use permits and leases.

b) Remotes has not prepared or commissioned such a study.

Nishnawbe Aski Nation (NAN) INTERROGATORY #4 List 1

Interrogatory

Ref: Exhibit A, Tab 8, Page 7 of 8

Provide particulars relating to the "long-term debt" of the Applicant. What costs and expenditures comprise this debt?

Response

Remotes long term debt components are described in Exhibit B1, Tab 1, Schedule 1. The capital structure is consistent with the OEB's Decision in RP-1998-0001 for Hydro One Remote Communities Inc.

Nishnawbe Aski Nation (NAN) INTERROGATORY #5 List 1

Interrogatory

Exhibit A-9-1, Attachment 3, Page 8 in the Financial Statements (December 31, 2007)

a) The "generation assets" used in the generation of electricity are identified as including "hydro-electric equipment, wind turbines, diesel generators, and tank farms". Are there any other generation assets of the Applicant not listed in the Financial Statements?

b) Has the Applicant prepared or commissioned any feasibility or cost/benefit study showing how costs could be reduced by shifting from diesel generation in any First Nation communities served by the Applicant to renewable forms of energy, such as wind turbine, hydro-electric generation, or solar energy? If so, please provide a copy of any such study.

c) If the Applicant has not prepared or commissioned such a study, why has that not been done given the significant increase in diesel fuel costs, customer arrears, and the shortage of skilled labour which has been experienced by the Applicant during the past few years?

Response

a) No, all generation asset groups are identified on the Financial Statements.

b) Although a feasibility study of all sites has not been commissioned, Remotes' has participated with project proponents in supporting initial resource analysis to assist First Nations in their development of renewable energy projects. These analyses are confidential under the provisions of Remotes' Licence and cannot be released without the written consent of project proponent(s).

   It should be noted that Remotes currently supplements diesel electric generation in two communities with hydro-electric generation and in two communities with wind generation.

c) Remotes acts as a facilitator in the development of renewable energy developments with First Nations and assists in producing information that can be used by First Nations to determine the feasibility of potential projects. Based on Remotes' renewable energy experience and knowledge of these communities, Remotes expects a few projects will be feasible at recent fuel prices. Remotes expects these projects will be developed by First Nations and their partners.

As noted in Exhibit H, Tab 2, Schedule 7, these projects are expected to produce benefits in relation to reduced emissions and local economic spin-offs including employment opportunities, which could have a beneficial impact on customer arrears.

Nishnawbe Aski Nation (NAN) INTERROGATORY #6 List 1

Interrogatory

Ref: Exhibit A, Tab 15, Schedule 1, Pages 1 to 3

a) What was the nature of the "information session" held by the Applicant on August 20, 2008? Please provide particulars describing in more detail the information session.

b) Who from First Nations communities was invited to attend the session? Who determined the list of invitees for the session?

c) What written information was distributed to attendees at the information session? If the written information was different from or in addition to that found at Exhibit A-15-1, Appendix B, please provide a copy of such written information.

d) What specific plans does the Applicant have to use "local resources" to reduce staff transportation costs in servicing First Nations communities?

e) What are the specific plans of the Applicant in respect of its self-described measures to control fuel cost increases, including enhancing the efficiency of generating stations, improving the use of winter roads, improving fuel supply contracts, and implementing a customer demand management program? Please provide particulars, including any written information relating to same.

f) What "potential renewable resources" have been identified in several First Nations communities, as indicated in the Applicant's evidence? Please identify such resources and the locations of such resources. Please also provide any feasibility or similar studies which the Applicant has prepared or commissioned on such resources.

g) What programs to develop renewable resources in partnership with First Nations are planned for 2009? Please provide particulars as well as any written material relating to such programs.

Response

a) The information session was a meeting designed to give representatives of First Nations' Band Councils a high level overview of our planned rate submission, including rate impacts and proposed programs, the OEB process for reviewing and approving rate submissions, and how to get involved in the OEB process.

b) The invitation was extended to each Chief and Council from the First Nation communities Remotes serves. The Chief and Council determined who, if anyone, would represent their community.

c) All of the written information distributed at the meeting is included in Exhibit A, Tab 15, Schedule 1 Appendix B.

d) As discussed in detail in Exhibit H, Tab 3, Schedule 1, parts (b) and (c), Remotes does not believe that local resources can be used to reduce the cost to transport skilled trades people to the communities.

e) Please see Exhibit H, Tab 1, Schedules 18, 21 and 24.

f) The proponents in these developments are First Nations and as such the information is theirs to distribute. Several RETScreen studies have been completed and older studies were performed by Ontario Hydro. Remotes intends to facilitate the initiation of development of renewable energy projects with the intent of offering a power purchase agreement to First Nations. Non-community identifying information is attached in table below.

Site	Capacity	Status
#1	1 MW	Studied by Ontario Hydro in 1991. Potential to carry community load in low usage seasons. Diesel still required for winter peak loads.
#2	< 1MW	Studied by Ontario Hydro in 1991. Potentially would require deep excavations for diversion structures, and likely more costly to develop.
#3	< 1MW	Cursory study by Ontario Hydro in 1991. No other engineering study available. From visual inspection in 1991 smaller drainage area and smaller hydraulic head. Would require run of the river development.
#4	220 kW per unit, 2 units	Study undertaken by Ontario Hydro in 1976.
#5	< 1MW	Same as above #4.
#6	780 kW	Preliminary assessment in 2001.
#7	2.65 MW	Ontario Hydro report 1991 - 2 - 1325 kW turbines.
#8	170 kW	Community working with RETScreens and consultants investigating feasibility.

g) Remotes plans to continue discussions to facilitate the deeper understanding of the resource developments and commercial partners to assist the First Nation with the development of projects. Development of renewable energy projects is balanced against other needs and priorities in communities. Remotes expects to assist with the collection of wind data and water resource determination in several communities. Because these activities are driven, in part, by the First Nation, Remotes does not have a detailed plan. Remotes expects other funding sources from levels of government will be leveraged by the First Nation. Please see Exhibit C1, Tab 2, Schedule 2, pages 3 - 4 of the updated evidence, and Exhibit C1, Tab 2, Schedule 3, item G8 (Investment Justification Document) of the pre-filed evidence, for written material regarding Remotes activities in renewable energy projects.

Nishnawbe Aski Nation (NAN) INTERROGATORY #7 List 1

Interrogatory

Ref: Exhibit A-15-1, Appendix B, Pages 1 to 29

a) In its materials at Exhibit A-15-l, Appendix B, which appear to have been used for the information session on August 20, 2008, the Applicant estimates that the monthly increase being proposed for the average Standard A customer would be approximately $57/month, while the average residential customer would incur an increase of approximately $5/month. Please provide recalculated figures for these estimates based on current costs for diesel fuel (given that diesel fuel prices have declined significantly since August 2008).

b) Why does the Applicant believe that increased costs in First Nations communities which are served by the Applicant should be "shared between customers and RRRP."

c) Does the Applicant agree that the circumstances of such communities are unique given their economic and social conditions (e.g. average unemployment rates of between 65% to 95%)?

d) Does the Applicant agree that it would be more consistent with the objective of ensuring equal access to electrical power, as well as the broader goal of sustainability (which the Applicant, OPG, Hydro One, and the Ontario Power Authority have all embraced), to have the RRRP pay for most of the proposed increase, while keeping increases for consumers well below the proposed increase of 4 to 5%?

Response

a) The decrease in fuel price, as given in the November 28, 2008 update, reduces revenue requirement by $1,152 thousand from the pre-filing. As discussed in Exhibit H, Tab 3, Schedule 10, since Remotes' customer rates are not recovering the full cost of service, any decrease in revenue requirement from the pre-filing would be applied to the RRRP subsidy, not to customer rates. Thus, there would be no change to customer rates presented at the information session in August, 2008.

b) Please see the part (d) response below.

c) Remotes agrees that the communities are unique and face economic disadvantages. In that context, Remotes believes that it would cause hardship if its customers were to bear the full brunt of cost increases.

d) Remotes has proposed that its customer rates be increased by the average 4.4% increase approved for customers of other regulated distribution utilities in Ontario. Remotes believes that this approach is reasonable and also consistent with its stated value of fair treatment of customers. Under this approach, the contribution to Remotes' revenue requirement from RRRP will increase by 31.8% from the previous Board-approved amount, assuming Board approval, which indicates that the majority of the increase in the cost to serve Remote communities is being borne by RRRP. Please see Exhibit H, Tab 3, Schedule 9 for details.

Nishnawbe Aski Nation (NAN) INTERROGATORY #8 List 1

Interrogatory

Ref: Exhibit Cl, Tab 2, Schedules 1 and 2

Data from the Canadian Government indicates that average diesel fuel prices have plummeted since July and August 2008 such that they are currently at levels comparable to the prices which existed in December 2005. (See the Natural Resources Canada website at http://fuelfocus.nrcan.gc.calprices_byyeare.cfm?ProductlD=5)

In Exhibit Cl, Tab 2, Schedule 1, Pages 1 to 4, the Applicant provides a summary of OM&A Expenditures based on higher diesel fuel prices for 2009, which higher prices have not actually materialized. Please recalculate the figures on the various charts provided in this Schedule based on current diesel fuel prices.

Response

Please see the evidence updates for Exhibit C1, Tab 2, Schedules 1 and 2, which reflect changes to OM&A expenditures for fuel plus other items.

Nishnawbe Aski Nation (NAN) INTERROGATORY #9 List 1

Interrogatory

The Applicant states that the Standard A (i.e. government) accounts make up approximately 13% (by number) of the customers of the Applicant but account for 93% of the outstanding arrears (based on 2007 figures).

a) The Applicant also advises that "payment plan arrangements and federal government support for those arrangements are being negotiated". What is the current state of such negotiations? Please provide particulars.

b) Given that the Standard A accounts constitute almost all of the outstanding customer arrears for the Applicant, why is the Applicant proposing a large increase in rates for Standard A accounts?

c) Does the Applicant not agree that raising customer rates (for residential consumers, Standard A accounts, and other customers) will likely result in an increase in defaults on accounts because there are simply no funds available to pay for the electricity being provided?

d) Would the First Nations communities dependent on services from the Applicant not be better served by the Applicant relying more heavily on the RRRP to prevent further customer arrears from arising?

Response

a) Payment plan negotiations with First Nations on Standard A accounts has been ongoing and the present status and recent history is attached. In the case where the First Nation is under co-management, they are supported by the Federal Government. For customer confidentiality reasons, non-identifying information is provided in the table below.

Community	Duration of Plan
A	Dec/06 – Oct/08 completed
B	Jul/08-Oct/11
C	No plan
D	No plan
E	July/08 – 2010
F	Nov/06-Jun/07 completed
G	Sept/05 – Aug/10
H	No Plan
I	Dec/06 – Dec/07 completed
J	Dec/07 – Nov/11
K	Sep/08 – Sep/11
L	No Plan
M	In Progress
N	No Plan

b) As discussed in Exhibit H, Tab 3, Schedule 1, Remotes does not believe that there is a direct link between rate increases and arrears. Remotes is proposing to increase Standard A customer rates by the average increase approved for customers of other regulated distribution utilities in Ontario. Remotes believes that its proposal is fair to all of its customers and to the customers who pay into RRRP.

c) Remotes does not believe there is a direct link between rate increases and increases in arrears. Please see Exhibit H, Tab 3, Schedule 1.

d) The proposal Remotes has made does rely on a larger increase to RRRP than to Remotes' customers. Remotes has proposed rate increases to its customers of 4.4% and has also proposed to increase the annual amount of RRRP (not including the recovery of the variance account amount) by $6.7M, from $21.1M to $27.8M, per Exhibit E1, Tab 1, Schedule 1, page 3. This is an increase of 31.8%.

Nishnawbe Aski Nation (NAN) INTERROGATORY #10 List 1

Interrogatory

Ref: Exhibit El, Tab 1, Schedule 1, Page 3 of 3

Ref: Exhibit Gi, Tab 1, Schedule 1, Pages 1 to 4

Ref: Exhibit Gl, Tab 2, Schedule 1, Pages 1 to 10

For Exhibit El, Tab 1, Schedule 1, Page 3 of 3, please provide a recalculated Table 2 (Comparison of Revenue Requirements: 2006 v. 2009) after inputting into the OM&A figures the current price for diesel fuel for all of the communities served by the Applicant. Please also advise how the new figures based on the current price for diesel fuel affect the following:

(a) the overall required budget of the Applicant for 2009;

(b) the rate increases which result for each customer class served by the Applicant. In other words, given the significant decline in fuel prices since July and August 2008, and assuming that the Applicant's funding request under the RRRP remains the same (i.e. as outlined in the Application), what is the proposed rate increase for each class of customers (e.g. residential, Standard A, etc.) that results when the figures based on current fuel prices are run through the Applicant's accounting program?

For Exhibit G1, Tab 1, Schedule 1, Pages 1 to 4, and assuming that the Applicant's funding request under the RRRP remains the same (i.e. as outlined in the Application), please provide the revised figures which result when the current cost of diesel fuel is run through the Applicant's accounting program for each of the tables on pp. 2 to 4.

For Exhibit G1, Tab 2, Schedule 1, Pages 1 to 10, please provide the revised figures for the tables in this Exhibit which result when the current cost of diesel fuel is run through the Applicant's accounting program. In doing so, assume that the Applicant's funding request under the RRRP shall remain the same (i.e. as outlined in the Application).

If the Applicant needs to revise any other tables containing in its pre-filed evidence in order to produce the revised tables identified above, NAN requests that the Applicant provide such additional information as part of the response to this interrogatory.

Response

Please see Exhibit El, Tab 1, Schedule 1, Page 3 of 3 of the updated evidence for an overview of the updated revenue requirement.

Based on the updated figures the overall revenue requirement for 2009 is $42,500 thousand, a decrease of $2,736 thousand. Of this, $1,152 thousand is attributable to the decline in fuel prices.

If only the fuel price decline is attributed to Remotes' customers, customer rates for all classes would decrease from current levels by 8.4%. This rate decrease compares with the 4.4% increase for all rate classes that Remotes has proposed.

Remotes would not want to set a precedent whereby Remotes customers absorb 100% of the volatility in changes to fuel prices, as the changes upward or downward can be very large. For this reason, Remotes does not believe it would be reasonable to attribute to Remotes customers the fuel-related reduction in the revenue requirement resulting from the updated evidence.

Remotes is of the view that the proposed 4.4% increase in customer rates, based on the Ontario LDC average, is equitable. Under this proposal, the contribution from RRRP to Remotes' revenue requirement would increase by 31.8% from the 2006 Board-approved to the 2009 Test Year, as noted in Exhibit E1, Tab 1, Schedule 9.