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Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

May 21, 2013

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

Dear Ms. Walli:

EB-2012-0137 - Hydro One Remote Communities Inc. 2013 Revenue Requirement and Rates Application – Responses to Supplementary Interrogatory Questions

Please find attached an electronic copy of responses provided by Hydro One Networks to Supplementary Interrogatory questions. Two (2) hard copies will be sent to the Board shortly.

The Interrogatory Responses have been filed by Intervenor:

Tab 1	Board Staff
Tab 2	Energy Probe
Tab 3	Vulnerable Energy Consumers Coalition (VECC)

An electronic copy of the Interrogatories have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank
Attach.

c Intervenors (electronic)

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #36 List 2

Interrogatory

Extending Service to Grid-connected Communities

References:
- Exhibit I / 2 / 2
- Exhibit A / 3 / 1 / p. 1
- EB-2004-0545, response to Staff interrogatory 4 (i), included as Attachment A to these interrogatories

In Exhibit I / 1 / 2, Remotes provided a single line diagram for the connection to the Provincial grid of both Cat Lake First Nation and Pikangikum First Nation. In regard to demarcation points on the diagram, and in particular to estimating the electrical losses on the connection to Cat Lake, Remotes indicated that:

- a computerized power flow simulation has been conducted for Cat Lake, the electrical losses from metering point to the community are estimated to be 2.46% at its peak loading conditions;
- facilities currently owned by Community of Cat Lake are shown marked on the drawing as part of the response to part a) of this interrogatory. Hydro One subsidiaries will take over these assets. Remotes expects to own the 75km of distribution line. However the final demarcation point has not been determined;
- Hydro One Networks - Transmission will continue to own the 115 kV line E1C from which the 18 kilometer line tap to Cat Lake substation is supplied.

The fourth reference is a response to an interrogatory, dated March 22, 2005, in EB-2004-0545. This proceeding was a joint application for Leave to Construct by De Beers Canada Inc, Five Nations Energy Inc, and Hydro One Networks Inc. The results of peak losses of approximately 450 km of 115 kV line supplying the De Beers mine range between 6.8 MW and 7.82 MW in serving a 20 MW load, in other words 25% or more. Board staff notes that losses on a 25 kV line is typically expected to be more than 16 times the losses on a 115 kV line, for the same amount of power transferred and for the same line length. Prorating these results to the connection to Cat Lake, assuming 1/6 of the line length (75 km) at 25 kV, the line losses would be in the range between 15% and 25 %.

a) In regard to the computerized power flow simulation for Cat Lake resulting in an estimate of 2.46% at its peaking loading condition, please provide the following:
   i. Size of the conductors used;
   ii. The peak loading assumed for Cat Lake;
   iii. The length of the 25 KV line assumed in the simulation; and

iv. Additional assumptions that were assumed that lead to the reported results of 2.46 % losses for Cat Lake.

b) With regard to Cat Lake, if the assumption of the length of the 25 kV line was less than 75 km as shown in the map, please repeat the calculation assuming that 75 km to be incorporated in the loss evaluation.

c) Please comment on the calculation that line losses would be in the range between 15% and 25%.

Response

a) Upon re-verification, the calculated line losses are 6.3%. This is based on the following:

i. The size of the conductors assumed in the simulation are as follows:
   - 250 MCM CU Egress Cables 0.1 km
   - 4/0 ACSR 427 75.0 km
   - 250 MCM CU Submarine Cable 0.7 km
   - 3/0 ACSR 425 1.0 km

ii. The peak load assumption used in the simulation is 1.5 MW.

iii. The length of the line is approximately 76.8 km in total.

iv. This assumes peak conditions.

b) N/A. The line length in the simulation exceeded 75km

c) The 25 kV line in question bears significantly less load than the 20 MW line described in the 2005 IR referenced above.

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #37 List 2

Interrogatory

Extending Service to Grid-connected Communities

References:
- Exhibit I / 2 / 2
- Exhibit A / 3 / 1 / p. 1
- Exhibit G1 / 1 / 2 / p. 4

In Exhibit I / 1 / 2, Remotes provided a single line diagram for the connection to the Provincial grid of both Cat Lake First Nation and Pikangikum First Nation. In regard to demarcation points on the diagram, and in particular to estimating the electrical losses on the connection to Pikangikum, Remotes indicated that:
- Remotes is unable to estimate the electrical losses for Pikangikum as no computerized model is readily available to conduct the simulation;
- The Hydro One facilities currently owned by the Community of Pikangikum are also shown on the drawing. The community is currently supplied by local Diesel Generation. Future ownership plans are that Hydro One Remotes will take over the community distribution system and the new supply feeder;
- A loss factor of 1.5% has been used in this application, reflecting the close proximity of generation to load in remote communities.

a) Please provide an estimate of the losses for Pikangikum using the computerized power flow simulation listing all assumptions including:
   i. Size of the conductors;
   ii. The peak loading for Pikangikum;
   iii. The length of the 25 KV (from the Metering Point to the Community); and
   iv. Any additional assumptions relevant to the evaluation.

b) Who will construct, pay for and own the new 100 Km 44 kV line between Red Lake TS and Pikangikum DS (is it Hydro One Networks Inc. – Distribution (“HONI-Distributuion”)?

c) If the response to e) indicates that HONI-Distributuion will be the owner of the noted 44 kV line, would Remotes be paying he LV Service Rates for the power delivery to Pikangikum in addition to the Retail Transmission Rates?

Response

a) The estimate total peak loss is calculated at 5.4%.
   i. Conductor size and assumptions from Red Lake TS to Pikangikum:
      (a) 336 ACSR, 3phase, 44 kV, (100 kms) 1.6%
      (b) Pikangikum DS (5MVA Transformer) 1.5%
      (c) 3/0 ACSR, 3 phase, 25 kV, (23 kms) 2.3%
   ii. Peak Loading: 1.5 MW
   iii. The length of the 25 kV line from the metering point to the community is 3 km. The estimate also assumes an additional 20 km of 25 kV line within the community of Pikangikum.
   iv. No other significant assumptions were included

b) The First Nation Community will construct and pay for the new 100 km long, 44 kV line. The First Nation Community will also construct and pay for the new Pikangikum DS. Hydro One Networks-Distribution will assume ownership and maintenance of the 44 kV line as well as the new Pikangikum DS at a final price to be determined once all construction details are available.

c) Remotes would be a sub-transmission customer of Hydro One Networks and would pay applicable LV service rates, which for Hydro One Networks are called ST rates, as well as applicable Retail Transmission Service Rates.

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #38 List 2

Interrogatory

Extending Service to Grid-connected Communities

Reference:

- Exhibit I / 1 / 6 (f)

Please provide the information, or a summary if too voluminous, that Remotes has provided to the OPA, AANDC and First Nations "to assist in the development of a business case for transmission to the north"

Response

Remotes has participated in meetings with the OPA and with community representatives to discuss planning and costs. Since 2009, Remotes has also responded to numerous requests for information from the OPA and from local communities regarding community load, annual peak load, forecasted load growth by community, litres of diesel fuel etc. The information provided includes the generation capital information found in Exhibit D1, Tab 2. Schedule 1, load forecasting information in Exhibit G1, Tab 1, Schedule Tab 3, Generation OM&A information found at Exhibit C1, Tab 2, Schedule 2, LAR information at Exhibit C1, Tab4, Schedule 1 and peak load reports at Exhibit I, Tab 4, Schedule 2.

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #39 List 2

Interrogatory

Pensions and OPEB

References:

- Exhibit I-1-4, Attachment 3 (2012 Financial Statement)
- Exhibit A-11-1, Attachment 3 (2011 Financial Statement)

On April 24, 2013, Remotes submitted its US GAAP December 31, 2012 audited financial statements at Exhibit I-1-4 Attachment 3. Remotes has recorded a $3,144,000 regulatory asset as at December 31, 2012 for "Post-retirement and post-employment benefits." (p. 18) Note 2 of the same reference includes the following explanation regarding the regulatory asset for "Post-retirement and post-employment benefits" at p. 13 (p. 81 of 565):

> "The Company records a regulatory asset equal to its allocated share of Hydro One's incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded on transition to US GAAP and at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for postretirement and post-employment plans, in absence of regulatory accounting, would be recognized in accumulated OCI ["Other Comprehensive Income"]. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process."

Board staff notes that neither a regulatory asset nor a regulatory liability was recorded in the December 31, 2011 CGAAP audited financial statements for "Post-retirement and post-employment benefits".

Questions / Requests:

a) Please explain in more detail the section of Note 2 of the audited financial statements referenced above regarding the $3,144,000 regulatory asset for "Post-retirement and post-employment benefits." Please explain why this balance was recorded in the 2012 US GAAP audited financial statements and not the 2011 CGAAP audited financial statements.

b) Please explain how and when Remotes is proposing to recover the $3,144,000 regulatory asset for "Post-retirement and post-employment benefits" in rates.

c) Please explain why this balance should not instead by charged to the shareholder in the company's accumulated other comprehensive income. As noted above, Remotes has recorded a regulatory asset for "Post-retirement and post-employment benefits" or "OPEB" in its financial statements. However, Remotes has not received a rate order by the Board to report such an asset. ASC 980-715-25-5 requires an order by the regulator.
   i. Why did Remotes not apply for such an order from the Board?
   ii. Does Remotes plan to apply for such an order from the Board?
   iii. Please clarify if this OPEB regulatory asset was $1,528,000 as at January 1, 2011, as noted in Note 18 (page 29) to the December 31, 2012 audited financial statements. If this was not the number, please provide the correct number.

Response

a) Please see exhibit I, Tab 1, Schedule 4, Attachment 3 (2012 Financial Statement) p.29 paragraph B which says: "Under Canadian GAAP, the Company disclosed, but was not required to recognize, the net unfunded status of post-retirement and post-employment benefit obligations on the Balance Sheets. Under US GAAP, the Company recognized the unfunded status of post-retirement and post-employment benefit obligations on the Balance Sheets with an offset to associated regulatory assets for the transitional fair value adjustments as the incremental obligations are expected to be recovered through future rates charged to customers." Please also see p. 19 of this exhibit under the title "Post-retirement and post-employment benefits."

b) The regulatory asset will not be recovered in rates in the same way a deferral or variance account balance would. OPEB and OPRB expense will continue to be reflected in rates on an accrual basis. Remotes expects this regulatory asset to be adjusted in value as the equivalent actuarial obligation changes in value, either through periodic actuarial re-measurement and/or through the future combination of expense recognition and/or benefits payments.

c)

   i. Remotes' assessment was that ASC 980-715-25-5 relates to transitional obligations when a Company first applies the provisions of ASC 715-60 (Compensation - Retirement Benefits). ASC 715-60 contains the accounting guidelines for deferral of transitional obligations when a Company changes from a cash basis of accounting for post-retirement plans to an accrual basis. ASC 980-715-25-5 is not relevant for Remotes because its predecessor entity Ontario Hydro had already adopted the accrual basis of accounting for OPRB/OPEB obligations under Canadian GAAP (CICA HB Section 3461-Employee Future Benefits).

   Remotes' regulatory asset for OPEB transitional obligations under US GAAP reflects the fact that change in the obligation is not included in rates when it occurs. Rather, the transitional impact is included in rates systematically and gradually in future periods. OPEB expense continues to be reflected and recovered in rates on accrual basis similar to Canadian GAAP.

Remotes' position is that no separate rate order is required given that there is no impact on amounts to be included in rates. This position is supported by US industry guidance issued by the Federal Energy Regulatory Commission (FERC). Per the FERC guidance document entitled "Commission Accounting and Reporting Guidance to Recognize the Funded Status of Defined Benefit Postretirement Plans" (issued under docket A107-1-000 March 29, 2007), regulatory assets or liabilities are to be established for amounts that are probable of recovery in future rates where an entity determines its postretirement benefits allowance included in its cost based, regulated-rates has a delayed recognition feature whereby changes in the post-retirement benefit obligations are not included in rates when they occur but rather are included in rates systematically and gradually in subsequent periods.

ii. No

iii. So confirmed

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #40 List 2

Interrogatory

Pensions and OPEB

Reference:

- Exhibit I-1-4, Attachment 3 (2012 Financial Statement)

How has Remotes recovered the following in past rates, and how does Remotes propose to recover these items in future rates:

a) Transitional asset/obligation generated on transition to CICA HB Section 3461. Please disclose initial amount and date and unamortized amount to date.

b) Transitional asset/obligation generated on transition to US GAAP. Please disclose initial amount and date and unamortized amount to date. Please confirm that these amounts were $1.528 million regulatory asset for OPEB as at January 1, 2011 under USGAAP.

c) Recognizing unamortized actuarial gains and losses and past service costs on the balance sheet under US GAAP

Response

a) There was no transitional asset or obligation generated on first time adoption of CICA HB Section 3461 –Employee Future Benefits.

The employee future benefit obligations that were initially recognized on Remotes' balance sheet upon demerger from Ontario Hydro in 1999 represented a proportionate share of its employee future benefit obligations based on actual funded/unfunded status of the plans. When Section 3461 was later adopted in fiscal year 2000, there was no accounting basis difference that resulted in transitional obligations. The benefit obligations were already recognized on Remotes' balance sheet based on current funded/unfunded status of the plans, before Section 3461 came into effect.

When Section 3461 was initially applied in fiscal year 2000, there was a change in the measurement basis of the discount rates used for the plans' valuations. The rates used to discount future benefits changed from management's best estimate to a market-based interest rate.

b) Regulatory asset amount is confirmed. On January 1, 2011, Remotes recognized an OPRB/OPEB obligation of $1.528 million to reflect the plans' relative funded status with an equal amount of offsetting regulatory assets.

Remotes will not directly recover/refund in rates the regulatory assets and liabilities that are recognized for financial reporting purposes for OPEB. This regulatory offset, results from the difference in the timing of recognition of employee benefit obligations. The changes in the obligations are not included in rates when they occur, but rather are included in rates systematically and gradually in future periods. The funded status are actuarially re-measured every year end and the offsets to regulatory assets are adjusted accordingly.

c) For Canadian GAAP, OPRB/OPEB obligations were recorded on the balance sheet using a "calculated value" instead of actual unfunded status of the plans. Unamortized gains and loss and past service costs were not recognized on the balance sheet but considered for supplementary disclosure only. OPRB and OPEB expense were recognized on an accrual basis whereby a portion of unamortized gains and losses and past service costs were recognized in the income statement based on the amortization provisions of the employee benefit cost accounting standard.

Under US GAAP, OPRB/OPEB expense continues to be recognized under an accrual basis. The actual unfunded statuses of OPRB/OPEB plans are recognized on balance sheet with offset to regulatory assets. There is no future rate impact from transitioning to US GAAP.

<u>Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #41 List 2</u>

Interrogatory

Pensions and OPEB

Reference:

- Exhibit I-1-4, Attachment 3 (2012 Financial Statement)

USGAAP does not recognize transitional assets/obligations generated from the transition to CICA HB Section 3461.

How did Remotes treat the unamortized amount on the transition to USGAAP?

Response

Please refer to response to Exhibit I, Tab 1, Schedule 40s, part b) for transitional obligation on adoption of CICA HB Section 3461. When Remotes transitioned to US GAAP, the actual funded/unfunded statutes of OPEB/OPRB plans were recognized on balance sheet with offset to associated regulatory asset accounts which otherwise would have been recognized in accumulated other comprehensive income. Recognition of actual funded/unfunded statuses on the balance sheet results in immediate recognition of any unamortized actuarial gains and losses for pension and OPRB/OPEB plans.

<u>Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #42 List 2</u>

<u>Interrogatory</u>

Pensions and OPEB

References:
- Exhibit I / 1 / 4(b)
- Board Staff IR #5

In the response to Board Staff IR#4(b), Remotes stated that it is proposing to recover its pension costs on a defined benefit cash basis, as follows:

> "Remotes recovers its pension costs in rates using the defined benefit cash basis, consistent with other Hydro One subsidiaries including Networks."

However, as noted in the preamble to Staff IR#4, the Remotes 2011 and 2012 audited financial statements articulates that Remotes records pension costs in its books on a defined contribution basis.

<u>Questions / Requests:</u>

a) Please provide reasons as to why the Board should approve recovery of Remotes pension costs on a different basis than that recorded in the audited financial statements (i.e. recover in rates on a defined benefit cash basis and record in books on a defined contribution basis).
b) Please explain why Remotes is applying for pension costs on a different basis (defined benefit cash basis) than that recorded in its audited financial statements. What are the external auditor's views on this fact?
c) Please provide an estimate of what Remotes 2013 pension cost would be using the defined contribution basis, including an explanation of the assumptions used in the calculations.
d) In the response to Board Staff IR#5, Remotes stated that actual 2009, 2010, 2011, and 2012 audited pension costs have been "sourced from financial system."
    i. Please describe how these costs were "sourced from financial system" and the basis of the sourcing.
    ii. Please explain why Remotes was able to source these amounts from the financial system, but these amounts were not included in the audited financial statements.
    iii. What are the external auditor's views on Remotes being able to source the pension costs from its system on a defined benefit cash basis, but recording the pension costs in its audited financial statements on a defined contribution basis?

Response

a) Remotes proposes to recover its defined benefit pension plan pension expense on a cash basis, consistent with past rate setting periods and consistent with all other Hydro One rate regulated subsidiaries and businesses except Hydro One Brampton Inc. This recovery by the subsidiaries does not differ with the method by which the pension plan is accounted for on an overall Hydro One basis. Given that the Hydro One pension plan does not segregate assets in a separate account for each individual subsidiary, the financial statements for Remotes necessarily record an allocation of Hydro One's contributions without the accompanying asset and liabilities.

The proposed method of recovery of pension costs and the related financial reporting of the pension plan within Remotes' audited financial statements are directly analogous to what the Board sees in Hydro One Networks' transmission and distribution filings and in related financial reports for many years.

The external auditor has provided an unqualified opinion on Remotes' annual financial statements for both 2011 and 2012.

b) Please see answer to part a) above.

c) Remotes' staff are members of Hydro One's defined benefit plan. It is not possible to develop contributions for a hypothetical contribution plan that does not exist.

d)

i. The capital and OM&A split of actual and forecast pension costs used to formulate the allocation of costs described above are based on the actual or forecast split of the work program between capital and OM&A available in the financial system. This information is either drawn from project account results (actuals) or business plans and budgets (forecast).

ii. Please refer to answers to parts a) and d) i) above.

iii. The external auditor has issued an unqualified audit opinion on Remotes' financial statements. These statements explicitly disclose Remotes' accounting policy with respect to its accounting for pension costs.

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #43 List 2

Interrogatory

Pensions and OPEB

References:

- Exhibit I-1-4, Attachment 1 (Pension Plan Actuarial Evaluation)
- Exhibit I-1-4, Attachment 3 (2012 Financial Statement)

As per Note 2 (page 13) of the December 31, 2012 audited financial statements, the Hydro One Inc. ("Hydro One") contributory defined benefit pension plan covers all regular employees of Hydro One and its subsidiaries, including Remotes and excluding Hydro One Brampton Inc.

Remotes provided the Hydro One Pension Plan "Report on the Actuarial Valuation for Funding Purposes as at December 31, 2011" as Attachment 1 to its response to Board Staff interrogatory #4.

Remotes stated that there is a later funding valuation available in the response to Board Staff interrogatory #4, with an effective date of December 31, 2012.

Questions / Requests:

a) Please confirm that the December 31, 2011 Hydro One valuation was prepared on the defined benefit cash basis.
b) Please provide the latest Hydro One valuation with an effective date of at December 31, 2012.
c) Has Mercer or another actuary ever prepared an Actuarial Valuation for Hydro One based on the accrual basis of accounting for pension expense? If so, please provide the latest valuation.

Response

a) So confirmed.

b) There is no such report. The reference in Exhibit I, Tab 1, Schedule 4 to December 31, 2012 was erroneous and should have read December 31, 2011.

c) Each year Mercer provides an actuarial valuation report in connection with the preparation of the year end disclosure information under the applicable accounting standards. Please see Attachment 1 for the most recent such report for the registered pension plan.

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #44 List 2

Interrogatory

Pensions and OPEB

Reference:

- Exhibit I-1-5

In the response to Board Staff interrogatory #5, Remotes provided unaudited numbers for the 2012 pension and OPEB costs The response included an explanation for the increase in pension and OPEB costs from 2009 through 2012, but no explanation from 2012 to 2013.

a) Please update the 2012 pension and OPEB costs in the table provided in the response to Board Staff interrogatory #5 with the audited numbers. Please update 2013 pension and OPEB costs in the table and any other appropriate evidence, if applicable.

b) Please provide an explanation for the increase or decrease in pension and OPEB costs from 2012 to 2013.

Response

a)

	Hydro One Remotes	**Reference**
Approved 2009 Pension Costs in Rates		
OM&A	691	Included within labour rates and costing of work in EB-2008-0232, C1, Tab 6, Schedule 1, pages 3 & 4.
Capital	214	
Total	905	
Total		
Actual Audited 2009 Pension Costs		
OM&A	691	Based on actual split of work program between capital and OM&A. All public filings related to pension cost are submitted on a Hydro One consolidated basis.
Capital	285	
Total	976	
Actual Audited 2010 Pension Costs		
OM&A	1,178	Based on actual split of work program between capital and OM&A. All public filings related to pension cost are submitted on a Hydro One consolidated basis.
Capital	405	
Total	1,583	

Actual Audited 2011 Pension Costs		
OM&A	818	Based on actual split of work program between capital and OM&A. All public filings related to pension cost are submitted on a Hydro One consolidated basis.
Capital	403	
Total	1,221	
Actual Audited 2012 Pension Costs		
OM&A	978	Based on actual split of work program between capital and OM&A. All public filings related to pension cost are submitted on a Hydro One consolidated basis.
Capital	406	
Total	1,384	
Proposed 2013 Pension Costs in Rates		
OM&A	799	Included in the labour rates and costing of work within the current business plan.
Capital	401	
Total	1,200	

Table 2 Annual OPEB cost (thousands)

	Hydro One Remotes	Reference
Approved 2009 OPEB Costs in Rates		
OM&A	579	Included within labour rates and costing of work in EB-2008-0232, C1, Tab 6, Schedule 1, pages 3 & 4.
Capital	179	
Total	758	
Actual Audited 2009 OPEB Costs		
OM&A	460	Exhibit A-11-1 Attachment 2
Capital	190	Exhibit A-11-1 Attachment 2
Total	650	
Actual Audited 2010 OPEB Costs		
OM&A	512	Exhibit A-11-1 Attachment 3
Capital	176	Exhibit A-11-1 Attachment 3 – Page 17 of 2010 Financial Stmts
Total	688	

Actual Audited 2011 OPEB Costs		
OM&A	551	Exhibit A-11-1 Attachment 3
Capital	271	Exhibit A-11-1 Attachment 3
Total	822	
Actual Audited 2012 OPEB Costs		
OM&A	537	Exhibit I-1-4 Attachment 3
Capital	223	
Total	760	
Proposed 2013 OPEB Costs in Rates		
OM&A	561	Included in the labour rates and costing of work within the current business plan.
Capital	281	
Total	842	

b) The modest increases forecast for 2013 vs. the results from 2012 relate primarily to changes in the assumed discount rates, timing differences and changes to Base Pensionable Earnings (BPE).

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #45 List 2

Interrogatory

Cost of Remediation of Contaminated Land

References:
- Exhibit C1-4-1
- Exhibit I-1-4, Attachment 3
- Exhibit I-1-29

In the response to Board staff interrogatory #29, Remotes stated that its environmental expense for 2012 and 2013 is expected to be $2,515,000 and $2,713,000 respectively, and provided the following table.

Remotes LAR Amortization Expense

$ Thousand

Actual				**Plan**				
2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
983	1,268	1,017	2,515	2,713	1,487	1,589	1,134	1,284

In the December 31, 2012 audited financial statements, Exhibit I-1-4, Attachment 3, submitted April 24, 2013, (note 13 on p. 23, p. 91 of 565) Remotes disclosed the following information:

> "As a result of its annual review of the environmental liabilities, the Company recorded a revaluation adjustment to reduce the LAR environmental liability by $583 thousand"

In the same note, Remotes updated its estimated future environmental expenditures as follows:
- 2013 - $1,823 thousand;
- 2014 - $2,783 thousand;
- 2015 - $1,457 thousand;
- 2016 - $980 thousand;
- 2017 - $1,104 thousand.

Board staff notes that the average of these five amounts is $1,630 thousand.

Questions / Requests:

a) Please provide an updated version of the table titled "Remotes LAR Amortization Expense".

b) Please describe the circumstances, assumptions and calculations used to arrive at the revaluation adjustment representing a $583,000 reduction in the environmental liability as at December 31, 2012.

c) Please comment on whether the amount of $1,630,000 would be a more suitable amount of Amortization Expense to include in Table 2 of Exhibit C1-4-1, p. 3, and in Remotes' revenue requirement. If so, please update the applicable evidence.

Response

a) Remotes' environmental liabilities were reviewed late in 2012 and the future expenditure estimates were revised and the values were provided in Note 13 of Remotes 2012 audited financial statements. For financial statement purposes, the values comprising the provision are expressed in constant 2012 dollars.

The table originally included in Exhibit I, Tab 1, Schedule 29 has been updated and included below. This table herein now includes the revised values resulting from the revision described in Note 13 of the audited statements. Moreover, this table contains the actual, undiscounted values that are expected to be spent in the noted years.

Remotes LAR Amortization Expense
$ Thousand

2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
983	1,268	1,017	2,515	1,861	2,901	1,546	1,061	1,219

b) The reduction to the provision in 2012 is mainly due to large cost savings associated with good weather and better than planned equipment operation during the Sandy Lake DGS remediation.

c) The $1,630,000 is not suitable for amortization since each year the project(s) scopes and size will vary. The estimates provided have taken the scope and size for each community into consideration when providing the estimate year over year. The year over year forecast may change based on negotiations, workload, and type of remediation measure(s) selected. From an expense recognition perspective, Remotes maintains that the current treatment is more in keeping with the accounting principle of *'matching'* wherein the company attempts to match expenses with their actual incurrence.

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #46 List 2

Interrogatory

Cost of Remediation of Contaminated Land

References:

- Exhibit A-8-1
- Exhibit I-4-12, parts a and c
- Exhibit I-1-18, part c
- RP-1998-0001, Appendix D to Rate Order,(OHSC Distribution), pp. 55-57

In its response to NAN interrogatory #12 concerning the cost of remediating contaminated land, in particular the site of a fuel tank at Attawapiskat, Remotes has cited the OEB's decision RP-1998-0001. Board staff notes that the decision on Distribution rates mentions 21 communities (at p. 56), and approved amounts for remediation in 1999 and 2000. From this information, it appears that the decision on OHSC rates in 1999 is not pertinent to remediation in Attawapiskat, Cat Lake, and Pikangikum.

Questions / Requests:

a) Please confirm that the 21 communities alluded to in the RP-1998-0001 proceeding are the same ones as are listed in the current application at Exhibit A-8-1, p. 1, Alternatively please provide a reference in the record of RP-1998-0001 to support a contention that the OEB approved remediation in some or all of these locations.

b) If RP-1998-0001 is not a suitable reference for the cost of remediation outside of the 21 communities served by Remotes, please provide an alternative reference(s) to regulations or OEB decisions which support Remotes' assumption of remediation costs in such locations.

c) Are there any other environmental liabilities from the legacy Ontario Hydro that have been assumed by Remotes in areas that Remotes does not currently service?

d) What are the criteria for Remotes recording some environmental liabilities and not others (both constructive and legal obligations)?

Response

a) Remotes notes that in its response, it referred to the Board's original approval for Land Assessment and Remediation funding. In no way did Remotes mean to imply that the Board's Decision in RP-1998-001 approved the LAR funding currently requested. Remotes referenced that Decision because during the technical conference in that proceeding, the question of whether or not it is acceptable to recover the costs for environmental activities to remediate historic contamination from ratepayers was specifically posed and discussed (pages 515-518). On page 56 of the Board's Decision, the Board stated that "With respect to the significant increases requested for environmental expenditures, the Board understands the need to address these issues, but also recognizes that many programs are being established to address long standing problems".

The 21 communities referenced in the RP-1998-001 filing does not match the communities listed at Exhibit A, Tab 8, Schedule 1, page 1. The differences are as follows:

- Fort Albany and Attawapiskat were served by Remotes in 1998, but the distribution and generation assets in Fort Albany and Attawapiskat were subsequently transferred to the local First Nations. The obligation to remediate the environmental contamination identified in the reports that were the subject of RP-1998-001 in both of these sites were transferred to Five Nations Energy Inc. ("**FNEI**") by contractual agreement. The obligation to remediate the soil associated with the tank was not transferred to FNEI as that asset was not transferred to the Attawapiskat First Nation.
- Cat Lake First Nation took control of Ontario Hydro's distribution assets in that community in December 2000. Because the community was not required to be licenced by the OEB, an agreement to transfer the assets from Ontario Hydro (OEFC) to Cat Lake was never signed.
- Marten Falls was added to Remotes' service territory in 2010.

Pikangikum was not served by Remotes at the time of that filing. However, costs related to assessing contamination in that community were specifically referenced on page 1 of Supplemental Filing D, filed December 23, 1998.

b) Remotes believes that RP 1998-0001 is a suitable reference for remediation outside of the listed communities insofar as it addresses the question of whether it is acceptable to recover costs for environmental activities to remediate historic contamination.

Under the Ontario *Environmental Protection Act*, Remotes or Ontario Electricity Finance Corporation (the statutory continuation of Ontario Hydro by virtue of Section 54(1) of the *Electricity Act*, *1998*) could be subject to a Ministry Order to clean up contamination associated with Ontario Hydro's operations and parties affected by the contamination could start a claim against Remotes or Ontario Electricity Finance Corporation to remediate the contamination.

c) In terms of its former diesel operations, Ontario Hydro had outstanding environmental liabilities in three communities that Remotes does not currently serve: Pikangikum, Cat Lake and Attawapiskat. Remotes inherited the liabilities associated with the remediation in these communities.

d) Remotes' environmental provision covers obligations it inherited from Ontario Hydro upon demerger in 1999. Remediation expenditures incurred to deal with contamination occurring since 1999 are funded through OM&A. Where on-site clean-up is required under existing regulations, the provision covers such expenditures. Where there is no existing regulatory requirement to clean-up on site, the provision covers clean-up of contaminants that have migrated off-site as well as non-capital expenditures made on-site to prevent such migration.

<u>Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #47 List 2</u>

<u>Interrogatory</u>

Cost of Remediation of Contaminated Land

References:

- EB-2008-0232, Exhibit C1-2-2, Appendix A
- Exhibit C1-4-1
- Exhibit I-1-4, Attachment 3
- Exhibit I-1-18, part c

In its response to Board staff interrogatory # 18 c, (pp. 311-312 of 565), Remotes has included an agreement for decommissioning and soil remediation in Attawapiskat, which was generated in 2007 and now includes an update of Remotes' cost at $664,765. This cost is larger than the amount that was included in Remotes' previous cost-of-service rate application EB-2008-0232, which was $150,000. It is also larger than the cost included in this application, which was $350,000. (Exh C1-4-1 p. 4)

<u>Questions / Requests:</u>

a) Please explain why the cost of this project has increased to such an extent.

b) Does the amount of the Environmental Liabilities in Remotes' 2012 audited Financial Statement at Exhibit I-1-4c, note 13 (p. 91 of 565) reflect the largest of the three amounts, or a lower remediation cost forecast such of one of the other amounts cited in the preamble?

<u>Response</u>

a) The 2008 filing referenced only the variance between 2007 and the bridge year for the Attawapiskat project. The total projected cost for the Attawapiskat project from 2006 to 2013 was $798K. The original estimate was a "C" estimate (within 50%) based on old data about the amount of remediation required. Further delineation was possible when old storage tank(s) were removed and a firm estimate was provided when a contractor was selected by AANDC to perform other work in the community including an estimate for remediation of the old tank farm area. The revised estimate is an "A" estimate based on new data on the extent of remediation required.

b) Note that the $350k referenced, in Exhibit C1, Tab 4, Schedule 1, page 4, is the difference between the 2012 ($100k) and the projected 2013 ($450k) and is not the total forecasted cost of remediation. The projected costs assumed in the 2012 filing are shown in the chart below.

2012 Filing Projected (Based on 2012 Business Plan) ($000's)	
Year	
2006-2011	290
2012	100
2013	450
2014-2016	60
Total	900

The amount in Remotes' 2012 audited financial statements reflects the latest estimate of Remotes' environmental liabilities; therefore, it includes the latest forecast for Attawapiskat and is also the highest.

2012 Year End Actual & Forecast (Provides the basis for the 2012 Provision in Financial Statements) ($000's)	
Year	
2006-2011	290
2012	2
2013	738
2014	184
Total	1,214

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #48 List 2

Interrogatory

Cost of Remediation of Contaminated Land

References:
- Exhibit I / 1 / 9
- Attachment 4 – 2E Project Table (filed October 31, 2012)

Remotes has explained that federal funding was received for the staff house in Marten Falls. According to the project tables provided in Attachment 4, other staff houses have been built or renovated at considerable cost including four staff houses at more than $400k each (Kingfisher, Sandy Lake, Fort Severn, Webeque)

What criteria are used to determine which staff houses are funded similar to Marten Falls, which are funded by Remotes alone, and which if any are funded by some other cost-sharing formula?

Response

The staff house in Marten Falls is funded in the same way as the other staff houses in First Nation communities in Remotes' service territory. Under the Electrification Agreements, AANDC funded the capital cost to build a staff house in each community. Remotes is responsible for maintenance and replacement costs.

Ontario Energy Board (Board Staff) Supplemental INTERROGATORY #49 List 2

Interrogatory

References:

- Exhibit I-1-4, Attachment 3
- Exhibit F1-1-1, Appendix D

In its pre-filed evidence submitted in September 2012, Exhibit F1-1-1 Appendix D, Remotes forecasted a debit balance of $747,000 in the RRRP variance account as at December 31, 2012.

On April 24, 2013, Remotes submitted its US GAAP December 31, 2012 audited financial statements at Exhibit I-1-4 Attachment 3. The audited balance of the RRRP variance account as at December 31, 2012 is now available, per Note 9 of the audited financial statements in Exhibit I-1-4, Attachment 3, p. 18 (p. 86 of 565). Board staff notes that the audited balance in the Regulatory Asset account is a debit balance of $787,000 as at December 31, 2012.

Questions / Requests:

a) Please confirm that the December 31, 2012 actual audited balance of the RRRP variance account is a debit balance of $787,000.

b) Please update the evidence in Exhibit F and any other appropriate evidence leading to this revised balance.

c) Please describe the reason for any substantial revisions in the line items in Exhibit F.

Response

a) So confirmed.

b) Please see Attachment 1.

c) Please see Attachment 2.

ATTACHMENT 1

HYDRO ONE REMOTE COMMUNITIES INC.
Variance Account Reconciliation
For the year ended Dec. 31, 2012

		Revenues and Expenses Audited Actuals		Approved	Variance
RRRP Variance Opening Balance	***Jan. 1/2012***		(3,098)		
RRRP Approved by OEB					
Annual Rural and Remote Rate Protection		(27,549)		(27,549)	
RRRP Variance Account Recovery		0		(3,381)	
Total RRRP Received		(27,549)	(27,549)	(30,930)	
Revenues					
Energy		(14,604)		(14,303)	301
Other - Late Payment, Service Fees, External		(656)		(609)	47
Total	**Note 1**	(15,260)	(15,260)	(14,912)	348
Costs			(42,809)		
OM&A					
Generation		11,762		9,248	2,514
Fuel		24,306		21,649	2,657
Distribution		1,986		1,648	338
Customer Care		1,928		1,230	698
Community Relations		393		599	(206)
Administration and Other OM&A		958		981	(23)
External Costs		144		90	54
Bad Debt	**Note 2**	(310)		575	(885)
Depreciation		3,504		2,969	535
Amortization of Environmental Asset		2,515		1,500	1,015
Other Post Employment Benefits		0		0	0
Interest		1,016		1,720	(704)
Income Tax (Includes capital taxes)		(1,436)		152	(1,588)
Total		46,766	46,766	42,361	4,405
Net (Income)/Loss [change in RRRP]		3,957			
IFRS Transition Account (Removed from RRRP Variance Account)			(72)		
Ending Balance RRRP VA	***December 31/2012***		787		

Note 1 - Hydro One Remote Communities conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result. Any excess or deficiency in remote rate protection revenues necessary to breakeven is added to, or drawn from, the Remote Rate Protection Variance Account. Remote Rate Protection amounts received for the year ended December 31, 2012 were $27,549 thousand. An additional $3,957 thousand was recognized as revenue consistent with the break-even business model. The balance of the remote rate protection amounts received has been allocated to the remote rate protection revenue variance account as illustrated in this reconciliation.

HYDRO ONE REMOTE COMMUNITIES INC.
Variance Account Reconciliation
For the year ended Dec. 31, 2012

	Revenues and Expenses		Variance from Budget	
	2012 Audited Actuals	**2012 Budget**		
RRRP Approved by OEB				
Annual Rural and Remote Rate Protection	(27,549)	(27,549)		
RRRP Variance Account Recovery	0	0		
Total RRRP Received	(27,549)	(27,549)		
Revenues				
Energy	(14,604)	(14,768)	(164)	Lower sales to Std A customers partially offset by increased sales
Other - Late Payment, Service Fees, External	(656)	(489)	167	Higher external revenues
Total	(15,260)	(15,257)	3	
Costs				
OM&A				
Generation	11,762	11,591	170	Higher tank and auxiliary maintenance
Fuel	24,306	22,864	1,442	Higher fuel prices and consumption
Distribution	1,986	1,902	84	
Customer Care	1,928	1,689	239	Higher billing associated with CIS project
Community Relations	393	846	(453)	Lower CDM due to delays in securing community advisors and lower community relations costs.
Administration and Other OM&A	958	1,042	(84)	Lower regulatory costs due to a lower than expected OEB cost allocation, later than planned Notice for this proceeding and later than planned cost awards for EB-2011-0021
External Costs	144	61	83	
Bad Debt	(310)	38	(348)	Success with high risk payment plan
Depreciation	3,504	3,491	13	
Amortization of Environmental Asset	2,515	3,474	(958)	Lower LAR primarily associated WITH savings on Sandy Lake DGS remediation and deferral of majority of Webequie project to determine the best option to remediate
Other Post Employment Benefits	0	0	0	
Interest	1,016	1,095	(79)	
Income Tax (Includes capital taxes)	(1,436)	(1,372)	(63)	
Total	46,766	46,721	45	

Energy Probe (EP) SUPPLEMENTAL INTERROGATORY #12 List 2

Interrogatory

Ref: A-Staff-2 d) &
Exhibit I, Tab 1, Schedule 2 d)

The response to Board Staff #2, Exhibit 1 Tab 1 Schedule 2, includes a statement in part d) that "Remotes expects to own the 75 km of distribution line":

a) Assuming that this 75 km of distribution line is the same as the portion shown on the single line diagram between Cat Lake SS and the first nation community, what voltage will this line be operating at? How will remotes deal with voltage drop on this line?

b) Is this 75 km section accessible by road year round? If not, how will Remotes access it for maintenance and repair?

c) What additional resources and equipment will Remotes require to maintain this section of line? How much will those additional resources and equipment cost?

d) Will backup generation still be needed at Cat Lake to provide power in the event of lengthy outages to the distribution line?

Response

a) The nominal operating voltage is 25 KV. The Cat Lake First Nation Community has a Voltage Regulator which will regulate voltage within the required voltage range.

b) Remotes expects to access the line by winter road and helicopter.

c) Remotes expects to contract with Hydro One Networks to perform forestry and line maintenance work under its SLA for Utility Services. The forestry work must be completed in order to establish a line clearance. Once the line clearance is established in 2013, an asset condition assessment would be completed to identify required line maintenance. The anticipated cost of $1.2M for forestry work is included in the 2013 budget.

d) In a meeting with community representatives, Remotes suggested that the community might wish to consider investing in the existing diesel generating station in Cat Lake to use as a source for backup generation.

Energy Probe (EP) SUPPLEMENTAL INTERROGATORY #13 List 2

Interrogatory

Ref: A-Staff-2 d) &
Exhibit I, Tab 1, Schedule 2 d)

The ownership notes on the single line diagram show an 18 km tap of cct. E1C supplying Cat Lake SS. As the schematic is in black and white it is unclear whether or not this line tap is operating at transmission voltage.

a) Please advise what voltage this line tap operates at.

b) If it operates at transmission voltage,
   i. Will Remotes assume ownership of it?
   ii. If yes, is Remotes equipped and staffed to perform maintenance and repair on transmission level assets or will it be done by others under contract?
   iii. Will Remotes require a transmission licence from the OEB in order to operate this line?

Response

a) The nominal operating voltage for the 18 kilometer section is 115 kV.

b)
   i. No – ownership of this line section will be maintained by Hydro One Networks.
   ii. N/A
   iii. N/A

Energy Probe (EP) SUPPLEMENTAL INTERROGATORY #14 List 2

Interrogatory

Ref: G-VECC-12 &
Exhibit I, Tab 3, Schedule 12

The response to VECC #12 presents a comparison of monthly bills between non standard A off grid customers and Hydro One Networks distribution customers. In every customer class the Remotes customer appears to pay significantly less than the Networks customer.

Please explain why the differences are so significant.

Response

Remotes' customer rates are not based on cost. Remotes notes that the comparison referenced above was for non-Standard A customers. Standard A customers pay rates that are much higher than the rates charged by Networks. Rates for customers in the remote north throughout Ontario are influenced by federal government funding and by federal and provincial government policies. Comparisons between cost based rates for Hydro One Networks or any other LDC to Remotes' rates are therefore not valid.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #1 List 2

Exhibit A - Administration

Reference: VECC #1

Interrogatory

a) Please provide a table showing the revenue received by Remotes from Networks in respect of metering and in respect of lines services provided by Remotes for each year 2008-2011 inclusive.

Response

The revenue received by Remotes from Networks in respect of metering and lines services for the years 2008 to 2013 is shown in the table below. The year 2012 has been updated to include training assistance provided to Networks. The services are generally demand or emergency related, however, the 2013 forecast has been corrected to reflect revenues included in the test year mostly for anticipated training assistance which is provided for under the same service level agreement.

Fees Payable by Networks to Remotes
($000s)

	Historic					Forecast
Services	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Metering	0	0	0	0	0	0
Lines Services	82	93	267	173	130	76
Total	82	93	267	173	130	76

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #2 List 2

Exhibit A - Administration

Reference: VECC #3 a)

Interrogatory

a) With respect to the relatively poor reliability performance in 2012, does Remotes expect this to be a one-time problem or a chronic problem?

b) With respect to the relatively poor reliability performance in 2012, please provide details with respect to the actions Remotes has taken to avoid similar results in future years.

Response

a) Remotes expects that the poor reliability noted in 2012 is due to a relatively isolated series of outages related to poor quality bio-diesel fuel and unexpected engine failures.

b) In the spring of 2012 Remotes experienced multiple power outages and reliability issues that, after investigation, were discovered to be directly related to poor quality bio-diesel fuel. The poor quality fuel resulted in mould-like growth that contaminates the fuel systems including day tanks, piping and bulk fuel tanks. The poor fuel quality clogged engine fuel filters choking and starving the generating units of fuel causing outages. As a defensive measure, the use of all bio-diesel related products has been discontinued indefinitely. Additionally, Remotes has cleaned the high risk bulk fuel tanks and worked with its fuel suppliers to enhance supply chain filtering, testing and quality control programs.

As a result of a decision to defer a required upgrade a decade ago, North Caribou First Nation (Weagamow) owns and maintains a 1 MW temporary unit in that community. This engine is the largest unit and is required to meet the community's electrical load, especially during higher load periods. In September 2012, the temporary unit suffered an unexpected failure. Given that Remotes has limited control of the maintenance and operating condition of this unit, the outage suffered and downtime experienced was unlike our normal operation. Remotes worked diligently with the First Nation, its consultants, and vendors to arrive at a suitable emergency plan. Along with the First Nation, Remotes continues to work with AANDC acquire funding for the plan. Currently, a new replacement unit (725kw) is in-place until such time as the rebuilt 1MW will be re-installed during the summer of 2013. Given that the 1MW has recently been rebuilt by the manufacturer's service department, it should perform an additional 42,000 hours without major incident based on manufacturer's expected life cycle, provided that routine preventative maintenance is performed by the First Nation or its contractors.

Other smaller engine failures also contributed to the poor reliability experienced in 2012. Remotes continues to work diligently to reduce its exposure by performing routine and preventative maintenance and by addressing unit operating concerns on a priority basis.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #3 List 2

Exhibit C – Cost of Service

Reference: VECC #4 b)

Interrogatory

a) The response to VECC #4 b) implies that the average cost per meter change was $235 in 2011. Please provide any available data from years other than 2011 regarding the number of meter changes and the total cost.

Response

The response to Exhibit I, Tab 3, Schedule 4, part b, of list 1, explained the residual variance between 2011 and 2010 Customer Care costs. The $94 k referred to does not represent the total costs to re-verify the meters that were tested, but only reflects the increased program activity required to re-verify an abnormally large number of meters in 2011.

Specific cost data related to meter reverification in not available because meter reverification activities are collected with general metering costs including reading and input.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #4 List 2

Exhibit C – Cost of Service

Reference: VECC #5 a) and b)

Interrogatory

a) Please update the referenced response to include actual 2012 data if available.

Response

The referenced response is updated to include actual data for 2012.

SCH A - Accounts Receivable Year End Amounts	Year End 2008	Year End 2009	Year End 2010	Year End 2011	Year End 2012
Accounts Receivable - All Gross	10,108	8,455	6,411	5,251	5,139
Allowance for Doubtful Accounts (AFDA)	(4,856)	(3,822)	(3,073)	(2,825)	(2,432)
Net	**5,253**	**4,633**	**3,338**	**2,425**	**2,707**

SCH B - Accounts Receivable Year over Year Change	Year 2008	Year 2009	Year 2010	Year 2011	Year 2012
Accounts Receivable - All Gross		(1,654)	(2,043)	(1,161)	(112)
Allowance for Doubtful Accounts (AFDA)		1,034	749	248	394
Net		**(620)**	**(1,295)**	**(913)**	**282**

SCH C - Reconciliation of AFDA Change to Bad Debt Expense	Year 2008	Year 2009	Year 2010	Year 2011	Year 2012
AFDA Change - Year		1,034	749	248	394
Corresponding Impact on Bad Debt		(1,034)	(749)	(248)	(394)
Other Changes Impacting Bad Debt		592	56	(8)	66
Add: Non Energy Bad Debts		77	69	60	17
Amounts Per Table 1 (C1) (+ 2012 Actual)		**(365)**	**(624)**	**(196)**	**(310)**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #5 List 2

Exhibit G – Cost Allocation and Rate Design

Reference: VECC #7

Interrogatory

a) Please explain why Hydro One Remotes considers it appropriate to apply to its circumstance a rate adjustment formula that was established specifically for Algoma Power Inc.

b) Using the average use values from G1/1/3, page 4, please provide a schedule that sets out the 2013 monthly bill for each Hydro One Remotes' non-Standard A Off Grid customer class and compares it with the monthly bill that a similar customer would receive for 2013 if served by Algoma Power Inc. (Note: The relevant case file for Algoma's 2013 approved rates is EB-2012-0104).

Response

a) Remotes notes that, in EB-2008-0232, the Board approved an increase to Remotes' customers based on the average increase for grid-connected customers. Remotes is proposing to increase rates using fundamentally the same approach. However the methodology was subsequently refined for Algoma Power Inc. because the "Board Staff Report on: Rural and Remote Rate Protection Adjustment Mechanism" set out a clear and transparent approach to calculating the average increase for customers benefiting from Rural and Remote Rate Protection. As stated in the evidence, Remotes has applied the methodology to the total bill in order to capture changes to both generation and distribution costs.

b) Please see the schedule below. Note that distribution rates effective January 1, 2013 (per EB-2012-0104) are used in the calculations for Algoma Power Inc. (API) and proposed rates effective May 1, 2013 are used for Remotes. As most customers in Remotes' service territory do not pay HST or DRC, monthly bills are shown without either DRC or HST.

Customer Class	Annual Avg kWh/Cust	Monthly Avg kWh/Cust	Total Monthly Bill After OCEB
Residential-R1 API	13,537	1,128	$156.49
Residential-Remotes	13,537	1,128	$106.06
Seasonal-API	2,153	179	$68.96
Seasonal-Remotes	2,153	179	$41.25
GS 1 Phase-R1 API*	20,212	1,684	$224.44
GS 1 Phase-Remotes	20,212	1,684	$172.26
GS 3 Phase-R2 API	133,901	11,158	NA**
GS 3 Phase-Remotes	133,901	11,158	$1,070.50
Streetlight-API	37,337	3,111	NA**
Streetlight-Remotes	37,337	3,111	$264.87

* Customers in Remotes' GS 1 Phase rate class are assumed to be similar to customers in API's Residential-R1 class.

** API's R2 and Street Lighting customers are charged based on their monthly peak demand (kW) for all R2 charges and for Street Lighting RTSR charges. Remotes' customers are all charged based on their monthly energy consumption (kWh) and peak demand billing information is not available. Therefore, the data required to calculate the monthly bills for API's R2 and Street Lighting class is not available.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #6 List 2

Exhibit G – Cost Allocation and Rate Design

Reference: VECC #10 c), Energy Probe #11 a)

Interrogatory

a) With respect to VECC #10 c), what is the earliest likely date that a grid connection to Pikangikum could be completed and what is Hydro One Remotes best estimate as to when such a connection will be completed?

Response

a) Based on previous discussions with Pikangikum's transmission project manager, the transmission line construction would take approximately six months. Remotes does not believe that funding for the line will be forthcoming unless the community has an agreement for service with an established distribution company. Assuming that most of the approvals outlined in Exhibit I, Tab 1, Schedule 1 are secured in 2013, Remotes believes the earliest date possible to serve the community could be March 31, 2014. Remotes notes that its original estimate for the timing of taking over service to this community of January 2013 was developed in 2011. Several required federal government approvals of funds to complete the project are still outstanding. The revenues and costs for this community were forecast to be basically offsetting. At the current time, Remotes' best estimate that this connection will be completed is December, 2014. The costs associated with serving the community are shown in detail in Exhibit I, Tab 1, Schedule 3.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #7 List 2

Exhibit G – Cost Allocation and Rate Design

Reference: VECC #12

Interrogatory

a) Please confirm that the bills for Hydro One Networks' customers are based on the 2013 rates effective January 1, 2013 while the Remotes' bills are based on 2012 rates prior to the proposed May 1, 2013 rate adjustment.

b) If part (a) is confirmed please re-do the response using – for Remotes – the proposed 2013 rates.

Response

a) Confirmed.

b) Please see the chart below.

Remotes Non-Standard A Customer Class	**Annual Avg kWh/Cust**	**Monthly Avg kWh**	**Total Monthly Bill After OCEB**
Residential-Networks	13,537	**1,128**	**$160.38**
Residential-Remotes	13,537	**1,128**	**$106.06**
Seasonal-Networks	2,153	**179**	**$50.79**
Seasonal-Remotes	2,153	**179**	**$41.25**
GS 1 Phase- Networks	20,212	**1,684**	**$256.81**
GS 1 Phase -Remotes	20,212	**1,684**	**$172.26**
GS 3 Phase-Networks	133,901	**11,158**	**$1,548.25**
GS 3 Phase-Remotes	133,901	**11,158**	**$1,070.50**
Streetlight-Networks	37,337	**3,111**	**$502.46**
Streetlight-Remotes	37,337	**3,111**	**$264.87**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #8 List 2

Exhibit G – Cost Allocation and Rate Design

Reference: OEB Staff #2

Interrogatory

a) Who will eventually "own and maintain" the new 44 kV line that is to be constructed to connect Pikangikum to the grid?

Response

Please refer to Part b) of Exhibit I, Tab 1, Section 37S.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #9 List 2

Exhibit G – Cost Allocation and Rate Design

Reference: OEB Staff #31

Interrogatory

a) As requested in the original interrogatory, please provide the calculation in an Excel Spread sheet.

b) Applying the same methodology please provide the average 2011 total bill increase using only the following distributors:
- Brant County Power
- Horizon Utilities
- Hydro One Brampton Networks
- Hydro One Networks
- Kenora Hydro
- Kingston Hydro
- Milton Hydro
- Niagara Peninsula Energy
- Norfolk Power
- Parry Sound Power
- St. Thomas Energy
- Toronto Hydro-Electric
- Waterloo North Hydro
- Woodstock Hydro

c) Please confirm that in the case of Algoma's Residential customers, the rate adjustment based on the average distribution rate increase experienced by other distributors is applicable regardless of whether the overall rate application is based on cost of service or IRM (See Algoma's 2012 Application (EB-2011-0152), page 10).

d) Does Hydro One Remotes plan to file its 2014 rate application on a cost of service or IRM basis?

e) If it is to be filed on an IRM basis, will Hydro One Remotes being adopting the same price escalation formula as used in the current application?

Response

a) The requested data is provided in Attachment 1.

b) The requested data is provided in Attachment 1.

c) This is confirmed.

d) Remotes plans to file its 2014 rate application on an IRM basis.

e) Remotes plans to adopt the same price escalation formula unless otherwise directed by the Board.

Applicant	Service_Territory	DX_Base (11/10)	Total bill (11/10)
Brant County Power Inc.	Residential	6.13%	5.65%
Brant County Power Inc.	General Service Less Than 50 kW	-5.05%	3.24%
Horizon Utilities Corporation	Residential	13.00%	7.39%
Horizon Utilities Corporation	General Service Less Than 50 kW	16.43%	7.49%
Hydro One Brampton Networks Inc.	Residential	-7.41%	1.19%
Hydro One Brampton Networks Inc.	General Service Less Than 50 kW	-12.81%	0.24%
Hydro One Networks Inc.	Residential Average	6.97%	4.82%
Hydro One Networks Inc.	General Service Average	5.96%	4.53%
Kenora Hydro Electric Corporation Ltd.	Residential	38.60%	11.66%
Kenora Hydro Electric Corporation Ltd.	General Service Less Than 50 kW	42.91%	9.90%
Kingston Hydro Corporation	Residential	19.26%	7.32%
Kingston Hydro Corporation	General Service Less Than 50 kW	6.17%	4.63%
Milton Hydro Distribution inc.	Residential	7.89%	4.20%
Milton Hydro Distribution inc.	General Service Less Than 50 kW	7.60%	4.19%
Niagara Peninsula Energy Inc.	Residential	4.99%	4.40%
Niagara Peninsula Energy Inc.	General Service Less Than 50 kW	-5.50%	1.81%
Norfolk Power Distribution Inc.	Residential	0.11%	2.26%
Norfolk Power Distribution Inc.	General Service Less Than 50 kW	0.12%	2.71%
Parry Sound Power Corporation	Residential	28.35%	10.85%
Parry Sound Power Corporation	General Service Less Than 50 kW	27.12%	9.50%
St. Thomas Energy Inc.	Residential	3.80%	3.61%
St. Thomas Energy Inc.	General Service Less Than 50 kW	5.69%	4.20%
Toronto Hydro-Electric System Limited	Residential Regular	-1.35%	2.22%
Toronto Hydro-Electric System Limited	General Service Less Than 50 kW	-0.66%	2.08%
Waterloo North Hydro Inc.	Residential	16.93%	7.70%
Waterloo North Hydro Inc.	General Service Less Than 50 kW	12.83%	6.17%
Woodstock Hydro Services Inc.	Residential	14.68%	5.73%
Woodstock Hydro Services Inc.	General Service Less Than 50 kW	14.61%	5.32%
		9.55%	**5.18%**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #10 List 2

Exhibit G – Cost Allocation and Rate Design

Reference: OEB Staff #35

Interrogatory

a) Please provide similar schedules for:
   a. Cat Lake's General Service Standard A customer class
   b. Pikangikum's Standard A customer class.

b) Please provide a breakdown of Cat Lake's Residential Year Round Non-Std. A class as to the number of customers that use less 500 kWh / month as compared to the number that use 500 kWh / month or more.

c) How many customers are in Pikangikum's Residential Year Round class and how many are in its Residential Old Age class?

d) Does Hydro One Remote's have any plans to mitigate the significant bill impacts that will be experienced by: i) the low volume customers in Cat Lake's Residential Year Round Non-Standard A class and ii) all of the customers in Pikangikum's Residential Old Age class?

e) Please provide a schedule that sets out (for each of Cat Lake and Pikangikum) the revenues that would be received in 2013 from Non Standard A and Standard A customers based on existing rates.

Response

a) Please see the charts below.

Cat Lake Standard A Compared to Remotes Standard A Grid Connected					
Monthly kWh	**Total Bill (Existing Rates)**	**OCEB**	**Remotes Total Bill**	**OCEB**	**Percentage Change**
500	$340.60	$306.54	$145.10	$130.59	-57.40%
1,000	$653.25	$587.93	$290.20	$261.18	-55.58%
1,500	$965.90	$869.31	$435.30	$391.77	-54.93%
2,500	$1,591.20	$1,432.08	$725.50	$652.95	-54.41%
3,000	$1,903.85	$1,713.47	$870.60	$783.54	-54.27%

Pikangikum Bill Impacts Standard A Compared to Remotes Grid Connected Standard A

Monthly kWh	Total Bill (Existing Rates)	OCEB	Remotes Total Bill	OCEB	Percentage Increase
500	$651.30	$586.17	$145.10	$130.59	-77.72%
1,000	$1,302.60	$1,172.34	$290.20	$261.18	-77.72%
1,500	$ 1,953.90	$1,758.51	$435.30	$391.77	-77.72%
2,000	$ 2,605.20	$2,344.68	$580.40	$522.36	-77.72%
3,000	$3,907.80	$3,517.02	$870.60	$783.54	-77.72%

b) Cat Lake Total Active Residential Customers: 102
Customers using less than 500 kWh/month: 6 (5.9%)
Customers using 500 kWh or more per month: 96 (94.1%)

c) Remotes does not have this information and is unable to source it from the First Nation. For the purposes of question e), Remotes has *assumed* that 5% of residential customers would qualify for old age rates.

d) No. Remotes has not taken steps to devise a mitigation plan for these classes. In both Cat Lake and Pikangikum the decision to be served by Remotes is a community decision and will be made based on extensive community consultation and discussion. Remotes believes that community members are able to weigh the benefit of being served by Remotes.

e) Please see Attachment 1. Note that in order to calculate current revenues based on existing rates in Pikangikum, a number of assumptions were made. Remotes has assumed that Old Age Rates apply to 5% of the customers. No census data is available for the community. Remotes has assumed that half of the commercial customers are native and half are non-native. Remotes has also assumed that the arena has three-phase power.

Pikangikum - Total Revenues at Current Rates

RESIDENTIAL - YEAR ROUND - NON STD 'A'	2013			
Pikangikum	**Eff. # Cust**	**Est. kWh**	**Rate***	**Revenue**
Monthly Service Charge	414.5		$16.04	$6,649
Monthly Energy Charge - 1st Block (1000)		7,227,786	0.1032	$745,908
Total Revenue				**$752,556**

*Note, rate assumes 95% Residential, 5% Old Age Residential

GENERAL SERVICE 1-PHASE - NON STD 'A'	Year 2			
Pikangikum	**Eff. # Cust**	**Est. kWh**	**Rate****	**Revenue**
Monthly Service Charge	27.0		$27.95	$755
Monthly Energy Charge - 1st Block (5000)		596,395	0.1609	$95,930
Total Revenue				**$96,685**

**Note, rate assumes 50% native, 50% non native. Rate shown is average

GENERAL SERVICE 3-PHASE - NON STD 'A'	Year 2			
Pikangikum	**Eff. # Cust**	**Est. kWh**	**Rate*****	**Revenue**
Monthly Service Charge	1.0		$27.95	$457
Monthly Energy Charge - 1st Block (25000)		**672,517.13**	0.5510	$370,557
Total Revenue				**$371,014**

***Note, rate assumes the arena is 3 phase power

STANDARD 'A'	Year 2			
Pikangikum	**Eff # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	49		$27.95	**$1,370**
Monthly Energy Charge		2,185,638	1.3026	$2,847,012
Total Revenue				**$2,848,382**
Revenue - Non Standard 'A'				$1,220,255
Revenue - Standard 'A'				$2,848,382
Total Revenue Pikangikum				$4,068,636
			($000's)	**$4,069**

Cat Lake - Non Standard 'A' Revenues

RESIDENTIAL - YEAR ROUND - NON STD 'A'	2013			
Cat Lake	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	59.5		$8.00	$476
Monthly Energy Charge		999,600	$0.09	$89,964
Total Revenue				**$90,440**

GENERAL SERVICE 1-PHASE - NON STD 'A'	Year 2 - 2013			
Cat Lake	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	16.2		$27.95	$452
Monthly Energy Charge - 1st Block (5000)		291,273	$0.10	$28,108
Total Revenue				**$28,560**

STANDARD 'A'	**Eff # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	21		27.95	**$587**
Monthly Energy Charge		630,000	0.6253	**$393,939**
Total Revenue				**$394,526**

Total Revenue - Non Standard 'A'		$119,000
Revenue - Standard 'A'		$394,526
Total Revenue Cat Lake		**$513,526**
	($000's)	**$514**