Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5700
Fax: (416) 345-5870
Cell: (416) 258-9383
Susan.E.Frank@HydroOne.com

Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

April 24, 2013

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

Dear Ms. Walli:

EB-2012-0137 - Hydro One Remote Communities Inc. 2013 Revenue Requirement and rates Application – Update to Exhibit I, Tab 1, Schedules 4 and 30

I am attaching ten (10) paper copies of an update to Exhibit I, Tab 1, Schedules 4 and 30.

The Interrogatory included in Schedule 4 requested a copy of the 2012 audited Financial Statements. At time of response the statements were not available but have since been released. A copy of those statements is now included as Attachment 3 to Exhibit I, Tab 1, Schedule 4.

Exhibit I, Tab 1, Schedule 30 requested detail on the Tax amount included in the RRRP account. With the release of the audited statement this has also been updated.

This update has been filed electronically using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

Hydro One Networks Inc.
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483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

April 17, 2013

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

Dear Ms. Walli:

EB-2012-0137 - Hydro One Remote Communities Inc. 2013 Revenue Requirement and rates Application – Update to Exhibit I, Tab 1, Schedule 15

I am attaching ten (10) paper copies of an update to Exhibit I, Tab 1, Schedule 15.

This Interrogatory Response relates to the provision of a CDM program to Remotes customers. At initial draft of the response, details of the OPA program were not known. Midway through the Interrogatory's response period, the OPA subsequently announced a program. Other relevant responses were changed to reflect this announcement. Exhibit I, Tab 1, Schedule 15 was overlooked at the time but has been corrected here.

This update has been filed electronically using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

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8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

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Cell: (416) 258-9383
Susan.E.Frank@HydroOne.com

Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

April 8, 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 Interrogatory Questions

Please find attached an electronic copy of responses provided by Hydro One Networks to Interrogatory questions. Ten (10) 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)
Tab 4	Nishnawbe Aski Nation (NAN)

An electronic copy of the Interrogatories has 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) INTERROGATORY #1 List 1

Implications of Extending Service to Grid-Connected Communities

References:
- Exhibit A / 2 / 1
- Exhibit A / 3 / 1 / p. 1

In item # 8 in Exhibit A / 2 / 1, Remotes states that it had identified the cost of extending the geographically remote grid-connected communities of Cat Lake and Pikangikum in two previous submissions to the Board. In A 3 / 1 at line 16, Remotes indicates that there are proposed grid connections for many communities.

Interrogatory

a) Were the costs of extending service to Cat Lake and Pikangikum quantified in the previous submissions, and if so did the Board indicate in either of those proceedings that it would expect to receive a formal application to approve the costs and rate implications of extending Remotes' service area? If so please provide the reference(s).

b) Does Remotes have an estimate or a working assumption of how many communities may be desirous and/or eligible to be served from the Hydro One grid in the foreseeable future on the same basis as proposed for Cat Lake and Pikangikum?

c) Is the revenue requirement in this application affected by preparations to extend service to any geographically remote communities other than Cat Lake and Pikangikum? If so, what is the cost in 2013 of Remotes' preparation for this eventuality?

Response

a) The costs of extending service to Cat Lake and Pikangikum were not quantified in previous submissions. The inclusion of new communities was identified as an anticipated future cost pressure in 2005 and 2008. The Board did not comment on the need for formal applications to approve the costs and rate implications of extending Remotes' service territory in these proceedings. Based on the recent approvals required to include Marten Falls in Remotes service territory, Remotes assumes that any change in its service territory requires the following:

   1. a Band Council Resolution or letter from the First Nation asking Remotes to negotiate an agreement for service;
   2. a letter from the Minister of Energy requesting that Remotes negotiate an agreement for service;
   3. approval of costs and rates through a cost of service application;

4. provincial government approval for the changes in service territory and remote rate protection;
5. approval for an application to amend Remotes' distribution licence.

   Any agreements for service negotiated between Remotes and a community would require receipt of all of these approvals as conditions precedent in the agreements.

b) The Ontario Power Authority (OPA) has identified up to 25 Remote First Nation communities currently served through diesel generation that could be connected to the transmission grid. The OPA has also undertaken a more detailed study to connect 20 communities, including 9 communities currently served by Remotes. The 11 other communities, including the community of Pikangikum, currently operate their own local distribution companies. Any or all of these communities could be desirous and eligible to be served by Remotes.

c) No, the revenue requirement related to grid connected communities in this application is limited only to the two communities (Cat Lake and Pikangikum).

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

Implications of Extending Service to Grid-Connected Communities

References:

- Exhibit A / 3 / 1 / p. 1
- Exhibit G1 / 1 / 2 / p. 4

Interrogatory

a) Please provide for each of the two communities Cat Lake and Pikangikum the following:
   - A single-line diagram of the transmission and distribution facilities that deliver power to the community, depicting for each : (i) the voltage level in kV, conductor size(s) used; (ii) distance in kilometres for each portion.
   - The metering point on the single-line diagram where purchase of electricity by Remotes is recorded (Energy from the IESO and Transmission or Sub-Transmission Services from HONI).

b) For Cat Lake and for Pikangikum, using the information provided in part a), please provide an estimate of the actual electrical losses from the metering point to the community. This estimate is expected to be based on a computer program simulation of the transmission and distribution lines conductor sizes, with assumed power flows to represent a typical year when the transition to grid connection is complete. Please list all relevant assumptions influencing the estimate.

c) Please explain why Remotes has assumed a loss factor of 1.5% in Table 4 in Exhibit G1, rather a site-specific loss factor such as calculated in part b), or alternatively the Supply Facility Loss Factor used by Hydro One Distribution for embedded distributors, which is 3.4%.

d) Please indicate who will own the various portions of the transmission, sub-transmission and distribution lines that connect each of the two communities to the nearest Hydro One transformer station, i.e. Hydro One Transmission, Hydro One Distribution, Remotes, local ownership, other. If owned by Remotes, is the cost included in the rate base in this application?

Response

a) Please see the single line diagram of the transmission and distribution facilities as well as the metering points for both communities included as Attachment 1 herein.

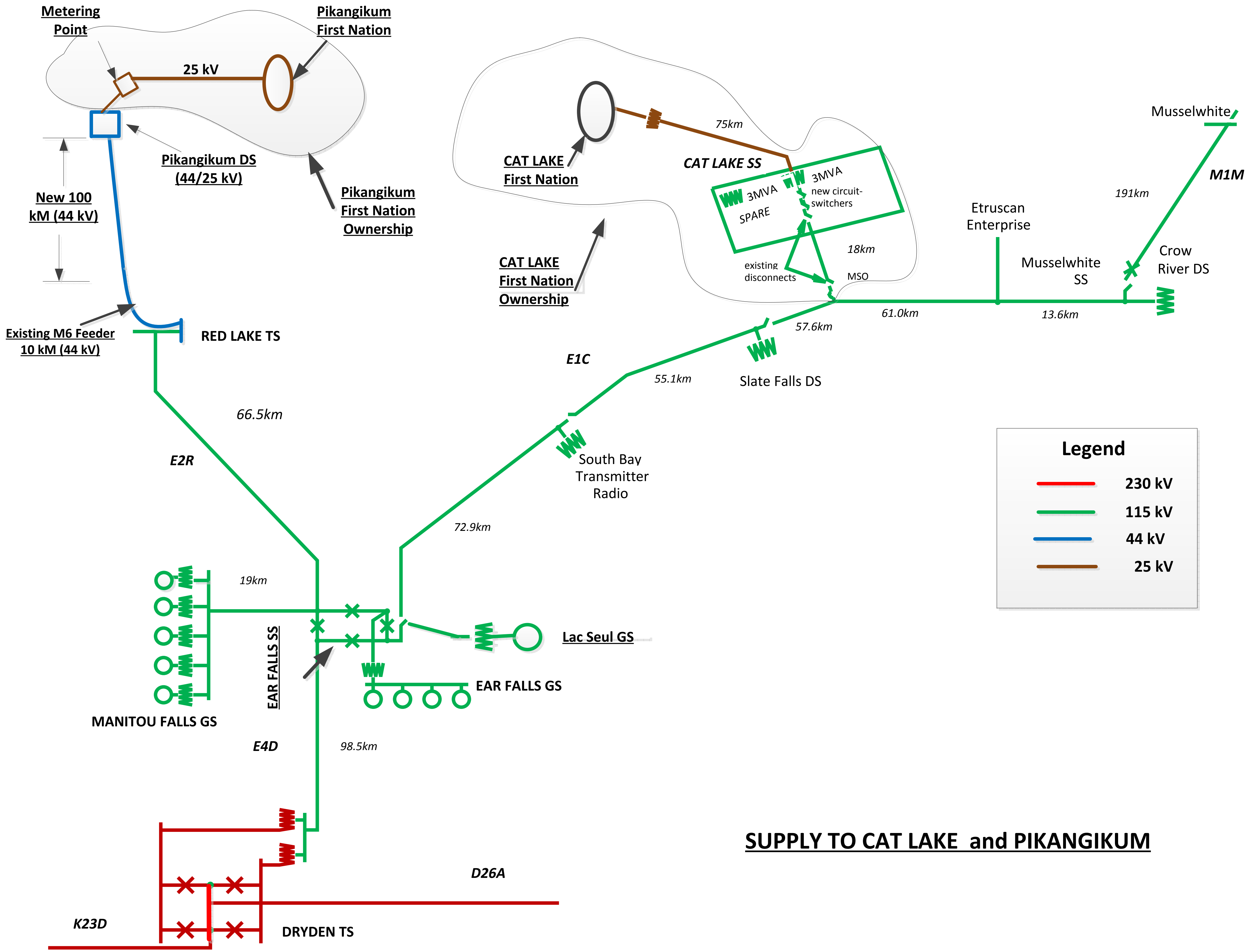
b) A computerized power flow simulation has been conducted for Cat Lake, the electrical losses from metering point to the community are estimated to be 2.46% at its peak loading conditions.

Remotes is unable to estimate the electrical losses for Pikangikum at this time as no computerized model is readily available to conduct the simulation.

c) A loss factor of 1.5% has been used in this application, as compared to the average province-wide loss factor of 3.4%, is due to the closer proximity of generation to load in the remote communities.

d) 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 will continue to own the 115 kV line E1C from which the 18 kilometer line tap to Cat Lake substation is supplied.

The Hydro One facilities currently owned by the Community of Pikangikum are also shown on the drawing in Attachment 1. 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.



SUPPLY TO CAT LAKE and PIKANGIKUM

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

Implications of Extending Service to Grid-Connected Communities

Reference: Exhibit A / 3 / 2/ pp. 2 -3

Remotes has indicated that the inclusion of Cat Lake and Pikangikum has added approximately $3,083,000 to Remotes revenue requirement for 2013.

Interrogatory

a) Please provide a breakdown of the additional revenue requirement of $3,083,000 to the various components, i.e OM&A, distribution assets, facilities,.etc.

b) Has there been any acquisition of existing transmission or distribution assets by Remotes, or will there be any acquisition when service agreements are signed to service the two communities? If so is the value of these assets included in the rate base in this application?

Response

a) Please see the chart below. Note that the $3,083 thousand referred to Operations, Maintenance and Administration only. Remotes notes that there will be very small additional amounts related to working capital and rate base.

All numbers in $000s	Cat Lake	Pikangikum	Total
OM&A			
Distribution	1,325	370	1,695
Community Relations	10	10	20
Power Purchased	208	1,160	1,368
Total OM&A	**1,543**	**1,540**	**3,083**
Rate Base			
In-Service Additions Planned	35	71	106
Incremental Working Capital Allowance (13% of OMA)	200	201	401
Interest Costs	12	13	25
Depreciation (Per OEB 1/2 year)	1	2	3
Total Rate Base Impact on Revenue Requirement	**13**	**15**	**28**
Total Revenue Requirement Impact	**1,556**	**1,555**	**3,111**

b) Remotes anticipates that all of the First Nation's respective assets will be transferred to Remotes for nominal consideration ($10) and that the capital cost to build these assets will be treated as contributed capital and will therefore not be included in the rate base.

To date, Remotes has not acquired any existing transmission or distribution assets related to Cat Lake or Pikangikum.

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

OM&A: Pensions and OPEB

Reference: Exhibit A / 11 / 1 / Attachment 3 / p. 16

Remotes' 2011 audited financial statements state:

"Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Inc. The Hydro One Pension Plan does not segregate assets in a separate account for individual subsidiaries, nor is the cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded."

Interrogatory

a) Please state the 2013 pension cost Remotes is proposing to recover in rates, separating the amount in OM&A and capitalized in rate base.

b) Please explain the basis chosen by Remotes to recover pension costs in rates (e.g. defined benefit accrual basis, defined benefit cash basis, or defined contribution basis). Please provide any documentation or memorandum that supports the choice.

c) Please provide an estimate of what Remotes 2013 pension cost would be using each of the defined benefit accrual basis and defined benefit cash basis, including an explanation of the assumptions used in the calculations.

d) Please detail any changes that were made to both Remotes' pension accounting for financial purposes and regulatory purposes with the move to USGAAP from CGAAP.

e) Please provide the latest actuarial valuation for Remotes, and state the basis under which it was prepared.

f) Does Remote's evidence reflect the latest actuarial valuation? If this is not the case, please explain.

g) Please provide impact on the proposed Remotes annual pension cost and annual OPEB cost in 2013 of a:
   i. 1% shift in the yield curve
   ii. 20% return asset shock

h) Has Mercer or another actuary prepared an Actuarial Valuation for Remotes based on the defined benefit accrual basis of accounting for pension expense? If so, please provide the most recent valuation.

i) Is Remotes proposing to recover 2013 pension and OPEB costs in rates on a different basis than what was approved in 2009 rates? Please explain any differences and on what basis the 2009 pension and OPEB costs were recovered in rates.

j) Please provide the December 31, 2012 Remotes audited financial statements. If the final version is not available, please provide a draft.

Response

a) For the Remotes 2013 proposed pension costs in rates, separated by OM&A and capital, refer to Exhibit I Tab 1 Schedule 5.

b) Remotes recovers its pension costs in rates using the defined benefit cash basis, consistent with other Hydro One subsidiaries including Networks. Use of the cash method is consistent with historical OEB guidance and approved rate orders. The cash basis, under a known three year actuarial funding period, results in less volatility over the short-term. This justification and explanation was provided to the Board and Intervenors as a response to the recent Hydro One Networks Transmission Cost of Service rate filing for 2013 and 2014 rates. Please refer to EB-2012-0031, Exhibit I, Tab 7 Schedule 1.07 Staff 45. For convenience, a copy of the response is included herein as Attachment 2.

c) Consolidated Hydro One pension cost (i.e. OM&A and capital) for 2013 under the accrual method is projected to be approximately $194 million, which is significantly higher than $154 million under the cash basis. The treatment of costs uner the cash basis for the pension was accepted by the Board in EB-2012-0031. An estimate of the hypothetical relative costs that would be charged to Remotes in an accrual based scenario would be on the same ratio as that outlined above for Networks.

The Hydro One consolidated projected estimates are based on the same data, assumptions, methods, and plan provisions used to prepare the December 31, 2011 year-ended disclosures for the Plan as disclosed in Note 12 to Hydro One Inc.'s annual consolidated financial statements. The key assumptions used to project the costs are as follows:

i) Accounting discount rate of 5.25% per annum.
ii) Pension fund returns will equal 6.25% per year (net of expenses) over the projection period.

Supporting calculations for Hydro One consolidated pension on an accrual basis are as follows:

($ millions)	2013
Current Service Costs	98
Interest Cost	292
Expected Return on plan assets	(300)
Amortisation of Past Service cost	2
Amortisation of Net Loss	102
Total	194

d) There is no change to the financial accounting for Remotes as a result of moving from Canadian GAAP to US GAAP. The cash basis of pension accounting remains the same under both and does not impact the pension costs included in 2013 revenue requirement or rate base from a regulatory perspective.

e) The latest Hydro One Report of Funding Valuation for Funding Purposes effective as at December 31, 2011, can be found in Attachment 1.

f) The 2013 Remotes evidence does not reflect the latest Hydro One Report of Funding valuation. The Hydro One Pension valuation, completed in early 2012, has an effective date of December 31, 2011. This funding valuation was not included in the Hydro One 2012 business plan on which the 2013 Remotes rate filing application is based. Based on the latest funding valuation, with an effective date of December 31, 2012, the Hydro One consolidated funding impact across all subsidiaries would have increased from $154 million to $162 million. Management has indicated that the funding change is not sufficiently significant to update the forecast revenue requirement for the change in valuation. Any change to actual results will be reflected in the RRRP variance account.

g) The next Hydro One valuation of the plan for funding purposes is not required for an effective date earlier than December 31, 2014. Accordingly, the 2013 Hydro One minimum funding requirements will not be impacted by changes in market conditions prior to that date.

For illustrative purposes, the following table summarizes the estimated hypothetical impact on the projected Hydro One consolidated 2013 funding amounts for a hypothetical 1% decrease in valuation discount rates (going concern and solvency) and a 20% equity investment loss at the valuation date.

	Base	1% Reduction in Valuation Discount Rates	20% Reduction in Market Value of Plan Equities
2013 Funding	$154 million	$266 million	$172 million

A 1% decrease in the valuation discount rates would increase Hydro One annual funding requirements by approximately $112 million per year. The going concern employer service cost would increase by roughly $40 million per year. The increase in the going concern funding target would be funded via special payments amortized over 15 years.

A 20% decrease in the market value of plan equities at the valuation date would increase Hydro One funding by roughly $18 million per year. Under the going concern asset valuation method, the equity loss would be recognized in the going concern financial position over 5 years. The portion of the equity loss would be funded via special payments amortized over 15 years.

Under both scenarios, the application of solvency smoothing permissible under the *Pension Benefits Act* would allow the plan to withstand the shocks described above without creating addition solvency funding requirements. However, over time persistent hypothetical low interest rates and the recognition of hypothetical investment losses in the smoothed asset value would require Hydro One to make solvency funding special payments at a future date.

The illustrative impacts shown above consider changes in valuation discount rates and changes in the pension fund independently. In a real world economic scenario, changes in market interest rates would impact both the plan's fixed income assets and the plan's funding liabilities.

h) No.

i) Remotes is not asking to recover pension or OPEB on a different basis in 2013 rates than it did in 2009 rates. Pension costs continue to be recovered on a cash basis in rates and OPEB continues to be recovered on an accrual basis in rates.

j) The 2012 Remotes audited Financial Statements are included herein as Attachment 3.

MERCER CONSULTING. OUTSOURCING. INVESTMENTS.

HYDRO ONE PENSION PLAN

REPORT ON THE ACTUARIAL VALUATION FOR FUNDING PURPOSES AS AT DECEMBER 31, 2011

MAY 2012

Ontario Registration Number: 1059104
Canada Revenue Agency Registration Number: 1059104

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The valuation results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the valuation.

Should the plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound-up on the valuation date. Emerging experience will affect the wind-up financial position of the plan assuming it is wound-up in the future. In fact, even if the plan were wound-up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Because actual plan experience will differ from the assumptions used in this valuation, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a valuation report or reports.

CONTENTS

1

Summary of Results

(in 000s)	31.12.11	31.12.09
Going Concern Financial Status		
Smoothed value of assets	$5,175,593	$4,771,203
Actuarial liability	$5,512,107	$5,205,515
Prior Year Credit Balance	$161,190	$0
Funding excess (shortfall)	($497,704)	($434,312)
Hypothetical Wind-up Financial Position		
Wind-up assets	$4,795,159	$4,334,416
Wind-up liability	$8,032,425	$6,468,702
Wind-up excess (shortfall)	($3,237,266)	($2,134,286)
Funding Requirements in the Year Following the Valuation [1]	2012	2010
Total current service cost	$126,221	$113,576
Estimated member's required contributions	($26,849)	($22,543)
Estimated employer's current service cost	$99,372	$91,033
Employer's current service cost as a percentage of members' pensionable earnings	18.9%	19.6%
Minimum annual special payments	$59,675	$48,380
Estimated minimum employer contribution	$159,047	$139,413
Estimated maximum eligible employer contribution	$3,336,638	$2,225,319
Next required valuation date	December 31, 2014	December 31, 2012

[1] Provided for reference purposes only. Contributions must be remitted to the Plan in accordance with the Minimum Funding Requirements and Maximum Eligible Contributions sections of this report.

2

Introduction

To Hydro One Inc.

At the request of Hydro One Inc., we have conducted an actuarial valuation of the Hydro One Pension Plan (the "Plan"), sponsored by Hydro One Inc. (the "Company"), as at the valuation date, December 31, 2011. We are pleased to present the results of the valuation.

Purpose

The purpose of this valuation is to determine:

- The funded status of the plan as at December 31, 2011 on going concern, hypothetical wind-up and solvency bases

- The minimum required funding contributions from 2012, in accordance with the *Pension Benefits Act (Ontario)*

- The maximum permissible funding contributions from 2012, in accordance with the *Income Tax Act*

The information contained in this report was prepared for the internal use of the Company and for filing with the Financial Services Commission of Ontario and with the Canada Revenue Agency, in connection with our actuarial valuation of the Plan. This report will be filed with the Financial Services Commission of Ontario and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2014, or as at the date of an earlier amendment to the Plan.

Terms of Engagement

In accordance with our terms of engagement with the Hydro One Inc., our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada.
- As instructed by the Hydro One Inc., we have reflected a margin for adverse deviations in our going concern valuation by reducing the going concern discount rate by 0.91% per year.
- We have reflected the Hydro One Inc. decisions for determining the solvency funding requirements, summarized as follows:
  - The same scenario was hypothesized for both the hypothetical wind-up and solvency valuations.
  - Certain excludable benefits were excluded from the solvency liabilities.
  - Solvency smoothing was used.
  - No funding relief measures have been applied.

See the Valuation Results - Solvency section of the report for more information.

Events Since the Last Valuation at December 31, 2009

Pension Plan

On March 19, 2010, the Superintendent of Financial Services (the "Superintendent") ordered that the Plan be partially wound up effective December 31, 2002 (the "Partial Wind-Up Date") in respect of a group of 73 Management Compensation Plan Members whose employment was terminated effective as of a date between September 1, 2002 and December 31, 2002, as a consequence of the merger of Hydro One Networks Inc. and Hydro One Network Services Inc. (the "Affected Members"). The partial wind-up report was filed with the Financial Services Commission of Ontario in June 2010. The partial wind-up shortfall was fully funded in 2011 and the benefits for Affected Members were settled on June 1, 2011. The impact of the partial wind-up has been fully reflected in this report.

There have been no other special events since the last valuation date.

This valuation reflects the provisions of the Plan as at December 31, 2011. The Plan was amended effective April 1, 2011 to increase employee contributions for members of the Power Workers Union by 0.5% of pensionable earnings. The Plan has not otherwise been amended since the date of the previous valuation, and we are not aware of any pending definitive or virtually definitive amendments coming into effect during the period covered by this report. The Plan provisions are summarised in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation, except for the following:

	Current valuation	Previous valuation
Interest on employee contributions:	2.00%	4.50%

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date.

A summary of the going concern, and hypothetical wind-up and solvency methods and assumptions are provided in Appendices C and D, respectively.

Regulatory Environment and Actuarial Standards

There have been a number of changes to the Pension Benefits Act (Ontario) (the "Act") and regulations which impact the funding of the Plan.

The Government of Ontario has announced its intentions to makes changes to the funding requirements for pension plans registered in Ontario. Since then Bill 120 received Royal assent. However, the intended changes to the funding requirements which impact the funding of single-employer pension plans will be contained in regulations which have not yet been adopted.

Certain changes to the Canadian Institute of Actuaries Standard of Practice for determining pension commuted values ("CIA CV Standard") became effective on February 1, 2011. The changes affect the mortality assumptions used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of the change in the CIA CV Standard has been reflected in this actuarial valuation.

A new Canadian actuarial Standard of Practice – *Practice Specific Standards of Practice for Pension Plans* became effective December 31, 2010 (the "CIA Pension Standards"). The requirements of the CIA Pension Standards have been reflected in this report.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation. Our valuation reflects the financial position of the Plan as of the valuation date and does not take into account any experience after the valuation date.

Impact of Case Law

This report has been prepared on the assumption that all of the assets in the pension fund are available to meet all of the claims on the Plan. We are not in a position to assess the impact that the Ontario Court of Appeal's decision in *Aegon Canada Inc. and Transamerica Life Canada versus ING Canada Inc.* or similar decisions in other jurisdictions might have on the validity of this assumption.

On July 29, 2004, the Supreme Court of Canada dismissed the appeal in Monsanto Canada Inc. versus Superintendent of Financial Services ("*Monsanto*"), thereby upholding the requirements to distribute surplus on partial plan wind-up under The *Pension Benefits Act (Ontario).* The decision has retroactive application and applies on the termination of Ontario employees if they are included in a partial plan wind-up, regardless of the province in which the pension plan is registered.

We are not aware of any partial plan wind-up having been declared in respect of the Plan where the Monsanto decision may apply. In preparing this actuarial valuation, we have therefore assumed that all the Plan's assets are available to cover the Plan's liabilities presented in this report. The subsequent declaration of a partial wind-up of the Plan where *Monsanto* may apply in respect of a past event, or disclosure of an existing past partial wind-up, could cause an additional claim on the Plan's assets, the consequences of which would be addressed in a subsequent report. We note the discretionary nature of the power of the regulatory authorities to declare partial wind-ups and the lack of clarity with respect to the retroactive scope of that power. We are making no representation as to whether the regulatory authorities might declare a partial wind-up in respect of other events in the Plan's history.

3

Valuation Results – Going Concern

Financial Status

A going concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

(in 000s)	31.12.11	31.12.09
Assets		
Market value of assets (including in-transits)	$4,806,893	$4,346,343
Asset smoothing adjustment	$368,700	$424,860
Smoothed value of assets	$5,175,593	$4,771,203
Going concern funding target		
• Active members	$2,185,022	$2,061,480
• Pensioners and survivors	$3,286,025	$3,100,493
• Deferred pensioners	$40,279	$43,524
• Additional voluntary contributions	$781	$18
Total	$5,512,107	$5,205,515
Funding excess (shortfall)	($336,514)	($434,312)
Prior Year Credit Balance	($161,190)	$0
Net position	($497,704)	($434,312)

The going concern funding target includes a provision for adverse deviations.

Reconciliation of Financial Status

Funding excess (shortfall) as at previous valuation		($434,312)
Interest on funding excess (funding shortfall) at 5.50% per year		($49,088)
Employer's special payments, with interest		$271,200
Expected funding excess (funding shortfall)		($212,200)
Net experience gains (losses)		
• Net investment return	($85,639)	
• Increases in pensionable earnings	$23,101	
• Increase in YMPE/maximum pension	($308)	
• Indexation	($20,984)	
• Mortality	$11,187	
• Retirement	($23,633)	
• Termination	($3,959)	
• Disability	($11,201)	
Total experience gains (losses)	($111,436)	($111,436)
Impact of changes in assumptions		$298
Net impact of other elements of gains and losses		($13,176)
Funding excess (shortfall) as at current valuation		($336,514)

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date compared with the corresponding value determined in the previous valuation, is as follows:

(in $000s)	2012	2010
Total current service cost	$126,221	$113,576
Estimated members' required contributions	($26,849)	($22,543)
Estimated employer's current service cost	$99,372	$91,033
Employer's current service cost expressed as a percentage of members' pensionable earnings	18.9%	19.6%

The key factors that have caused a change in the employer's current service cost since the previous valuation are summarized in the following table:

Employer's current service cost as at previous valuation	19.6%
Demographic changes	(0.4%)
Plan amendments	(0.3%)
Employer's current service cost as at current valuation	18.9%

Discount Rate Sensitivity

The following table summarises the effect on the going concern funding target shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario	Valuation Basis	Reduce Discount Rate by 1%
(in 000s)		
Going concern funding target	$5,512,107	$6,352,769
Current service cost		
• Total current service cost	$126,221	$162,417
• Estimated members' required contributions	($26,849)	($26,849)
• Estimated employer's current service cost	$99,372	$135,568

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Valuation Results – Hypothetical Wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances producing the maximum wind-up liabilities on the valuation date. However, to the extent permitted by law, the actuary may disregard:

- Benefits that would not be payable under the hypothesized scenario
- Plan member earnings after the valuation date.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

(in $000s)	31.12.11	31.12.09
Assets		
Market value of assets (including in-transits)	$4,806,893	$4,346,343
Termination expense provision	($11,734)	($11,927)
Wind-up assets	$4,795,159	$4,334,416
Present value of accrued benefits for:		
• active members	$3,493,583	$2,718,326
• pensioners and survivors	$4,474,424	$3,696,529
• deferred pensioners	$63,637	$53,829
• additional voluntary contributions	$781	$18
Total wind-up liability	$8,032,425	$6,468,702
Wind-up excess (shortfall)	($3,237,266)	($2,134,286)

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Valuation Results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. The financial position on a solvency basis is determined in a similar manner to the Hypothetical Wind-up Basis, except for the following:

Exceptions	Reflected in valuation based on the terms of engagement
The circumstance under which the Plan is assumed to be wound-up could differ for the solvency and hypothetical wind-up valuations.	The same circumstances were assumed for the solvency valuation as were assumed for the hypothetical wind-up.
Certain benefits can be excluded from the solvency financial position. These include: (a) any escalated adjustment (e.g. indexing), (b) certain plant closure benefits, (c) certain permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	The following benefits were excluded from the solvency liabilities shown in this valuation: • Indexing of benefits
The financial position on the solvency basis needs to be adjusted for any Prior Year Credit Balance.	A Prior Year Credit Balance has been reflected in the financial position
The solvency financial position can be determined by smoothing assets and the solvency discount rate over a period of up to 5 years.	Solvency assets and liabilities were smoothed over 5 years.
The benefit rate increases coming into effect after the valuation date can be reflected in the solvency valuation.	Not applicable.

Financial Position

The financial position on a solvency basis, compared with the corresponding figures from the previous valuation, is as follows:

	31.12.11	31.12.09
Assets		
Market value of assets (including in-transits)	$4,806,893	$4,346,343
Termination expense provision	($11,734)	($11,927)
Net assets	$4,795,159	$4,334,416
Present value of special payments	$269,350	$216,275
	$5,064,509	$4,550,691
Liabilities		
Total hypothetical wind-up liabilities	$8,032,425	$6,468,702
Difference in circumstances of assumed wind-up	$0	$0
Value of excluded benefits	($2,398,746)	($1,859,412)
Liabilities on a solvency basis	$5,633,679	$4,609,290
Surplus (shortfall) on a market value basis	($569,170)	($58,599)
Prior Year Credit Balance	($161,190)	$0
Liability smoothing adjustment	$626,531	$118,283
Asset smoothing adjustment	$368,700	$424,860
Surplus (shortfall) on a solvency basis	$264,871	$484,544
Solvency Ratio	100%	100%

Discount Rate Sensitivity

The following table summarises the effect on the solvency liabilities shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario (in 000s)	Valuation Basis	Reduce Discount Rate by 1%
Total hypothetical solvency liability	$5,633,679	$6,413,186

Solvency Incremental Cost to December 31, 2014

The solvency incremental cost is an estimate of the present value of the projected change in the solvency liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period.

The solvency incremental cost determined in this valuation is as follows:

	31.12.11
Number of years covered by report	3 years
Total solvency liabilities at the valuation date (A)	$5,633,679
Present value of projected solvency liability at the next required valuation (including expected new entrants) plus benefit payments until the next required valuation (B)	$6,310,401
Solvency incremental cost (B – A)	$676,722

The incremental cost is not an appropriate measure of the contributions that would be required to maintain the financial position of the Plan on a solvency basis unchanged from the valuation date and the next required valuation date, if actual experience is exactly in accordance with the going concern valuation assumptions. This is because it does not reflect the fact that the expected return on plan assets (based on the going concern assumptions) is greater than the discount rate used to determine the solvency liabilities.

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Minimum Funding Requirements

The Act prescribes the minimum contributions that Hydro One Inc. must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost and special payments to fund any going concern or solvency shortfalls.

On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer monthly contributions, as well as an estimate of the employer contributions, from the valuation date until the next required valuation are as follows:

	Employer's contribution rule			Estimated employer's contributions	
Period beginning	Monthly current service cost[2]	Explicit monthly expense allowance	Minimum monthly special payments	Monthly current service cost	Total minimum monthly contributions
December 31, 2011	18.9%	$0	$4,972,906	$8,281,000	$13,253,906
December 31, 2012	18.9%	$0	$4,972,906	$8,509,000	$13,481,906
December 31, 2013	18.9%	$0	$4,972,906	$8,743,000	$13,715,906

The estimated contribution amounts above are based on projected members' pensionable earnings. Therefore the actual employer's current service cost will be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions are made in accordance with the Act.

The development of the minimum special payments is summarized in Appendix A.

The estimated minimum employer contribution for 2012 if the Prior Year Credit Balance were fully applied is $0.

Other Considerations

Differences between Valuation Bases

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and solvency shortfalls, if any.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost, there is no requirement to fund the expected growth in the hypothetical wind-up or solvency liability after the valuation date, which could be greater than the going concern current service cost.

[2] Expressed as a percentage of members' pensionable earnings.

Timing of Contributions

Funding contributions are due on monthly basis. Contributions for current service cost must be made within 30 days following the month to which they apply. Special payment contributions must be made in the month to which they apply.

Retroactive Contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution, along with an allowance for interest, is due no later than 60 days following the date this report is filed.

Payment of Benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the transfer ratio revealed in an actuarial valuation is less than one. If the transfer ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions.

Additional restrictions are imposed when:

- The transfer ratio revealed in the most recently filed actuarial valuation is less than one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined by 10% or more since the date the last valuation was filed.

- The transfer ratio revealed in the most recently filed actuarial valuation is greater than or equal to one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined to less than 0.9 since the date the last valuation was filed.

As such, the administrator should monitor the transfer ratio of the Plan and, if necessary, take the prescribed actions.

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Maximum Eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan. However, notwithstanding the limit imposed by the ITA, for plans which are not 'Designated' as defined in the ITA, in general, the minimum required contributions under the Act can be remitted.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan which is underfunded on either a going concern or on a hypothetical wind-up basis the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan which is fully funded on both going concern and hypothetical wind-up bases, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan which is fully funded on both going concern and hypothetical wind-up bases, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Schedule of Maximum Contributions

The Company is permitted to fully fund the greater of the going concern and hypothetical wind-up shortfalls; $3,237,266,000 as well as make current service cost contributions. The portion of this contribution representing the payment of the hypothetical wind-up shortfall can be increased with interest at 4.18% per year from the valuation date to the date the payment is made, and must be reduced by the amount of any deficit funding made from the valuation date to the date the payment is made.

Assuming the Company contributes the greater of the going concern and hypothetical wind-up shortfall of $3,237,266,000 as of the valuation date, the rule for determining the estimated maximum eligible annual contributions, as well as an estimate of the maximum eligible contributions until the next valuation are as follows:

	Employer's contribution rule			Estimated employer's contributions
Year beginning	**Monthly current service cost[3]**	**Monthly expense allowance**	**Deficit Funding**	**Monthly current service cost**
December 31, 2011	18.9%	$0	$3,237,266,000	$8,281,000
December 31, 2012	18.9%	$0	$0	$8,509,000
December 31, 2013	18.9%	$0	$0	$8,743,000

The employer's current service cost in the above table was estimated based on projected members' pensionable earnings. The actual employer's current service cost will be different from these estimates and, as such, the contribution requirements should be monitored closely to ensure compliance with the ITA.

[3] Expressed as a percentage of members' pensionable earnings.

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Actuarial Opinion

In our opinion, for the purposes of the valuations,

- the membership data on which the valuation is based are sufficient and reliable
- the assumptions are appropriate
- the methods employed in the valuation are appropriate

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the Pension Benefits Act (Ontario).

Scott Clausen
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

29 May 2012
Date

M. Teresa Palandra
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

29 May 2012
Date

APPENDIX A

Prescribed Disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description	Result (in 000s)
Transfer Ratio	The ratio of: (a) solvency assets minus the lesser of the Prior Year Credit Balance and the minimum required employer contributions until the next required valuation; to (b) the sum of the solvency liabilities and liabilities for benefits, other than benefits payable under qualifying annuity contracts that were excluded in calculating the solvency liabilities.	0.58
Prior Year Credit Balance	Accumulated excess of contributions made to the pension plan in excess of the minimum required contributions (note: only applies if the Company chooses to treat the excess contributions as a Prior Year Credit Balance). Development summarized below.	$161,190
Solvency Assets	Market value of assets including accrued or receivable income and excluding the value of any qualifying annuity contracts.	$4,806,893
Solvency Asset Adjustment	The sum of:	
	(a) the difference between smoothed value of assets and the market value of assets	$368,700
	(b) the present value of any going concern special payments (including those identified in this report) within 5 years following the valuation date	$269,350
	(c) the present value of any previously scheduled solvency special payments (excluding those identified in this report)	$0
		$638,050
Solvency Liabilities	Liabilities determined as if the plan had been wound up on the valuation date, including liabilities for plant closure benefits or permanent layoff benefits that would be immediately payable if the employer's business were discontinued on the valuation date of the report, but, if elected by the plan sponsor, excluding liabilities for, (a) any escalated adjustment, (b) excluded plant closure benefits, (c) excluded permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	$5,633,679
Solvency Liability Adjustment	The amount by which solvency liabilities are adjusted as a result of using a solvency valuation interest rate that is the average of market interest rates calculated over the period of time used in the determination of the smoothed value of assets.	($626,531)

Defined Term	Description	Result (in 000s)
Solvency Deficiency	The amount, if any, by which the sum of:	
	(a) the solvency liabilities	$5,633,679
	(b) the solvency liability adjustment	($626,531)
	(c) the prior year credit balance	$161,190
		$5,168,338
	Exceeds the sum of	
	(d) the solvency assets net of termination expense provision	$4,795,159
	(e) the solvency asset adjustment	$638,050
		$5,433,209
		$0

Timing of Next Required Valuation

In accordance with the *Act* the next valuation of the Plan would be required at an effective date within one year of the current valuation date if:

- The ratio of solvency assets to solvency liabilities is less than 80%.
- The ratio of solvency assets to solvency liabilities is less than 85% and solvency liabilities exceed solvency assets by $5 million or more.
- The employer elected to exclude plant closure or permanent lay-off benefits under Section 5(18) of the regulations, and has not rescinded that election.

Otherwise, the next valuation of the Plan would be required at an effective date no later than three years after the current valuation date.

Accordingly, the next valuation of the Plan will be required as of December 31, 2014.

Special Payments

Based on the results of this valuation, the Plan is not fully funded. In accordance with the Act, any going concern deficits must be amortized over a period not exceeding 15 years and any solvency deficits must be amortized over a period not exceeding 5 years.

As such, special payments must be made as follows:

Type of payment	Start date	End date	Monthly Special Payment	Present Value: Going Concern Basis[4]	Present Value: Solvency Basis[5]
Going concern	Dec. 31, 2003	Dec. 31, 2018	$1,397,417	$97,677,000	$75,689,000
Going concern	Dec. 31, 2006	Dec. 31, 2021	$595,637	$55,221,000	$32,262,000
Going concern	Dec. 31, 2009	Dec. 31, 2024	$2,038,594	$228,600,000	$110,417,000
				$381,498,000	
New going concern	Dec. 31, 2011	Dec. 31, 2026	$941,258	$116,206,000	$50,982,000
				$497,704,000	$269,350,000
Total			$4,972,906		

The present value of going concern special payments scheduled in the previous valuation is lower than the going concern shortfall resulting in a going concern unfunded liability of $116,206,000. As a result, a new going concern special payment schedule had to be established.

Pension Benefit Guarantee Fund (PBGF) Assessment

The PBGF assessment base and liabilities are derived as follows:

Solvency assets	$4,806,893	(a)
PBGF liabilities	$5,633,679	(b)
Solvency liabilities	$5,633,679	(c)
Ontario asset ratio	100%	(d) = (b) ÷ (c)
Ontario portion of the fund	$4,806,893	(e) = (a) x (d)
PBGF assessment base	$826,786	(f) = (b) – (e)
Amount of additional liability for plant closure and/or permanent layoff benefits which is not funded and subject to the 2% assessment pursuant to s.37(4)	$0	(g)

[4] Calculation only considers going concern special payments and is based on a going concern discount rate.

[5] Calculation considers both solvency and going concern special payments (five years only) and is based on the average solvency discount rate.

The PBGF assessment is calculated as follows:

$5 for each Ontario member	$64,775	(h)
0.5% of PBGF assessment base up to 10% of PBGF liabilities	$2,817,000	(i)
1.0% of PBGF assessment base between 10% and 20% of PBGF liabilities	$2,634,000	(j)
1.5% of PBGF assessment base over 20% of PBGF liabilities	$0	(k)
Sum of (h), (i), (j) and (k)	$5,515,775	(l)
$300 for each Ontario member	$3,886,500	(m)
Lesser of (l) and (m)	$3,886,500	(n)
2.0% of additional liabilities ((g) x 2%)	$0	(o)
Total Guarantee Fund Assessment ((n) + (o), no less than $250) (before applicable tax)	$3,886,500	(p)

Prior Year Credit Balance

The Prior Year Credit Balance was determined as follows:

Prior Year Credit Balance at previous valuation	$0	(a)
Actual employer contributions	$458,225,000	(b)
Required employer contributions	$297,035,000	(c)
Prior Year Credit Balance at current valuation	$161,190,000	(d) = (a) + (b) – (c)

APPENDIX B

Plan Assets

The pension fund is held in trust by CIBC Mellon and is invested in accordance with investment policy. In preparing this report, we have relied upon the auditors' report signed by KPMG and the fund statements prepared by CIBC Mellon.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

(in 000s)	2010	2011
January 1	$4,346,096	$4,708,666
PLUS		
Members' contributions	$23,784	$26,501
Company's contributions	$193,493	$151,542
Reciprocal transfers	$3,963	$4,008
Investment income	$420,835	$102,394
	$642,075	$284,445
LESS		
Pensions paid	$248,404	$255,676
Lump-sums paid	$16,367	$30,128
Administration and investment fees	$14,734	$13,603
	$279,505	$299,407
December 31	$4,708,666	$4,693,703
Gross rate of return[6]	9.7%	2.2%
Rate of return net of expenses[7]	9.4%	1.9%

The market value of assets shown in the above table is adjusted to reflect in-transit amounts as follows:

(in 000s)	Previous Valuation	Current Valuation
Market value of invested assets	$4,346,096	$4,693,703
In-transit amounts		
• Company contributions	$0	$113,190
• Transfers	$247	$0
Market value of assets adjusted for in-transit amounts	$4,346,343	$4,806,893

We have tested the pensions paid, the lump-sums paid and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

[6] Assuming mid-period cash flows.

[7] Assuming mid-period cash flows.

Investment Policy

The plan administrator adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The constraints on the asset mix and the actual asset mix at the valuation date are provided for information purposes:

	Investment Policy	Actual Asset Mix as at December 31, 2011
	Target	
Cash, cash equivalents, and short term securities	2%	4%
Fixed income	33%	36%
Canadian public equity	17%	18%
Foreign public equity	41%	39%
Private equity and hedge funds	2%	3%
Real estate and infrastructure	5%	0%
	100%	100%

Because of the mismatch between the Plan's assets (which are invested in accordance with the above investment policy) and the Plan's liabilities (which tend to behave like long bonds) the Plan's financial position will fluctuate over time. These fluctuations could be significant and could cause the Plan to become under, or over, funded even if the Company contributes to the Plan based on the funding requirements presented in this report.

APPENDIX C

Methods and Assumptions – Going Concern

Valuation of Assets

For this valuation, we have used an adjusted market-value method to determine the smoothed value of assets. Under this method, the difference between actual and expected equity performance during a given year are spread on a straight-line basis over 5 years in accordance with the schedule shown in the following table:

(in 000s)	2008	2009	2010	2011
Equity portion of assets at year-end	$2,414,263	$2,855,533	$2,944,478	$2,727,859
Rate of return earning on equities (reported by fund managers)	-27.77%	16.63%	9.37%	-4.45%
Change in CPI	1.20%	1.26%	2.42%	2.22%
Expected rate of return on equities (change in CPI + 6%)	7.20%	7.26%	8.42%	8.22%
Investment return loss/(gain) on equities	$982,994	($246,987)	($27,490)	$359,238
Carry forward of 2008 loss/(gain)	$786,395	$589,796	$393,198	$196,599
Carry forward of 2009 loss/(gain)		($197,590)	($148,192)	($98,795)
Carry forward of 2010 loss/(gain)			($21,992)	($16,494)
Carry forward of 2011 loss/(gain)				$287,390
Total adjustment to assets				$368,700

Accordingly, the smoothed value of assets as at December 31, 2011 is $5,062,403,000 (market value of $4,693,703,000 plus $368,700,000).

The asset values produced by this method are related to the market value of the assets, with the advantage that, over time, the market-related asset values will tend to be more stable than market values. To the extent that more equity investments outperform the CPI + 6% benchmark over the long term, the smoothed value will tend to be lower than the market value.

The smoothed value of assets shown above is adjusted to reflect in-transit amounts as follows:

(in 000s)	Previous Valuation	Current Valuation
Smoothed value of assets	$4,770,956	$5,062,403
In-transit amounts		
• Employer contributions	$0	$113,190
• Transfers	$247	$0
Smoothed value of assets, adjusted for in-transit amounts	$4,771,203	$5,175,593

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target. For each individual plan member, accumulated contributions with interest are established as a minimum actuarial liability.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to meet the plan's cash flow requirements in respect of accrued benefits and absent additional contributions.

As required under the Act, a funding shortfall must be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. However, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, can be expected to remain stable as long as the average age of the group remains constant.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	5.50%	5.50%
Inflation:	2.25%	2.25%
ITA limit / YMPE increases:	3.25%	3.25%
Pensionable earnings increases:	2.75% + Merit	2.75% + Merit
Post retirement pension increases:	2.25%	2.25%
Interest on employee contributions:	2.00%	4.50%
Retirement rates:	Age related table	Age related table
Termination rates:	Age related table	Age related table
Mortality rates:	100% of the rates of the 1994 Uninsured Pensioner Mortality Table	100% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality improvements:	Fully Generational	Fully Generational
Disability rates:	Age Related Table	Age Related Table
Eligible spouse at retirement:	80%	80%
Spousal age difference:	Male 3 years older	Male 3 years older

The assumptions are best-estimate with the exception that the discount rate includes a margin for adverse deviations, as shown below.

Age and Service Related Tables

Sample rates from the age and service related tables are summarized in the following table:

	Termination			Retirement		
					Reduction Eligible	
Age	**Males**	**Females**	**Disability**	**Unreduced**	**Male**	**Female**
15	4%	5%				
20	4%	5%	0.00%	15%	0%	0%
25	4%	5%	0.00%	15%	0%	0%
30	2%	4%	0.105%	15%	0%	0%
35	2%	4%	0.110%	15%	0%	0%
40	1%	3%	0.115%	15%	0%	0%
45	1%	3%	0.120%	15%	0%	0%
50	1%	3%	0.295%	15%	0%	0%
55	0%	0%	1.000%	15%	2%	5%
56	0%	0%	1.000%	25%	2%	5%
57	0%	0%	1.000%	25%	2%	5%
58	0%	0%	1.000%	25%	2%	5%
59	0%	0%	1.000%	25%	2%	5%
60	0%	0%	1.878%	25%	2%	5%
61	0%	0%	1.878%	25%	7%	10%
62	0%	0%	1.878%	25%	7%	10%
63	0%	0%	1.878%	25%	7%	10%
64	0%	0%	1.878%	25%	7%	10%
65	0%	0%	1.878%	100%	100%	100%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken 2011 pensionable earnings and assumed that such earnings will increase at 3.25% per year plus and age/service dependent merit factor described below.

	Salary increases due to movement within the salary structure*	
Age	**First 4 Years of Employment**	**Subsequent Years**
Under 25	7.0%	1.0%
25 – 29	3.0%	1.0%
30 – 34	3.5%	1.5%
35 – 39	3.5%	1.5%
40 – 44	3.5%	2.0%
45 – 49	3.5%	1.5%
50 – 54	2.0%	1.5%
55 – 59	2.0%	1.5%
60 & over	2.0%	0.0%

* *Over and above any increase in salaries due to adjustments to the salary structure itself.*

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy
- Additional returns assumed to be achievable due to active equity management equal to the fees related to active equity management.
- Implicit provision for expenses determined as the average rate of expenses paid from the fund
- A margin for adverse deviations of 0.91%

The discount rate was developed as follows:

Assumed investment return	6.48%
Additional returns for active management	0.18%
Expense provision	(0.25%)
Margin for adverse deviation	(0.91%)
Net discount rate	5.50%

Explicit Expenses

$0 explicit expense

Inflation

The inflation assumption is based on market expectations of long-term inflation implied by the yields on nominal and real return bonds at the valuation date

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

The general wage growth component of this assumption is based on historical real economic growth, current market conditions and the underlying inflation assumption.

The assumption for future merit and promotional increases over general wage growth is based on an experience study that was conducted in 2001 considering increases over the years 1998 to 2000.

Post Retirement Pension Increases

The assumption is based on the Plan formula and inflation assumption above.

Retirement Rates

The assumption is based on experience over the years 2000 to 2006. Subsequent experience has been consistent with these rates.

Termination Rates

The assumption is based on experience from 2000 to 2006. Subsequent experience has been consistent with these rates. For employees who terminate and will qualify for an unreduced pension or have 25 or more years of continuous service, the value includes the member's right to subsidized reductions if the pension commences before age 65 (age 60 for females hired before 1976).

Mortality Rates

There is no reason to expect the mortality to differ from the 1994 Uninsured Pensioners mortality table. Furthermore, there is strong evidence of continuing improvement in mortality since 1994 and it has become an industry standard to assume this trend continues into the future. We have used the AA projection scale to allow for improvements in mortality since 1994 up to 2012 and applied on a generational basis thereafter

Based on to the assumption used, the life expectancy of a member age 65 at the valuation date is 19.7 years for males and 22.1 years for females.

Recent experience has been consistent with the assumptions.

Interest on Employee Contributions

The assumption is based on Plan terms and the underlying investment return assumption.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

Eligible Spouse

The assumption is based on an industry standard for non-retired members (actual status used for retirees).

Spousal Age Difference

The assumption is based on an industry standard showing males are typically 4 years older than their spouse.

APPENDIX D

Methods and Assumptions – Hypothetical Wind-up and Solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound-up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit. For the purposes of the hypothetical wind-up valuation, the plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, including benefits that would be immediately payable if the employer's business were discontinued on the valuation date, with all members fully vested in their accrued benefits.

The circumstances in which the plan wind-up is assumed to have taken place are as follows: unilateral termination of the plan. To determine the solvency actuarial liability, the cost of future indexing as been excluded from the solvency liabilities as permitted under the *Pension Benefits Act* (Ontario).

Upon plan wind-up members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for December 31, 2011.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

However, it may not be possible to settle the liabilities through the purchase of annuities due to the size of the Plan and the limited annuity market in Canada. In accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2011 and December 30, 2012,* we have assumed that the settlement of such liabilities would be priced on the same basis as the smaller group annuities that are available in the market.

There is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. In accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2011 and December 30, 2012,* we have assumed that an appropriate proxy for estimating the cost of such purchase is using the yield on the long-term Government of Canada Real Return bonds.

We have not included a margin for adverse deviation in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Member	
Lump sum	70% of active members under age 55 and 40% of active members over age 55 elect to receive their benefit entitlement in a lump sum
Annuity purchase	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Basis for Benefits Assumed to be Settled through a Lump Sum	
Mortality rates:	U94 Generational
Interest rate (for solvency calculations):	3.74% per year for 10 years, 5.04% per year thereafter
Interest rate (for wind-up calculations):	2.60% per year for 10 years, 4.10% per year thereafter (non-indexed rates); and 1.30% per year for 10 years, 1.60% per year thereafter (indexed rates) *New Society and Management Members:* 2.60% per year for 10 years, 4.10% per year thereafter (non-indexed rates); and 1.60% per year for 10 years, 2.20% per year thereafter (indexed rates)
Basis for Benefits Assumed to be Settled through the Purchase of an Annuity	
Mortality rates:	U94 Generational
Interest rate (for solvency calculations):	4.30% per year
Interest rate (for wind-up calculations):	3.31% per year (non-indexed rates); 0.45% per year (indexed rates) *New Society and Management Members:* 3.31% per year (non-indexed rates); and 0.78% per year for 10 years, 1.06% per year thereafter (indexed rates)
Retirement Age	
Maximum value:	Members are assumed to retire at the age which maximizes the value of their entitlement from the Plan based on the eligibility requirements which have been met at the valuation date
Grow-in:	The benefit entitlement and assumed retirement age of Ontario members whose age plus service equals at least 55 at the valuation date, reflect their entitlement to grow into early retirement subsidies

Other Assumptions	
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	Same as for going concern valuation
Maximum pension limit:	$2,646.67 increasing at 2.31% per year for 10 years, 3.44% per year thereafter
Termination expenses:	0.25% of assets

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

In addition, termination expenses also include a provision for transaction fees related to the liquidation of the Plan's assets and for the reduction in the value of the Plan's equity assets resulting from their liquidation. Such fees and liquidation impact are difficult to assess and will vary depending on the nature of the assets held and market conditions at the time assets are liquidated.

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested. Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the hypothetical wind-up liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected hypothetical wind-up liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members terminate, retire and die consistent with the termination, retirement and mortality rates used for the going concern valuation.
- Pensionable earnings, the Income Tax Act pension limit and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions.
- Active members accrue pensionable service in accordance with the terms of the Plan.
- To accommodate for new entrants to the Plan, we have added to the projected liability an amount based on the liability of new entrants that have joined the Plan since the previous valuation.
- Cost of living adjustments are consistent with the inflation assumption used for the going concern valuation.

Solvency Basis

In determining the financial position of the Plan on the solvency basis, we have used the same assumptions and methodology as were used for determining the financial position of the Plan on the hypothetical wind-up basis, except for the differences in assumptions described above.

The solvency position is determined in accordance with the requirements of the Act.

APPENDIX E

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2011, provided by Hydro One Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	31.12.11	31.12.09
Active Members		
Number	5,446	5,042
Total pensionable earnings for the following year	$493,804,272	$435,017,627
Average pensionable earnings for the following year	$90,673	$86,279
Average years of pensionable service	13.9	14.8
Average age	44.2	44.8
Accumulated contributions with interest	$350,040,313	$334,148,262
Members on Long Term Disability		
Number	130	125
Total pensionable earnings for the following year	$9,669,278	$8,808,644
Average pensionable earnings for the following year	$74,379	$70,469
Average years of pensionable service	24.6	25.2
Average age	55.4	55.2
Accumulated contributions with interest	$9,231,515	$9,126,864
Deferred Pensioners		
Number	299	320
Total annual pension	$3,223,848	$3,565,653
Average annual pension	$10,782	$11,143
Average age	52.6	52.0
Pensioners and Survivors		
Number	5,304	5,265
Total annual lifetime pension	$199,441,218	$184,259,583
Total annual temporary pension	$25,244,104	$25,090,168
Average annual lifetime pension	$37,602	$34,997
Average age	71.0	70.4
Pensioners and Survivors		
Number	1,776	1,819
Total annual lifetime pension	$41,307,153	$37,199,616
Total annual temporary pension	$567,542	$557,903
Average annual lifetime pension	$23,259	$20,451
Average age	79.6	78.3

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Actives	Long Term Disabilities	Deferred Vested	Pensioners	Survivors	Total
Total at 12.31.2009	5,042	125	320	5,265	1,819	12,571
New entrants	792	2				794
Actives to LTD	(21)	21				0
LTD to actives	2	(2)				0
Terminations:						0
• transfers/ lump sums	(33)	0	(9)			(42)
• deferred pensions	(26)	0	26			0
• reciprocal completed	(3)					(3)
Deaths	(20)	(1)	(1)	(298)		(320)
Retirements	(287)	(15)	(37)	339		0
Beneficiaries					168	168
Benefits Expired	0	0	0	(2)	(211)	(213)
Total at 12.31.2011	5,446	130	299	5,304	1,776	12,955

The distribution of the active members by age and pensionable service as at the valuation date is summarized as follows:

	Years of Pensionable Service							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30 +**	**Total**
Under 25	89	1						90
	$67,198	*						$67,219
25 to 29	640	71						711
	$74,538	$85,163						$75,599
30 to 34	358	234	25					617
	$78,717	$87,303	$92,286					$82,523
35 to 39	221	175	68					464
	$83,728	$87,584	$93,907					$86,674
40 to 44	191	127	44	20	99	3		484
	$87,326	$97,027	$97,626	$89,937	$91,566	*		$91,828
45 to 49	166	105	94	23	359	240	23	1,010
	$86,793	$93,384	$92,418	$97,790	$95,369	$92,735	$100,098	$93,016
50 to 54	121	83	85	14	201	265	364	1,133
	$90,437	$91,976	$98,472	$98,471	$93,948	$95,350	$99,716	$96,005
55 to 59	64	48	60	14	86	110	320	702
	$90,254	$91,561	$94,603	$109,499	$93,755	$94,508	$102,475	$97,766
60 to 64	25	22	23	6	42	39	139	296
	$106,534	$99,304	$100,846	$113,676	$99,340	$93,695	$102,363	$101,028
65 +	9	7	15	2	12	9	15	69
	$90,817	$95,773	$109,138	*	$94,742	$90,858	$102,871	$99,123
Total	1,884	873	414	79	799	666	714	5,576
	$80,497	$90,359	$95,842	$99,475	$94,566	$94,108	$102,568	$90,293

* Data for cells with three or fewer members have been suppressed to preserve confidentiality of information.

The distribution of the inactive members by age as at the valuation date is summarized as follows:

	Deferred Pensioners		Pensioners		Survivors	
Age	Number	Average Pension	Number	Average Pension	Number	Average Pension
<45	31	$8,845			5	$14,235
45 - 49	49	$8,039			7	$16,209
50 - 54	93	$11,213	66	$44,807	21	$18,130
55 - 59	85	$12,983	520	$43,205	60	$19,212
60 - 64	38	$10,531	1,094	$39,507	82	$20,835
65 - 69	3	$3,075	985	$37,558	112	$25,972
70 - 74			706	$35,566	150	$24,132
75 - 79			701	$34,740	283	$23,279
80 - 84			706	$36,871	461	$24,857
85 - 89			370	$35,794	352	$23,002
90 - 94			129	$34,686	193	$22,333
95 +			27	$21,924	50	$17,959
Total	299	$10,782	5,304	$37,602	1,776	$23,259

APPENDIX F

Summary of Plan Provisions

This valuation is based on the plan provisions in effect on December 31, 2011.

The following is a summary of the main provisions of the Plan in effect on December 31, 2011. This summary is not intended as a complete description of the Plan.

Eligibility for membership	The following categories of employees are members of the Plan: • All regular employees • Employees for whom the Office and Professional Employees International Union was the bargaining agent prior to July 30, 1982. • Employees who became continuing construction clerical employees after July 29, 1982 and before August 8, 1984. • Employees who have completed three months of continuous employment as a probationary employee Any other employee, with the exception of construction trades, machinists, and hotel and restaurant employees, who has completed twenty-four months of continuous employment and who has at least 700 hours of employment or earnings of 35% of the YMPE (see note on next page) in each of the two previous calendar years, may elect to become a member of the Plan. Other members include pensioners, terminated employees with deferred pensions, and employees receiving long term disability benefits. **Note:** "YMPE" is the Year's Maximum Pensionable Earnings as defined under the Canada Pension Plan.
Employee Contributions	The employees contribute at the following rates until they complete 35 years of credited service: Power Workers Union members • 4.5% of base annual earnings up to the YMPE, • And 6.5% of base annual earnings in excess of the YMPE. Management and Society members • 4.0% of base annual earnings up to the YMPE, • And 6.0% of base annual earnings in excess of the YMPE. Society members are required to contribute an additional 0.5% of base annual earnings when the ratio of solvency assets to solvency liabilities is less than 106%.

Retirement Dates

Normal Retirement Date

- Female members whose continuous employment commenced prior to January 1, 1976:
  The first day of the month when she in fact retires, coincident with or next following the attainment of age 60 or any subsequent month up to the month coincident with or next following her sixty-fifth birthday.
- All other members:
  The first day of the month coincident with or next following the attainment of age 65.

Early Retirement Date

- An employee may retire prior to the normal retirement date without any reduction in the accrued pension, if the sum of the employee's age and years of continuous employment is equal to or greater than 82 (for management employees hired on or after January 1, 2004 and Society employees hired on or after November 17, 2005, if the sum of the employee's age and years of credited service is equal to or greater than 85).
- A female employee whose continuous employment commenced prior to 1976 with at least 15 years of continuous employment, or any other employee with 15 or more years of continuous employment but less than 25 years of continuous employment, who does not qualify for any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. In such a case the employee's accrued pension is reduced by 2% for each year up to five years and 3% for each additional year by which the early retirement date precedes the employee's normal retirement date.
- Otherwise, an employee may retire prior to age 60 with 25 or more years of continuous employment, but within 10 years of normal retirement date. In such a case, the employee's accrued pension is reduced by 3% for each year by which early retirement precedes age 60.
- An employee, who does not qualify under any of the previously mentioned early retirement provisions and who has at least two years of Plan membership, may retire within 10 years of normal retirement date. In such a case, the pension is the actuarial equivalent of the member's deferred pension.
- A terminated employee with a deferred pension may retire under any of the previously mentioned provisions for early retirement without reduction provided that such provision was in effect on the date of termination.
- A terminated employee with a deferred pension, who terminated after March 31, 1986, with 25 or more years of continuous employment has the same early retirement provisions as those in effect for active employees at the date of termination.
- Otherwise, a terminated employee with a deferred pension, who terminated with 15 or more years of continuous employment, or who terminated with 2 or more years of Plan membership after 1987, may receive a pension within 10 years of normal retirement in accordance with the rules in effect on the date of termination. In such a case, the pension is the actuarial equivalent of the member's deferred pension.

Normal Retirement Pension	(a) 2% of the member's "high three-year average" (high five-year average for management employees hired on or after January 1, 2004 and Society employees hired on or after November 17, 2005) (see note below) for each year of credited service, subject to a maximum of 35 years LESS (b) 0.625% of the member's "high five-year average" up to the "average YMPE" (see note below) for each year of credited service included in (a) above subsequent to December 31, 1965. This factor has been reduced from 0.625% to 0.50% for members of the Power Workers Union (PWU) and for Society members hired prior to November 17, 2005.
Bridge Pension	For everyone except management employees hired on or after January 1, 2004 and Society members hires on or after November 17, 2005, 0.625% of the member's "high five-year average" up to the "average YMPE" (see note below) for each year of credited service included in (a) above, subject to a maximum of 30 years, multiplied by 35, and divided by 30. The bridge benefit is payable in the same form as the lifetime pension, until the member attains age 65. Management employees hired on or after January 1, 2004 and Society members hired after November 17, 2005 are not entitled to receive a bridge benefit from the Plan. **Note:** "High three-year average" is the average of the member's base annual earnings plus bonuses up to a set percentage during the thirty-six consecutive months when the base earnings were highest. For earnings after 1999, the percentage of bonus under the performance achievement plan included in pensionable earnings is 50%. The "average YMPE" is the average of the YMPEs during the sixty consecutive months when the base earnings were highest.
Pension Increases	Pension increases of 100% (75% for management employees hired on or after January 1, 2004 and Society employees hired after November 17, 2005) of the increase in the CPI (Ontario) will be given every January 1 to pensioners, beneficiaries and terminated employees with deferred pensions.
Maximum Pension	The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the Income Tax Act.

Death benefits	Pre-retirement: (a) Benefits in respect of Continuous Employment Prior to 1987 (i) If the member has completed 10 years of continuous employment, the surviving spouse or dependent child is entitled to a survivor's pension. The survivor's pension is an amount equal to 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement. The survivor's pension is payable to the surviving spouse until death or, if there is no eligible spouse, to the dependent children until age 18 (longer if disabled or in full-time attendance at a school or university). The total benefits paid are subject to a minimum of the member's contributions with interest. (ii) Otherwise, a payment of the member's contributions with interest is made to the beneficiary or estate. (b) Benefits in respect of Continuous Employment After 1986 (i) If the member has less than 2 years of Plan membership and has not completed 10 years of continuous employment, a payment of the member's contributions with interest is made to the beneficiary or estate. (ii) If the member has less than 2 years of Plan membership, but has completed 10 years of continuous employment, the surviving spouse is entitled to a survivor's pension as described in (a)(i) above. (iii) If the member has at least 2 years of Plan membership, but has not completed 10 years of continuous employment, the surviving spouse is entitled to receive the commuted value of the member's deferred pension. In lieu of such payment, the surviving spouse may elect to receive an immediate or deferred pension of equivalent commuted value. If there is no surviving spouse, a payment of the commuted value of the member's deferred pension is made to the beneficiary or estate. (iv) If the member has at least 2 years of Plan membership and has completed 10 years of continuous employment, the surviving spouse is entitled to the greater of an immediate pension of 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement, or an immediate pension with commuted value equivalent to the commuted value of the member's deferred pension. In lieu of this pension, the surviving spouse may elect to receive the commuted value of the member's deferred pension or a deferred pension of equivalent commuted value. If there is no surviving spouse, the dependent children are entitled to a pension of 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement, payable to age 18 (longer if disabled or in full-time attendance at a school or university). If there is no surviving spouse, a payment of the commuted value of the member's deferred pension less the commuted value of the pension payable to any dependent children is made to the beneficiary or estate.
Death benefits	Post retirement: • A survivor's pension, an amount equal to 66.67% of the pension to which the member would have been entitled, is payable on death after retirement to the surviving spouse or dependent children, subject to other options chosen at the time of retirement.

Termination Benefits

(a) Benefits in respect of Continuous Employment Prior to 1987

(i) The member is entitled to a refund of all of the member's pre-1987 contributions with interest, subject to (iv) below.

(ii) A member, who has at least one year of Plan membership, may elect to receive, in lieu of (i) above, the pension accrued prior to 1987 commencing at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment.

(iii) A member, who has at least 10 years of Plan membership, may elect to receive, in lieu of (i) or (ii) above, a cash payment of 25% of the commuted value of the pension accrued prior to 1987, with 75% of such pension being paid at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment.

(iv) A member, who has both attained age 45 and completed 10 or more years of continuous employment, may not elect to receive a refund of contributions in respect of service between January 1, 1965 and December 31, 1986. The member may, however, elect to receive, in lieu of (ii) or (iii) above, a refund of the member's contributions to the Fund prior to 1965 together with credited interest plus 25% of the commuted value of the pension accrued after 1964 but prior to 1987, with entitlement to 75% of such pension being paid commencing on the normal or early retirement date ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment. The member may elect to transfer (see note below) the greater of the commuted value of the 75% pension or 75% of the member" contributions with interest made after 1964 but prior to 1987.

(b) Benefits in respect of Continuous Employment After 1986

(i) A member is entitled to a refund of the member's post-1986 contributions with interest, subject to (iii) below.

(ii) A member, who has at least one year of Plan membership, may elect to receive, in lieu of (i) above, the pension accrued after 1986 commencing at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment.

(iii) A member, who has at least two years of Plan membership, may not elect to receive a refund under (i) above. The member may, however, elect, in lieu of (ii) above, to transfer (see note below) the commuted value of the deferred pension.

Note: Amounts must be transferred to a pension fund related to another pension plan, a prescribed retirement savings arrangement, or a life annuity which does not commence before the earliest date on which the member would have been entitled to retire.

Disability Benefits

A totally disabled employee receives benefits from an income replacement plan and ceases to contribute to the Pension Fund, but continues to accrue credited service. For this member, the base annual earnings for pension purposes are deemed to be increased by the same percentage increases described for pensions above.

Excess Contributions	Upon the earliest of termination of employment, death or retirement, the amount by which the member's post-1986 contributions with interest exceed 50% of the commuted value of the deferred pension accrued after 1986 is refunded to the member (to the spouse, beneficiary or estate, in the case of death). Upon termination of employment, if a member who has attained age 45 and completed 10 or more years of continuous employment elects to fully divest the pension accrued prior to 1987, the member is entitled to receive the amount by which the contributions with interest made after 1964 but prior to 1987 exceeds the commuted value of the pension accrued after 1964 but prior to 1987.

APPENDIX G

Employer Certification

With respect to the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2011, of the Hydro One Pension Plan I hereby certify that, to the best of my knowledge and belief:

- The valuation reflects the terms of the Company's engagement with the actuary, particularly the requirement to include a margin of 0.91% in the discount rate used to perform the going concern valuation.
- The valuation reflects the Company's decisions in regards to determining the solvency funding requirements.
- A copy of the official plan documents and of all amendments made up to December 31, 2011 were provided to the actuary and is reflected appropriately in the summary of plan provisions contained herein.
- The asset information summarised in Appendix B is reflective of the Plan's assets.
- The membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2011.

All events subsequent to December 31, 2011 that may have an impact on the Plan have been communicated to the actuary.

MAY 25/12
Date

Signed

SANDY STRUTHERS
Name

MERCER

Mercer (Canada) Limited
161 Bay Street, P.O. Box 501
Toronto, Ontario M5J 2S5
+1 416 868 2000

Consulting. Outsourcing. Investments.

Ontario Energy Board (Board Staff) INTERROGATORY #45 List 1

Issue 7 **Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

Interrogatory

Ref: Exhibit C1/Tab 5/Sch3
As per Exhibit C1/Tab 5/Schedule 3, Hydro One is proposing to recover pension costs in the 2013 and 2014 test years on a cash basis.

a) Has Hydro One explored switching to the accrual basis to account for pension costs for financial reporting purposes and for regulatory purposes? Please provide any supporting documentation or memorandum that analyses a switch by Hydro One to the accrual basis.

b) What would the pension costs for the 2013 and 2014 test years amount to under the accrual basis of accounting? Please provide supporting documentation, including underlying assumptions.

c) Please confirm that the cash basis is more volatile compared to the accrual basis under both positive and negative asset and liability shocks. Please provide supporting documentation. If this is not the case, please explain.

d) Please confirm that the cash basis will produce lower costs than the accrual basis when market conditions or discount rates are favourable because gains on a cash basis can be realized immediately through contribution holidays. However gains on an accrual basis are amortized over the expected average service life. If this is not the case, please explain.

e) Please confirm that the cash basis will produce higher costs than the accrual basis when market conditions or discount rates are not favourable because losses on a cash basis are amortized over a small time period. However, losses on an accrual basis are amortized over the expected average service life. If this is not the case, please explain.

f) Please provide Hydro One's justification for using the cash method versus the accrual method for pension costs.

g) Please provide any documentation from Hydro One's external auditor regarding the choice of the cash method versus the accrual method – particularly the external auditor agreeing or disagreeing with Hydro One's choice of the cash method for pension costs.

h) Please list the relevant section of the USGAAP accounting standards that permits the use of the cash method for pension costs for financial reporting purposes.

Response

a) Hydro One has not explored switching to the accrual basis to account for pension costs for financial reporting and for regulatory purposes.

b) The pension costs for 2013 and 2014 under the accrual method are projected to be approximately $194 million and $182 million, respectively, which is significantly higher than under the cash basis of $154 million and $158 million, respectively. The projected estimates are based on the same data, assumptions, methods, and plan provisions used to prepare the December 31, 2011 year-ended disclosures for the Plan as disclosed in Note 12 to Hydro One's consolidated financial statements. The key assumptions used to project the costs are as follows:

   i) Accounting discount rate of 5.25% per annum.
   ii) Pension fund returns will equal 6.25% per year (net of expenses) over the projection period.

   Supporting calculations are as follows:

	2013	2014
Current Service Costs	$98	$100
Interest Cost	$292	$299
Expected Return on Plan Assets	($300)	($312)
Amortization of Past Service Cost	$2	$2
Amortization of Net Loss	$102	$93
Total	$194	$182

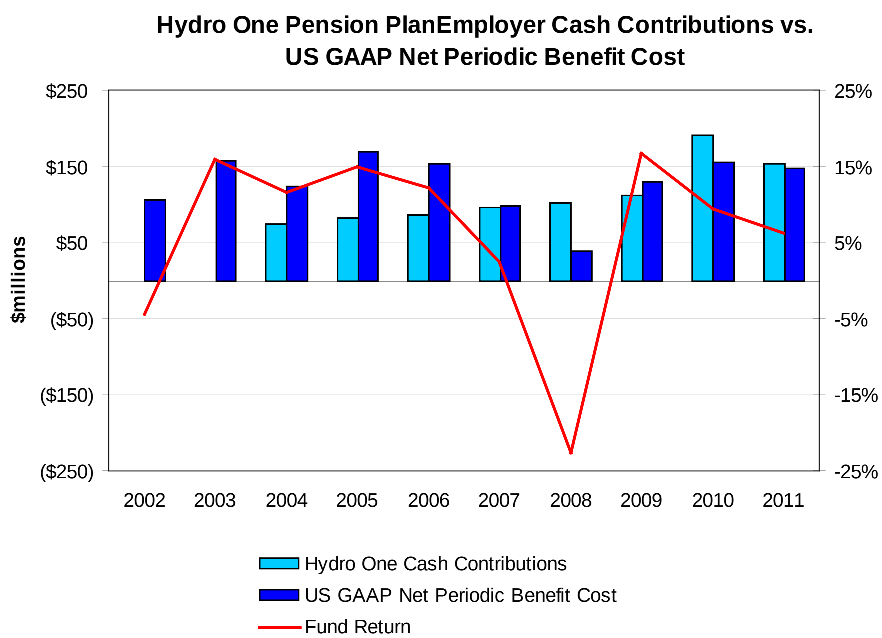
c) The following chart compares Hydro One's actual cash contributions made from 2002 to 2011 and the Net Periodic Benefit Costs (accrual basis) that Hydro One would have recorded under US GAAP accounting if US GAAP accounting had been used over this historical illustration period. The retroactive application of US GAAP was based on a number of key assumptions:

   i) The initial balance sheet position of the plan as at January 1, 2000 was the funded status of the plan on that date.

   ii) The reconciliation of plan assets and obligations under US GAAP from January 1, 2000 to December 31, 2011 is the same as the assets and obligations reported under Canadian GAAP.

iii) The accounting policies under retroactive US GAAP were assumed to be the same as they had been under Canadian GAAP. In particular, we assumed that the 10% corridor for amortization of net actuarial gains and losses would not have been applied under US GAAP, and we assumed that any one-time special adjustments that were made to the balance sheet under Canadian GAAP would have also been made under US GAAP.

This chart includes the additional contribution of $48 million that Hydro One chose to make in 2010 that was in excess of the minimum contribution required under pension legislation.



Cash basis would not have been more volatile than accrual basis under the Plan over the past 10 years as demonstrated in the above table. There are elements of the going concern valuation which mitigate the volatility of cash funding requirements. These include:

i) The smoothing of assets for going concern valuation purposes. Equity experience (returns) is smoothed over five years rather than recognized immediately by using a market value of assets as is the case for accounting costs.

ii) The going concern funding valuation discount rate is based on a long-term outlook for future Fund returns, taking into account market conditions at the time and reasonable expectations for future economic growth. By contrast, the accounting discount rate is set solely with reference to market yields on Canadian AA corporate bonds and is more responsive to movements in bond yields.

iii) The impacts of both asset and going concern liability shocks are amortized over 15 years. For accounting purposes, gains and/or losses are amortized over expected average service life (EARSL) of 11 years.

Cash contributions can be more volatile if a company is required to fund a solvency deficit in addition to a going-concern deficit as solvency deficits must be funded over a five year period under Ontario funding rules. However, Hydro One has not historically been required to fund a solvency deficit.

Hydro One's experience over the past decade may not necessarily be indicative of future experience. The relative volatility between cash basis and accrual basis may change significantly if Hydro One is subject to solvency funding requirements in the future. Nonetheless, Hydro One's historical experience may provide a useful illustration for understanding the implications of volatile markets on the cash and accounting basis. These same statements can be extended to our responses directly below.

d) It is true that experience gains can be used to reduce cash funding requirements and in certain circumstances, reduce them to zero. For accounting purposes, it is also true that experience gains would be amortized over EARSL. However, in certain circumstances (such as for pension plans with a large surplus), it is possible to produce a negative pension expense (or income). The smoothing of investment gains may also lead to delays before favourable market conditions are reflected in the contribution requirements. As such, it cannot unequivocally be said that cash basis will always be lower than accrual basis when market conditions and/or discount rates are favourable.

e) Cash basis will not necessarily be higher than accrual basis under the Hydro One Plan when market conditions and/or discount rates are not favourable. Because Hydro One's cash funding requirements are currently driven by its going concern valuation results and not solvency valuation results, the amortization period for funding experience losses is in fact longer than the current EARSL. The impacts of both asset and going concern liability shocks are amortized over 15 years for funding purposes. For accounting purposes, gains and/or losses are amortized over EARSL (currently 11 years).

f) Hydro One uses the cash method versus the accrual method for pension costs as it believes that historical OEB rate orders requested such at a time in which the cash basis resulted in lower pension expense and thus lower electricity rates. As well, the cash basis, under a known three year actuarial funding period, allows for less volatility in the short-term.

g) Hydro One's external auditor agrees with the accounting policies chosen by the company as set out in (Exhibit A, Tab 9, Schedule 1, Attachment 3) the Independent

Auditors' Report ("Report"). The Report states that they "…have audited the accompanying financial statements of the Transmission Business (a business of Hydro One Networks Inc.), which comprises…notes, comprising a summary of significant accounting policies…" and that "in our (their) opinion, the financial statements present fairly, in all material respects…in accordance with basis of accounting as set out in Note 2 to these financial statements." In Note 2 for Employee Future Benefits of our financial statements we state "In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund…" also known as the cash method.

h) The source of USGAAP is the Accounting Standards Codification (ASC). ASC 980 Regulated Operations permits the use of an accounting methodology as established by a regulator for its basis of accounting for financial reporting purposes.

HYDRO ONE REMOTE COMMUNITIES INC.

FINANCIAL STATEMENTS

DECEMBER 31, 2012

HYDRO ONE REMOTE COMMUNITIES INC.
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Remote Communities Inc.

We have audited the accompanying consolidated financial statements of Hydro One Remote Communities Inc., which comprise the balance sheets as at December 31, 2012 and December 31, 2011, the statements of operations and comprehensive income, changes in shareholder's deficit and cash flows for the year ended December 31, 2012 and December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Hydro One Remote Communities Inc. as at December 31, 2012 and December 31, 2011, and its statements of operations and comprehensive income, changes in shareholder's deficit and cash flows for the year ended December 31, 2012 and December 31, 2011 in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
April 18, 2013

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (thousands of dollars)	**2012**	**2011**
		(Note 18)
Revenues *(Note 15)*	46,766	43,472
Costs		
Operation, maintenance and administration *(Note 15)*	16,861	15,610
Fuel used for electric generation	24,306	22,161
Depreciation and amortization *(Note 4)*	6,019	4,694
	47,186	42,465
Income (loss) before financing charges and recovery of payments in lieu of corporate income taxes	(420)	1,007
Financing charges *(Notes 5, 15)*	1,016	1,134
Loss before recovery of payments in lieu of corporate income taxes	(1,436)	(127)
Recovery of payments in lieu of corporate income taxes *(Notes 6, 15)*	(1,436)	(127)
Net income	-	-
Other comprehensive income	12	11
Comprehensive income	12	11

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS

December 31 (thousands of dollars)	**2012**	**2011**
Assets		*(Note 18)*
Current assets:		
Accounts receivable (net of allowance for doubtful accounts - $297; 2011 - $430) *(Notes 7, 15)*	4,193	3,935
Regulatory assets *(Note 9)*	1,823	3,402
Fuel, materials and supplies	2,179	2,817
Deferred income tax assets *(Note 6)*	108	107
Income tax receivable *(Notes 6, 15)*	1,589	163
	9,892	10,424
Property, plant and equipment *(Note 8)*:		
Property, plant and equipment in service	54,790	52,622
Less: accumulated depreciation	25,779	24,128
	29,011	28,494
Construction in progress	7,250	3,679
Future use components and spares	1,573	1,550
	37,834	33,723
Other long-term assets:		
Regulatory assets *(Note 9)*	14,060	12,380
Deferred income tax assets *(Note 6)*	4,733	5,667
Deferred debt costs *(Note 10)*	101	102
Net unamortized debt discounts *(Note 10)*	27	28
Long-term accounts receivable (net of allowance for doubtful accounts - $5; 2011 - $228) *(Note 7)*	418	369
	19,339	18,546
Total assets	67,065	62,693

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
BALANCE SHEETS (continued)

December 31 (thousands of dollars)	**2012**	**2011**
Liabilities		*(Note 18)*
Current liabilities:		
Inter-company demand facility *(Notes 11, 15)*	11,212	2,212
Accounts payable	987	1,430
Accrued liabilities *(Notes 12, 13)*	5,876	7,363
Accrued interest *(Note 15)*	142	142
Regulatory liabilities *(Note 9)*	108	107
	18,325	11,254
Long-term debt *(Notes 10, 11, 15)*	23,000	23,000
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 12)*	11,532	9,091
Regulatory liabilities *(Note 9)*	4,733	8,765
Environmental liabilities *(Note 13)*	10,057	11,177
	26,322	29,033
Total liabilities	67,647	63,287
Contingencies (Note 17)		
Shareholder's deficit		
Common shares (authorized: unlimited; issued: 2) *(Note 14)*	-	-
Retained earnings *(Note 14)*	-	-
Accumulated other comprehensive loss	(582)	(594)
Total shareholder's deficit	(582)	(594)
Total liabilities and shareholder's deficit	67,065	62,693

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Carmine Marcello
Chair

Myles D'Arcey
Director

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CHANGES IN SHAREHOLDER'S DEFICIT

Year ended December 31, 2012 *(thousands of dollars)*	Common shares	Retained earnings	Accumulated other comprehensive loss	Total shareholder's deficit
January 1, 2012	-	-	(594)	(594)
Net income	-	-	-	-
Other comprehensive income	-	-	12	12
December 31, 2012	-	-	(582)	(582)

Year ended December 31, 2011 *(thousands of dollars)* *(Note 18)*	Common shares	Retained earnings	Accumulated other comprehensive loss	Total shareholder's deficit
January 1, 2011	-	-	(605)	(605)
Net income	-	-	-	-
Other comprehensive income	-	-	11	11
December 31, 2011	-	-	(594)	(594)

See accompanying notes to Financial Statements.

HYDRO ONE REMOTE COMMUNITIES INC.
STATEMENTS OF CASH FLOWS

Year ended December 31 (thousands of dollars)	**2012**	**2011**
		(Note 18)
Operating activities		
Net income	-	-
Environmental expenditures	(2,515)	(1,017)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	5,461	3,926
Regulatory assets and liabilities	(3,957)	(834)
Amortization of hedging losses	12	11
Amortization of deferred debt costs and debt discounts	2	2
Gain on disposition of property, plant and equipment	(2)	-
Changes in non-cash balances related to operations *(Note 16)*	(947)	97
Net cash from (used in) operating activities	(1,946)	2,185
Investing activities		
Capital expenditures	(7,042)	(7,229)
Proceeds on disposition of property, plant and equipment	11	-
Future use assets	(23)	(17)
Net cash used in investing activities	(7,054)	(7,246)
Net change in inter-company demand facility	(9,000)	(5,061)
Inter-company demand facility, beginning of year	(2,212)	2,849
Inter-company demand facility, end of year	(11,212)	(2,212)

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Remote Communities Inc. (Hydro One Remote Communities or the Company) was incorporated on August 18, 1998 under the *Business Corporations Act* (Ontario), and is a wholly owned subsidiary of Hydro One. Hydro One Remote Communities operates 19 small electrical, generation and distribution systems in remote communities in northern Ontario that are not connected to the province's electricity grid. The Company's business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. These statements are to be read in conjunction with Note 18 - Transition to US GAAP, which discloses information on the Canadian GAAP to US GAAP transition and related reconciliations from Canadian GAAP to US GAAP. The results of operations for the year ended December 31, 2011, and the Balance Sheet as at December 31, 2011 have been restated under US GAAP for comparative purposes. The Company's Financial Statements were previously prepared using Canadian GAAP.

These Financial Statements are prepared using a cost recovery model applied to achieve breakeven net income and are for the specific use of the OEB. Certain amounts presented in these Financial Statements represent allocations from Hydro One that are subject to review and approval by the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2012 have been prepared on a US GAAP basis and are publicly available.

Hydro One Remote Communities performed an evaluation of subsequent events for the accompanying Financial Statements and notes included through to April 18, 2013, the date these Financial Statements were available to be issued, to determine whether the circumstances warranted recognition and disclosure of any events or transactions. No such events or transactions were identified.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Management evaluates these estimates on an on-going basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumption is made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, post-retirement and post-employment benefits, asset impairment, contingencies, unbilled revenue, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate Setting

On April 3, 2012, the OEB approved the Company's request to use US GAAP as the basis for rate setting and regulatory accounting and reporting, effective January 1, 2012.

In October 2010, Hydro One Remote Communities filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2011 rates. In March 2011, the OEB approved an increase of approximately 0.4% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2011. In November 2011, Hydro One Remote Communities filed an IRM application with the OEB for 2012 rates. In March 2012, the OEB approved an increase of approximately 1.1% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2012.

Regulatory Accounting

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future electricity customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Hydro One Remote Communities is regulated under a cost recovery model applied to achieve breakeven net income, after consideration of the recovery of / provision for payments in lieu of corporate income taxes (PILs). Any excess or deficiency in remote rate protection amounts necessary to lead to breakeven net income is added to, or drawn from, the Remote Rate Protection Revenue (RRPR) variance account. The balance in the RRPR variance account is subject to future review and disposition by the OEB.

Revenue Recognition

Revenues are recognized on an accrual basis and include billed and unbilled revenues. Revenues attributable to the generation and delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates monthly revenue for a period based on wholesale electricity purchases because customer meters are not generally read at the end of each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides rate protection for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 120 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One Remote Communities is required to make PILs to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998*, and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgement is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

Current Income Taxes

The recovery of / provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from, or payable to, the OEFC.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only the ITCs are recognized as a reduction to income tax expense.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, including Hydro One Remote Communities. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Company to and from the pooled cash accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

Fuel, Materials and Supplies

Fuel is used in the generation of electricity. Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of contributions received in aid of construction and any accumulated impairment losses. The cost of additions, including betterments and replacements of asset components, is included on the Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, and direct and indirect overheads that are related to the capital project. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of generation, distribution, and administration and service assets. Property, plant and equipment also includes future use assets, such as major components and spare parts.

Generation

Generation assets are used in the generation of electricity, including hydroelectric equipment, wind turbines, diesel generators, and tank farms.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices, and metering systems.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools, and other minor assets.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company’s weighted average effective cost of debt.

Construction in Progress

Construction in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment depreciation rates, as required by the OEB. Any changes arising from such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2007.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate (%)	
	Service Life	Range	Average
Generation	25 years	1% - 13%	6%
Distribution	39 years	1% - 10%	3%
Administration and service	37 years	3% - 20%	3%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, that are normally retired, is charged to accumulated depreciation with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment assets where no asset retirement obligation has been recorded.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset’s carrying value is adjusted to its estimated fair value. As at December 31, 2012, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company’s proportionate share of Hydro One’s discontinued cash flow hedges. The Company amortizes its net unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the associated hedged debt. Hydro One Remote Communities presents OCI and net income in a single continuous Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity investments; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms.

The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 11 – Fair Value of Financial Instruments and Risk Management.

Transaction costs associated with financial assets and liabilities that are measured at fair value are recognized immediately in results of operations. All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

The Company currently does not engage in derivative trading or speculative activities and had no derivative instruments outstanding at December 31, 2012. OCI includes the amortization of net unamortized hedging losses on the Company's proportionate share of Hydro One's discontinued cash flow hedges.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of Hydro One's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment funds are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The net asset for an overfunded plan is classified as a long-term asset in the Consolidated Balance Sheets. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets. For the year ended December 31, 2012, the measurement date for the Plans was December 31.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities, but not including Hydro One Brampton Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

A detailed description of Hydro One pension benefits is provided in Note 14 - Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2012.

Post-retirement and post-employment benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Remote Communities. The benefit obligations of the these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Remote Communities. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

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 post-retirement and post-employment plans, in absence of regulatory accounting, would be recognized in accumulated OCI. 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.

Post-retirement and post-employment benefits, are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in Note 14 - Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2012.

Loss Contingencies

Hydro One Remote Communities is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Financial Statements, management makes judgements regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgements about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty the longer the projection period. A significant upward or downward trend in the number of claims filed, the nature of the alleged injury, and the average cost of resolving each such claim could change the estimated provision, as could any substantial adverse or favorable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One Remote Communities records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One Remote Communities reviews its estimates of future environmental expenditures annually or more frequently if there are indications that circumstances have changed.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In June 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-05, Presentation of Comprehensive Income, to clarify that an entity has the option to present the total of comprehensive income, the components of net income, and the components of OCI either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. This update eliminates the option to present the components of OCI as part of the statement of changes in shareholders' equity. The amendments in this ASU do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. Hydro One Remote Communities has elected to present OCI and net income in a single continuous Statement of Operations and Comprehensive Income.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and International Financial Reporting Standards (IFRS). This ASU is the result of joint efforts by the FASB and the International Accounting Standards Board to develop common, converged fair value guidance on how to measure fair value and on what disclosures to provide about fair value measurements. This ASU is largely consistent with existing US GAAP fair value measurement principles under Accounting Standards Codification 820. However, this ASU expands the existing disclosure requirements for fair value measurements, particularly of Level 3 inputs, and requires categorization by level of the fair value hierarchy for items that are not measured at fair value on the Balance Sheets but for which the fair value is required to be disclosed. Required disclosures have been included in Note 11 – Fair Value of Financial Instruments and Risk Management. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Company’s Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an entity to disclose both gross and net information about financial instruments and transactions eligible for offset in the Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on its financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this ASU only requires enhanced disclosures, the adoption of this ASU is not anticipated to have a significant impact on the Company’s Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (thousands of dollars)	**2012**	**2011**
Depreciation of property, plant and equipment	2,946	2,909
Asset removal costs	560	768
Gain on disposition of property, plant and equipment	(2)	-
Amortization of regulatory assets	2,515	1,017
	6,019	4,694

5. FINANCING CHARGES

Year ended December 31 (thousands of dollars)	**2012**	**2011**
Interest on long-term debt	1,237	1,237
Interest on inter-company demand facility	83	19
Amortization of hedging losses	12	11
Other	5	33
Less: Interest capitalized on construction in progress	(321)	(166)
	1,016	1,134

6. PROVISION FOR PILs

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (thousands of dollars)	**2012**	**2011**
Loss before recovery of PILs	(1,436)	(127)
Canadian Federal and Ontario statutory income tax rate	26.50%	28.25%
Recovery of PILs at statutory rate	(381)	(36)
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Depreciation and amortization in excess of capital cost allowance	913	585
Environmental expenditures	(667)	(287)
Overheads capitalized for accounting but deducted for tax purposes	(102)	(138)
Interest capitalized for accounting but deducted for tax purposes	(85)	(47)
Post-retirement and post-employment benefit expense in excess of cash payments	74	86
RRPR variance account	(1,029)	(236)
Pension contribution in excess of pension expense	(107)	(88)
Other	(15)	4
Net temporary differences	(1,018)	(121)
Net permanent differences	(37)	30
Total recovery of PILs	(1,436)	(127)
Current recovery of PILs	(1,436)	(127)
Deferred recovery of PILs	-	-
Total recovery of PILs	(1,436)	(127)
Effective income tax rate	100%	100%

The recovery of payments in lieu of current income taxes of $1,436 thousand (2011 - $127 thousand) represents the amount that is recoverable from the OEFC with respect to current year income. The balance receivable from the OEFC at December 31, 2012 was $1,589 thousand (2011- $163 thousand).

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company’s assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (thousands of dollars)	**2012**	**2011**
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	4,266	2,736
Depreciation and amortization in excess of capital cost allowance	2,263	2,237
Regulatory amounts received but not recognized for accounting purposes	-	1,032
Total deferred income tax assets	6,529	6,005
Less: current portion	108	107
	6,421	5,898

December 31 (thousands of dollars)	**2012**	**2011**
Deferred income tax liabilities		
Debt costs and hedging losses recognized for tax but not for accounting purposes	245	231
Regulatory amounts received but not recognized for accounting purposes	1,443	-
Total deferred income tax liabilities	1,688	231
Less: current portion	-	-
	1,688	231

The deferred income tax assets and liabilities are presented on the Balance Sheets as follows:

December 31 (millions of dollars)	**2012**	**2011**
Current deferred income tax assets	108	107
Current deferred income tax liabilties	-	-
Net current deferred income tax assets	108	107
Long-term deferred income tax assets	6,421	5,898
Long-term deferred income tax liabilties	(1,688)	(231)
Net long-term deferred income tax assets	4,733	5,667

During 2012, the deferred tax liability increased by $464 thousand as a result of the change in the rate applicable to future taxes.

7. ACCOUNTS RECEIVABLE

December 31 (thousands of dollars)	Current accounts receivable	Long-term accounts receivable	Total
2012			
Accounts receivable - billed	2,963	423	3,386
Accounts receivable - unbilled	1,527	-	1,527
Accounts receivable, gross	4,490	423	4,913
Allowance for doubtful accounts	(297)	(5)	(302)
Accounts receivable, net	4,193	418	4,611
2011			
Accounts receivable - billed	2,915	597	3,512
Accounts receivable - unbilled	1,450	-	1,450
Accounts receivable, gross	4,365	597	4,962
Allowance for doubtful accounts	(430)	(228)	(658)
Accounts receivable, net	3,935	369	4,304

The following table shows the movements in the total allowance for doubtful accounts for the years ended December 31, 2012 and 2011.

Year ended December 31 (thousands of dollars)	**2012**	**2011**
Allowance for doubtful accounts – January 1	(658)	(875)
Write-offs	222	79
Adjustments to allowance for doubtful accounts	134	138
Allowance for doubtful accounts – December 31	(302)	(658)

8. PROPERTY, PLANT AND EQUIPMENT

December 31 (thousands of dollars)	Costs	Accumulated Depreciation	Construction in Progress	Total
2012				
Generation	38,803	22,056	6,764	23,511
Distribution	7,757	1,785	315	6,287
Administration and Service	9,803	1,938	171	8,036
	56,363	25,779	7,250	37,834
2011				
Generation	38,259	20,895	2,966	20,330
Distribution	7,485	1,612	202	6,075
Administration and Service	8,428	1,621	511	7,318
	54,172	24,128	3,679	33,723

Financing charges capitalized on property, plant and equipment under construction were $321 thousand in 2012 (2011 - $166 thousand).

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One Remote Communities has recorded the following regulatory assets and liabilities:

December 31 (thousands of dollars)	**2012**	**2011**
Regulatory assets:		
Environmental	11,880	14,579
Post-retirement and post-employment benefits	3,144	1,203
RRPR variance account	787	-
IFRS transition cost variance	72	-
Total regulatory assets	15,883	15,782
Less: current portion	1,823	3,402
	14,060	12,380
Regulatory liabilities:		
Deferred income tax regulatory liability	4,841	5,774
RRPR variance account	-	3,098
Total regulatory liabilities	4,841	8,872
Less: current portion	108	107
	4,733	8,765

Environmental

The Company records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 13 – Environmental Liabilities). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2012, this regulatory asset decreased by $583 thousand (2011 – increased by $7,043 thousand) to reflect related changes in the Company's environmental liabilities. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, 2012 operation, maintenance and administration expenses would have been lower by $583 thousand (2011 – higher by $7,043 thousand). In addition, 2012 amortization expense would have been lower by $2,515 thousand (2011 – $1,017 thousand), and 2012 financing charges would have been higher by $399 thousand (2011 – $261 thousand).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Balance Sheets with an incremental offset to the associated regulatory assets. 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. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $1,941 thousand (2011 – higher by $325 thousand).

RRPR Variance Account

Hydro One Remote Communities receives remote rate protection amounts from the IESO. At December 31, 2012, the Company has recognized a regulatory asset representing the amounts required to achieve breakeven net income, as regulated under the cost recovery model, in excess of net remote rate protection amounts received. At December 31, 2011, net remote rate protection amounts received were in excess of the amounts required to achieve breakeven net income, and as such, a regulatory liability was recognized. In the absence of rate-regulated accounting, 2012 revenue would have been lower by $3,957 thousand (2011 - $835 thousand).

IFRS Transition Costs Variance

Hydro One Remote Communities records an asset for the variance between its one-time incremental costs incurred in its uncompleted transition to IFRS and amounts included in rates in respect of this project.

Deferred Income Tax Regulatory Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2012 recovery of PILs would have been higher by approximately $771 thousand (2011 – $154 thousand), including the impact of a change in enacted tax rates.

10. LONG-TERM DEBT

Long-term debt represents a note payable to Hydro One. The note was issued on May 19, 2005, with a carrying value of $23,000 thousand and interest at a rate of 5.38% per annum. The note matures on May 20, 2036. The note was issued on maturity of a previous note in the same principal amount that was issued on April 1, 1999 in consideration of the purchase price of Hydro One Remote Communities' net assets.

On issuance of this note, $115 thousand of transaction costs and a $31 thousand debt discount incurred by Hydro One were allocated to Hydro One Remote Communities, based on its proportionate share of Hydro One's related debt issue.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One Remote Communities classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One Remote Communities has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occurs with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

At December 31, 2012 and 2011, the Company’s carrying amounts of accounts receivable, accounts payable and accrued liabilities are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company’s long-term debt at December 31, 2012 and 2011 are as follows:

December 31 (thousands of dollars)	2012 Carrying Value	2012 Fair Value	2011 Carrying Value	2011 Fair Value
Long-term debt	23,000	28,486	23,000	27,844

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2012 and 2011 are as follows:

December 31, 2012 (thousands of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	11,212	11,212	11,212	-	-
Long-term debt	23,000	28,486	-	28,486	-
	34,212	39,698	11,212	28,486	-

December 31, 2011 (thousands of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	2,212	2,212	2,212	-	-
Long-term debt	23,000	27,844	-	27,844	-
	25,212	30,056	2,212	27,844	-

The fair value of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2012 and 2011.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The foreign exchange risk is currently not significant, although Hydro One could in the future decide to issue and allocate foreign currency-denominated debt to the Company, along with an allocation of the resulting foreign exchange gains and losses. The Company is exposed to fluctuations in interest rates related to the interest charges passed on by Hydro One on the outstanding inter-company demand facility. The Company is charged interest on overdraft inter-company balances based on the bankers' acceptance rate, plus 0.15%.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2012 and 2011, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One Remote Communities did not earn a significant amount of revenue from any individual customer. At December 31, 2012 and 2011, there was no significant accounts receivable balance due from any single customer.

At December 31, 2012, the Company's total provision for bad debts was $302 thousand (2011 - $658 thousand). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2012, approximately 34% of the Company's current accounts receivable were aged more than 60 days (2011 - 32%). Sufficient allowances have been recorded to reflect the risk of potential credit losses.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Remote Communities meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

At December 31, 2012, accounts payable and accrued liabilities in the amount of $6,863 thousand (2011 - $8,793 thousand) are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2012, Hydro One Remote Communities had long-term debt in the notional amount of $23,000 thousand (2011 – $23,000 thousand). No long-term debt matures during the next year. Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $1,237 thousand (2011 – $1,237 thousand). Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table.

Years to Maturity	Principal Outstanding on Long-term Debt *(thousands of dollars)*	Interest Payments *(thousands of dollars)*
1 year	-	1,237
2 years	-	1,237
3 years	-	1,237
4 years	-	1,237
5 years	-	1,237
	-	6,185
6 - 10 years	-	6,185
Over 10 years	23,000	16,705
	23,000	29,075

12. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Balance Sheets.

Pension Benefits

The Pension Plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Company and employees’ contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Hydro One’s annual Pension Plan contributions for 2012 of $163 million (2011 – $152 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2012 pensionable earnings. Hydro One’s estimated annual Pension Plan contributions for 2013 are approximately $160 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

At December 31, 2012, based on the December 31, 2011 actuarial valuation, the present value of Hydro One’s projected pension benefit obligation was estimated to be $6,507 million (2011 - $5,461 million). The fair value of pension plan assets available for these benefits was $4,992 million (2011 - $4,682 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2012, Hydro One Remote Communities charged $537 thousand (2011 – $551 thousand) of post-retirement and post-employment benefit costs to results of operations, and capitalized $223 thousand (2011 - $271 thousand) as part of of the cost of property, plant and equipment. Benefits paid by the Company in 2012 were $259 thousand (2011 - $248 thousand). In addition, an incremental offset to increase the associated post-retirement and post-employment benefits regulatory assets by $1,941 thousand (2011 – decrease by $325 thousand) was recorded on the Company’s Balance Sheets to reflect the expected regulatory inclusion of this amounts in future rates, which would otherwise be recorded in OCI.

The Company presents its post-retirement and post-employment benefit liability on the Balance Sheets within the following line items:

December 31 (thousands of dollars)	**2012**	**2011**
Accrued liabilities	300	300
Post-retirement and post-employment benefit liability	11,532	9,091
	11,832	9,391

13. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Balance Sheets at December 31, 2012 and 2011:

December 31 (thousands of dollars)	**2012**	**2011**
Environmental liabilities, January 1	14,579	8,292
Interest accretion	399	261
Expenditures	(2,515)	(1,017)
Revaluation adjustment	(583)	7,043
Environmental liabilities, December 31	11,880	14,579
Less: current portion	1,823	3,402
	10,057	11,177

The following table illustrates the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized in the Balance Sheets after factoring in the discount rate:

December 31 (thousands of dollars)	**2012**	**2011**
Undiscounted environmental liabilities, December 31	12,503	15,421
Less: discounting accumulated liabilities to present value	623	842
Discounted environmental liabilities, December 31	11,880	14,579

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2012 and in total thereafter are as follows: 2013 - $1,823 thousand; 2014 - $2,783 thousand; 2015 - $1,457 thousand; 2016 - $980 thousand; 2017 - $1,104 thousand; and thereafter - $4,356 thousand. These expenditures are expected to be incurred over the period from 2013 to 2020

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting its expectation that future enfironmental costs will be recoverable in rates.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.57% to 4.87%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

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 (2011 – increase by $7,043 thousand).

14. SHARE CAPITAL

Common Shares

The Company has 2 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Dividends

The Company has no retained earnings and does not pay dividends under its breakeven business model.

15. RELATED PARTY TRANSACTIONS

Hydro One Remote Communities is a subsidiary of Hydro One, and Hydro One is owned by the Province. The OEFC, IESO, Ontario Power Authority (OPA), Ontario Power Generation Inc. (OPG) and the OEB are related parties to Hydro One Remote Communities because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One Remote Communities are described below.

Hydro One Remote Communities receives amounts for remote rate protection from the IESO. Remote rate protection amounts received for the year ended December 31, 2012 were $27,549 thousand (2011 - $27,549 thousand). Consistent with its breakeven business model, the Company recognized $31,506 thousand as remote rate protection revenue in 2012 (2011 - $28,384 thousand). This 2012 revenue exceeded amounts received by $3,957 thousand (2011 - $835 thousand) and the RRPR variance account balance was adjusted by this amount.

The recovery of PILs was received or receivable from the OEFC.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (thousands of dollars)	**2012**	**2011**
Accounts receivable	88	111
Income tax receivable	1,589	163

Transactions with related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are unsecured, interest free and settled in cash.

Hydro One and Subsidiaries

The Company provides services to, and receives services from, Hydro One and its other subsidiaries. Amounts due to and from Hydro One and its other subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2012 revenues include $130 thousand (2011 - $173 thousand) related to the provision of services to Hydro One and its other subsidiaries. 2012 operation, maintenance and administration costs include $2,607 thousand (2011 - $1,918 thousand) related to the purchase of services from Hydro One and its other subsidiaries.

The Company's long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or from Hydro One and its other subsidiaries. Financing charges include interest expense on the long-term debt in the amount of $1,237 thousand (2011 - $1,237 thousand), and interest expense on the inter-company demand facility in the amount of $83 thousand (2011 - $19 thousand). At December 31, 2012, the Company had accrued interest payable to Hydro One totaling $142 thousand (2011 - $142 thousand).

16. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (thousands of dollars)	**2012**	**2011**
Accounts receivable	(258)	547
Materials and supplies	638	(663)
Income taxes receivable	(1,426)	1,026
Long-term accounts receivable	(49)	183
Accounts payable	(443)	303
Accrued liabilities increase	91	(1,870)
Post-retirement and post-employment benefit liability	500	571
	(947)	97
Supplementary information:		
Net interest paid	1,320	1,256

As a result of using the cost recovery model applied to achieve after tax breakeven net income, any PILs paid are fully recovered.

17. CONTINGENCIES

Legal Proceedings

Hydro One Remote Communities is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which Hydro One Remote Communities acquired Ontario Hydro's remote communities business on April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds legal title to these assets. Under the terms of the transfer orders, Hydro One Remote Communities is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. If Hydro One Remote Communities cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if it is not able to recover them in future rate orders.

18. TRANSITION TO US GAAP

The adoption of US GAAP has been made on a retrospective basis with restatement of comparative information to reflect US GAAP requirements in effect at that time. The Company's transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to the Company's 2012 Financial Statements.

Measurement and classification differences resulting from Hydro One Remote Communities' adoption of US GAAP are presented below. With respect to measurement and classification differences, the tables under the heading US GAAP Differences, represent quantitative reconciliations of the Balance Sheets previously presented in accordance with Canadian GAAP, to the respective amounts and classifications under US GAAP, together with descriptions of the various significant measurement and classification differences arising from the adoption of US GAAP. Balance Sheets reconciliations are presented as at January 1, 2011 and December 31, 2011, representing the commencement and ending dates of the comparative financial year to 2012. There were no measurement or classification differences resulting from Hydro One Remote Communities' adoption of US GAAP on the Statements of Operations and Comprehensive Income and the Statements in Changes in Shareholder's Deficit.

Except as otherwise disclosed in this note, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the Canadian GAAP Financial Statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP accounting policies and practices.

The following table summarizes the increases to total assets:

(thousands of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total assets – Canadian GAAP		54,622	61,360
Deferred debt costs	A	105	102
Net unamortized debt discounts	A	28	28
Regulatory assets	B	1,528	1,203
Total assets – US GAAP		56,283	62,693

The following table summarizes the increases to total liabilities:

(thousands of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total liabilities – Canadian GAAP		55,227	61,954
Long-term debt	A	133	130
Post-retirement and post-employment benefit liability	B	1,528	1,203
Total liabilities – US GAAP		56,888	63,287

US GAAP Differences

The reconciliations of the January 1, 2011 and December 31, 2011 Balance Sheets from Canadian GAAP to US GAAP are as follows:

January 1, 2011 (thousands of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Inter-company demand facility		2,849	-	2,849
Accounts receivable		4,482	-	4,482
Regulatory assets		1,866	-	1,866
Fuel, materials and supplies		2,154	-	2,154
Deferred income tax assets		118	-	118
Income taxes receivable		1,189	-	1,189
		12,658	-	12,658
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		25,507	-	25,507
Construction in progress		2,348	-	2,348
Future use land, components and spares		1,533	-	1,533
		29,388	-	29,388
Other long-term assets:				
Regulatory assets	B	6,426	1,528	7,954
Deferred income taxes		5,598	-	5,598
Deferred debt costs	A	-	105	105
Net unamortized debt discounts	A	-	28	28
Long-term accounts receivable		552	-	552
		12,576	1,661	14,237
Total assets		54,622	1,661	56,283
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	C	8,827	(8,827)	-
Accounts payable	C	-	1,127	1,127
Accrued liabilities	C	-	7,700	7,700
Regulatory liabilities		118	-	118
Accrued interest		142	-	142
		9,087	-	9,087
Long-term debt	A	22,867	133	23,000
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	7,317	1,528	8,845
Regulatory liabilities		9,530	-	9,530
Environmental liabilities		6,426	-	6,426
		23,273	1,528	24,801
Total liabilities		55,227	1,661	56,888
Shareholder's deficit				
Common shares		-	-	-
Retained earnings		-	-	-
Accumulated other comprehensive loss		(605)	-	(605)
Total shareholder's deficit		(605)	-	(605)
Total liabilities and shareholder's deficit		54,622	1,661	56,283

December 31, 2011 (thousands of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Accounts receivable		3,935	-	3,935
Regulatory assets		3,402	-	3,402
Fuel, materials and supplies		2,817	-	2,817
Deferred income tax assets		107	-	107
Income taxes receivable		163	-	163
		10,424	-	10,424
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		28,494	-	28,494
Construction in progress		3,679	-	3,679
Future use land, components and spares		1,550	-	1,550
		33,723	-	33,723
Other long-term assets:				
Regulatory assets		11,177	1,203	12,380
Deferred income taxes		5,667	-	5,667
Deferred debt costs	A	-	102	102
Net unamortized debt discounts	A	-	28	28
Long-term accounts receivable		369	-	369
		17,213	1,333	18,546
Total assets		61,360	1,333	62,693
Liabilities				
Current liabilities:				
Inter-company demand facility		2,212	-	2,212
Accounts payable and accrued charges	C	8,793	(8,793)	-
Accounts payable	C	-	1,430	1,430
Accrued liabilities	C	-	7,363	7,363
Regulatory liabilities		107	-	107
Accrued interest		142	-	142
		11,254	-	11,254
Long-term debt	A	22,870	130	23,000
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	7,888	1,203	9,091
Regulatory liabilities		8,765	-	8,765
Environmental liabilities		11,177	-	11,177
		27,830	1,203	29,033
Total liabilities		61,954	1,333	63,287
Shareholder's deficit				
Common shares		-	-	-
Retained earnings		-	-	-
Accumulated other comprehensive loss		(594)	-	(594)
Total shareholder's deficit		(594)	-	(594)
Total liabilities and shareholder's deficit		61,360	1,333	62,693

Notes to the Transitional Adjustments

Under US GAAP, the Company (i) measures certain assets and liabilities differently than it had under Canadian GAAP (see details on each measurement change below); and (ii) discloses certain assets, liabilities and equity on different lines in the Financial Statements than it had under Canadian GAAP (see details on each classification change below).

A. Debt Issuance Costs (classification change)

Under Canadian GAAP, costs of arranging debt financing, premiums and discounts were netted against long-term debt. Under US GAAP, costs of arranging debt financing are included in "Deferred debt costs" and net unamortized discounts are included in "Net unamortized debt discounts", both are part of "Other long-term assets".

At January 1, 2011 and December 31, 2011, the effect on the Balance Sheets is reflected by the following increases:

(thousands of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Deferred debt costs	105	102
Net unamortized debt discounts	28	28
Long-term debt	133	130

B. Post-Retirement and Post-Employment Benefits (measurement change)

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. The deferred tax assets and liabilities arising on recognition of incremental post-retirement and post-employment benefit obligations and the associated regulatory assets offset each other, with no material impact on the Statements of Operations and Comprehensive Income. In the absence of regulatory accounting, the related tax impact on the opening transitional adjustments would result in the recognition of deferred tax assets of $382 thousand on January 1, 2011 and $301 thousand on December 31, 2011.

At January 1, 2011 and December 31, 2011, the effect on the Balance Sheets is reflected by the following increases:

(thousands of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Regulatory assets	1,528	1,203
Other long-term liabilities:		
Post-retirement and post-employment benefit liability	1,528	1,203

C. Accounts Payable (classification change)

Under Canadian GAAP, trade and non-trade payables were disclosed as "Accounts payable and accrued charges". Under US GAAP, trade payables are recognized in "Accounts payable" and non-trade payables are recognized in "Accrued liabilities".

At January 1, 2011 and December 31, 2011, the effect on the Balance Sheets is reflected by the following increases (decreases):

(thousands of dollars)	**January 1, 2011**	**December 31, 2011**
Current liabilities:		
Accounts payable	1,127	1,430
Accrued liabilities	7,700	7,363
Accounts payable and accrued charges	(8,827)	(8,793)

19. COMPARATIVE FIGURES

The comparative Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2012 Financial Statements.

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

OM&A: Pensions and OPEB

Reference: Exhibit A / 11 / 1 / Attachments 2 & 3

Interrogatory

a) Please complete the blank cells and references in Table 1 and Table 2 on the following two pages

Table 1
Annual Pension Cost (thousands)

	Hydro One Remotes	Reference
Approved 2009 Pension Costs in Rates		
OM&A		
Capital		
Total		
Total		
Actual Audited 2009 Pension Costs		
OM&A		
Capital		
Total		
Actual Audited 2010 Pension Costs		
OM&A		
Capital		
Total		
Actual Audited 2011 Pension Costs		
OM&A		
Capital		
Total		
Actual Audited (or unaudited if not available) 2012 Pension Costs		
OM&A		
Capital		
Total		
Proposed 2013 Pension Costs in Rates		
OM&A		
Capital		
Total		

Table 2 Annual OPEB cost (thousands)

	Hydro One Remotes	Reference
Approved 2009 OPEB Costs in Rates		
OM&A		
Capital		
Total		
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	116	Exhibit A-11-1 Attachment 3
Total	628	
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 (or unaudited if not available) 2012 Pension Costs		
OM&A		
Capital		
Total		
Proposed 2013 Pension Costs in Rates		
OM&A		
Capital		
Total		

b) In the cells where Board staff has entered data, please confirm that the amounts and references reported in Table 1 and Table 2 are correct. If they are not correct, please provide the correct amounts and references in the table.

c) Please provide explanations for the increases or decreases in each of:
   i. Pension OM&A, Pension Capital, and Pension Total from 2009 through 2013
   ii. OPEB OM&A, OPEB Capital, and OPEB Total from 2009 through 2013.

d) Please explain if a larger proportion is capitalized in 2013 compared to 2009, for each of pension and OPEB. Please provide reasons.

e) Please provide the basis of capitalizing pension and OPEB versus expensing pension and OPEB. Please include Remotes' capitalization policy for pension and OPEB.

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	Sourced from financial system. 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	Sourced from financial system. 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	Sourced from financial system. All public filings related to pension cost are submitted on a Hydro One consolidated basis.
Capital	403	
Total	1,221	
Actual Audited (or unaudited if not available) 2012 Pension Costs		
OM&A	978	Sourced from financial

Capital	406	system. All public filings related to pension cost are submitted on a Hydro One consolidated basis.
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 (or unaudited if not available) 2012 OPEB Costs		
OM&A	537	Unaudited number provided. Audited statements not available
Capital	223	
Total	760	

		at time of filing.
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 audited 2010 Remotes OPEB costs have been updated. The capitalization portion was corrected to show $176K making the total OPEB $688K as per Page 17 of the Remotes 2010 Audited Financial Statements as per EB-2012-0137-Exhibit A, Tab 11, Schedule 1, Attachment 3.

c)

i. Total pension cost increased from 2009 to 2010 mainly due to the increase in minimum special payments (deficiency) as determined in the pension valuation report for the year ended 2009, produced by Hydro One's independent actuary, Mercer. This increase was marginally offset by a reduced contribution rate of 19.6%, compared to 20.3% in 2009. In addition, Remotes' share of Hydro One's voluntary additional payment made in 2010 was $401K. Total pension cost decreased from 2010 to 2011 mainly due to there being no additional voluntary payments in the 2011. Total pension cost increased from 2011 to 2012 mainly due to the increase in minimum special payments (deficiency) as determined in the Mercer pension valuation report effective the year ended 2011. This increase was marginally offset by the reduced contribution rate of 18.9% versus 19.6% in 2011.

   The changes in the proportions of OM&A and capital for the years 2009 through 2013 are a direct result of the size of the relative work programs completed, for years 2009 through 2012 and the planned work program proposed for the test year, 2013.

ii. Total OPEB cost increased by $38K from 2009 to 2010 mainly due to the decrease in discount rate from 7.25% to 6.5%. Total OPEB cost increased by $134K from 2010 to 2011 due to the decrease in discount rate from 6.5% to 5.75% and the introduction of actuarial loss amortization due to discount rate decrease. Total OPEB cost decreased by $62K from 2011 to 2012. This decrease was due to updated demographic information of members and claims history determined in the valuation as at Jan 1, 2011, completed in 2011. This was partially offset by an increase in OPEB cost due to a decrease in the discount rate from 5.75% to 5.25%.

   The changes in the proportions of OM&A and capital for the years 2009 through 2013 are a direct result of the size of the relative work programs completed, for years 2009 through 2012 and the planned work program proposed for the test year, 2013.

d) A larger proportion of pension and OPEB costs are capitalized in 2013 compared to 2009. All pension and OPEB costs are attributed to labour and are either charged to results of operations (i.e. OM&A) or capitalized as part of the cost of property, plant and equipment and intangible assets. The classification of these costs is determined by the actual work program results in each year between OM&A and capital work.

e) Hydro One subsidiaries, including Remotes, have consistently applied pension and OPEB costs to the labour components of OM&A and capital. This practice has always been accepted by the Board.

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

General - Impact of Aboriginal Affairs and Northern Development Canada (“AANDC”) Funding Constraints

References:

- Exhibit A / 4 / 1/ p. 4
- Exhibit C1 / 2 / 2 / p. 2
- Exhibit F1 / 1 / 1 / Appendix A – D

Remotes has stated in Exhibit A / 4 / 1 / p. 4 / lines 4 - 12:

“ In 2011 AANDC informed Remotes that no funding for generation upgrades was included in its 2012-2016 capital plan due to funding constraints. In 2012, AANDC informed Remotes that the funding constraints were continuing and generation capital would not be included in the 2013-2017 capital plan. Upgrades are currently required in three communities and are expected to be needed in seven communities over the next five years. As a result, Remotes will not be able to connect new customers in communities where generation has reached its limits. As a result of the delays to planned upgrades, Remotes’ capital and maintenance work programs must increase in order to meet safety, environmental and reliability standards.”

In Exhibit C1, Remotes is requesting $10.6 million annually for Generation O&M in the test year, compared to $9.3 million approved in the previous cost-of-service proceeding. In the period since then, Remotes spent more than the approved amount for Generation (not including Fuel) in three of the four years, according to the evidence in Exhibit F1

Interrogatory

a) How did AANDC inform Remotes or Hydro One that funding for generation upgrades would not be available in 2011 and in 2012? Please provide a copy of correspondence or a description of the communication from AANDC.

b) Does Remotes expect that the lack of funding is temporary, or does it expect that there will be reduced or no funding for an indefinite period?

c) Is the additional expenditure noted in Exhibit F1 during 2009 – 2012 for Generation, in excess of the amount approved in Remotes’ cost-of-service application, a result of failing to upgrade generation assets according to a previous agreement?

d) Please provide the names of the communities are the three that currently are in need of an upgrade, and also the seven additional communities where upgrade will be needed in the next five years.

e) Has Remotes received any requests to connect new load in the three noted communities which it has had to refuse?

f) If the response to part b) is that the lack of funding is not temporary, what is Remotes' strategy concerning upgrades of generation assets, other than requesting additional funding for maintenance and repairs?

Response

a) Remotes holds an annual meeting with AANDC to discuss AANDC's capital plans, including required generation upgrades. AANDC first informed Remotes that no funding for upgrades was included in its 2011-2016 capital plan in April 12, 2011 at the annual meeting.

b) Remotes is unable to provide an opinion about the future availability of funding. When first informed of the freeze in 2011, Remotes assumed funding would eventually become available. On August 20, 2012, AANDC informed Remotes that funding would also not be available in its 2012-2017 capital plan.

c) Yes. Both the generation maintenance and the capital budget for engine replacements are affected by the lack of AANDC upgrade funding. Many genset units were originally installed through upgrade projects in the late 1990's and early 2000's and are now approaching end-of-life. Normally, when these assets approach end of life, communities have grown significantly and an upgrade project is initiated. The upgrade project would include the purchase of new, larger gensets and, in some cases, brand new stations that meet updated standards. As upgrades are delayed, increased engine and generator maintenance is required to maintain system reliability given the high running hours. The aging of assets and limited upgrade funding also impacts the maintenance of facilities, electrical, ventilation, exhaust, noise, fire and fuel systems as technologies and legal standards improve. Maintaining older gensets by finding obsolete or discontinued replacement parts and integrating both new and old assets together continues to be an operational challenge.

d) The three communities referred to in the submission were Kingfisher Lake, Kasabonika Lake and Deer Lake. Connections are also now restricted in the community of Weagamow (North Caribou) as a result of an unexpected failure of the First Nation owned generator. All peak load data is renewed annually in the spring to determine if further community restriction are necessary. Over the next five years seven communites are expected to be on restriction, including Kingfisher Lake, Kasabonika Lake, Deer Lake, Weagamow (North Caribou), Wapakeka, Big Trout Lake, and Fort Severn.

e) Yes. Remotes has worked closely with each of the communities to try to mitigate the impact of the connection restrictions. Remotes does allow connections on a like for like basis based on service size. This allows communities to eliminate old services in order to connect new services. For example, in Kasabonika Lake, Remotes recently worked with the community to allow the connection of a new Northern store while managing the load of the temporary store. In Deer Lake Remotes was able to accommodate the connection of seven additional houses while working in co-operation with the First Nation. In Kingfisher solar panels and improved lighting have been installed by the community in an attempt to reduce overall community load. Weagamow recently was in an emergency situation when the First Nation-owned 1,000 kW generator broke down. Remotes worked closely with the community on a replacement plan for the generation, on conservation measures and on implementing rotating blackouts to ensure that the community power would be available throughout the winter. Additionally, we have worked with other communities to inform them of the limits on their community's generation capacity so that appropriate development planning can take place to manage the remaining connection capacity.

f) Remotes is uncertain as to whether the lack of funding is permanent. In order to mitigate the impact to costs and to customers, Remotes has reviewed its engine replacements to increase engine size where the generating stations can accommodate a larger unit and has installed breakers to permit load shedding where possible. Remotes has also stepped up its CDM program opening it to Standard A customers to try to attain permanent kilowatt hour reductions related to commercial lighting and other larger applications. At the same time, Remotes has instituted a program to purchase renewable energy based on the offsetting cost of fuel. Additionally, Remotes has increased its capital spending and also reviews capital vs maintenance spending to determine the most cost-effective options. Remotes has also worked with individual First Nations to help bring the federal government's attention to the need for upgrade funding and has provided information to the OPA, AANDC and First Nations to assist in the development of a business case for transmission to the north.

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

Cost of Capital

References:

- Exhibit E / 1 / 1 / item 2.5
- Exhibit F1 / 1 / 1 / Appendixes A – D

Remotes' request for recovery of the cost of long-term debt is the same as in its previous application [EB-2008-0232], at 5.60%. However, Remotes' interest costs during 2009-2012 have ranged from $1.095 million in 2012 to $1.134 million in 2011), all years well below the amount approved for 2009, which was $1.72 million, and considerably below the amount requested for 2013, which is $2.242 million.

Interrogatory

Why is Remotes' not requesting a lower cost in 2013, similar to its annual costs in recent years?

Response

As discussed in Exhibit B, Tab 1, Schedule 1, Remotes is following the methodology prescribed in the 2006 Rate Handbook as amended by the Board's filing guidelines issued June 28, 2012. For deemed long-term debt, Remotes is following the Board's Decision in EB-2008-0232. Remotes notes that it operates on a break-even basis, and that differences between the expected and actual cost of debt flow to the Remote Rate Protection Variance Account.

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

Generation OM&A
Reference: Exhibit C1 / 2 / 2/ p. 1

Interrogatory

a) Please provide the name of two communities that each has a mini-hydro-electric generating facility and also provide for each installation, the year it was installed, the capacity in kW and the production in kWh achieved in each of the years 2009 – 2011, 2012 to date, and forecast for 2012 and 2013.

b) Please provide the names of the four communities that each has a windmill project and also provide for each installation, the year it was installed, the capacity in kW and the production in kWh achieved in each of the years 2009 – 2011, 2012 to date, and forecast for 2012 and 2013.

Response

a) Sultan and Deer Lake are the two communities with mini-hydro-electric facilities. Information on the operation of the two facilities is provided in the chart below.

			Actual				Forecast
Community	**Year installed**	**Prime Capacity KW**	**2009**	**2010**	**2011**	**2012**	**2013**
Deer Lake	1998	500	1,674,339	1,675,727	1,732,002	1,314,774	1,903,000
Sultan	1982	150	562,200	410,800	392,400	338,200	476,000
Totals			**2,236,539**	**2,086,527**	**2,124,402**	**1,652,974**	**2,379,000**

The Deer Lake Hydel was installed and commissioned in October 1998. Forecasted production increases for 2013 as compared to 2012 are the result of a closer to normal historical water levels and a return to service of one of the Hydel units that was being repaired in 2012. Improvements in 2013 as compared to other years are the result of improved reliability of the smaller diesel unit and the benefits of an optimization project in 2010.

b) There are 4 windmills in 2 communities. As indicated in Exhibit C1, Tab 2, Schedule 2, the wind assets are demonstration project windmills. Please see the chart below for production in 2009-2013. Note that the windmill in Big Trout is an obsolete model that is expensive to repair.

			Actual				**Forecast**
Community	**Year installed**	**Prime Capacity KW**	**2009**	**2010**	**2011**	**2012**	**2013**
Kasabonika (3 10 kW units)	1996	10 each	9,220	8,100	11,730	16,450	12,150
Big Trout (1)	1997	60	0	0	0	0	0

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

Generation OM&A - Marten Falls

References:

- Exhibit C1 / 2 / 2 / p. 1 / lines 27 -29
- Attachment 4 'Capital Projects'

At the reference it is indicated that a staff house is also planned in Marten Falls, to be built by the First Nation and maintained by Remotes.

Interrogatory

a) Who would pay for construction, and who would own the staff house?

b) The details provided in Attachment 4 for the years 2012 and 2013, there is no listing for a staff house in Marten Falls. What year is the staff house expected to be completed?

Response

a) Marten Falls First Nation applied for and received funding from AANDC to build the staff house. Under the Agreement for Service with Marten Falls, the house is owned by the First Nation and is provided to Remotes for the exclusive use of Remotes' staff.

b) The staff house is expected to be in service by late spring, 2013.

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

Generation OM&A - Automation Benefits

Reference: Exhibit C1 / 2 / 2 / p. 4

It is indicated at the reference that changes associated with automation resulted in 10% improvement in fuel efficiency.

Interrogatory

Please provide evidence to demonstrate achievement of the noted 10% improvement in fuel efficiency, including:

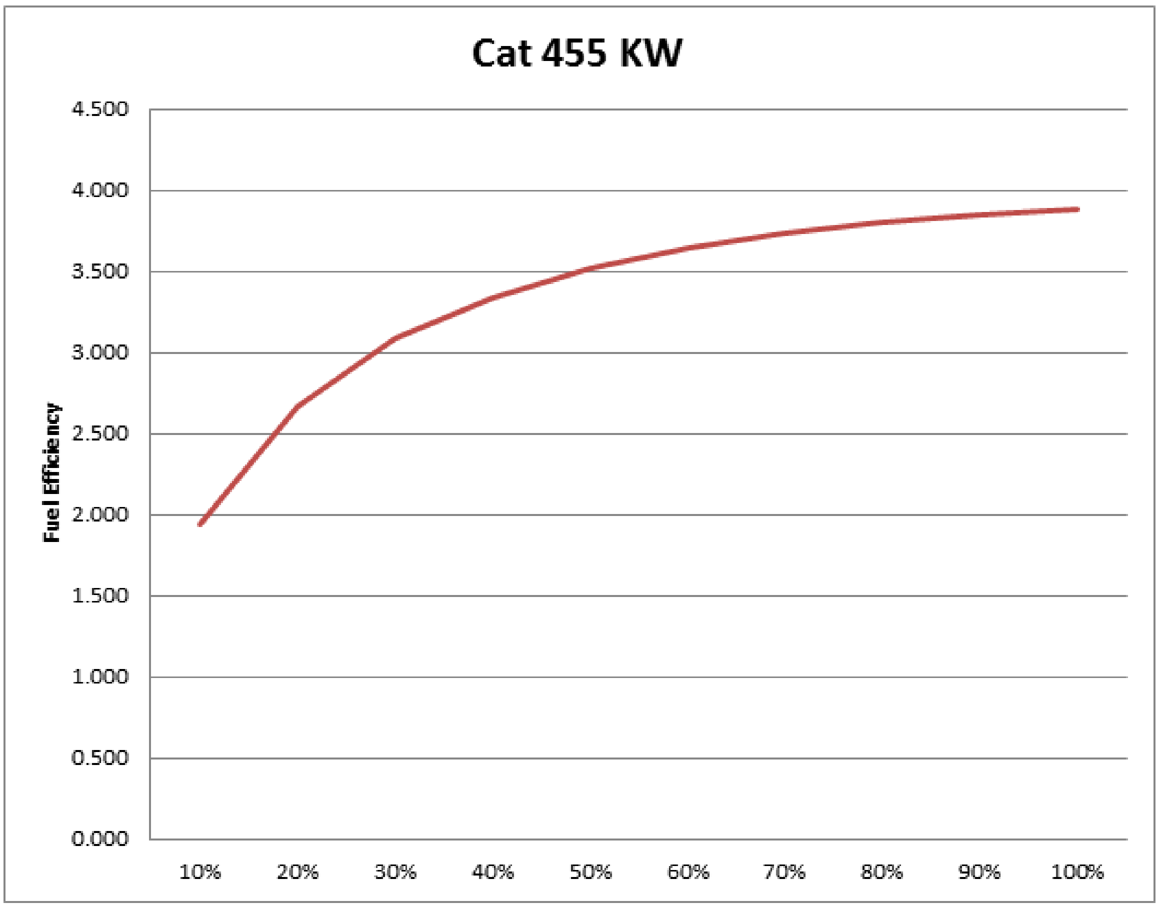
- The study period;
- The names of the communities where the comparison of the Before Automation and After Automation of fuel consumption and generated kilowatt-hours is/are presented.
- The fuel consumption and generated kilowatt hours for a period of time prior to introduction of automation (“Before Automation”) and for the fuel consumption and generated kilowatt hours for a period of time after introduction of automation (“After Automation”);
- Please explain whether the efficiency gains were consistent across the systems before and after they were automated, or alternatively whether there was large variation amongst the project results.

Response

Please see Exhibit I, Tab 1, Schedule 10, Attachment 1 for a comparison between 1998, 2004 and 2011 fuel efficiency. In 1998, none of the listed communities were operated through SCADA systems. All had systems installed prior to 2004. For comparison purposes, communities with hydro-electric resources are excluded and small communities (Oba, Hillsport, Sultan) where no SCADA system is in place due to the very small loads are also excluded. Marten Falls is also excluded because it has had a SCADA system in place since Remotes assumed operation of the station. Note that reduced station efficiency in Webequie in 2011 occurred as a result of commissioning the new station.

Although no formal study has been undertaken to confirm the improved fuel efficiency directly related to the SCADA systems the major fuel efficiency gains occurred as a result of the introduction of SCADA automation. Efficiency gains are also attributed to manufacturer enhancements in engine performance, increased station size and lower station service load. There are large variations in efficiency gains from the implementation of SCADA systems, since no two systems, equipment, community loads or operators are exactly the same. For example, Stations that were actively switched by operators throughout the day show smaller efficiency improvements.

Remotes notes that the SCADA system automatically selects the most appropriately sized generator to run based on the electrical load in the community. The system adapts in real time to load changes throughout the day. The illustration below shows a recent manufacturer's fuel efficiency curve during testing conditions for a Cat 455 KW engine. At 40% load (182kW, 3.339 kWh/L) this unit uses 12% more fuel than at 70% load (318.50kW 3.74 kWh/L). The SCADA system exploits the fuel curves to select the most efficient unit. Additionally, the SCADA helps to manage operating hours so that the average generating unit load is in the 70% range as directed by manufacturers and prime power standards, resulting in lower maintenance and operating costs than would otherwise be experienced.



COMMUNITY	December, 1998 ENERGY (kwh's generated) ACTUAL	December, 1998 FUEL (litres) ACTUAL	December, 1998 EFFICIENCY kWh's per litre of fuel ACTUAL	December, 2004 (kwh's generated) ACTUAL	December, 2004 FUEL (litres) ACTUAL	December, 2004 EFFICIENCY kWh's per litre of fuel ACTUAL	December, 2011 (kwh's generated) ACTUAL	December, 2011 FUEL (litres) ACTUAL	December, 2011 EFFICIENCY kWh's per litre of fuel ACTUAL	EFFICIENCY% CHANGE 1998-2004 ACTUAL	EFFICIENCY% CHANGE 1998-2011 ACTUAL
ARMSTRONG	3,778,800	1,118,458	3.38	4,328,490	1,152,496	3.76	4,104,510	1,097,786	3.74	11.16%	10.66%
BEARSKIN	1,826,400	679,735	2.69	2,734,500	758,802	3.60	2,826,000	785,091	3.60	34.12%	33.97%
BIG TROUT	3,908,800	1,101,579	3.55	5,553,600	1,512,992	3.67	6,059,200	1,677,785	3.61	3.45%	1.78%
FORT SEVERN	1,872,000	618,972	3.02	2,652,800	787,745	3.37	2,420,800	743,573	3.26	11.35%	7.65%
GULL BAY	654,900	229,685	2.85	969,000	289,431	3.35	1,282,500	389,224	3.30	17.42%	15.56%
KASABONIKA	2,545,500	744,321	3.42	3,627,000	1,010,838	3.59	4,114,500	1,136,943	3.62	4.92%	5.82%
KINGFISHER	1,394,400	492,689	2.83	1,900,000	585,469	3.25	2,370,400	655,985	3.61	14.67%	27.68%
LANSDOWNE HOUSE	1,349,700	439,555	3.07	2,055,000	617,944	3.33	1,795,000	556,202	3.23	8.30%	5.10%
SACHIGO	1,686,000	647,477	2.60	2,862,000	819,845	3.49	2,847,000	788,068	3.61	34.06%	38.74%
SANDY LAKE	7,962,500	2,271,550	3.51	10,772,500	2,951,531	3.65	11,290,000	2,928,070	3.86	4.12%	10.00%
WAPEKEKA	913,000	304,100	3.00	2,127,000	679,849	3.13	2,535,000	765,876	3.31	4.21%	10.25%
WEAGAMOW	2,416,000	693,435	3.48	4,224,000	1,165,609	3.62	4,480,500	1,232,453	3.64	4.01%	4.34%
WEBEQUIE	1,981,600	624,073	3.18	2,739,200	773,918	3.54	2,737,762	850,044	3.22	11.47%	1.43%
TOTALS	**32,289,600**	**9,965,629**	**3.24**	**46,545,090**	**13,106,469**	**3.55**	**48,863,172**	**13,607,100**	**3.59**	**9.60%**	**10.83%**

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

Generation OM&A - Fuel Cost Management

References:
- Exhibit C1 / 2 / 2 / p. 8 / Table 4
- Exhibit C1 / 2 / 2 / p.9 / lines 20-26
- Exhibit C1 / 2 / 2 / p. 10 / Table 5

At Table 4 of the first reference Remotes provides the forecast for 2013 Fuel Purchases is $24,067,000, which is 5.26% higher than the 2012 level of $22,864,000.

The second reference provides the percentage of fuel delivery modes assumed, with the resulting costs for 2013 shown in Table 5 of the third reference.

Interrogatory

Please provide the assumptions and a detailed calculation showing how the forecast for the 2013 level of $24,067,000 is determined.

Response

Please refer to Exhibit I, Tab 1, Schedule 1, Attachment 1 included herein for details.

Forecasted fuel cost for 2013 is driven by projected fuel consumption for that year. Projected fuel consumption (litres needed) is a factor of the projected level of kWh sales in a given community for the year. Individual plant efficiency generally dictates how much fuel is required to meet the expected level of sales at a given location. In locations where there are renewable technologies in place, the renewable generation capacity is deducted from required diesel generation capacity. With this, the following specific assumptions are implicit in the detailed calculations that substantiate the forecasted level of fuel cost of $24,067K for the 2013 year:

- Sales forecasts in kWh’s are based on prior year(s) actual sales data,
- Individual plant efficiency is based on prior year(s) actual plant efficiency,
- Fuel quantities received by source are based on actual prior year(s) realized volumes by source (i.e. all weather road, winter road, air delivery, purchased from a First Nation source),
- Fuel unit pricing is based on the most recent actual pricing at the time of preparation, escalated or de-escalated in a reasonable, professionally evaluated manner.

Community	KWH's Required for Resale (incl load loss)	Fuel QTY Received By Source (Litres)					Fuel COST By Source ($Dollars$)				
		All Weather Road	Winter Road	Air	First Nation	Total	All Weather Road	Winter Road	Air	First Nation	Total
Armstrong	4,136,100	1,105,987				1,105,987	$1,102,941				$1,102,941
Bearskin Lake	2,811,413		140,000	680,311		820,311		$142,585	$1,253,931		$1,396,516
Big Trout Lake	6,155,305		130,000	1,551,360		1,681,360		$128,263	$2,876,048		$3,004,311
Biscotasing	516,054	179,632				179,632	$184,454				$184,454
Deer Lake	5,045,720		160,000	730,780		890,780		$179,929	$1,088,527		$1,268,456
Fort Severn	2,439,295		80,000	231,735	400,000	711,735		$144,283	$608,409	$916,803	$1,669,495
Gull Bay	1,315,615	401,586				401,586	$396,981				$396,981
Hillsport	247,071	102,128				102,128	$105,097				$105,097
Kasabonika	4,337,640		360,000	825,998		1,185,998		$359,009	$1,354,279		$1,713,288
Kingfisher	2,411,533		240,000	443,531		683,531		$211,331	$741,532		$952,863
Lansdowne	1,891,757		220,000	364,646		584,646		$196,054	$548,170		$744,224
Marten Falls	1,202,070			420,744		420,744			$732,804		$732,804
Oba	207,002	94,200				94,200	$96,091				$96,091
Sachigo Lake	2,980,020		240,000	588,102		828,102		$282,624	$1,039,859		$1,322,483
Sandy Lake	11,738,083		340,000	1,330,600	1,300,000	2,970,600		$375,432	$2,352,713	$1,905,564	$4,633,709
Sultan	536,775	30,146				30,146	$31,022				$31,022
Wapakeka	2,674,988		60,000	741,728		801,728		$58,562	$1,351,235		$1,409,797
Weagamow	4,606,589		250,000	1,005,484		1,255,484		$209,528	$1,476,159		$1,685,687
Webequie	2,973,384		10,000	908,928		918,928		$9,654	$1,558,420		$1,568,074
Service Centre (Admin Cost)											$48,400
Total	**58,226,414**	**1,913,679**	**2,230,000**	**9,823,947**	**1,700,000**	**15,667,626**	**$1,916,587**	**$2,297,253**	**$16,982,086**	**$2,822,367**	**$24,066,693**
	(a)					(b)					

Plan-wide pure efficiency (= (a) / (b)) **3.716**

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

Generation OM&A - Fuel Cost Management

References:
Exhibit C1 / 2 / 2 / p. 11 / lines 8 -14
Exhibit H / 1./ 18 / Remotes' response to Board staff IRR #18 in the previous cost-of-service proceeding [EB-2008-0232]

At the first reference, it is stated that:
"In order to mitigate the impact of rising fuel rates Remotes has done the following things:

- Negotiated long-term fuel delivery contracts with multiple suppliers
- Maximized winter road deliveries (cheaper delivery methods) where possible through supplier relationships and improved tank storage
- Negotiated an increased number of fuel contracts directly with the First Nation communities with fuel storage on site where Remotes does not have adequate fuel storage facilities to take advantage of winter road delivery pricing.

At the second reference, Remotes gave a description of the comprehensive tendering process initiated in 2007. [A 2-page excerpt is attached as Appendix A to this document for convenience]

Interrogatory

a) Please provide an outline of the negotiated long term fuel delivery contracts and identify the multiple suppliers referred to in the first reference, and how these contracts are contributing to lowering the fuel delivery costs.

b) Please identify the fuel contracts negotiated directly with the First Nation communities with fuel storage on site where Remotes does not have adequate fuel storage facilities as described in the first reference.

c) Does Remotes still use an RFP process as described in the second reference? If so please provide an update in regard to the 2007 RFP detailing the process and the participants, and description of the terms of the contracts that provide flexibility in meeting unpredictable weather conditions affecting such conditions as less reliance on winter road access in a given year.

Response

a) In April 2010, Remotes initiated a comprehensive tender process for fuel delivery. Contract awards were made to four suppliers to service specific locations outlined in the tender: Wasaya Airways LP; First Canadian Fuels Ltd; Central Canadian Fuels

Inc; and Wilderness North Air. The contracts outline expected quantities and predictable delivery schedules for a period of up to five years. The following strategic attributes in the contracts ensure that Remotes is afforded the lowest possible delivered prices:

- Fixed annual distribution rates for air and road delivery (per litre);
- Discount terms for prompt payment, which can result in savings;
- Variable surcharge, or surcharge reductions on distribution rates that are tied to current fuel commodity prices to ensure that delivery rates (air and road) represent current market conditions;
- Clear identification of all factors of the final price including; commodity price, distribution rate, surcharge/reduction on distribution rate, profit margin and other fees if applicable (storage, handling, etc.);
- Variable rates for winter road deliveries for: (1) full loads, (2) ¾ loads and (3) half or less than half loads;
- Fixed total pricing for each calendar month for each location;
- Monthly fixed commodity cost of approximately 83% of the awarded contracts is based on the average *prior* month costing, allowing Remotes to plan deliveries to maximize savings.
- The award of substantial business to a "new" vendor with experience and capacity allowing for continued vendor development and competition in preparation of future RFT renewals.

b) For 2013, mutually beneficial fuel contracts have been negotiated directly with First Nation owned and operated tank farms in the following communities: Bearskin Lake, Fort Severn, Kasabonika Lake, Kingfisher Lake, Sachigo Lake and Sandy Lake. The contracts offer an economic development and capacity building opportunity to local First Nations. The agreements are negotiated annually, are subject to commodity fluctuation and delivery costs, and are compared to the alternative of fly-in prices at the time of purchase. Fuel purchases are not made unless proven and suitable cost savings are realized as compared to the fly-in alternative. Agreements with local First Nation owned and operated tank farms reduces environmental risks associated with fuel spills since larger quantities of fuel are transferred in winter road deliveries as compared to air deliveries, reducing handling risks. Additionally, emissions associated with winter road delivers are lower than air freight. Quantities of fuel purchased will depend on the success of the winter road fuel deliveries to each first Nation. In 2012, only Sandy Lake and Fort Severn were able to transport fuel over winter road for sale to Remotes.

c) The RFP process was similar to the one in 2007. The RFP was posted on Hydro One's website and advertised in the "Globe and Mail" and "Thunder Bay Chronicle Journal." Wasaya Air LP, First Canadian Fuels Ltd, Wilderness North Air and Central Canada Fuels Inc. submitted bids. Following an evaluation of pricing, risk and experience, split and overlapping awards were made to each of the four companies.

Several aspects of the tender improved upon the 2007 process.

- The invitation to tender specified that the submissions were to offer their choice of fuel index benchmark as the basis for the monthly pricing offered to Remotes. The vendor's choice of the fuel index benchmark represents their likely purchased cost and the price offered to Remotes. Remotes was able to then model the history of the vendors' chosen index to determine a reasonable amount of expected variation and the behavior of that index to market forces.
- The tender was issued with detailed estimates of annual volumes by location, which enabled an evaluation of the proponents' technical compliance to deliver required combinations using the required delivery method at any time.
- Remotes is not required to commit to the purchase of any specific or minimum volume of diesel fuel at any time, which provides needed flexibility to purchase fuel from local First Nation vendors.
- The contracts provide for minimum tank volumes to ensure that fuel is available for generation at all times.
- To address the potential for poor winter roads when full loads cannot be delivered, pricing terms for ½ and ¾ load pricing for winter road fuel were added.
- Overlapping and joint awards were made for winter road deliveries. The overlapping awards give the benefit of two suppliers delivering fuel during the short winter road season.

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

Distribution OM&A and Rate Base

Reference: Exhibit C1 / 2 / 3 / p. 3 /

Remotes states at lines 8 – 12:

"Increases between 2012 and 2013 reflect increased trouble response ($180 thousand), higher planned maintenance ($111 thousand) and higher forestry services (1,200 thousand) mainly associated with clearing the transmission line right-of-way to Cat Lake and costs associated with service to Pikangikum ($380 thousand)."

Interrogatory

a) Please indicate whether or not the transmission/distribution lines connecting Cat Lake to HONI's transmission are presently in-service? If yes please indicate whether the $1,200,000 to be spent in 2013 on clearing the right of way is an average annual amount expected in future years or is it an amount reflecting special circumstances in 2013 due to the acquisition.

b) Please indicate whether or not the transmission/distribution lines connecting Pikangikum to HONI's transmission are presently in-service? Please also provide a breakdown of the services and related costs of $380,000 required to serve Pikangikum.

Response

a) The distribution line connecting Cat Lake to the transmission system is currently in service. The $1,200,000 to be spent in 2013 clearing the right of way is not an estimate of an annual expense, but is currently needed and would be required on a cyclical basis, once every six to eight years depending on the growth rate of the vegetation.

b) The transmission/distribution line connecting Pikangikum to the grid is not yet in service. The estimated costs are below. The estimates were largely based on number of customers. Forestry services is included in Distribution Maintenance and is expected to be a two-year expenditure ($100,000 in 2013 and $75,000 in 2014). Thereafter, it would completed on a cyclical basis.

Description	Cost
Community Relations	10,000
Distribution Maintenance	370,000

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

Community Relations - OM&A

References:

- Exhibit C1 / 2 / 5
- Exhibit H/.1./ 22./ Remotes' Board staff IRR #22 in proceeding EB-2008-0232[a 2-page excerpt is attached as Appendix B to this interrogatory for convenience]

At the reference, it is indicated that:

- Remotes' program focuses on conservation and energy efficiency awareness and on deploying energy efficient appliances within these communities and that it includes three communities a year in this program and expects that eventually each community will have participated in the program.
- In 2011, Remotes initiated an ongoing partnership with the Northern stores to offer rebates on ENERGY STAR appliances, promising to lead to long term energy savings and help make energy efficient appliances available throughout Remotes' service territory and extends energy conservation activities to communities that are not part of the intensive pilot program.
- Remotes indicated that in 2011, Remotes' customer conservation programs resulted in 245,600 kWh of in-year savings and life cycle savings of 1,891,878 kWh.

Interrogatory

a) Please indicate which communities are now participating in deploying energy efficient appliances, and also provide the longer-term plan showing which communities will be covered in each year under that initiative.

b) Please provide elements of Remotes' energy conservation programs for the most recent completed year, e.g., 2011, in tabular form, similar to the table provided in the second reference in proceeding EB-2008-0232.

c) Please clarify whether the noted savings of 245,600 kWh achieved in 2011 is attributable to all conservation programs, or only to the ENERGY STAR initiative.

d) If the noted 2011 savings are attributable to all of Remotes' customer conservation programs, please provide an explanation of the much higher amount provided in the second reference for the year 2007, which was an estimate of 1,069,848 kWh.

Response

a) Remotes' community conservation program was completed in Sachigo Lake and Fort Severn in 2011 and is currently active in Bearskin Lake First Nation and Kingfisher

Lake First Nation. Two other communities, yet to be finalized, will be chosen for 2014. The longer term schedule is shown in the chart below. The actual timing for program activity depends on the interest and participation of the local First Nation. Note that energy efficient appliances rebates are available across Remotes' fly in service territory through the Rebate program.

Year	Communities
2011	Sachigo Lake, Fort Severn
2012	Bearskin Lake, Kingfisher Lake
2013	Bearskin Lake, Kingfisher Lake and discussions begin with two new communities from the list below
2014	In each of the following years, Remotes expects to work with two or three communities from the following group, depending on the interest in each community and the availability of advisors: Deer Lake, Sandy Lake, Weagamow (North Caribou), Landsdown House (Neskantaga), Marten Falls, Whitesand and Wapekeka. In the later years, Big Trout Lake (Kitchenuhmaykoosib Inninuwug) and Webequie would also be considered eligible.
2015	
2016	

b) Please see the chart below showing the results for 2011.

Item	No. of Units	Est. 2011 kWh Savings / Unit	Est. 2011 Annual kWh Savings	2011 Est. Diesel Savings (litres)
Community Conservation Program				
13W CFL	30	25.58	767.4	211
Outdoor Motion Sensors	69	159.38	10,997.22	3,017
Power Cost Monitors	111	483.55	53,674.05	14,726
Cold Water Detergent	130	623	80,990	22,221
Low Flow Showerheads	111	377	41,847	11,481
Faucet Aerators (Kitchen 1.5 GPM)	226	176.29	39,841.54	10,931
Smart Power Bars	3	53.39	160.17	44
Commercial Lighting Retrofits				
25W Fluorescents	207	53.20	11,011.92	3,021
10W LED wall pack	5	137.28	686.4	188
Remotes Rebate Program				
LED Holiday Lighting	322	4.83	1,555.26	427
Energy Star Freezers	7	45.81	320.67	88
Energy Star Refrigerators	15	112.8	1,692	464
Energy Efficient Range <500kWh	11	55	605	166
Energy Star Washing Machine	8	181.27	1,450.16	398
Energy Star Dishwasher	1	7	7	2
Total	1256	195.55	245,605.79	67,386

c) As indicated above, the 245,605 kWh savings in 2011 includes the community conservation program, commercial lighting retrofits and the rebate program for the ENERGY STAR appliances and other items. Note that the life-cycle savings are 1.89 million kWhs or approximately 519,068 litres of fuel.

d) The lower savings for the community conservation program in 2011, as compared to 2007, is because fewer energy efficient products were installed on an incremental basis. In 2007, more products were installed through community meetings rather than by hiring energy advisors. Hiring energy advisors requires time to adequately select and train individuals. In 2011, work was also undertaken to establish the partnership and rebate program with the Northern stores. Remotes believes that making more efficient appliances available across its fly-in service territory will lead to long term savings.

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

Community Relations - OM&A

Reference:

- Exhibit C1 / 2 / 5 / p. 2
- Exhibit A / 16 / 1 / Appendix B

Interrogatory

Does Remotes expect that the OPA will develop its programs for delivery during the test year, and if so, does this affect the amount that Remotes would require in its revenue requirement request?

Response

The OPA announced an Aboriginal Conservation Program on March 25, 2013. Based on previous discussions with the OPA, Remotes believes that any programs that the OPA develops for remote communities should focus on community energy planning. Remotes' program to make energy efficient products available in the communities will continue to be required. Remotes and the OPA have initiated discussions to determine how to coordinate the two programs. Remotes believes its program will continue to be required. Remotes does not anticipate a change in the amount of funding requested at this time.

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

Shared Services and Other Administrative Costs

Reference: Exhibit C1 / 2 / 6 / p.3 Table 2 & p. 4

At the reference, Table 2 includes $140,000 for each of the two years 2012 and 2013 described as “Regulatory and Project Expenses. On page 4 it is stated in part that:

“Regulatory and Project Expenses include costs directly associated with Ontario Energy Board hearings on Remotes’ matters and also include, starting in 2011, the Ontario Energy Board’s allocation of its expenses to Remotes (approximately $80 thousand each year).”

Interrogatory

Please explain the breakdown of the $140,000 expenses for both 2012 and 2013, given that only about $80,000 in each of the two years are costs allocated directly by the Ontario Energy Board to Remotes, leaving $60,000 in each of the two years for Regulatory and Project Expenses.

Response

2012 costs included estimated intervenor cost awards related to EB-2011-0021 and estimated preparation and Notice costs for this proceeding. 2013 costs included estimated intervenor cost awards for this proceeding.

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

Shared Services and Other Administrative Costs

Reference: Exhibit C1 / 2 / 6 / p. 3

Interrogatory

Please confirm that the LEAP component of OM&A has been calculated on the basis of Remotes' revenue requirement, including generation cost. What would be the amount of LEAP if it were calculated on the basis of distribution cost only?

Response

The LEAP component of OM&A was calculated on the basis of Remotes' 2009 Revenue Requirement, including generation costs. If LEAP were calculated on the basis of distribution cost only, the amount would be approximately $5,200.

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

Cost of remediation of contaminated land

References:
- Exh A / 7 / 2
- Exh C1 / 4 / 1

Interrogatory

a) Please describe what type of contamination comprises the environmental regulatory asset. Over what period did the contamination occur, and/or is expected to occur?

b) Does the "regulatory asset" consist of remediation activities that have already taken place, or the present value of future expenditures, or both?

c) Please provide any studies or decisions that support the required remediation and the extent of the extent of Remotes' culpability (or any of its affiliates) for the contamination whose effects are being remediated?

d) Does the amount of the regulatory asset include the cost of remediation in Pikangikum, mentioned in the letter the Minister of Energy to Chief Strang, date-stamped March 23, 2012 … (Exhibit A / 7 / 2)

Response

a) The contamination is related to the former Ontario Hydro's storage and handling of petroleum hydrocarbon (PHC) products such as diesel fuel, lubricating oils, gasoline and varsol, and potential issues related to ethylene glycol, pentachlorophenol, polychlorinated biphenyls (PCBs) and polynuclear aromatic hydrocarbons (PAHs). The contamination relates to spills and leaks that occurred during the period of time that Ontario Hydro occupied lands and operated stations in these communities until the demerger of Ontario Hydro in 1999. The period of time that Ontario Hydro began operating generating stations varies by community, with the first in the late 1960s and the most recent in the mid 1980s. In some cases, responsibility for contamination is shared with other parties. The estimated future costs for remediation are limited to Ontario Hydro's share of the remediation.
b) The "regulatory asset" consists only of the present value of the estimated future remediation expenditures related to committed remediation activities yet to take place.
c) Please see Attachment 1 to this Exhibit.

d) Yes

True Grit Consulting Ltd.
PO Box 2047
Sioux Lookout, ON P8T-1J7
T 807.737.7132 F 807.737.1091 www.tgcl.ca

TRUE GRIT CONSULTING LTD

May 10, 2011

Project No. 10-221-02F

VIA EMAIL (jacobostaman@kitchenuhmaykoosib.com)

Mr. Jacob Ostaman
Kitchenuhmaykoosib Inninuwug Lands and Environment Unit
PO Box 331
Big Trout Lake, Ontario
P0V 1G0

Re: 2011 Proposed Work Program
On-Site In Sit Remediation of Hydro One DGS Site
Big Trout Lake, Ontario

Dear: Mr. Ostaman,

Based on the findings of the 2010 work program and discussion during the Project Team meeting held on May 3, 2011, the following scope of work is proposed for the 2011 remedial program at the Hydro One DGS site in Big Trout Lake:

- monitoring of site wells for depth to water/LPH and temperature/dissolved oxygen concentrations in early summer 2011;
- monitoring of site wells for depth to water/LPH and dissolved oxygen concentrations in late fall 2011;
- sampling of select site wells for laboratory analysis of petroleum hydrocarbon parameters in late fall 2011; and,
- application of ORC to the amendment distribution system in late fall 2011, to ensure that elevated dissolved oxygen concentrations are maintained to promote degradation of petroleum hydrocarbons.

The proposed 2011 work program is outlined in more detail below.

Project Kickoff Meeting

Prior to starting work on the site, a project kickoff and health and safety meeting will take place. All TGCL, Hydro One, and First Nation workers who will be involved in the project will participate in the meeting. The following will be discussed at the meeting:

- a review of the project scope in the work plan, and the project schedule;
- a review of a completed project Health and Safety Plan and Hydro One Contractor Safety and Environment Pre-Job Meeting Checklist form; and,

- identification of roles and responsibilities with respect to direction of work, and health and safety issues.

Designation of Work Area

Immediately after the kickoff and health and safety meeting, a site office / support zone will be established. A line storage shed located in the northwest part of the site will be designated as site meeting place and support zone. Daily tailgate meetings will be held in this location. This location will also be used for first aid, coffee breaks, and drinking water storage.

Site Monitoring

The proposed site monitoring (summer and fall) includes:

- monitoring the existing accessible on-site wells for LPH thickness, water levels, and headspace combustible vapours; and,

- sampling select wells for field parameters (dissolved oxygen and temperature).

Groundwater Sampling

Groundwater samples will be collected from 10 monitoring wells and two sump wells during the fall site visit. Prior to sampling, each well will be either purged dry or until a minimum of three standing wells volumes are removed. Groundwater samples will be collected using dedicated inertial-lift foot valves and polyethylene tubing. Samples will be collected into pre-cleaned laboratory supplied bottles. Sample bottles will be packed with completed chain of custody forms into coolers with ice packs, and shipped by air to the laboratory.

A total of 12 samples, plus two QA/QC duplicates, and one field blank, will be submitted for laboratory analysis of benzene, toluene, ethylbenzene, and xylenes (BTEX) and petroleum hydrocarbons (PHCs).

Injection of Oxygen Releasing Compound

The in-situ distribution piping system installed in 2006 will be utilized to apply the ORC to the subsurface. The distribution system consists of 150 mm screen PVC piping, installed immediately above bedrock, connected to vertical sumps consisting of 150 mm solid PVC pipe.

The results from the 2010 monitoring suggest that a maximum of 200 kg of ORC is sufficient to ensure an elevated concentration of oxygen in the *in-situ* amendment distribution system over the course of the year. It is proposed that the 150 kg of ORC currently stored at the site be applied in 2011.

The ORC will be installed generally as follows:

- the ORC and water will be mixed in a 205-L drum to form a slurry with a consistency of approximately 25% solids (approximately 0.25 kg of powder to 1 L of water);

- an injection hose will be fed down the existing vertical sumps and through the horizontal distribution pipes; and,

- the slurry mixture will be pumped into the distribution piping using an electric submersible pump.

The dissipation rate of the slurry into the subsurface will be monitored and documented to determine if distribution system piping will require rehabilitation prior to the next injection event.

Project Management and Reporting

The project will be administered by a Project Team comprised of the Kitchenuhmaykoosib Inninuwug (KI) Lands and Environment Office and Hydro One Remote Communities Inc. Once this proposed scope of work is approved, a Letter of Understanding will form the agreement between Hydro One and KI. TGCL will be contracted by KI to oversee the project. Mr. Bob Shine will be the primary contact for Hydro One. All correspondence between the project team including TGCL, Hydro One, and KI will be copied to each party.

A project kickoff meeting will be scheduled for the start of the field work. At this meeting, the project requirements, scope, schedule and budget will be reviewed / confirmed. Also, a Health and Safety meeting will take place.

The project duration is anticipated to be approximately five days on-site, over two site visits. Verbal communication will be constant, and a brief written progress report will be completed, and submitted to the Project Team members by email.

The TGCL Field Supervisor and KI Project Manager will monitor the equipment and labour requirements daily, and will track anticipated and actual usage on daily tracking forms.

Any major changes to the project identified in the field will be communicated immediately to the KI Project Manager, and to the Hydro One Project Manager. Any change significantly altering the scope and/or cost of the project, will be documented on a field change order form once discussed and agreed.

Approximately eight weeks after completion, a project completion report will be submitted. The report will include details of the work completed, site plans, and monitoring results.

A formal agreement between TGCL and KI Lands and Environment will be signed. This agreement will include payment terms.

Cost Estimate

The estimated cost to complete the above scope of work is attached. The estimate assumes Hydro One will provide transportation to and from KI for TGCL personnel.

TGCL will invoice KI, and KI will invoice Hydro One for overall project costs, based on actual quantities, verified by TGCL. The project will be will be invoiced by TGCL and KI following completion of each of the two proposed site visits and at submission of the report.

Respectfully submitted by:

True Grit Consulting Ltd.

Randy Edwards, A Sc.T
Project Manager
redwards@tgcl.ca

Jason Garatti, M.Sc.Eng., P.Geo.
Principal/Manager, Environmental Services
jgaratti@tgcl.ca

JG/RE:shc

c.c Bob Shine, Hydro One
Adrian Andreaachi, Hydro One

TABLE 1 - PROJECT COST BREAKDOWN - KITCHENUHMAYKOOSIB INNINUWUG HYDRO ONE DGS SITE MONITORING 2011 WORKPLAN

TASK		TGCL FEES	TGCL DISBURSEMENTS	REMEDIATION SYSTEM MATERIALS	SHIPPING - EQUIP. & SUPPLIES	LABORATORY	DRILLING SUBCONTRACTOR	TOTALS
1.0 Project Development, Site Kickoff Meeting, and Corrspondence		$4,666.00	$279.50	-	-	-	-	**$4,945.50**
2.0 July 2011 Site Monitoring Event		$4,630.00	$932.50	$55.00	$165.00	$0.00	$0.00	**$5,782.50**
3.0 October Site Monitoring Event & In-situ Injection		$9,406.00	$2,062.50	$880.00	$165.00	$2,156.00	$0.00	**$14,669.50**
4.0 Project Meetings (in Thunder Bay)	**2**	$1,954.00	$265.00	-	-	-	-	**$2,219.00**
5.0 Annual Site Monitoring Report		$4,922.00	$300.00	-	-	-	-	**$5,222.00**
TGCL TOTAL		**$25,578.00**	**$3,839.50**	**$935.00**	**$330.00**	**$2,156.00**	**$0.00**	**$32,838.50**

TOTAL KITCHENUHMAYKOOSIB INNINUWUG EQUIPMENT & LABOUR COST	**$3,750.00**
SUBTOTAL	**$36,588.50**
FIRST NATION ADMINISTRATION & MANAGEMENT (10%)	**$3,658.85**
PROJECT TOTAL	**$40,247.35**

TABLE 2 - KITCHENUHMAYKOOSIB INNINUWUG COSTS

Local Monitoring (assist TGCL - July)				**TOTAL**	**$750.00**
First Nation Equipment & Labour					
Local Labourer	hr	$25	12	$300	
Local Labourer	hr	$25	12	$300	
Generator	day	$100	0	$0	
Excavator	hr	$200	0	$0	
Dozer	hr	$175	0	$0	
Loader	hr	$175	0	$0	
Tandem Truck	hr	$150	0	$0	
Vacuum Truck	hr	$125	0	$0	
Rental Vehicle	day	$150	1	$150	
ATV	day	$100	0	$0	

Local Monitoring (assist TGCL - October)				**TOTAL**	**$3,000.00**
First Nation Equipment & Labour					
Local Labourer	hr	$25	48	$1,200	
Local Labourer	hr	$25	48	$1,200	
Generator	day	$100	0	$0	
Excavator	hr	$200	0	$0	
Dozer	hr	$175	0	$0	
Loader	hr	$175	0	$0	
Tandem Truck	hr	$150	0	$0	
Vacuum Truck	hr	$125	0	$0	
Rental Vehicle	day	$150	4	$600	
ATV	day	$100	0	$0	

TOTAL	**$3,750.00**

True Grit Consulting Ltd.
PO Box 607
Sioux Lookout, ON P8T-1B
T 807.737.7132 F 807.737.1091 www.tgcl.ca

May 10, 2011 File No.10-230-03F

VIA EMAIL (harrymeekis@yahoo.ca)

Harry Meekis
Sandy Lake First Nation
PO Box 12
Sandy Lake, ON, P0V 1V0

Re: Former DGS Remedial Design Proposal

Dear: Mr. Meekis

True Grit Consulting Ltd (TGCL), is pleased to provide a proposal for development of a site remediation plan for the former Hydro One Remote Communities Inc. (Hydro One) Diesel Generating Station (DGS) site in Sandy Lake. This proposal is an addendum to our previous *Revised Proposal for Development and Implementation of a Site Remediation Plan May 18, 2009*, and subsequent cost revisions.

The project is being overseen by a Steering Committee comprised of members of Sandy Lake First Nation, Sandy Lake Community Development Services (SLCDS) and Hydro One. TGCL has been contracted by SLCDS to provide environmental consulting services for the project.

The Scope of Work outlined in the previous proposal is presented below, along with progress status:

- Information Review – Completed.
- Development of the SLCDS Health and Safety policies and procedures - Completed
- Bioremediation Cell Design – Completed.
- Bioremediation Cell Construction – Completed.
- Supplementary Environmental Site Investigation and the added Drilling Program – Completed.
- Remedial Design – In Progress.
- Remedial Excavation – Pending the completion of the Remedial Design.
- Soil Treatment – Pending the completion of the Remedial Excavation.

Results of the completed Supplementary Investigation and Drilling Program have identified that petroleum hydrocarbon impact at the Former DGS site is more extensive than originally anticipated. The scope of work and level of effort outlined in the original proposal are not sufficient to complete the remedial design. Additional work will be required by the Project Team to develop appropriate remedial measures for the site.

A report documenting the work completed to date, including the findings of the Supplementary Investigation and Drilling Program, is near completion and will be submitted shortly. The report will also include any recommended immediate remedial measures and costs estimates.

The proposed scope of work for completion of design of a remedial program for the Former DGS site is outlined below:

- presentation of the report documenting the work completed to date and findings of the Supplementary Investigation and Drilling Program to the Project Team, along with discussion of potential remedial options;
- some limited additional field work, including monitoring of water levels and liquid petroleum hydrocarbon (LPH) thicknesses in site monitoring wells, collection of groundwater samples from select monitoring wells, and LPH purging and recovery testing;
- development of remedial options and costs estimates;
- presentation of remedial options to the Project Team;
- selection of a preferred remedial option by the Project Team.

Using all of the information collected and compiled from the previous tasks, we will prepare a detailed Remedial Design Brief containing all necessary details of the proposed work plan. The Remedial Design Brief will include the following:

- a general description of the proposed work plan;
- the project objectives, including specific site and soil treatment criteria to be achieved;
- a description of regulatory approval requirements, and federal and provincial environmental compliance/conformance requirements;
- a public communication/consultation plan;
- a description of all preparation and construction activities;
- the quality, quantity, source locations, haul distances and costs of all fill materials to be used for backfilling the excavation during the remedial work;
- a description of the confirmatory and verification sampling plans;
- requirements for site restoration and landscaping;

- a description of on-site supervision and field service requirements;
- project schedule/duration;
- a site-specific health and safety plan;
- Quality Assurance/Quality programs;
- a description of operations and maintenance plans for the post-construction ex-situ treatment phase;
- a description of site monitoring, risk management, in-situ remediation programs (if required);
- requirements for reporting/documentation including as-built drawings, completion certificates, etc.;
- contingency plans; and,
- Class "B" Cost estimates.

Schedule

We anticipate completion of the report documenting the work completed to date and results of the additional investigation by May 20, 2011. The report will also include any recommended immediate remedial measures and costs estimates.

Presentation of the report, along with discussion of potential remedial options, is proposed for the week of May 23rd, pending Project Team member availability. It is assumed that the presentation meeting would be held in Sandy Lake.

The proposed additional field work would be completed in conjunction with the report presentation meeting.

We have allowed four weeks for development of remedial options and cost estimates. Options and costs could be presented to the Project Team by the end of June, 2011. It is assumed that the presentation meeting would be held in Sandy Lake.

Following reviews of options by the Project Team and selection of a preferred remedial approach TGCL would completed the Design Brief as previously outlined. We anticipate that preparation of the Design Brief would take approximately four weeks to complete.

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Following completion of the Design Brief, a meeting would be held to present and discuss the remedial design, cost estimate, and schedule.

Cost Estimate

A cost estimate for the proposed scope of work, broken down by task, has been attached. The estimate includes all TGCL fees and disbursements, as well as First Nation Labour costs. This estimate also includes First Nation project management/administration/travel costs. The cost estimate may be revised as project tasks are completed.

In the cost estimate we have allowed for three meetings in Sandy Lake, during remedial design development. We have assumed that TGCL Staff in Thunder Bay and Sioux Lookout will mobilize to Sandy Lake on a Hydro One air charter. Additional site meetings would be an extra cost. Teleconference meetings are covered under the TGCL's project management/administration task.

We hope this meets your needs at this time. We are available to discuss the revised scope of work and cost estimates at your convenience.

Respectfully submitted by:

True Grit Consulting Ltd.

Randy Edwards, A Sc.T
Project Manager
redwards@tgcl.ca

Jason Garatti, M.Sc.Eng., P.Geo.
Principal/Manager, Environmental Services
jgaratti@tgcl.ca

JG/RE:shc

c.c Bob Shine, Hydro One
Adrian Andreaachi, Hydro One

TABLE A - PROJECT COST BREAKDOWN - SANDY LAKE DGS SITE REMEDIATION DESIGN - May 2011

TASK	AEI FEES	AEI DISBURSEMENTS	SHIPPING - EQUIP. & SUPPLIES	LABORATORY	FIRST NATION LABOUR & EQUIP. & SHIPPING	TOTALS
1.0 Project Mgmt/Admin, Coordination, Physical/Financial Reporting	$3,986	$250				**$4,236**
2.0 Remedial Option Evaluation and Costing	$10,568	$100				**$10,668**
3.0 Additional Field Work	$4,493	$5,510	$165	$1,337	$1,205	**$12,709**
5.0 Remediation Design	$9,994	$100				**$10,094**
6.1 Project Meetings - Work to Date Report Presentation (Sandy Lake)	$4,277	$220				**$4,497**
6.2 Project Meetings - Remedial Options Presentation (Sandy Lake)	$3,341	$220				**$3,561**
6.3 Project Meetings - Remedial Design Presentation (Sandy Lake)	$3,341	$220				**$3,561**
7.0 First Nation Project Mgmt/Admin/Travel						**$4,933**
TOTAL	**$40,000.00**	**$6,620.00**	**$165.00**	**$1,336.50**	**$1,204.50**	**$54,259**

WARDROP
A TETRA TECH COMPANY

May 26, 2011 1031872400-REP-V0001-00

Mr. Bob Shine
Environment and Health Coordinator
Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay ON P7E 6G9

Dear Mr. Shine,

Subject **Hydro One Remote Communities Inc.**
2010 Progress Report - Bearskin Lake DGS

This report describes the results of the 2010 progress monitoring and sampling conducted by Wardrop Engineering Inc. DBA Tetra Tech (Wardrop) at the Hydro One Remote Communities (Hydro One) Biocell facility developed in association with the previous hydrocarbon impacted soil remediation of the Bearskin Lake Diesel Generating Station (DGS). A summary of previous site investigations, remediation efforts, and annual site monitoring results is also provided.

BACKGROUND

Site Characterization

The Bearskin Lake First Nation is located in the District of Kenora on the north end of Michikan Lake, approximately 370 km northeast of Red Lake, Ontario. The community of Bearskin Lake is accessible by air and winter roads.

Former DGS Location

The former Bearskin Lake DGS is located about 500 m west of the community. Adjacent land uses include undeveloped forested land to the north and west, a First Nation maintenance garage to the south and a former First Nation fuel storage area to the southeast, as shown on Figure 1.

Previous Investigations

Ontario Hydro Technologies completed a Phase I Environmental Site Assessment (Phase I ESA) of the site in 1998.

The subsequent report entitled *Phase I Environmental Site Assessment of Bearskin Diesel Generating Station* (Report No. 6624-003-1998-RA-0013-R00, dated December 3, 1998) identified several areas of known and potential impact at the site. The report recommended completion of a Phase II Environmental Site Assessment (Phase II ESA) comprising soil and groundwater sampling and analysis.

Wardrop completed a Phase II ESA in 2001, the details of which are summarized in a report entitled *Phase II Environmental Site Assessment, Bearskin Lake Diesel Generating Station, Final Report* (Ref. No. 003187-13-00, dated February 2002). The investigations identified approximately 1,350 m^3 of soil, *in situ*, which had been affected by petroleum hydrocarbon (PHC) arising from several historical spills and leaks at levels that exceeded the Canadian Council of Ministers of the Environment (CCME) residential/parkland guidelines. The impacts were mainly in the vicinity of the former powerhouse, tank farm and fuel offload area.

Following the Phase II ESA, possible remedial options were explored and a remediation strategy was recommended to address the identified soil impacts in Wardrop's report entitled *Design Brief Biopile Soil Remediation System for Hydrocarbon Impacted Soil Bearskin Lake, Ontario* (Ref. No. 003187-13-00, dated January 2003). Following discussions between Hydro One and the First Nation, an alternate strategy was developed for an ex-situ bioremediation cell (biocell) facility, as presented in Wardrop's *Design Brief, Biocell Soil Remediation for Hydrocarbon Impacted Soils, Bearskin Lake, Ontario, Final* (Ref. No. 0031871300-REP-V0002-00, dated July 2004).

As directed by the First Nation, a biocell was constructed adjacent to four existing community biocells, located approximately 100 m north of the community's waste disposal site, as shown on Figure 2. The biocell site is approximately 6 km from the former DGS site and 6.5 km west of the community.

2004/05 DGS Site Remediation

Details on the 2004 and 2005 site remediation work are summarized in Wardrop's report entitled *Biocell Construction and Soil Remediation, Former Hydro One DGS, Bearskin Lake, Ontario*, dated April 2006.

Approximately 2,100 m^3 of soil was removed from the former diesel generating station site and deposited in the Hydro One biocell facility as non-hazardous solid waste for remediation. Sampling indicated that the extents of impact were generally reached, both vertically (to bedrock) and laterally, with the exception of a small area near the former pole storage area. The impacted soil that remained in the pole storage area was proposed to be excavated in 2006.

About 2,200 m^3 of clean fill was used to backfill these excavations. During placement of the backfill, around 2,600 kg of urea nitrogen fertilizer was added and mixed into the soil.

2006 Follow-up Remediation and Biocell Monitoring and Sampling

Details of the 2006 follow-up remediation, biocell sampling, and maintenance activities are provided in our report titled *Hydro One Bearskin Lake DGS 2006 Progress Report* (Ref. No. 0031871302-REP-V0002-00, dated May 23, 2007).

Approximately 40 m³ of impacted soil was excavated from the former pole storage area and deposited into the biocell for remediation, and about 50 m³ of clean fill was used to backfill the excavation.

The hydrocarbon impacted soil deposited in the biocell facility during 2005 and 2006 was formed into windrows to promote water drainage from the biocell soil to the sump.

About 1,200 kg of urea nitrogen fertilizer was mixed into this soil to promote biological degradation. To evaluate the condition of the local environment, monitoring of the four existing shallow groundwater monitoring wells was undertaken and found no measurable or physical indication of hydrocarbon impacts. A water sample was also collected from the biocell sump and showed dissolved hydrocarbon concentrations to be at acceptable levels to permit pumping and discharging the sump water onto the ground.

2007 Biocell Monitoring and Sampling

Details of the 2007 biocell sampling and maintenance activities are provided in Wardrop's report titled *Hydro One Bearskin Lake DGS 2006 Progress Report* (Ref. No. 0031871302-REP-V0002-00, dated May 23, 2007). Soil sample analytical results exceeding the reference standards occurred for TPH (Gas/Diesel or Heavy Oils) in two of the nine sampling locations across the three existing windrows. Nutrient levels in these soils were at acceptable levels for on-going bioremediation. Groundwater sample analytical results indicated that the residual hydrocarbon levels in the groundwater around MW1 and MW3 were decreasing. Results for the water sample collected from the sump showed hydrocarbon concentrations at acceptable levels to permit discharging the sump water onto the ground.

2008 Biocell Monitoring and Sampling

Details of the 2008 biocell sampling and maintenance activities are provided in Wardrop's report titled *Hydro One Bearskin Lake DGS 2008 Progress Report* (Ref. No. 0831875800-REP-V0001-00, dated April 1, 2008). Soil sample analytical results exceeding the reference standards occurred for TPH (Gas/Diesel or Heavy Oils) in eight of the nine sampling locations across the three existing windrows. Nutrient concentrations in the nine soil samples were below the target standards for nitrogen in six of the samples, for potassium in three of the samples, and for phosphorus in all of the samples. Groundwater sample analytical results indicated that toluene and ethylbenzene were detected at concentrations below the reference standards in the groundwater sample collected from monitoring well MW1. Concentrations in samples from the other monitoring wells were below the laboratory method detection limits. Results for the water sample collected from the sump showed hydrocarbon concentrations at acceptable levels to permit discharging the sump water onto the ground.

2009 Biocell Monitoring and Sampling

Details of the 2009 biocell sampling and maintenance activities are provided in Wardrop's report titled *Hydro One Bearskin Lake DGS 2009 Progress Report* (Ref. No. 0031871303-REP-V0001-00, dated March 11, 2010). Soil sample analytical results exceeding the targeted remediation criteria for TPH (Gas/Diesel) occurred in three of the nine sampling locations across the three existing windrows.

Nutrient levels at the nine sampling locations were below the target standards for nitrogen at seven locations and for phosphorus at all locations. Nutrient levels for potassium met the target standards for all nine locations. Mechanical disturbance of these soils by leveling of the existing windrows and re-piling of the soils was completed to assist in the bioremediation process through the introduction of additional oxygen into the soil and nutrient. In addition, fifteen bags of nutrient were applied to the soil in the biocell during levelling and re-piling of the soils.

Groundwater sample analytical results indicated that concentrations of BTEX in all analyzed groundwater samples were below the applicable Table 3 standards. PHC F1+F2 and PHC F3+F4 in all analyzed groundwater samples were below the Table 2 Standards.

Results for the water sample collected from the sump showed hydrocarbon concentrations at acceptable levels to permit discharging the sump water onto the ground.

2010 Scope of Work

Based on the conclusions of the 2009 annual report and discussions with Hydro One, 2010 scope of work included the following:

- Consideration should be given to update the target remediation guidelines for soil remediation (currently still related to TPH as per agreement with INAC);
- Bio-remediation of the soils in the biocell should continue in 2010;
- Consideration should be given to apply the nutrients to soils in the biocell in 2010;
- The physical condition of the biocell facilities should be assessed annually. Maintenance or repairs to the biocell should be completed as required;
- Water in the biocell sump should be sampled and emptied as necessary in 2010;
- Discussion should commence with INAC to arrange for reuse of soil, meeting remediation guidelines.

SELECTION OF SOIL AND GROUNDWATER ASSESSMENT STANDARDS

Target Soil Remediation Criteria

The soil from the DGS is intended to remain in the biocell until the residual hydrocarbon concentrations meet the standards as agreed with INAC. Subsequently, the treated soils could be removed for use as cover material at the community landfill. Based on the Letter of Understanding between Hydro One and the Bearskin Lake First Nation, dated April 13, 2004, it is our understanding that once the impacted soil has met the standards, the First Nation will assume responsibility for its removal from the biocell and for use as landfill cover.

The target soil remediation standards as agreed with INAC were the Table B criteria provided in former Guideline for Use at Contaminated Sites in Ontario (1997). It should be noted that the former guideline for Use at the Contaminated Sites in Ontario has been replaced with the Ministry of Environment, Ontario Regulation 153/04, Soil, Groundwater and sediment Standards.

Selection of Groundwater Assessment Standards

An assessment of appropriate standards was conducted in accordance with the requirements of *Ontario Regulation (O. Reg.) 153/04* made under the *Environmental Protection Act*. Based on the results of this assessment, the *Table 3* Full Depth Generic Site Condition Standards in a Non-Potable Groundwater Condition was selected for assessment of groundwater results.

The rationale for this selection is based on the fact that the site is located greater than 30 m from a surface body of water, has greater than 2 m of overburden and doesn't appear to be situated in a sensitive area. The Biocell site is serviced with the community water system which extracts water from Lake Michikan. A flow chart showing the selection process is presented in Figure 3.

Because the site is in the Federal jurisdiction, the site is also assessed against the Federal guidelines as well as provincial standards. It should be noted that no applicable Federal guidelines for non-potable groundwater conditions exist.

2010 SITE MONITORING METHODOLOGY

Biocell Monitoring and Maintenance

Between June 2 and 3, 2011, the existing windrows of impacted soils were mechanically levelled and re-formed with a track mounted excavator supplied by the Bearskin Lake First Nation community. Hydro One personnel were on site during this activity to monitor the work.
On October 26, 2010, Hydro One and Wardrop personnel visited the site to assess the condition of the biocell and to note recommendations, if warranted, for maintenance or repairs.

…6

Soil Monitoring and Sampling

The hydrocarbon impacted soil disposal area was previously formed into three windrows, each measuring approximately 70 metres in length, as shown in Figure 4. During the week of October 26, 2010, each windrow was divided to ten sections and one soil sample was collected from each section of each windrow above the drainage layer which was the anticipated "worst case" depth. Ten soil samples were collected from each windrow using a stainless steel hand auger. A total of thirty soil samples were collected from three windrows.

All thirty soil samples were submitted for analysis of benzene, toluene, ethylbenzene and xylenes (BTEX), petroleum hydrocarbon fractions F1 to F4 and total petroleum hydrocarbons (TPH). Vapour concentrations were determined for the soil samples collected along the three windrows. These soil sampling locations are shown in Figure 4.

Groundwater Monitoring Well Inspection

Visual inspection of the monitoring wells was performed and their conditions were documented.

Biocell Monitoring Well Sampling

On October 26, 2010, measurements of static water levels and phase separated hydrocarbon (PSH), if present, were performed in each of the four on-site shallow groundwater monitoring wells (MW1 to MW4) using an electronic interface probe. Groundwater samples were then collected from each monitoring well using dedicated Waterra sampling systems, after purging the wells dry twice or until a volume equivalent to at least three well casing volumes of groundwater was removed from each well.

These groundwater samples were stored in chilled coolers and shipped via chain of custody procedures to ALS Laboratory Group, in Thunder Bay, Ontario for analysis of benzene, toluene, ethylbenzene and xylenes (BTEX), and petroleum hydrocarbon (PHC) fractions F1 to F4.

Quality Assurance / Quality Control (QA/QC)

Quality assurance was established in the field by applying strict material handling, monitoring and sampling equipment operating, and documentation controls. New, clean, disposable nitrile gloves were worn when handling samples and were discarded and replaced after each sample was collected to prevent cross-contamination. Samples were collected in laboratory supplied pre-cleaned jars and/or bottles. Water sample bottles were provided with the appropriate preservative.

Waterra foot valves and polyethylene tubing were originally provided pre-cleaned and sealed in plastic by the manufacturer and each was dedicated to only one well to prevent sample cross-contamination.

During the October 2010 monitoring event three duplicate soil and one duplicate groundwater samples were collected to check analytical reproducibility. The duplicate soil samples were collected at soil sampling locations R1-9, R2-8 and R3-8 and were identified as R1-9 Dup, R2-8 Dup and R3-8 Dup, respectively. The duplicate groundwater sample was collected from monitoring well MW2 and was identified as MW2 DUP.

The laboratory analyzed method blanks, replicates, standard reference materials and matrix spikes as part of its internal QA/QC program.

Data Analysis and Reporting

The biocell soil monitoring results were referenced to the soil criteria for non-potable groundwater conditions presented in the *Guideline for Use at Contaminated Sites in Ontario* (1997), as previously agreed with INAC.

Groundwater monitoring results were compared to the criteria listed in O.Reg. 153/04 *Soil, Groundwater and Sediment Standards for Use under Part XV.1 of the Environmental Protection Act* (SGWS Standards) for an industrial/commercial site with non-potable groundwater conditions.

2010 SITE MONITORING RESULTS

Biocell Monitoring and Maintenance

Soil Monitoring and Quality

Analytical results are provided in the attached Certificate of Analysis and are summarized along with historical results in Tables 1, 2 and 3. The 2010 soil results are also presented on Figure 4.

Concentrations of BTEX, TPH (Gas/Diesel) or TPH (Heavy Oils) above the target soil remediation criteria for non-potable groundwater conditions presented in the *Guideline for Use at Contaminated Sites in Ontario* (1997), as previously agreed with INAC, were not detected in any of the thirty soil samples or the three duplicate samples.

Monitoring Well Conditions

A summary of the condition of each well is provided on Table 5. Generally, the wells appeared to be in good condition and no repairs were required.

Groundwater Levels

A summary of groundwater level measurements is provided in Table 6. Water levels ranged from about 0.62 m below ground surface (mbgs) in MW3 at the north side of the biocell to about 4.65 mbgs in MW4 located on the east side of the biocell. The 2010 groundwater levels indicate that the water table slopes generally toward the west and northwest.

Evidence of Petroleum Hydrocarbons

There was no phase separated hydrocarbon (PSH) measured floating on the groundwater in any of the monitoring wells. There were also no hydrocarbon odours noted in any of the collected groundwater samples. A summary of observations of the appearance of the groundwater contained in the wells is summarized in Table 5.

Groundwater Quality

Analytical results are provided in the attached Certificate of Analysis and are summarized with historical results in Table 6. Figure 5 displays the 2010 groundwater sampling results in relation to features at the site.

Toluene and ethylbenzene were detected at concentrations below the reference Table 3 standards in the field duplicate sample from monitoring well MW2. Concentrations of BTEX in samples from the other monitoring wells were below the laboratory method detection limits and the Table 3 Standards. There are no Table 3 standards for PHC F1 to F4. For comparison purposes, concentrations of PHC F1 + F2 and F3 + F4 were compared with Table 2 Full Depth Genetic Site Condition Standards in a potable groundwater condition. The concentrations of PHC F1 + F2 and PHC F3 + F4 in all analyzed groundwater samples were below the laboratory detection limits and the Table 2 Standards.

The presence of these low levels of hydrocarbon parameters is consistent with historical results.

Quality Assurance/Quality Control

Laboratory's calibration checks, quality control standard recoveries, spikes, RPDs, and blanks were within the laboratory's quality control limits. The laboratory certificates are attached.

The analytical results for duplicate samples are compared by calculating the relative percent difference (RPD_{DUP}); which is the difference between the results, divided by the average of the results.

Three duplicate soil samples were collected from three soil sampling locations R1-9, R2-8 and R3-8 (identified as R1-9 Dup, R2-8 Dup and R3-8 Dup, respectively). The RPD_{DUP} values for PHC F2 and F3 ranged from 16% to 60% and were considered acceptable. The RPD_{DUP} values

...9

for other parameters could not be calculated because one and/or both analytical results are less than the method detection limits.

One duplicate groundwater sample was collected from monitoring well MW2 (identified as MW2 DUP) during the groundwater monitoring program. The RPD_{DUP} values could not be calculated because both analytical results are less than the method detection limits.

The results for process blanks, process recoveries and matrix spikes, shown on the Certificate of Quality Control provided by ALS Laboratory Group, attached, were within standard tolerances and are considered acceptable.

Discussion/Conclusions

In 2010, soil sample analytical results indicated that all analyzed soil samples met the targeted remediation criteria.

Review of the biocell monitoring well groundwater sample analytical results indicate that the concentrations of BTEX in all analyzed groundwater samples were below the applicable Table 3 standards. PHC F1+F2 and PHC F3+F4 in all analyzed groundwater samples were below the Table 2 Standards.

Recommendations

Based on the results of the monitoring and sampling activities conducted in October 2010, we provide the following recommendations:

- Discussion should commence with INAC to arrange for reuse of soil, meeting remediation guidelines.

We trust that this progress report is sufficient for your current requirements. Should some point require clarification or further discussion, please contact us at your convenience.

Sincerely

Wardrop Engineering Inc., DBA Tetra Tech

John Guan, M.Eng., P.Eng.
Project Engineer
/mi

Approved by

Wardrop Engineering Inc., DBA Tetra Tech

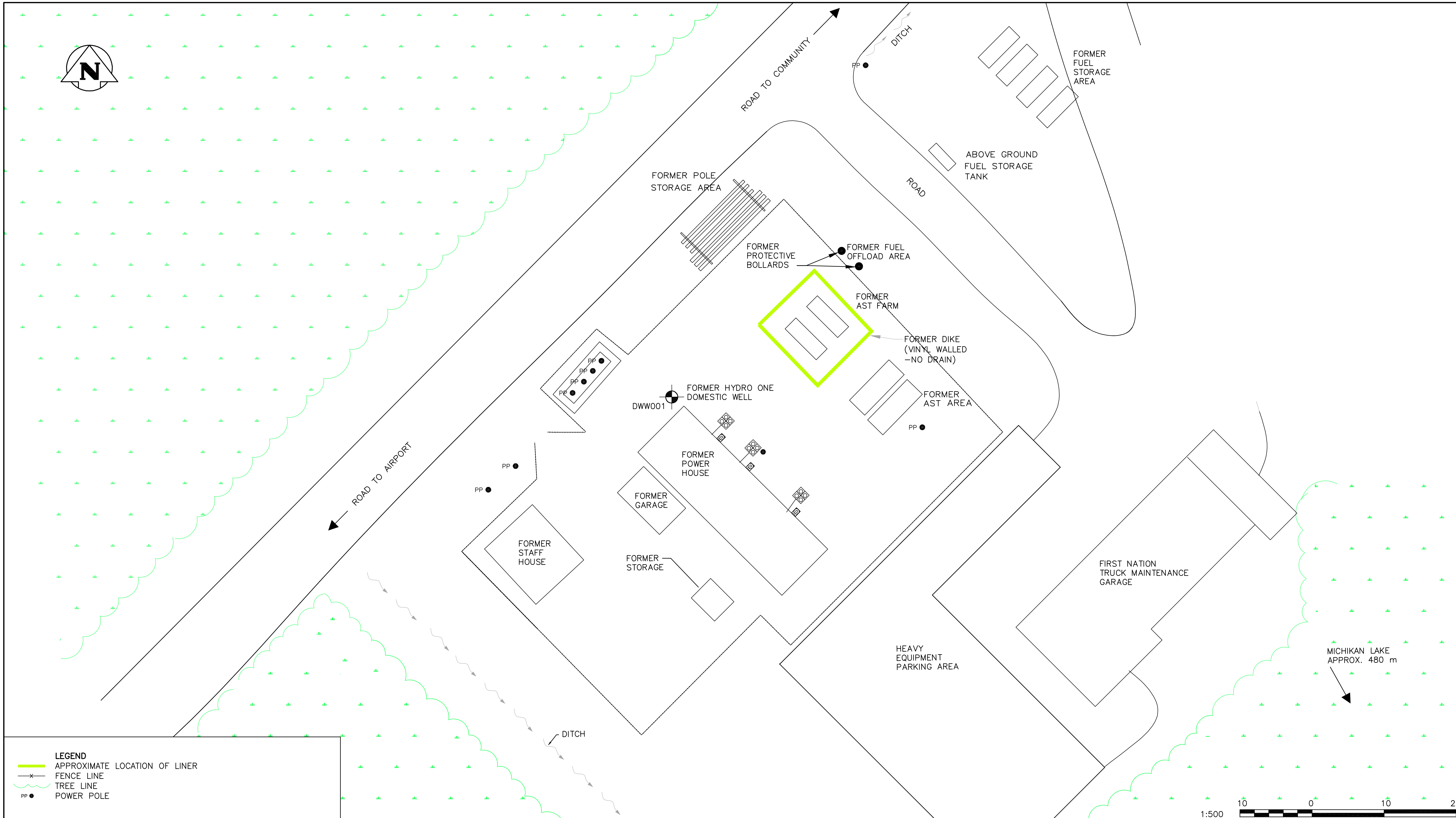
René de Vries, P.Geo
Sr. Environmental Scientist

PROFESSIONAL GEOSCIENTIST
R.A. DE VRIES
PRACTISING MEMBER
1161
ONTARIO

Attachments Figures 1 – 5
Tables 1 - 6
Laboratory Certificates of Analysis

FIGURES 1 – 5

W:\H-M\HYDRO ONE REMOTE COMMUNITIES - 3187\10318724.00 - BEARSKIN LAKE 2010 MONITORING AND SAMPLING\ENGINEERING\USER FOLDERS\CAD\1031872400-SKT-V0001-00.DWG 11.06.01 9:33 AM PARADOSKI, GORDON



LEGEND

- APPROXIMATE LOCATION OF LINER
- FENCE LINE
- TREE LINE
- PP POWER POLE

NO.	DESCRIPTION

REFERENCE DRAWINGS

NO.	DATE	DESCRIPTION	PREPARED	REVIEW	DESIGN	AUTHORIZE
00	10.03.15	ISSUED WITH REPORT	AR	RDV	JG	RDV

REVISIONS/ISSUE — DRAFTING — ENGINEERING

WARDROP A TETRA TECH COMPANY — PEOPLE, PASSION, PERFORMANCE. TRUSTED GLOBALLY

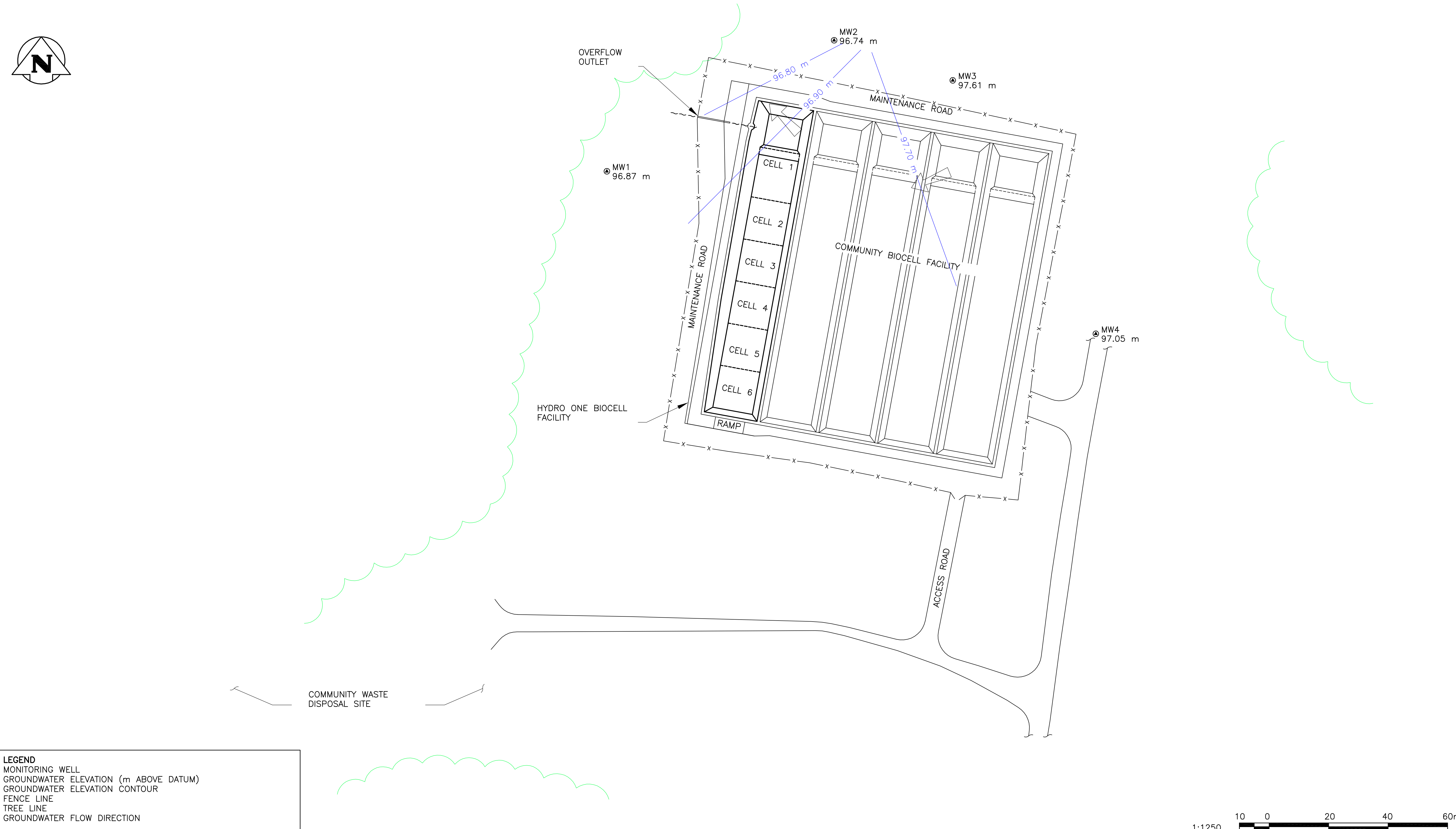
AUTHORIZED BY: JG
DATE: 11.06.01
CLIENT DRAWING NO.

CLIENT: HYDRO ONE REMOTE COMMUNITIES INC.

DRAWING DESCRIPTION:
FIGURE 1: FORMER SITE PLAN
FORMER DGS, BEARSKIN LAKE, ONTARIO

DESIGNED BY:	JG	DRAWN BY:	GP	DRAWING NO.	REV.
REVIEWED BY:	RDV	SCALE:	1:500	1031872400-SKT-V0001	00

B (17" x 11")



LEGEND

⦿	MONITORING WELL
97.77 m	GROUNDWATER ELEVATION (m ABOVE DATUM)
–97.70 m–	GROUNDWATER ELEVATION CONTOUR
—x—	FENCE LINE
	TREE LINE
⇨	GROUNDWATER FLOW DIRECTION

NO.	DESCRIPTION

REFERENCE DRAWINGS

NO.	DATE	DESCRIPTION	PREPARED	REVIEW	DESIGN	AUTHORIZE
REVISIONS/ISSUE			DRAFTING		ENGINEERING	

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AUTHORIZED BY: JG
DATE: 11.06.01
CLIENT DRAWING NO.

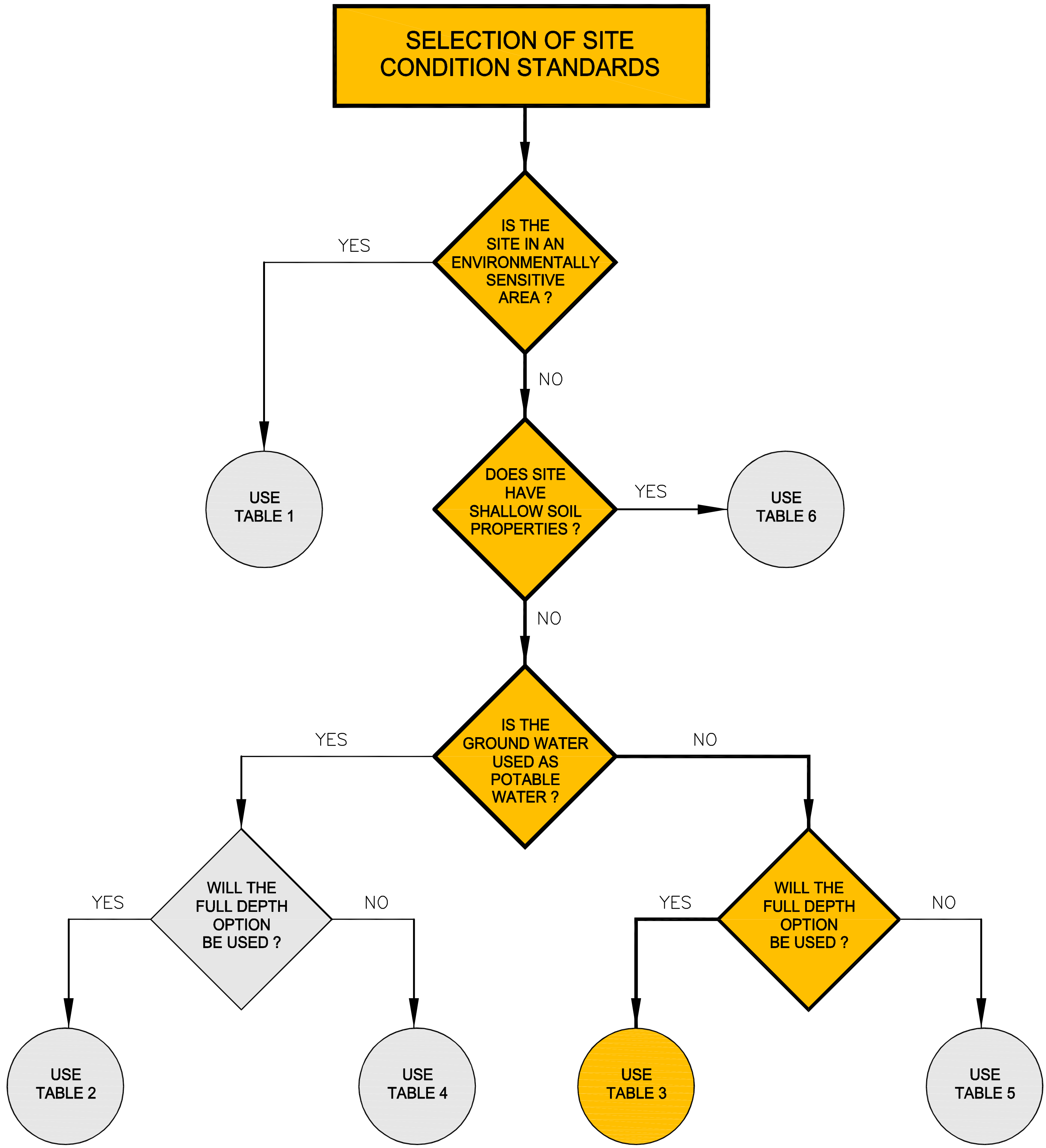
CLIENT
HYDRO ONE REMOTE COMMUNITIES INC.
FORMER BEARSKIN LAKE DGS

DRAWING DESCRIPTION
FIG 2: SITE PLAN SHOWING BIOCELL FACILITY, GROUNDWATER ELEVATIONS AND FLOW DIRECTIONS; BEARSKIN LAKE, ONTARIO

DESIGNED BY: JG	DRAWN BY: GP	DRAWING NO.	REV.
REVIEWED BY: RDV	SCALE: 1:1250	1031872400-SKT-V0002	00

B (17" x 11")

W:\H-M\HYDRO ONE REMOTE COMMUNITIES - 318/\10318/24.00 - BEARSKIN LAKE 2010 MONITORING AND SAMPLING\ENGINEERING\USER FOLDERS\CAD\1031872400-SKT-V0003-00.DWG 11.06.01 9:37 AM PARADOSKI, GORDON



REFERENCE DRAWINGS:

A TETRA TECH COMPANY

PEOPLE, PASSION, PERFORMANCE. TRUSTED GLOBALLY

NO.	DATE	DESCRIPTION	ISSUED BY

REVISIONS/ISSUE

AUTHORIZED BY: JG

DATE: 11.06.01

CLIENT DRAWING NO.

CLIENT
HYDRO ONE REMOTE COMMUNITIES INC.
FORMER BEARSKIN LAKE DGS

DRAWING DESCRIPTION
FIGURE 3: SITE CONDITION STANDARDS FLOWCHART
BEARSKIN LAKE, ON

DESIGNED BY: JG	DRAWN BY: GP	DRAWING NO.	REV.
REVIEWED BY: RDV	SCALE: N.T.S.	1031872400-SKT-V0003	00

A (8.5" x 11")

Table 1: Summary of 2010 Soil Monitoring Analytical Results, Hydro One Biocell, Bearskin Lake

Sample Location	Sample ID	Date	OVM Reading	Moisture %	Benzene ug/g	Toluene ug/g	Ethyl-benzene ug/g	Xylenes ug/g	PHC F1 ug/g	PHC F2 ug/g	PHC F3 ug/g	PHC F4 ug/g	TPH Gas/Diesel ug/g	TPH Heavy Oils ug/g
Window 1-1	R1-1	2010-10-26	10	6.18	<0.050	<0.050	<0.050	<0.15	<5.0	37	170	<50	150	<100
Window 1-2	R1-2	2010-10-26	0	5.79	<0.050	<0.050	<0.050	<0.15	<5.0	37	195	<50	166	110
Window 1-3	R1-3	2010-10-26	25	6.02	<0.050	<0.050	<0.050	<0.15	<5.0	66	271	<50	248	<100
Window 1-4	R1-4	2010-10-26	5	6.12	<0.050	<0.050	<0.050	<0.15	<5.0	116	433	<50	471	230
Window 1-5	R1-5	2010-10-26	15	7.52	<0.050	<0.050	<0.050	<0.15	<5.0	38	202	<50	181	<100
Window 1-6	R1-6	2010-10-26	15	8.09	<0.050	<0.050	<0.050	<0.15	<5.0	100	392	<50	386	190
Window 1-7	R1-7	2010-10-26	10	10.6	<0.050	<0.050	<0.050	<0.15	<5.0		356	<50	415	150
Window 1-8	R1-8	2010-10-26	25	9.55	<0.050	<0.050	<0.050	<0.15	<5.0	66	239	<50	225	<100
Window 1-9	R1-9	2010-10-26	30	11.9	<0.050	<0.050	<0.050	<0.15	<5.0	104	258	<50	288	<100
Window 1-9	R1-9 Dup	2010-10-26	30	10.5	<0.050	<0.050	<0.050	<0.15	<5.0	56	221	<50	204	<100
Window 1-10	R1-10	2010-10-26	15	5.02	<0.050	<0.050	<0.050	<0.15	<5.0	18	127	<50	73	<100
Window 2-1	R2-1	2010-10-26	5	5.71	<0.050	<0.050	<0.050	<0.15	<5.0	50	162	<50	160	<100
Window 2-2	R2-2	2010-10-26	15	5.87	<0.050	<0.050	<0.050	<0.15	<5.0	37	145	<50	122	<100
Window 2-3	R2-3	2010-10-26	5	5.85	<0.050	<0.050	<0.050	<0.15	<5.0	64	268	<50	258	200
Window 2-4	R2-4	2010-10-26	5	7.46	<0.050	<0.050	<0.050	<0.15	<5.0	51	241	<50	222	130
Window 2-5	R2-5	2010-10-26	10	7.78	<0.050	<0.050	<0.050	<0.15	<5.0	144	366	<50	434	190
Window 2-6	R2-6	2010-10-26	30	8.78	<0.050	<0.050	<0.050	<0.15	<5.0	96	295	<50	314	170
Window 2-7	R2-7	2010-10-26	20	9.46	<0.050	<0.050	<0.050	<0.15	<5.0	132	710	110	509	380
Window 2-8	R2-8	2010-10-26	30	8.67	<0.050	<0.050	<0.050	<0.15	<5.0		477	<50	512	220
Window 2-8	R2-8 Dup	2010-10-26	30	10.0	<0.050	<0.050	<0.050	<0.15	<5.0	112	408	<50	404	<100
Window 2-9	R2-9	2010-10-26	20	11.6	<0.050	<0.050	<0.050	<0.15	<5.0	68	289	<50	277	100
Window 2-10	R2-10	2010-10-26	25	7.92	<0.050	<0.050	<0.050	<0.15	<5.0	49	229	<50	178	120
Window 3-1	R3-1	2010-10-26	10	7.63	<0.050	<0.050	<0.050	<0.15	<5.0	58	189	<50	194	<100
Window 3-2	R3-2	2010-10-26	15	5.91	<0.050	<0.050	<0.050	<0.15	<5.0	48	201	<50	191	<100
Window 3-3	R3-3	2010-10-26	0	6.40	<0.050	<0.050	<0.050	<0.15	<5.0	71	244	<50	250	<100
Window 3-4	R3-4	2010-10-26	20	6.23	<0.050	<0.050	<0.050	<0.15	<5.0	59	251	<50	243	160
Window 3-5	R3-5	2010-10-26	20	6.98	<0.050	<0.050	<0.050	<0.15	<5.0	66	282	<50	274	110
Window 3-6	R3-6	2010-10-26	25	11.0	<0.050	<0.050	<0.050	<0.15	18.0		526	<50	719	280
Window 3-7	R3-7	2010-10-26	25	9.00	<0.050	<0.050	<0.050	<0.15	<5.0	138	361	<50	400	240
Window 3-8	R3-8	2010-10-26	35	8.69	<0.050	<0.050	<0.050	<0.15	<5.0	87	327	<50	324	200
Window 3-8	R3-8 Dup	2010-10-26	35	6.32	<0.050	<0.050	<0.050	<0.15	<5.0		403	<50	443	240
Window 3-9	R3-9	2010-10-26	25	10.3	<0.050	<0.050	<0.050	<0.15	<5.0	71	303	<50	275	150
Window 3-10	R3-10	2010-10-26	15	9.12	<0.050	<0.050	<0.050	<0.15	<5.0	26	206	<50	126	<100
Target Remediation Standards					5.3	34	290	34	-	-	-	-	1000	1000
Table 3 Standards					5.3	34	290	34	230	150	1700	3300	-	-
Esimated Quantitation Limit					0.050	0.050	0.050	0.15	5.0	10	50	50	-	-

Notes: Concentrations expressed as micrograms per gram (ug/g) unless otherwise indicated; **D** = Duplicate sample. ***Exceedances of Target remediation Standards.***
Target remediation Standards: Soil criteria for non-potable groundwater conditions provided in the Guideline for Use at Contaminated Sites in Ontario (1997)

In case of a discrepancy between this table and the Laboratory Reports of Analysis, the laboratory reports shall be considered correct.
Table to be read in conjunction with accompanying report.
OVM = organic vapour meter; ppm = parts per million

LEGEND

RED SOIL ANALYTICAL ABOVE TARGET REMEDIATION STANDARDS
GREEN SOIL ANALYTICAL BELOW TARGET REMEDIATION STANDARDS
—x— FENCE LINE
TREE LINE

NO.	DESCRIPTION
031871303-SKT-V0002	SITE PLAN BIOCELL FACILITY

REFERENCE DRAWINGS

NO.	DATE	DESCRIPTION	PREPARED	REVIEW	DESIGN	AUTHORIZE
REVISIONS/ISSUE			DRAFTING		ENGINEERING	

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AUTHORIZED BY: JG
DATE: 11.06.01
CLIENT DRAWING NO.

CLIENT
HYDRO ONE REMOTE COMMUNITIES INC.
FORMER BEARSKIN LAKE DGS

DRAWING DESCRIPTION
FIGURE 4: SITE PLAN SHOWING SOIL ANALYTICAL RESULTS
BEARSKIN LAKE, ONTARIO

DESIGNED BY: JG	DRAWN BY: GP	DRAWING NO. 1031872400-SKT-V0004	REV. 00
REVIEWED BY: RDV	SCALE: 1:500		

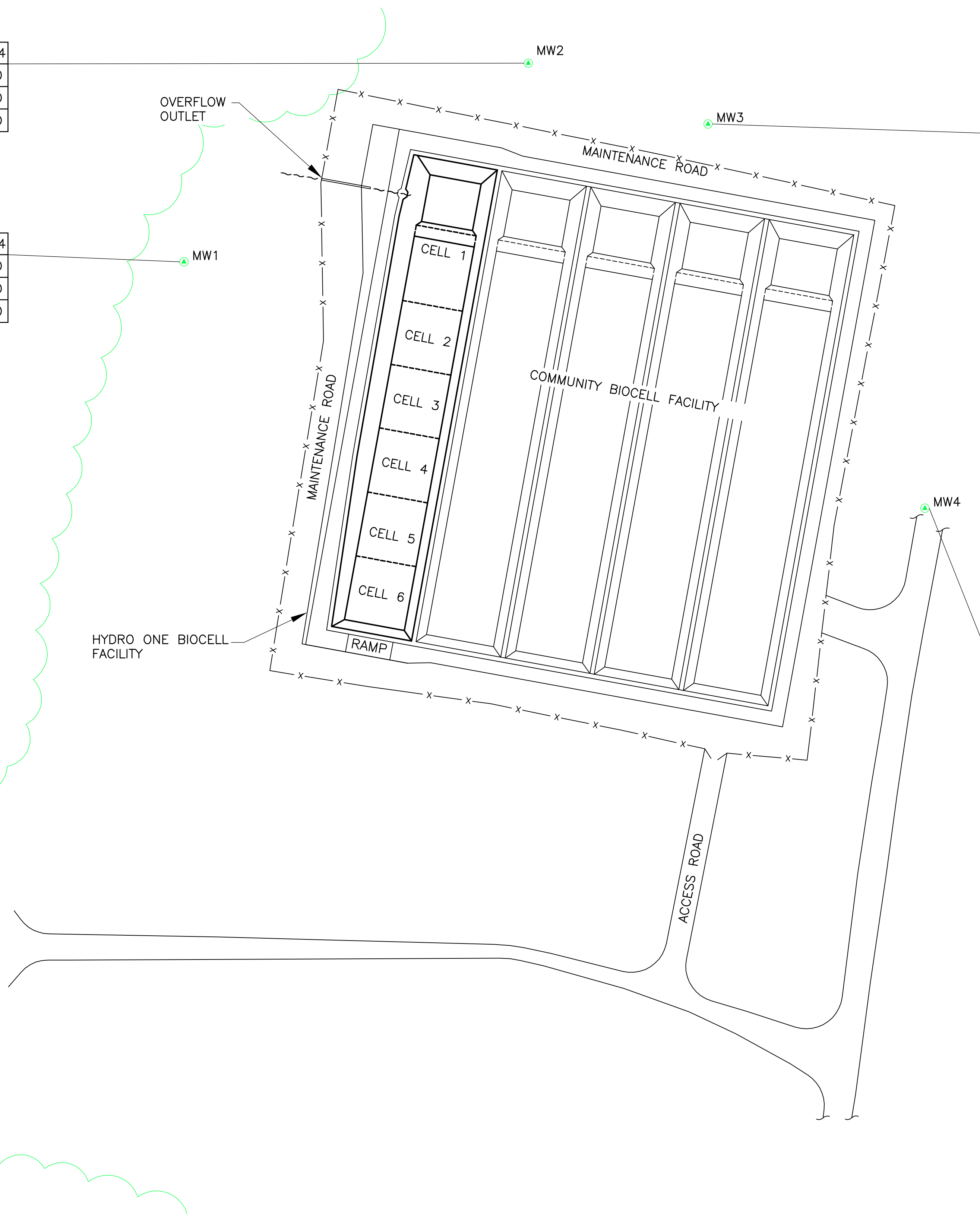
B (17" x 11")

SAMPLE ID	DATE	B	T	E	X	F1+F2	F3+F4
MW2	13/08/2009	<0.2	<0.2	<0.2	<0.4	<100	<100
MW2	26/10/2010	<0.5	<0.5	<0.5	<1.5	<100	<250
MW2 DUP*	26/10/2010	<0.5	<0.5	<0.5	<1.5	<100	<250

SAMPLE ID	DATE	B	T	E	X	F1+F2	F3+F4
MW1	13/08/2009	<0.2	0.3	0.3	<0.4	<100	<100
MW1 DUP*	13/08/2009	<0.2	0.3	0.3	<0.4	<100	<100
MW1	26/10/2010	<0.5	<0.5	1.75	2.2	<100	<250

SAMPLE ID	DATE	B	T	E	X	F1+F2	F3+F4
MW3	13/08/2009	<0.2	<0.2	<0.2	<0.4	<100	<100
MW3	26/10/2010	<0.5	<0.5	<0.5	<1.5	<100	<250

SAMPLE ID	DATE	B	T	E	X	F1+F2	F3+F4
MW4	13/08/2009	<0.2	<0.2	<0.2	<0.4	<100	<100
MW4	26/10/2010	<0.5	<0.5	<0.5	<1.5	<100	<250



GROUNDWATER STANDARDS	
BENZENE (B)	1900 [1]
TOLUENE (T)	5900 [1]
ETHYLBENZENE (E)	28000 [1]
TOTAL XYLENES (X)	5600 [1]
F1+F2 (C6-C16; excluding BTEX)	1000 [2]
F3+F4 (>C16-C50)	1000 [2]

1. MOE ONTARIO REGULATION 153/04, SOIL, GROUNDWATER AND SEDIMENT STANDARDS (MARCH 9, 2004), TABLE 3 FULL DEPTH GENERIC SITE STANDARDS IN A NON-POTABLE GROUNDWATER CONDITION WITH INDUSTRIAL/COMMERICAL/ COMMUNITY PROPERTY USE.

2. TABLE 2 FULL DEPTH GENERIC SITE CONDITION STANDARDS IN A POTABLE GROUNDWATER CONDITION WITH INDUSTRIAL/COMMERICAL/COMMUNITY PROPERTY USE.

LEGEND

- ⦿ MONITORING WELL
- RED GROUNDWATER ANALYTICAL ABOVE APPLICABLE STANDARD
- GREEN GROUNDWATER ANALYTICAL BELOW APPLICABLE STANDARD
- 0.3 GROUNDWATER SAMPLE CONCENTRATION (ug/L)
- 13/08/2009 GROUNDWATER SAMPLING DATE (DD/MM/YYYY)
- —x— FENCE LINE
- TREE LINE

1:1250 10 0 20 40 60m
APPROXIMATE SCALE

NO.	DESCRIPTION
REFERENCE DRAWINGS	

NO.	DATE	DESCRIPTION	PREPARED	REVIEW	DESIGN	AUTHORIZE
REVISIONS/ISSUE			DRAFTING		ENGINEERING	

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AUTHORIZED BY: JG
DATE: 11.06.01
CLIENT DRAWING NO.

CLIENT
HYDRO ONE REMOTE COMMUNITIES INC.
FORMER BEARSKIN LAKE DGS

DRAWING DESCRIPTION
FIGURE 5: SITE PLAN SHOWING GROUNDWATER ANALYTICAL RESULTS BEARSKIN LAKE, ONTARIO

DESIGNED BY: JG | DRAWN BY: GP | DRAWING NO. 1031872400-SKT-V0005 | REV. 00
REVIEWED BY: RDV | SCALE: 1:1250

B (17" x 11")

TABLES 1 – 6

Table 1: Summary of 2010 Soil Monitoring Analytical Results, Hydro One Biocell, Bearskin Lake

Sample Location	Sample ID	Date	OVM Reading	Moisture	Benzene	Toluene	Ethyl -benzene	Xylenes	PHC F1	PHC F2	PHC F3	PHC F4	TPH Gas/Diesel	TPH Heavy Oils
				%	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g
Windrow 1-1	R1-1	2010-10-26	10	6.18	<0.050	<0.050	<0.050	<0.15	<5.0	37	170	<50	150	<100
Windrow 1-2	R1-2	2010-10-26	0	5.79	<0.050	<0.050	<0.050	<0.15	<5.0	37	195	<50	166	110
Windrow 1-3	R1-3	2010-10-26	25	6.02	<0.050	<0.050	<0.050	<0.15	<5.0	66	271	<50	248	<100
Windrow 1-4	R1-4	2010-10-26	5	6.12	<0.050	<0.050	<0.050	<0.15	<5.0	116	433	<50	471	230
Windrow 1-5	R1-5	2010-10-26	15	7.52	<0.050	<0.050	<0.050	<0.15	<5.0	38	202	<50	181	<100
Windrow 1-6	R1-6	2010-10-26	15	8.09	<0.050	<0.050	<0.050	<0.15	<5.0	100	392	<50	386	190
Windrow 1-7	R1-7	2010-10-26	10	10.6	<0.050	<0.050	<0.050	<0.15	<5.0	174	356	<50	415	150
Windrow 1-8	R1-8	2010-10-26	25	9.55	<0.050	<0.050	<0.050	<0.15	<5.0	66	239	<50	225	<100
Windrow 1-9	R1-9	2010-10-26	30	11.9	<0.050	<0.050	<0.050	<0.15	<5.0	104	258	<50	288	<100
Windrow 1-9	R1-9 Dup	2010-10-26	30	10.5	<0.050	<0.050	<0.050	<0.15	<5.0	56	221	<50	204	<100
Windrow 1-10	R1-10	2010-10-26	15	5.02	<0.050	<0.050	<0.050	<0.15	<5.0	18	127	<50	73	<100
Windrow 2-1	R2-1	2010-10-26	5	5.71	<0.050	<0.050	<0.050	<0.15	<5.0	50	162	<50	160	<100
Windrow 2-2	R2-2	2010-10-26	15	5.87	<0.050	<0.050	<0.050	<0.15	<5.0	37	145	<50	122	<100
Windrow 2-3	R2-3	2010-10-26	5	5.85	<0.050	<0.050	<0.050	<0.15	<5.0	64	268	<50	258	200
Windrow 2-4	R2-4	2010-10-26	5	7.46	<0.050	<0.050	<0.050	<0.15	<5.0	51	241	<50	222	130
Windrow 2-5	R2-5	2010-10-26	10	7.78	<0.050	<0.050	<0.050	<0.15	<5.0	144	366	<50	434	190
Windrow 2-6	R2-6	2010-10-26	30	8.78	<0.050	<0.050	<0.050	<0.15	<5.0	96	295	<50	314	170
Windrow 2-7	R2-7	2010-10-26	20	9.46	<0.050	<0.050	<0.050	<0.15	<5.0	132	710	110	509	380
Windrow 2-8	R2-8	2010-10-26	30	8.67	<0.050	<0.050	<0.050	<0.15	<5.0	152	477	<50	512	220
Windrow 2-8	R2-8 Dup	2010-10-26	30	10.0	<0.050	<0.050	<0.050	<0.15	<5.0	112	408	<50	404	<100
Windrow 2-9	R2-9	2010-10-26	20	11.6	<0.050	<0.050	<0.050	<0.15	<5.0	68	289	<50	277	100
Windrow 2-10	R2-10	2010-10-26	25	7.92	<0.050	<0.050	<0.050	<0.15	<5.0	49	229	<50	178	120
Windrow 3-1	R3-1	2010-10-26	10	7.63	<0.050	<0.050	<0.050	<0.15	<5.0	58	189	<50	194	<100
Windrow 3-2	R3-2	2010-10-26	15	5.91	<0.050	<0.050	<0.050	<0.15	<5.0	48	201	<50	191	<100
Windrow 3-3	R3-3	2010-10-26	0	6.40	<0.050	<0.050	<0.050	<0.15	<5.0	71	244	<50	250	<100
Windrow 3-4	R3-4	2010-10-26	20	6.23	<0.050	<0.050	<0.050	<0.15	<5.0	59	251	<50	243	160
Windrow 3-5	R3-5	2010-10-26	20	6.98	<0.050	<0.050	<0.050	<0.15	<5.0	66	282	<50	274	110
Windrow 3-6	R3-6	2010-10-26	25	11.0	<0.050	<0.050	<0.050	<0.15	18.0	367	526	<50	719	280
Windrow 3-7	R3-7	2010-10-26	25	9.00	<0.050	<0.050	<0.050	<0.15	<5.0	138	361	<50	400	240
Windrow 3-8	R3-8	2010-10-26	35	8.69	<0.050	<0.050	<0.050	<0.15	<5.0	87	327	<50	324	200
Windrow 3-8	R3-8 Dup	2010-10-26	35	6.32	<0.050	<0.050	<0.050	<0.15	<5.0	155	403	<50	443	240
Windrow 3-9	R3-9	2010-10-26	25	10.3	<0.050	<0.050	<0.050	<0.15	<5.0	71	303	<50	275	150
Windrow 3-10	R3-10	2010-10-26	15	9.12	<0.050	<0.050	<0.050	<0.15	<5.0	26	206	<50	126	<100
Target Remediation Standards					5.3	34	290	34	-	-	-	-	1000	1000
Esimated Quantitation Limit					0.050	0.050	0.050	0.15	5.0	10	50	50	-	-

Notes: Concentrations expressed as micrograms per gram (ug/g) unless otherwise indicated; **D** = Duplicate sample. ***Exceedances of Target Remediation Standards.***
Target remediation Standards: Soil criteria (Table B) for non-potable groundwater conditions provided in the Guideline for Use at Contaminated Sites in Ontario (1997)
In case of a discrepancy between this table and the Laboratory Reports of Analysis, the laboratory reports shall be considered correct.
Table to be read in conjunction with accompanying report.
OVM = organic vapour meter; ppm = parts per million

Table 2: Summary of 2009 Soil Monitoring Analytical Results, Hydro One Biocell, Bearskin Lake

Sample Location	Sample ID	Date	Moisture	Benzene	Toluene	Ethyl -benzene	Xylenes	PHC F1	PHC F2	TPH Gas/Diesel	PHC F3	PHC F4	TPH Heavy Oils
			%	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g
Windrow 1-2	ROW 1-2	2009-08-13	7.4	< 0.02	< 0.02	< 0.02	< 0.04	<10	90	340	300	<10	300
Windrow 1-8	ROW 1-8	2009-08-13	9.6	< 0.02	< 0.02	< 0.02	< 0.04	25	600	***1025***	470	<10	470
Windrow 1-11	ROW 1-11	2009-08-13	8.2	< 0.02	< 0.02	< 0.02	< 0.04	24	180	424	220	<10	220
D Windrow 1-11	ROW 1-11 DUP	2009-08-13	8.8	< 0.02	< 0.02	< 0.02	< 0.04	25	270	555	270	<10	270
Windrow 2-4	ROW 2-4	2009-08-13	10	< 0.02	< 0.02	< 0.02	< 0.04	21	550	***1021***	520	<10	520
Windrow 2-8	ROW 2-8	2009-08-13	10	< 0.02	< 0.02	< 0.02	0.17	110	980	***1610***	550	<10	550
Windrow 2-12	ROW 2-12	2009-08-13	12	< 0.02	< 0.02	< 0.02	0.10	35	340	675	330	<10	330
Windrow 3-1	ROW 3-1	2009-08-13	8.0	< 0.02	< 0.02	< 0.02	< 0.04	17	130	357	330	17	347
Windrow 3-10	ROW 3-10	2009-08-13	8.9	< 0.02	< 0.02	< 0.02	< 0.04	30	470	920	480	<10	468
Windrow 3-14	ROW 3-14	2009-08-13	8.9	< 0.02	< 0.02	< 0.02	< 0.04	<10	66	190	130	<10	130
Target Remediation Standards				5.3	34	290	34	-	-	1000	-	-	1000
Esimated Quantitation Limit				0.02	0.02	0.02	0.04	10	10	-	10	10	-

Sample Location	Sample ID	TOC	pH	Nitrate	Nitrite	Nitrogen	Phosphorus	Potassium	Sulphur	HUB	C:N:P:K Ratios
		mg/kg		ug/g	ug/g	mg/kg	mg/kg	mg/kg	mg/kg	(Cfu/g)	
Windrow 1-2	ROW 1-2	21000	7.54	46	<0.5	72	< 4	39	< 2	3.5×10^5	100 : 3.7 : 0.2 : 2.0
Windrow 1-8	ROW 1-8	18000	7.45	55	<0.5	<50	< 4	28	< 2	4.5×10^4	100 : 0.0 : 0.2 : 1.1
Windrow 1-11	ROW 1-11	20000	7.53	87	1.4	450	< 4	29	4	1.4×10^4	100 : 29.4 : 0.3 : 1.9
D Windrow 1-11	ROW 1-11 DUP	19000	7.57	93	1.9	290	< 4	31	5	4.5×10^4	100 : 17.3 : 0.2 : 1.9
Windrow 2-4	ROW 2-4	19000	7.52	180	1.6	250	4	39	4	2.1×10^4	100 : 10.8 : 0.2 : 1.7
Windrow 2-8	ROW 2-8	21000	7.49	75	0.9	<50	5	30	3	2.7×10^5	100 : 0.0 : 0.2 : 1.3
Windrow 2-12	ROW 2-12	14000	7.64	26	1.4	<50	< 4	16	2	4.3×10^5	100 : 0.0 : 0.3 : 1.1
Windrow 3-1	ROW 3-1	21000	7.47	56	1.4	<50	< 4	31	2	4.3×10^4	100 0.0 : 0.2 : 1.8
Windrow 3-10	ROW 3-10	16000	7.43	240	1.2	570	< 4	27	3	1.5×10^3	100 20.7 : 0.1 : 1.0
Windrow 3-14	ROW 3-14	22000	7.55	30	<0.5	<50	< 4	28	< 2	5.7×10^5	100 : 0.0 : 0.2 : 1.5
Target Remediation Standards		-	-	-	-	-	-	-	-	-	100 : 15 : 1 : 1
Esimated Quantitation Limit		500	-	1	0.5	50	4	4	2	-	

Notes: Concentrations expressed as micrograms per gram (ug/g) unless otherwise indicated; **D** = Duplicate sample. ***Exceedances of Target Remediation Standards.***
Target remediation Standards: Soil criteria (Table B) for non-potable groundwater conditions provided in the Guideline for Use at Contaminated Sites in Ontario (1997)
In case of a discrepancy between this table and the Laboratory Reports of Analysis, the laboratory reports shall be considered correct.
Table to be read in conjunction with accompanying report.

Table 3: Summary of 2008 Soil Monitoring Analytical Results, Hydro One Biocell, Bearskin Lake

Sample Location	Sample ID	Date	Moisture	Benzene	Toluene	Ethyl -benzene	Xylenes	T P H Gas/Diesel	T P H Heavy Oils	TOC	pH	Nitrate	Nitrite	Nitrogen	Phosphorus	Potassium	Sulphur	HUB	C:N:P:K Ratios
			%	ug/g	ug/g	ug/g	ug/g	ug/g	ug/g	mg/kg		ug/g	ug/g	mg/kg	mg/kg	mg/kg	mg/kg	(Cfu/g)	
Windrow 1-1	BRGS-W1-40-08	2008-07-08	10	< 0.02	0.11	0.08	0.77	***1600***	301	21000	7.20	28	2.7	780	< 4	31	3	$7.2x10^6$	100 : 26.3 : 0.1 : 1.0
D Windrow 1-1	BRGS-W1-40-08 DUP	2008-07-08	12	< 0.02	0.13	0.07	0.77	***1578***	544										
Windrow 1-2	BRGS-W1-60-08	2008-07-08	11	< 0.02	< 0.02	< 0.02	< 0.04	***1141***	191	21000	7.43	28	12	140	< 4	41	4	$3.2x10^5$	100 : 6.7 : 0.2 : 2.0
Windrow 2-1	BRGS-W2-45-08	2008-07-08	11	< 0.02	0.02	0.04	0.41	***1281***	162	22000	7.26	14	2.4	200	5	32	3	$3.5x10^5$	100 : 9.0 : 0.2 : 1.4
Windrow 2-2	BRGS-W2-55-08	2008-07-08	10	< 0.02	< 0.02	< 0.02	< 0.04	817	32	20000	7.44	34	34	580	< 4	30	3	$2.1x10^5$	100 : 44.3 : 0.3 : 2.3
Windrow 3-1	BRGS-W3-10-08	2008-07-08	11	< 0.02	0.03	0.15	0.89	***1420***	238	14000	7.40	4	1.7	11000	< 4	33	5	$1.0x10^5$	100 444.4 : 0.2 : 1.3
Windrow 3-2	BRGS-W3-20-08	2008-07-08	12	< 0.04	< 0.04	< 0.04	0.16	***1875***	468	12000	7.59	20	0.7	110	5	24	3	$1.2x10^7$	100 3.1 : 0.1 : 0.7
Windrow 3-3	BRGS-W3-40-08	2008-07-08	10	< 0.02	< 0.02	< 0.02	0.20	***1976***	376	26000	7.40	22	13	150	5	28	< 2	$8.2x10^6$	100 : 4.2 : 0.1 : 0.8
Windrow 3-4	BRGS-W3-50-08	2008-07-08	11	< 0.02	< 0.02	0.11	0.48	***2020***	150	19000	7.41	44	8.8	190	4	30	2	$2.6x10^5$	100 : 5.9 : 0.1 : 0.9
Windrow 3-5	BRGS-W3-60-08	2008-07-08	9.3	< 0.02	< 0.02	< 0.02	< 0.04	***1810***	248	19000	7.50	34	15	190	< 4	35	2	$1.1x10^5$	100 : 5.9 : 0.1 : 1.1
Target Remediation Standards.				5.3	34	290	34	1000	1000	-	-	-	-	-	-	-		-	100 : 15 : 1 : 1
Esimated Quantitation Limit				0.02	0.02	0.02	-	-	10	500	-	4	2	2	1	1		-	

Notes: Concentrations expressed as micrograms per gram (ug/g) unless otherwise indicated; nd = non detectable; tr = trace; **D** = Duplicate sample. ***Exceedances.***
Target Remediation Standards: Soil criteria (Table B) for non-potable groundwater conditions provided in the Guideline for Use at Contaminated Sites in Ontario (1997)
In case of a discrepancy between this table and the Laboratory Reports of Analysis, the laboratory reports shall be considered correct.
Table to be read in conjunction with accompanying report.

Table 4: Summary of Monitoring Well Field Observations, Bearskin Lake Hydro One Biocell

Location	Date	Appearance	Well Condition Comments
MW1	04-08-16	Light brown	Good condition
	05-08-27	Light brown	Good condition
	05-11-29	Dark brown	Waterra tubing system replaced
	06-05-31	Dark brown	Good condition
	07-06-09	Cloudy, mod. turbid	Good condition
	08-07-07	Clear to Cloudy	Good condition
	09-08-11	Clear to Cloudy	Good condition
	10-10-26	Clear to Cloudy	Good condition
MW2	04-08-16	Light brown	Good condition
	05-08-27	Light brown	Good condition
	05-11-29	Light brown	Good condition
	06-05-31	Light brown	Good condition
	07-06-09	Light brown, turbid	Repaired Waterra tubing
	08-07-07	Clear to Cloudy	Good condition
	09-08-11	Clear to Cloudy	Good condition
	10-10-26	Clear to Cloudy	Good condition
MW3	04-08-16	Light brown	Good condition
	05-08-27	Light brown	Good condition
	05-11-29	Light brown	Waterra tubing system replaced
	06-05-31	Light brown	Good condition
	07-06-09	Cloudy, mod. turbid	Good condition
	08-07-07	Clear to Cloudy	Repaired Waterra tubing
	09-08-11	Clear to Cloudy	Good condition
	10-10-26	Clear to Cloudy	Good condition
MW4	04-08-16	Dark brown	Good condition
	05-08-27	Dark brown	Good condition
	05-11-29	Dark brown	Good condition
	06-05-31	Dark brown	Good condition
	07-06-09	Brown, cloudy	Good condition
	08-07-07	Clear to Cloudy	Repaired Waterra tubing
	09-08-11	Clear to Cloudy	Good condition
	10-10-26	Clear to Cloudy	Good condition

Table to be read in conjunction with accompanying report.

Table 5: Summary of Groundwater Levels, Bearskin Lake Hydro One Biocell

Location	Date	Ground Elevation (metres)	Top of Pipe (TOP) Elev. (metres)	Groundwater Level Ref. TOP (metres)	Groundwater Level Ref. Ground (metres)	Elevation (metres)
MW1	16-Aug-04	98.73	99.44	2.78	2.07	96.67
	27-Aug-05			1.68	0.97	97.76
	29-Nov-05			2.26	1.55	97.18
	31-May-06			2.46	1.75	96.98
	9-Jun-07			2.04	1.33	97.40
	7-Jul-08			2.36	1.65	97.08
	11-Aug-09			1.89	1.18	97.55
	26-Oct-10			2.57	1.86	96.87
MW2	16-Aug-04	98.13	99.34	2.73	1.52	96.61
	27-Aug-05			2.18	2.18	97.17
	29-Nov-05			2.39	1.18	96.95
	31-May-06			2.57	1.36	96.77
	9-Jun-07			2.29	1.07	97.06
	7-Jul-08			2.44	1.23	96.90
	11-Aug-09			2.25	1.54	97.09
	26-Oct-10			2.60	1.89	96.74
MW3	16-Aug-04	97.99	98.94	2.44	1.49	96.50
	27-Aug-05			1.73	1.73	97.21
	29-Nov-05			2.06	1.11	96.88
	31-May-06			2.26	1.31	96.68
	9-Jun-07			1.85	0.90	97.09
	7-Jul-08			2.16	1.21	96.78
	11-Aug-09			1.81	1.10	97.13
	26-Oct-10			1.33	0.62	97.61
MW4	16-Aug-04	100.56	101.70	4.83	3.69	96.87
	27-Aug-05			3.99	3.99	97.72
	29-Nov-05			4.32	3.17	97.39
	31-May-06			4.68	3.53	97.03
	9-Jun-07			4.07	2.93	97.63
	7-Jul-08			4.56	3.42	97.14
	11-Aug-09			3.93	3.93	97.77
	26-Oct-10			4.65	4.65	97.05

Notes: Bench mark reference - top of south east berm - 102.71 m
Survey completed on August 26, 2004
Table to be read in conjunction with accompanying report.

Table 6: Summary of Groundwater Analytical Results, Hydro One Biocell, Bearskin Lake

Location		Date	Benzene	6 Toluene	Ethyl-benzene	Xylenes	TPH (Gas/Diesel)	F1 + F2 PHC	F3 + F4 PHC	PCB
MW1		04-08-16	nd	nd	nd	nd	nd	-	-	nd
		05-08-27	4	278	14	14.3	nd	nd	nd	-
		05-12-02	nd	200	7.8	0.8	-	nd	nd	-
		07-06-09	nd	160	4.6	nd	180	nd	nd	-
	R	07-06-09	nd	120	3.3	0.4	140	nd	nd	-
		08-07-07	<0.5	35	2.6	<1.5	-	<100	<250	-
	D	08-07-07	<0.5	36	2.6	<1.5	-	<100	<250	-
		09-08-13	nd	nd	nd	nd	-	<100	<100	-
	D	09-08-13	nd	0.3	0.3	nd	-	<100	<100	-
		10-10-26	<0.50	<0.50	1.75	2.2	-	<100	<250	-
MW2		04-08-16	nd	nd	nd	nd	nd	-	-	-
		05-08-27	nd	nd	nd	nd	nd	nd	nd	-
		07-06-09	nd	nd	nd	nd	nd	nd	nd	-
		08-07-07	<0.5	<0.5	<0.5	<1.5	-	<100	<250	-
		09-08-13	nd	nd	nd	nd	-	<100	<100	-
		10-10-26	<0.50	<0.50	<0.50	<1.5	-	<100	<250	-
	D	10-10-26	<0.50	<0.50	<0.50	<1.5	-	<100	<250	-
MW3		04-08-16	nd	1.87	nd	1.13	nd	-	-	-
	R	04-08-16	nd	1.95	nd	1.23	nd	-	-	-
		05-08-27	nd	51.1	1.3	nd	nd	nd	nd	-
	R	05-08-27	nd	50.7	1.3	nd	nd	nd	nd	-
		05-12-02	nd	9.6	0.5	1.6	-	nd	nd	-
		07-06-09	nd	0.5	nd	nd	nd	nd	nd	-
		08-07-07	<0.5	<0.5	<0.5	<1.5	-	<100	<250	-
		09-08-13	nd	nd	nd	nd	-	<100	<100	-
		10-10-26	<0.50	<0.50	<0.50	<1.5	-	<100	<250	-
MW4		04-08-16	nd	nd	nd	nd	nd	-	-	-
		05-08-27	nd	nd	nd	nd	nd	nd	nd	-
		07-06-09	nd	nd	nd	nd	nd	nd	nd	-
		08-07-07	<0.5	<0.5	<0.5	<1.5	-	<100	<250	-
		09-08-13	nd	nd	nd	nd	-	<100	<100	-
		10-10-26	<0.50	<0.50	<0.50	<1.5	-	<100	<250	-
Criteria		Nonpotable	1900	5900	28000	5600	-	-	-	0.2
		Potable	5	24	2.4	300	1000	1000	1000	0.2
Est. Quantitation Limit			0.2	0.2	0.2	0.4	200	-	-	0.05

Notes: Concentrations expressed in micrograms per litre (ug/L); nd = non-detectable.
The Standards shown are the MOE Ontario Regulation 153/04 Soil, Ground Water and Sediment Standards (March 9, 2004), Table 3 Full Depth Generic Site Condition Standards in a Non-Potable Ground Water Condition with Industrial/Commercial/Community Property Use and Coarse Textured Soil Conditions.
Bold - Parameter exceeded the applicable MOE Table 3 Standards.. Potable standards for reference purposes only.
R = Replicate sample. D = Duplicate sample.
In case of a discrepancy between this table and the Laboratory Reports of Analysis, the laboratory reports shall be considered corr
Table to be read in conjunction with accompanying report.

LABORATORY CERTIFICATES OF ANALYSIS

TETRA TECH (MARKHAM)
ATTN: JOHN GUAN
250 SHIELDS CT.
UNIT #5
MARKHAM ON L3R 9W7
Phone: 905-470-6570

Date Received: 29-OCT-10
Report Date: 09-NOV-10 11:01 (MT)
Version: FINAL

Certificate of Analysis

Lab Work Order #: L948719
Project P.O. #: 34819
Job Reference:
Legal Site Desc: 1031872400 JCE
C of C Numbers: L948719

Richard Clara
General Manager, Thunder Bay

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948719-1 MW1							
Sampled By: KO on 26-OCT-10 @ 15:00							
Matrix: WATER							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX (O.Reg.153/04)							
Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Ethyl Benzene	1.75		0.50	ug/L		02-NOV-10	R1541423
m+p-Xylenes	2.2		1.0	ug/L		02-NOV-10	R1541423
o-Xylene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Toluene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Xylenes (Total)	2.2		1.5	ug/L		02-NOV-10	R1541423
Surrogate: 2,5-Dibromotoluene	118		70-130	%		02-NOV-10	R1541423
CCME Total Hydrocarbons							
F1-BTEX	<100		100	ug/L		08-NOV-10	
Total Hydrocarbons (C6-C50)	<250		250	ug/L		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<100		100	ug/L	01-NOV-10	02-NOV-10	R1541543
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	<100		100	ug/L	08-NOV-10	08-NOV-10	R1574523
F3 (C16-C34)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
F4 (C34-C50)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574523
Surrogate: Octacosane	87		50-120	%	08-NOV-10	08-NOV-10	R1574523
Surrogate: 2-Bromobenzotrifluoride	70		30-120	%	08-NOV-10	08-NOV-10	R1574523
L948719-2 MW2							
Sampled By: KO on 26-OCT-10 @ 15:30							
Matrix: WATER							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX (O.Reg.153/04)							
Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Ethyl Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
m+p-Xylenes	<1.0		1.0	ug/L		02-NOV-10	R1541423
o-Xylene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Toluene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Xylenes (Total)	<1.5		1.5	ug/L		02-NOV-10	R1541423
Surrogate: 2,5-Dibromotoluene	120		70-130	%		02-NOV-10	R1541423
CCME Total Hydrocarbons							
F1-BTEX	<100		100	ug/L		08-NOV-10	
Total Hydrocarbons (C6-C50)	<250		250	ug/L		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<100		100	ug/L	01-NOV-10	02-NOV-10	R1541543
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	<100		100	ug/L	08-NOV-10	08-NOV-10	R1574523
F3 (C16-C34)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
F4 (C34-C50)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574523
Surrogate: Octacosane	83		50-120	%	08-NOV-10	08-NOV-10	R1574523
Surrogate: 2-Bromobenzotrifluoride	57		30-120	%	08-NOV-10	08-NOV-10	R1574523
L948719-3 MW3							
Sampled By: KO on 26-OCT-10 @ 16:00							
Matrix: WATER							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX (O.Reg.153/04)							

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948719-3 MW3							
Sampled By: KO on 26-OCT-10 @ 16:00							
Matrix: WATER							
BTEX (O.Reg.153/04)							
Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Ethyl Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
m+p-Xylenes	<1.0		1.0	ug/L		02-NOV-10	R1541423
o-Xylene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Toluene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Xylenes (Total)	<1.5		1.5	ug/L		02-NOV-10	R1541423
Surrogate: 2,5-Dibromotoluene	126		70-130	%		02-NOV-10	R1541423
CCME Total Hydrocarbons							
F1-BTEX	<100		100	ug/L		08-NOV-10	
Total Hydrocarbons (C6-C50)	<250		250	ug/L		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<100		100	ug/L	01-NOV-10	02-NOV-10	R1541543
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	<100		100	ug/L	08-NOV-10	08-NOV-10	R1574523
F3 (C16-C34)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
F4 (C34-C50)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574523
Surrogate: Octacosane	85		50-120	%	08-NOV-10	08-NOV-10	R1574523
Surrogate: 2-Bromobenzotrifluoride	66		30-120	%	08-NOV-10	08-NOV-10	R1574523
L948719-4 MW4							
Sampled By: KO on 26-OCT-10 @ 17:30							
Matrix: WATER							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX (O.Reg.153/04)							
Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Ethyl Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
m+p-Xylenes	<1.0		1.0	ug/L		02-NOV-10	R1541423
o-Xylene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Toluene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Xylenes (Total)	<1.5		1.5	ug/L		02-NOV-10	R1541423
Surrogate: 2,5-Dibromotoluene	118		70-130	%		02-NOV-10	R1541423
CCME Total Hydrocarbons							
F1-BTEX	<100		100	ug/L		08-NOV-10	
Total Hydrocarbons (C6-C50)	<250		250	ug/L		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<100		100	ug/L	01-NOV-10	02-NOV-10	R1541543
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	<100		100	ug/L	08-NOV-10	08-NOV-10	R1574523
F3 (C16-C34)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
F4 (C34-C50)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574523
Surrogate: Octacosane	86		50-120	%	08-NOV-10	08-NOV-10	R1574523
Surrogate: 2-Bromobenzotrifluoride	66		30-120	%	08-NOV-10	08-NOV-10	R1574523
L948719-5 MW2 DUP							
Sampled By: KO on 26-OCT-10 @ 15:30							
Matrix: WATER							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX (O.Reg.153/04)							
Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948719-5 MW2 DUP							
Sampled By: KO on 26-OCT-10 @ 15:30							
Matrix: WATER							
BTEX (O.Reg.153/04)							
Ethyl Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
m+p-Xylenes	<1.0		1.0	ug/L		02-NOV-10	R1541423
o-Xylene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Toluene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Xylenes (Total)	<1.5		1.5	ug/L		02-NOV-10	R1541423
Surrogate: 2,5-Dibromotoluene	123		70-130	%		02-NOV-10	R1541423
CCME Total Hydrocarbons							
F1-BTEX	<100		100	ug/L		08-NOV-10	
Total Hydrocarbons (C6-C50)	<250		250	ug/L		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<100		100	ug/L	01-NOV-10	02-NOV-10	R1541543
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	<100		100	ug/L	08-NOV-10	08-NOV-10	R1574523
F3 (C16-C34)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
F4 (C34-C50)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574523
Surrogate: Octacosane	86		50-120	%	08-NOV-10	08-NOV-10	R1574523
Surrogate: 2-Bromobenzotrifluoride	60		30-120	%	08-NOV-10	08-NOV-10	R1574523
L948719-6 FB							
Sampled By: KO on 26-OCT-10 @ 18:00							
Matrix: WATER							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX (O.Reg.153/04)							
Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Ethyl Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
m+p-Xylenes	<1.0		1.0	ug/L		02-NOV-10	R1541423
o-Xylene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Toluene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Xylenes (Total)	<1.5		1.5	ug/L		02-NOV-10	R1541423
Surrogate: 2,5-Dibromotoluene	120		70-130	%		02-NOV-10	R1541423
CCME Total Hydrocarbons							
F1-BTEX	<100		100	ug/L		08-NOV-10	
Total Hydrocarbons (C6-C50)	<250		250	ug/L		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<100		100	ug/L	01-NOV-10	02-NOV-10	R1541543
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	<100		100	ug/L	08-NOV-10	08-NOV-10	R1574523
F3 (C16-C34)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
F4 (C34-C50)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574523
Surrogate: Octacosane	86		50-120	%	08-NOV-10	08-NOV-10	R1574523
Surrogate: 2-Bromobenzotrifluoride	58		30-120	%	08-NOV-10	08-NOV-10	R1574523
L948719-7 TRAVEL BLANK							
Sampled By: KO on 26-OCT-10							
Matrix: WATER							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX (O.Reg.153/04)							
Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Ethyl Benzene	<0.50		0.50	ug/L		02-NOV-10	R1541423

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948719-7 TRAVEL BLANK							
Sampled By: KO on 26-OCT-10							
Matrix: WATER							
BTEX (O.Reg.153/04)							
m+p-Xylenes	<1.0		1.0	ug/L		02-NOV-10	R1541423
o-Xylene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Toluene	<0.50		0.50	ug/L		02-NOV-10	R1541423
Xylenes (Total)	<1.5		1.5	ug/L		02-NOV-10	R1541423
Surrogate: 2,5-Dibromotoluene	105		70-130	%		02-NOV-10	R1541423
CCME Total Hydrocarbons							
F1-BTEX	<100		100	ug/L		08-NOV-10	
Total Hydrocarbons (C6-C50)	<250		250	ug/L		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<100		100	ug/L	01-NOV-10	02-NOV-10	R1541543
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	<100		100	ug/L	08-NOV-10	08-NOV-10	R1574523
F3 (C16-C34)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
F4 (C34-C50)	<250		250	ug/L	08-NOV-10	08-NOV-10	R1574523
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574523
Surrogate: Octacosane	86		50-120	%	08-NOV-10	08-NOV-10	R1574523
Surrogate: 2-Bromobenzotrifluoride	64		30-120	%	08-NOV-10	08-NOV-10	R1574523

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

Reference Information

Test Method References:

ALS Test Code	Matrix	Test Description	Method Reference**
BTX-R153-WT	Water	BTEX (O.Reg.153/04)	MOE DECPH-E3421/CCME TIER 1
F1-F4-CALC-WT	Water	CCME Total Hydrocarbons	CCME CWS-PHC DEC-2000 - PUB# 1310-L

Analytical methods used for analysis of CCME Petroleum Hydrocarbons have been validated and comply with the Reference Method for the CWS PHC.

In cases where results for both F4 and F4G are reported, the greater of the two results must be used in any application of the CWS PHC guidelines and the gravimetric heavy hydrocarbons cannot be added to the C6 to C50 hydrocarbons.
In samples where BTEX and F1 were analyzed , F1-BTEX represents a value where the sum of Benzene, Toluene, Ethylbenzene and total Xylenes has been subtracted from F1.

In samples where PAHs, F2 and F3 were analyzed, F2-Naphth represents the result where Naphthalene has been subtracted from F2. F3-PAH represents a result where the sum of Benzo(a)anthracene, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, Dibenzo(a,h)anthracene, Fluoranthene, Indeno(1,2,3-cd)pyrene, Phenanthrene, and Pyrene has been subtracted from F3.

Unless otherwise qualified, the following quality control criteria have been met for the F1 hydrocarbon range:
1. All extraction and analysis holding times were met.
2. Instrument performance showing response factors for C6 and C10 within 30% of the response factor for toluene.
3. Linearity of gasoline response within 15% throughout the calibration range.

Unless otherwise qualified, the following quality control criteria have been met for the F2-F4 hydrocarbon ranges:
1. All extraction and analysis holding times were met.
2. Instrument performance showing C10, C16 and C34 response factors within 10% of their average.
3. Instrument performance showing the C50 response factor within 30% of the average of the C10, C16 and C34 response factors.
4. Linearity of diesel or motor oil response within 15% throughout the calibration range.

F1-WT	Water	F1 (O.Reg.153/04)	MOE DECPH-E3421/CCME TIER 1

The F1 fraction, nC6 to nC10 hydrocarbons, is determined by purging a known volume or weight of the original sample. The sample is analyzed by purge and trap, gas chromatography (GC) with a 100% poly(dimethylsiloxane) (DB-1 or equivalent) column and a combination of a flame ionization detector (FID) and a mass selective detector (MSD). All area counts from the FID are integrated from the beginning of the nC6 peak to the apex of the nC10 peak to give F1. Standards containing nC6, nC10 and toluene are run at least once daily. Toluene is used as the calibration standard for the F1 fraction. The nC6 and nC10 response factors must be within 30% of the response factor for toluene.

F2-F4-WT	Water	F2-F4 (O.Reg.153/04)	MOE DECPH-E3421/CCME TIER 1

The petroleum hydrocarbons are extracted from the aqueous samples using solvent partition. The extracts are treated with silica gel to remove polar contaminants. The final concentrated extract is analyzed by gas chromatography (GC) using flame ionization detection (FID) and a 100% polydimethylsiloxane column.

The F2 fraction is determined by integrating the area in the chromatogram from the apex of nC10 to the apex nC16 and quantitating using external calibration using a standard mix containing nC10, nC16 and nC34. Similarly, the F3 fraction extends from the apex of nC16 to the apex nC34 and the F4 fraction covers the area from the apex nC34 to the apex nC50. If the chromatogram does not return to the baseline by the time nC50 elutes, a gravimetric determination of the F4 is performed.

** ALS test methods may incorporate modifications from specified reference methods to improve performance.

The last two letters of the above test code(s) indicate the laboratory that performed analytical analysis for that test. Refer to the list below:

Laboratory Definition Code	Laboratory Location
WT	ALS LABORATORY GROUP - WATERLOO, ONTARIO, CANADA

Chain of Custody Numbers:

L948719

Reference Information

Test Method References:

ALS Test Code	Matrix	Test Description	Method Reference**

GLOSSARY OF REPORT TERMS

Surrogates are compounds that are similar in behaviour to target analyte(s), but that do not normally occur in environmental samples. For applicable tests, surrogates are added to samples prior to analysis as a check on recovery. In reports that display the D.L. column, laboratory objectives for surrogates are listed there.
mg/kg - milligrams per kilogram based on dry weight of sample
mg/kg wwt - milligrams per kilogram based on wet weight of sample
mg/kg lwt - milligrams per kilogram based on lipid-adjusted weight
mg/L - unit of concentration based on volume, parts per million.
< - Less than.
D.L. - The reporting limit.
N/A - Result not available. Refer to qualifier code and definition for explanation.

Test results reported relate only to the samples as received by the laboratory.
UNLESS OTHERWISE STATED, ALL SAMPLES WERE RECEIVED IN ACCEPTABLE CONDITION.
Analytical results in unsigned test reports with the DRAFT watermark are subject to change, pending final QC review.

Quality Control Report

Client: TETRA TECH (MARKHAM)
250 SHIELDS CT. UNIT #5
MARKHAM ON L3R 9W7

Contact: JOHN GUAN

Test	Matrix	Reference	Result	Qualifier	Units	RPD	Limit	Analyzed
BTX-R153-WT	**Water**							
Batch R1541423								
WG1194517-1 CVS								
Benzene			86		%		70-130	02-NOV-10
Ethyl Benzene			93		%		70-130	02-NOV-10
m+p-Xylenes			83		%		70-130	02-NOV-10
o-Xylene			84		%		70-130	02-NOV-10
Toluene			101		%		70-130	02-NOV-10
WG1194517-3 DUP		**L948719-6**						
Benzene		<0.50	<0.50	RPD-NA	ug/L	N/A	30	02-NOV-10
Ethyl Benzene		<0.50	<0.50	RPD-NA	ug/L	N/A	30	02-NOV-10
m+p-Xylenes		<1.0	<1.0	RPD-NA	ug/L	N/A	50	02-NOV-10
o-Xylene		<0.50	<0.50	RPD-NA	ug/L	N/A	30	02-NOV-10
Toluene		<0.50	<0.50	RPD-NA	ug/L	N/A	50	02-NOV-10
WG1194517-2 MB								
Benzene			<0.50		ug/L		0.5	02-NOV-10
Ethyl Benzene			<0.50		ug/L		0.5	02-NOV-10
m+p-Xylenes			<1.0		ug/L		1	02-NOV-10
o-Xylene			<0.50		ug/L		0.5	02-NOV-10
Toluene			<0.50		ug/L		0.5	02-NOV-10
F1-WT	**Water**							
Batch R1541543								
WG1194518-1 CVS								
F1 (C6-C10)			74		%		80-120	02-NOV-10
WG1194518-4 DUP		**L948719-6**						
F1 (C6-C10)		<100	<100	RPD-NA	ug/L	N/A	30	02-NOV-10
WG1194518-2 MB								
F1 (C6-C10)			<100		ug/L		100	02-NOV-10
F2-F4-WT	**Water**							
Batch R1574523								
WG1198093-1 CVS								
F2 (C10-C16)			103		%		80-120	08-NOV-10
F3 (C16-C34)			102		%		80-120	08-NOV-10
F4 (C34-C50)			97		%		80-120	08-NOV-10
WG1197374-2 LCS								
F2 (C10-C16)			77		%		50-120	08-NOV-10
F3 (C16-C34)			80		%		50-120	08-NOV-10
F4 (C34-C50)			78		%		50-120	08-NOV-10
WG1197374-3		**WG1197374-2**						

Quality Control Report

Test		Matrix	Reference	Result	Qualifier	Units	RPD	Limit	Analyzed
F2-F4-WT		**Water**							
Batch	**R1574523**								
WG1197374-3	**LCSD**		**WG1197374-2**						
F2 (C10-C16)			77	51		%	39	50	08-NOV-10
F3 (C16-C34)			80	54		%	39	50	08-NOV-10
F4 (C34-C50)			78	53		%	38	50	08-NOV-10
WG1197374-1	**MB**								
F2 (C10-C16)				<100		ug/L		100	08-NOV-10
F3 (C16-C34)				<250		ug/L		250	08-NOV-10
F4 (C34-C50)				<250		ug/L		250	08-NOV-10

Legend:

Limit	99% Confidence Interval (Laboratory Control Limits)
DUP	Duplicate
RPD	Relative Percent Difference
N/A	Not Available
LCS	Laboratory Control Sample
SRM	Standard Reference Material
MS	Matrix Spike
MSD	Matrix Spike Duplicate
ADE	Average Desorption Efficiency
MB	Method Blank
IRM	Internal Reference Material
CRM	Certified Reference Material
CCV	Continuing Calibration Verification
CVS	Calibration Verification Standard
LCSD	Laboratory Control Sample Duplicate

Sample Parameter Qualifier Definitions:

Qualifier	Description
RPD-NA	Relative Percent Difference Not Available due to result(s) being less than detection limit.

Hold Time Exceedances:

All test results reported with this submission were conducted within ALS recommended hold times.

ALS recommended hold times may vary by province. They are assigned to meet known provincial and/or federal government requirements. In the absence of regulatory hold times, ALS establishes recommendations based on guidelines published by the US EPA, APHA Standard Methods, or Environment Canada (where available). For more information, please contact ALS.

The ALS Quality Control Report is provided to ALS clients upon request. ALS includes comprehensive QC checks with every analysis to ensure our high standards of quality are met. Each QC result has a known or expected target value, which is compared against pre-determined data quality objectives to provide confidence in the accuracy of associated test results.

Please note that this report may contain QC results from anonymous Sample Duplicates and Matrix Spikes that do not originate from this Work Order.

ALS Environmental

Chain of Custody / Analytical Request Form
Canada Toll Free: 1 800 668 9878
www.alsglobal.com

COC # L948719

Page 1 of 1

Report To
Company: Tetra Tech (Wardrop)
Contact: John Guan
Address: 250 Shields Crt #15
Markham, ON L3R 9W7
Phone: 905-470-6570 Fax: 905-470-0958

Report Format / Distribution
Standard Other (specify): email
PDF Excel Digital Fax
Email 1: john.guan@tetratech.com
Email 2: rene.devries@tetratech.com
#3: labresultsON@tetratech.com

Service Requested (Rush for routine analysis subject to availability)
Regular (Default) ✓
Priority (Specify Date Required → →) Surcharges apply
Emergency (1 Business Day) - 100% Surcharge
For Emergency < 1 Day, ASAP or Weekend - Contact ALS

Invoice To Same as Report ? Yes No

THE QUESTIONS BELOW MUST BE ANSWERED FOR WATER SAMPLES (circle Yes or No)
Are any samples taken from a regulated DW System? Yes **No**
If yes, an authorized Drinking Water COC MUST be used for this submission.
Is the water sampled intended to be potable for human consumption? Yes **No**

Client / Project Information
Job #: ~~0013~~ ~~0031871304~~
PO / AFE: 34819
LSD:
1031872400 (JCC)
Quote #:

Lab Work Order # (lab use only)

ALS Contact: Karen Sampler: KO

Analysis Request
Please indicate below Filtered, Preserved or both (F, P, F/P)

Sample #	Sample Identification (This description will appear on the report)	Date (dd-mmm-yy)	Time (hh:mm)	Sample Type	BTEX (P)	F1-F4 (P)	~~PHC (g/d)~~	Number of Containers
1	MW1	26-oct-10	3:00	water	X	X	~~X~~	4
2	MW2	↓	3:30	↓	X	X	~~X~~	4
3	MW3		4:00		X	X	~~X~~	4
4	MW4		5:30		X	X	~~X~~	4
5	MW2dup		3:30		X	X	~~X~~	4
6	FB		6:00		X	X	~~X~~	4
7	Travel ~~Trip~~ Blank	↓	–	↓	X	X	~~X~~	4

NOT CONSU[illegible]D

Special Instructions / Regulations / Hazardous Details

Reg 153 Table 1 2 3 TCLP MISA PWQO OTHER (please specify):
Circle one - Note drinking water samples MUST USE DW Chain of Custody

Failure to complete all portions of this form may delay analysis. Please fill in this form LEGIBLY.
By the use of this form the user acknowledges and agrees with the Terms and Conditions as specified on the back page of the white - report copy.

SHIPMENT RELEASE (client use)			SHIPMENT RECEPTION (lab use only)				SHIPMENT VERIFICATION (lab use only)			
Released by:	Date:	Time:	Received by:	Date:	Time:	Temperature:	Verified by:	Date:	Time:	Observations: Yes / No ? If Yes add SIF
[illegible]	29 OCT 2010	10.00	REB	Oct 29/10	12:10	8.0 °C	REB	Oct 29/10	13:18	

TYFM014 26-Mar-10

Wardrop Engineering Inc. Lab Data Checklist

ALS Job Number:	L948719	Client:	Hydro One
Chain of Custody #	NA	Location No.:	Bearskin Lake
		Wardrop Project Number:	1031872400

General

Questions	Answers (Y/N)	Comments
Was **Chain of Custody** completed correctly?	Yes	
Was **Temperature** acceptable upon arrival to lab.?	Yes	
Were samples analysed within the **hold time**?	Yes	
Methanol Extracted within 48 hrs?	NA	
Is the **Certificate of Analysis** signed?	Yes	

Laboratory Quality Control Check

Are the following within acceptable criteria?	Answers (Y/N)	Comments
Calibration Verification Standard Recovery	Yes	
Spike blank Recovery (LCS)	Yes	
Matrix Spike Recovery	NA	
Blank (MB) Concentration	Yes	
Matrix Duplicate (MSD) **RPD**	Yes	

Field Quality Control Samples

Are the following within alert limits?	Answers (Y/N)	Comments
Field Blank Concentration	Yes	
Equipment Blank Concentration	NA	No equipment blank in submission.
Trip Blank Concentration	Yes	
Field Duplicate RPD	Yes	

Data quality check performed by: Kelly Jones

Date: 11-Nov-10

TETRA TECH (MARKHAM)
ATTN: JOHN GUAN
250 SHIELDS CT.
UNIT #5
MARKHAM ON L3R 9W7

Phone: 905-470-6570

Date Received: 29-OCT-10
Report Date: 14-DEC-10 16:16 (MT)
Version: FINAL REV. 3

Certificate of Analysis

Lab Work Order #: L948740
Project P.O. #: 34819
Job Reference:
Legal Site Desc: 1031872400
C of C Numbers: L948740

Comments: ADDITIONAL 24-NOV-10 11:58

Results reported for TVH, TEH and heavy oil on the samples for login number L935513 were not extracted according to the method requirements stated in the Guideline for Use at Contaminated Sites (GUCS). For the TVH and TEH analysis, the samples were extracted according to the CCME methods and then the extracts were run by GCFID and were integrated according to the carbon ranges used in the GUCS methods. The heavy oil determination was performed on samples that were extracted and cleaned-up with silica gel according to the F4G method prescribed by CCME and then the gravimetric results were reported as heavy oil for the TPH heavy oil determination.
26-Nov-10:
08-DEC-10: Added determinations for TPH
14-DEC-10:

Richard Clara
General Manager, Thunder Bay

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-1 R1-1							
Sampled By: K.O. on 26-OCT-10 @ 09:30							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	99		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	95		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	107		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	207		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	37		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	170		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	93		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	80		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	6.18		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	150		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	56		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	150		10	mg/kg		26-NOV-10	
L948740-2 R1 - 2							
Sampled By: K.O. on 26-OCT-10 @ 10:00							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	96		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	90		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	101		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	232		50	mg/kg		08-NOV-10	

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-2 R1 - 2							
Sampled By: K.O. on 26-OCT-10 @ 10:00							
Matrix: SOIL							
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	37		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	195		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	108		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	84		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	5.79		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	110		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	166		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	65		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	166		10	mg/kg		26-NOV-10	
L948740-3 R1 - 3							
Sampled By: K.O. on 26-OCT-10 @ 10:30							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	97		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	92		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	105		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	337		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	66		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	271		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	116		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	83		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	6.02		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655365

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-3 R1 - 3							
Sampled By: K.O. on 26-OCT-10 @ 10:30							
Matrix: SOIL							
TPH (C10-C24)							
TPH (C10-C24)	248		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	60		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	248		10	mg/kg		26-NOV-10	
L948740-4 R1 - 4							
Sampled By: K.O. on 26-OCT-10 @ 10:45							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	102		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	97		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	118		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	549		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	116		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	433		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	103		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	80		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	6.12		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	230		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	471		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	62		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	471		10	mg/kg		26-NOV-10	
L948740-5 R1 - 5							
Sampled By: K.O. on 26-OCT-10 @ 13:00							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-5 R1 - 5							
Sampled By: K.O. on 26-OCT-10 @ 13:00							
Matrix: SOIL							
BTEX by Headspace							
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	93		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	92		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	109		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	240		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	38		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	202		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	101		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	75		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	7.52		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	181		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	60		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	181		10	mg/kg		26-NOV-10	
L948740-6 R1 - 6							
Sampled By: K.O. on 26-OCT-10 @ 13:20							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	95		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	91		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	109		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	492		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-6 R1 - 6							
Sampled By: K.O. on 26-OCT-10 @ 13:20							
Matrix: SOIL							
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	100		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	392		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	103		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	81		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	8.09		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	190		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	386		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	62		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	386		10	mg/kg		26-NOV-10	
L948740-7 R1 - 7							
Sampled By: K.O. on 26-OCT-10 @ 13:40							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	95		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	94		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	103		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	530		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	174		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	356		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	89		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	89		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	10.6		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	150		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	415		10	mg/kg	24-NOV-10	24-NOV-10	R1649603

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-7 R1 - 7							
Sampled By: K.O. on 26-OCT-10 @ 13:40							
Matrix: SOIL							
TPH (C10-C24)							
Surrogate: Octacosane	53		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	415		10	mg/kg		26-NOV-10	
L948740-8 R1 - 8							
Sampled By: K.O. on 26-OCT-10 @ 14:10							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	96		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	93		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	103		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	305		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	66		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	239		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	98		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	78		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	9.55		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	225		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	59		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	225		10	mg/kg		26-NOV-10	
L948740-9 R1 - 9							
Sampled By: K.O. on 26-OCT-10 @ 14:15							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-9 R1 - 9							
Sampled By: K.O. on 26-OCT-10 @ 14:15							
Matrix: SOIL							
BTEX by Headspace							
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	94		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	88		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	102		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	362		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	104		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	258		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	100		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	74		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	11.9		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	288		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	60		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	288		10	mg/kg		26-NOV-10	
L948740-10 R1 - 10							
Sampled By: K.O. on 26-OCT-10 @ 15:00							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	95		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	92		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	107		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	145		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	18		10	mg/kg	05-NOV-10	08-NOV-10	R1572044

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-10 R1 - 10							
Sampled By: K.O. on 26-OCT-10 @ 15:00							
Matrix: SOIL							
F2-F4 (O.Reg.153/04)							
F3 (C16-C34)	127		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	102		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	79		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	5.02		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	73		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	61		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	73		10	mg/kg		26-NOV-10	
L948740-11 R1 - 9 DUP							
Sampled By: K.O. on 26-OCT-10 @ 14:25							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	95		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	90		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	107		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	277		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	56		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	221		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	92		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	75		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	10.5		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	204		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	55		N/A	%	24-NOV-10	24-NOV-10	R1649603

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-11 R1 - 9 DUP							
Sampled By: K.O. on 26-OCT-10 @ 14:25							
Matrix: SOIL							
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	204		10	mg/kg		26-NOV-10	
L948740-12 R2 - 1							
Sampled By: K.O. on 26-OCT-10 @ 09:40							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	94		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	91		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	109		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	212		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	50		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	162		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	97		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	77		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	5.71		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	160		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	58		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	160		10	mg/kg		26-NOV-10	
L948740-13 R2 - 2							
Sampled By: K.O. on 26-OCT-10 @ 10:20							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-13 R2 - 2							
Sampled By: K.O. on 26-OCT-10 @ 10:20							
Matrix: SOIL							
BTEX by Headspace							
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	95		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	91		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	102		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	182		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	37		10	mg/kg	05-NOV-10	08-NOV-10	R1572044
F3 (C16-C34)	145		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
F4 (C34-C50)	<50		50	mg/kg	05-NOV-10	08-NOV-10	R1572044
Chrom. to baseline at nC50	YES				05-NOV-10	08-NOV-10	R1572044
Surrogate: Octacosane	90		70-130	%	05-NOV-10	08-NOV-10	R1572044
Surrogate: 2-Bromobenzotrifluoride	75		70-130	%	05-NOV-10	08-NOV-10	R1572044
Miscellaneous Parameters							
% Moisture	5.87		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655365
TPH (C10-C24)							
TPH (C10-C24)	122		10	mg/kg	24-NOV-10	24-NOV-10	R1649603
Surrogate: Octacosane	54		N/A	%	24-NOV-10	24-NOV-10	R1649603
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	122		10	mg/kg		26-NOV-10	
L948740-14 R2 - 3							
Sampled By: K.O. on 26-OCT-10 @ 10:40							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	95		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	106		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	96		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	332		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	64		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	268		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-14 R2 - 3							
Sampled By: K.O. on 26-OCT-10 @ 10:40							
Matrix: SOIL							
F2-F4 (O.Reg.153/04)							
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	100		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	75		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	5.85		0.10	%	01-NOV-10	01-NOV-10	R1538483
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	200		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	258		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	60		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	258		10	mg/kg		26-NOV-10	
L948740-15 R2 - 4							
Sampled By: K.O. on 26-OCT-10 @ 11:00							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	98		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	90		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	108		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	292		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	51		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	241		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	92		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	71		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	7.46		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	130		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	222		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	55		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-15 R2 - 4							
Sampled By: K.O. on 26-OCT-10 @ 11:00							
Matrix: SOIL							
TPH Total (C5-C24)							
TPH Total (C5-C24)	222		10	mg/kg		26-NOV-10	
L948740-16 R2 - 5							
Sampled By: K.O. on 26-OCT-10 @ 13:15							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	95		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	91		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	107		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	510		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	144		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	366		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	96		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	73		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	7.78		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	190		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	434		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	58		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	434		10	mg/kg		26-NOV-10	
L948740-17 R2 - 6							
Sampled By: K.O. on 26-OCT-10 @ 13:30							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	94		70-130	%	01-NOV-10	02-NOV-10	R1544203

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ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-17 R2 - 6							
Sampled By: K.O. on 26-OCT-10 @ 13:30							
Matrix: SOIL							
BTEX by Headspace							
Surrogate: 4-Bromofluorobenzene	88		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	95		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	391		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	96		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	295		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	93		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	88		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	8.78		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	170		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	314		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	56		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	314		10	mg/kg		26-NOV-10	
L948740-18 R2 - 7							
Sampled By: K.O. on 26-OCT-10 @ 13:50							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	98		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	94		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	99		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	952		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	132		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	710		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	110		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	110		70-130	%	08-NOV-10	08-NOV-10	R1574623

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-18 R2 - 7							
Sampled By: K.O. on 26-OCT-10 @ 13:50							
Matrix: SOIL							
F2-F4 (O.Reg.153/04)							
Surrogate: 2-Bromobenzotrifluoride	81		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	9.46		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	380		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	509		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	66		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	509		10	mg/kg		26-NOV-10	
L948740-19 R2 - 8							
Sampled By: K.O. on 26-OCT-10 @ 13:55							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	93		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	90		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	96		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	629		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	152		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	477		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	111		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	84		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	8.67		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	220		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	512		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	67		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	512		10	mg/kg		26-NOV-10	

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-20 R2 - 9							
Sampled By: K.O. on 26-OCT-10 @ 14:35							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544203
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544203
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544203
Surrogate: 1,4-Difluorobenzene	93		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 4-Bromofluorobenzene	88		70-130	%	01-NOV-10	02-NOV-10	R1544203
Surrogate: 3,4-Dichlorotoluene	94		70-130	%	01-NOV-10	02-NOV-10	R1544203
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	357		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544203
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	68		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	289		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	103		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	79		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	11.6		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	100		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	277		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	62		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656243
TPH Total (C5-C24)							
TPH Total (C5-C24)	277		10	mg/kg		26-NOV-10	
L948740-21 R2 - 10							
Sampled By: K.O. on 26-OCT-10 @ 14:45							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	99		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	96		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	94		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	278		50	mg/kg		08-NOV-10	

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-21 R2 - 10							
Sampled By: K.O. on 26-OCT-10 @ 14:45							
Matrix: SOIL							
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	49		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	229		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	107		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	84		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	7.92		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	120		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	178		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	64		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	178		10	mg/kg		26-NOV-10	
L948740-22 R2 - 8 DUP							
Sampled By: K.O. on 26-OCT-10 @ 13:55							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	98		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	93		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	98		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	520		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	112		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	408		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	106		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	81		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	10.0		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655384

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-22 R2 - 8 DUP							
Sampled By: K.O. on 26-OCT-10 @ 13:55							
Matrix: SOIL							
TPH (C10-C24)							
TPH (C10-C24)	404		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	63		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	404		10	mg/kg		26-NOV-10	
L948740-23 R3 - 1							
Sampled By: K.O. on 26-OCT-10 @ 09:50							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	102		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	97		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	101		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	247		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	58		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	189		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	98		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	78		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	7.63		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	194		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	59		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	194		10	mg/kg		26-NOV-10	
L948740-24 R3 - 2							
Sampled By: K.O. on 26-OCT-10 @ 10:10							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764

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Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-24 R3 - 2							
Sampled By: K.O. on 26-OCT-10 @ 10:10							
Matrix: SOIL							
BTEX by Headspace							
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	104		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	96		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	102		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	249		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	48		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	201		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	99		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	82		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	5.91		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	191		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	59		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	191		10	mg/kg		26-NOV-10	
L948740-25 R3 - 3							
Sampled By: K.O. on 26-OCT-10 @ 10:35							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	103		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	96		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	101		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	315		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

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Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-25 R3 - 3							
Sampled By: K.O. on 26-OCT-10 @ 10:35							
Matrix: SOIL							
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	71		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	244		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	91		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	73		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	6.40		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	250		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	55		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	250		10	mg/kg		26-NOV-10	
L948740-26 R3 - 4							
Sampled By: K.O. on 26-OCT-10 @ 10:50							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	102		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	100		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	99		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	310		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	59		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	251		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	88		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	83		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	6.23		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	160		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	243		10	mg/kg	24-NOV-10	24-NOV-10	R1649523

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-26 R3 - 4							
Sampled By: K.O. on 26-OCT-10 @ 10:50							
Matrix: SOIL							
TPH (C10-C24)							
Surrogate: Octacosane	53		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	243		10	mg/kg		26-NOV-10	
L948740-27 R3 - 5							
Sampled By: K.O. on 26-OCT-10 @ 13:05							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	102		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	96		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	110		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	348		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	66		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	282		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	102		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	76		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	6.98		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	110		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	274		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	61		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	274		10	mg/kg		26-NOV-10	
L948740-28 R3 - 6							
Sampled By: K.O. on 26-OCT-10 @ 13:25							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-28 R3 - 6							
Sampled By: K.O. on 26-OCT-10 @ 13:25							
Matrix: SOIL							
BTEX by Headspace							
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	101		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	98		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	112		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	18.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	911		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	18.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	367		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	526		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	96		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	70		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	11.0		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	280		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	719		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	58		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	719		10	mg/kg		26-NOV-10	
L948740-29 R3 - 7							
Sampled By: K.O. on 26-OCT-10 @ 03:45							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	100		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	98		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	102		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	499		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	138		10	mg/kg	08-NOV-10	08-NOV-10	R1574623

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-29 R3 - 7							
Sampled By: K.O. on 26-OCT-10 @ 03:45							
Matrix: SOIL							
F2-F4 (O.Reg.153/04)							
F3 (C16-C34)	361		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	102		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	74		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	9.00		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	240		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	400		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	61		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	400		10	mg/kg		26-NOV-10	
L948740-30 R3 - 8							
Sampled By: K.O. on 26-OCT-10 @ 14:00							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	103		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	98		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	105		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	414		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	87		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	327		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	98		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	75		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	8.69		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	200		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	324		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	59		N/A	%	24-NOV-10	24-NOV-10	R1649523

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-30 R3 - 8							
Sampled By: K.O. on 26-OCT-10 @ 14:00							
Matrix: SOIL							
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	324		10	mg/kg		26-NOV-10	
L948740-31 R3 - 9							
Sampled By: K.O. on 26-OCT-10 @ 14:25							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	102		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	97		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	105		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	374		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	71		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	303		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	100		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	79		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	10.3		0.10	%	01-NOV-10	01-NOV-10	R1538564
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	150		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	275		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	60		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	275		10	mg/kg		26-NOV-10	
L948740-32 R3 - 10							
Sampled By: K.O. on 26-OCT-10 @ 14:55							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-32 R3 - 10							
Sampled By: K.O. on 26-OCT-10 @ 14:55							
Matrix: SOIL							
BTEX by Headspace							
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	102		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	97		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	89		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	232		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	26		10	mg/kg	08-NOV-10	08-NOV-10	R1574623
F3 (C16-C34)	206		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574623
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574623
Surrogate: Octacosane	111		70-130	%	08-NOV-10	08-NOV-10	R1574623
Surrogate: 2-Bromobenzotrifluoride	78		70-130	%	08-NOV-10	08-NOV-10	R1574623
Miscellaneous Parameters							
% Moisture	9.12		0.10	%	01-NOV-10	01-NOV-10	R1540243
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	<100		100	mg/kg	25-NOV-10	25-NOV-10	R1655384
TPH (C10-C24)							
TPH (C10-C24)	126		10	mg/kg	24-NOV-10	24-NOV-10	R1649523
Surrogate: Octacosane	67		N/A	%	24-NOV-10	24-NOV-10	R1649523
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	126		10	mg/kg		26-NOV-10	
L948740-33 R3 - 8 DUP							
Sampled By: K.O. on 26-OCT-10 @ 14:00							
Matrix: SOIL							
BTEX, F1-F4 (O.Reg.153/04)							
BTEX by Headspace							
Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Ethyl Benzene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
m+p-Xylenes	<0.10		0.10	mg/kg	01-NOV-10	02-NOV-10	R1544764
o-Xylene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Toluene	<0.050		0.050	mg/kg	01-NOV-10	02-NOV-10	R1544764
Xylenes (Total)	<0.15		0.15	mg/kg	01-NOV-10	02-NOV-10	R1544764
Surrogate: 1,4-Difluorobenzene	99		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 4-Bromofluorobenzene	95		70-130	%	01-NOV-10	02-NOV-10	R1544764
Surrogate: 3,4-Dichlorotoluene	91		70-130	%	01-NOV-10	02-NOV-10	R1544764
CCME Total Hydrocarbons							
F1-BTEX	<5.0		5.0	mg/kg		08-NOV-10	
Total Hydrocarbons (C6-C50)	558		50	mg/kg		08-NOV-10	
F1 (O.Reg.153/04)							
F1 (C6-C10)	<5.0		5.0	mg/kg	01-NOV-10	02-NOV-10	R1544764
F2-F4 (O.Reg.153/04)							
F2 (C10-C16)	155		10	mg/kg	08-NOV-10	08-NOV-10	R1574743
F3 (C16-C34)	403		50	mg/kg	08-NOV-10	08-NOV-10	R1574743
F4 (C34-C50)	<50		50	mg/kg	08-NOV-10	08-NOV-10	R1574743

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

ALS LABORATORY GROUP ANALYTICAL REPORT

Sample Details/Parameters	Result	Qualifier*	D.L.	Units	Extracted	Analyzed	Batch
L948740-33 R3 - 8 DUP							
Sampled By: K.O. on 26-OCT-10 @ 14:00							
Matrix: SOIL							
F2-F4 (O.Reg.153/04)							
Chrom. to baseline at nC50	YES				08-NOV-10	08-NOV-10	R1574743
Surrogate: Octacosane	98		70-130	%	08-NOV-10	08-NOV-10	R1574743
Surrogate: 2-Bromobenzotrifluoride	76		70-130	%	08-NOV-10	08-NOV-10	R1574743
Miscellaneous Parameters							
% Moisture	6.32		0.10	%	01-NOV-10	01-NOV-10	R1540243
Total Petroleum Hydrocarbons + Heavy Oil							
Heavy Oil (C24-C50)							
Heavy Oil (C24-C50)	240		100	mg/kg	25-NOV-10	25-NOV-10	R1655385
TPH (C10-C24)							
TPH (C10-C24)	443		10	mg/kg	24-NOV-10	24-NOV-10	R1649563
Surrogate: Octacosane	59		N/A	%	24-NOV-10	24-NOV-10	R1649563
TPH (C5-C10)							
TPH (C5-C10)	<10		10	mg/kg	25-NOV-10	26-NOV-10	R1656603
TPH Total (C5-C24)							
TPH Total (C5-C24)	443		10	mg/kg		26-NOV-10	

* Refer to Referenced Information for Qualifiers (if any) and Methodology.

Reference Information

Test Method References:

ALS Test Code	Matrix	Test Description	Method Reference**
BTX-HS-WT	Soil	BTEX by Headspace	SW846 8260 (HEADSPACE)
ETL-TPH-ONT-WT	Soil	TPH Total (C5-C24)	Calculation
F1-F4-CALC-WT	Soil	CCME Total Hydrocarbons	CCME CWS-PHC DEC-2000 - PUB# 1310-S

Analytical methods used for analysis of CCME Petroleum Hydrocarbons have been validated and comply with the Reference Method for the CWS PHC.

Hydrocarbon results are expressed on a dry weight basis.

In cases where results for both F4 and F4G are reported, the greater of the two results must be used in any application of the CWS PHC guidelines and the gravimetric heavy hydrocarbons cannot be added to the C6 to C50 hydrocarbons.
In samples where BTEX and F1 were analyzed , F1-BTEX represents a value where the sum of Benzene, Toluene, Ethylbenzene and total Xylenes has been subtracted from F1.

In samples where PAHs, F2 and F3 were analyzed, F2-Naphth represents the result where Naphthalene has been subtracted from F2. F3-PAH represents a result where the sum of Benzo(a)anthracene, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, Dibenzo(a,h)anthracene, Fluoranthene, Indeno(1,2,3-cd)pyrene, Phenanthrene, and Pyrene has been subtracted from F3.

Unless otherwise qualified, the following quality control criteria have been met for the F1 hydrocarbon range:
1. All extraction and analysis holding times were met.
2. Instrument performance showing response factors for C6 and C10 within 30% of the response factor for toluene.
3. Linearity of gasoline response within 15% throughout the calibration range.

Unless otherwise qualified, the following quality control criteria have been met for the F2-F4 hydrocarbon ranges:
1. All extraction and analysis holding times were met.
2. Instrument performance showing C10, C16 and C34 response factors within 10% of their average.
3. Instrument performance showing the C50 response factor within 30% of the average of the C10, C16 and C34 response factors.
4. Linearity of diesel or motor oil response within 15% throughout the calibration range.

ALS Test Code	Matrix	Test Description	Method Reference**
F1-HS-WT	Soil	F1 (O.Reg.153/04)	E3398/CCME TIER 1-HS
F2-F4-WT	Soil	F2-F4 (O.Reg.153/04)	MOE DECPH-E3398/CCME TIER 1

A sub-sample of the solid sample is extracted with a solvent mixture. Following extraction, the sample extract is treated in situ with Silica Gel analyzed by GC/FID.

The F2 fraction is determined by integrating the area in the chromatogram from the apex of nC10 to the apex nC16 and quantitating using external calibration using a standard mix containing nC10, nC16 and nC34. Similarly, the F3 fraction extends from the apex of nC16 to the apex nC34 and the F4 fraction covers the area from the apex nC34 to the apex nC50. If the chromatogram does not return to the baseline by the time nC50 elutes, a gravimetric determination of the F4 is performed.

ALS Test Code	Matrix	Test Description	Method Reference**
MOISTURE-WT	Soil	% Moisture	Gravimetric: Oven Dried
OGG-HYDR-WT	Soil	Heavy Oil (C24-C50)	GRAV

Sample is extraction using a soxtec with an acetone:hexane mixture followed by a silica gel cleanup, the extract is then weighed to determine the concentration gravimetrically.

ALS Test Code	Matrix	Test Description	Method Reference**
TEH-ON-WT	Soil	TPH (C10-C24)	Contam. Sites
TVH-WT	Soil	TPH (C5-C10)	Contam. Sites

** ALS test methods may incorporate modifications from specified reference methods to improve performance.

The last two letters of the above test code(s) indicate the laboratory that performed analytical analysis for that test. Refer to the list below:

Laboratory Definition Code	Laboratory Location
WT	ALS LABORATORY GROUP - WATERLOO, ONTARIO, CANADA

Chain of Custody Numbers:

L948740

Reference Information

Test Method References:

ALS Test Code	Matrix	Test Description	Method Reference**

GLOSSARY OF REPORT TERMS

Surrogates are compounds that are similar in behaviour to target analyte(s), but that do not normally occur in environmental samples. For applicable tests, surrogates are added to samples prior to analysis as a check on recovery. In reports that display the D.L. column, laboratory objectives for surrogates are listed there.

mg/kg - milligrams per kilogram based on dry weight of sample
mg/kg wwt - milligrams per kilogram based on wet weight of sample
mg/kg lwt - milligrams per kilogram based on lipid-adjusted weight
mg/L - unit of concentration based on volume, parts per million.
< - Less than.
D.L. - The reporting limit.
N/A - Result not available. Refer to qualifier code and definition for explanation.

Test results reported relate only to the samples as received by the laboratory.
UNLESS OTHERWISE STATED, ALL SAMPLES WERE RECEIVED IN ACCEPTABLE CONDITION.
Analytical results in unsigned test reports with the DRAFT watermark are subject to change, pending final QC review.

ALS Environmental

Quality Control Report

Workorder: L948740 Report Date: 14-DEC-10

Client: TETRA TECH (MARKHAM)
250 SHIELDS CT. UNIT #5
MARKHAM ON L3R 9W7
Contact: JOHN GUAN

Test	Matrix	Reference	Result	Qualifier	Units	RPD	Limit	Analyzed
BTX-HS-WT	**Soil**							
Batch R1544203								
WG1194050-1 CVS								
Benzene			84		%		75-125	02-NOV-10
Ethyl Benzene			92		%		75-125	02-NOV-10
m+p-Xylenes			93		%		75-125	02-NOV-10
o-Xylene			91		%		75-125	02-NOV-10
Toluene			92		%		75-125	02-NOV-10
WG1194052-1 MB								
Benzene			<0.050		mg/kg		0.05	02-NOV-10
Ethyl Benzene			<0.050		mg/kg		0.05	02-NOV-10
m+p-Xylenes			<0.10		mg/kg		0.1	02-NOV-10
o-Xylene			<0.050		mg/kg		0.05	02-NOV-10
Toluene			<0.050		mg/kg		0.05	02-NOV-10
Batch R1544764								
WG1194472-1 CVS								
Benzene			84		%		75-125	02-NOV-10
Ethyl Benzene			90		%		75-125	02-NOV-10
m+p-Xylenes			90		%		75-125	02-NOV-10
o-Xylene			91		%		75-125	02-NOV-10
Toluene			98		%		75-125	02-NOV-10
WG1194053-1 MB								
Benzene			<0.050		mg/kg		0.05	02-NOV-10
Ethyl Benzene			<0.050		mg/kg		0.05	02-NOV-10
m+p-Xylenes			<0.10		mg/kg		0.1	02-NOV-10
o-Xylene			<0.050		mg/kg		0.05	02-NOV-10
Toluene			<0.050		mg/kg		0.05	02-NOV-10
F1-HS-WT	**Soil**							
Batch R1544203								
WG1194050-1 CVS								
F1 (C6-C10)			98		%		70-130	02-NOV-10
WG1194052-1 MB								
F1 (C6-C10)			<5.0		mg/kg		5	02-NOV-10
Batch R1544764								
WG1194472-1 CVS								
F1 (C6-C10)			84		%		70-130	02-NOV-10
WG1194053-1 MB								
F1 (C6-C10)			<5.0		mg/kg		5	02-NOV-10

Quality Control Report

Test	Matrix	Reference	Result	Qualifier	Units	RPD	Limit	Analyzed
F2-F4-WT	**Soil**							
Batch R1572044								
WG1197711-1 CVS								
F2 (C10-C16)			99		%		80-120	08-NOV-10
F3 (C16-C34)			104		%		80-120	08-NOV-10
F4 (C34-C50)			96		%		70-130	08-NOV-10
WG1197711-2 CVS								
F2 (C10-C16)			96		%		80-120	08-NOV-10
F3 (C16-C34)			102		%		80-120	08-NOV-10
F4 (C34-C50)			104		%		70-130	08-NOV-10
WG1197098-2 LCS								
F2 (C10-C16)			74		%		70-130	08-NOV-10
F3 (C16-C34)			91		%		70-130	08-NOV-10
F4 (C34-C50)			88		%		70-130	08-NOV-10
WG1197098-3 LCSD		**WG1197098-2**						
F2 (C10-C16)		74	81		%	9.3	50	08-NOV-10
F3 (C16-C34)		91	103		%	12	50	08-NOV-10
F4 (C34-C50)		88	101		%	15	50	08-NOV-10
WG1197098-1 MB								
F2 (C10-C16)			<10		mg/kg		10	08-NOV-10
F3 (C16-C34)			<50		mg/kg		50	08-NOV-10
F4 (C34-C50)			<50		mg/kg		50	08-NOV-10
Batch R1574623								
WG1198089-1 CVS								
F2 (C10-C16)			97		%		80-120	08-NOV-10
F3 (C16-C34)			98		%		80-120	08-NOV-10
F4 (C34-C50)			98		%		70-130	08-NOV-10
WG1197484-2 LCS								
F2 (C10-C16)			88		%		70-130	08-NOV-10
F3 (C16-C34)			98		%		70-130	08-NOV-10
F4 (C34-C50)			112		%		70-130	08-NOV-10
WG1197484-3 LCSD		**WG1197484-2**						
F2 (C10-C16)		88	87		%	1.9	50	08-NOV-10
F3 (C16-C34)		98	98		%	0.35	50	08-NOV-10
F4 (C34-C50)		112	100		%	11	50	08-NOV-10
WG1197484-1 MB								
F2 (C10-C16)			<10		mg/kg		10	08-NOV-10
F3 (C16-C34)			<50		mg/kg		50	08-NOV-10
F4 (C34-C50)			<50		mg/kg		50	08-NOV-10

Quality Control Report

Workorder: L948740 Report Date: 14-DEC-10

Test	Matrix	Reference	Result	Qualifier	Units	RPD	Limit	Analyzed
F2-F4-WT	**Soil**							
Batch R1574743								
WG1198092-1 CVS								
F2 (C10-C16)			96		%		80-120	08-NOV-10
F3 (C16-C34)			100		%		80-120	08-NOV-10
F4 (C34-C50)			100		%		70-130	08-NOV-10
WG1198004-2 LCS								
F2 (C10-C16)			87		%		70-130	08-NOV-10
F3 (C16-C34)			106		%		70-130	08-NOV-10
F4 (C34-C50)			109		%		70-130	08-NOV-10
WG1198004-3 LCSD		**WG1198004-2**						
F2 (C10-C16)		87	89		%	2.0	50	08-NOV-10
F3 (C16-C34)		106	109		%	2.8	50	08-NOV-10
F4 (C34-C50)		109	107		%	1.7	50	08-NOV-10
WG1198004-1 MB								
F2 (C10-C16)			<10		mg/kg		10	08-NOV-10
F3 (C16-C34)			<50		mg/kg		50	08-NOV-10
F4 (C34-C50)			<50		mg/kg		50	08-NOV-10
MOISTURE-WT	**Soil**							
Batch R1538483								
WG1194054-2 LCS								
% Moisture			103		%		70-130	01-NOV-10
WG1194054-1 MB								
% Moisture			<0.10		%		0.1	01-NOV-10
Batch R1538564								
WG1194055-3 DUP		**L948740-31**						
% Moisture		10.3	9.77		%	4.8	26	01-NOV-10
WG1194055-2 LCS								
% Moisture			109		%		70-130	01-NOV-10
WG1194055-1 MB								
% Moisture			<0.10		%		0.1	01-NOV-10
Batch R1540243								
WG1194056-2 LCS								
% Moisture			95		%		70-130	01-NOV-10
WG1194056-1 MB								
% Moisture			<0.10		%		0.1	01-NOV-10
OGG-HYDR-WT	**Soil**							

Quality Control Report

Test	Matrix	Reference	Result	Qualifier	Units	RPD	Limit	Analyzed
OGG-HYDR-WT	**Soil**							
Batch R1655365								
WG1207801-1 MB								
Heavy Oil (C24-C50)			<100		mg/kg		100	25-NOV-10
Batch R1655384								
WG1207802-2 MB								
Heavy Oil (C24-C50)			<100		mg/kg		100	25-NOV-10
Batch R1655385								
WG1207816-1 MB								
Heavy Oil (C24-C50)			<100		mg/kg		100	25-NOV-10
TVH-WT	**Soil**							
Batch R1656243								
WG1207613-1 CVS								
TPH (C5-C10)			120		%		65-130	26-NOV-10
WG1194052-1 MB								
TPH (C5-C10)			<10		mg/kg		10	26-NOV-10
Batch R1656603								
WG1208101-1 CVS								
TPH (C5-C10)			119		%		65-130	26-NOV-10
WG1194053-1 MB								
TPH (C5-C10)			<10		mg/kg		10	26-NOV-10

Legend:

Limit	99% Confidence Interval (Laboratory Control Limits)
DUP	Duplicate
RPD	Relative Percent Difference
N/A	Not Available
LCS	Laboratory Control Sample
SRM	Standard Reference Material
MS	Matrix Spike
MSD	Matrix Spike Duplicate
ADE	Average Desorption Efficiency
MB	Method Blank
IRM	Internal Reference Material
CRM	Certified Reference Material
CCV	Continuing Calibration Verification
CVS	Calibration Verification Standard
LCSD	Laboratory Control Sample Duplicate

Sample Parameter Qualifier Definitions:

Qualifier	Description
RPD-NA	Relative Percent Difference Not Available due to result(s) being less than detection limit.

Quality Control Report

Hold Time Exceedances:

ALS Product Description	Sample ID	Sampling Date	Date Processed	Rec. HT	Actual HT	Units	Qualifier
Aggregate Organics							
Heavy Oil (C24-C50)							
	1	26-OCT-10 09:30	25-NOV-10 12:37	28	30	days	EHT
	2	26-OCT-10 10:00	25-NOV-10 12:38	28	30	days	EHT
	3	26-OCT-10 10:30	25-NOV-10 12:39	28	30	days	EHT
	4	26-OCT-10 10:45	25-NOV-10 12:40	28	30	days	EHT
	5	26-OCT-10 13:00	25-NOV-10 12:41	28	30	days	EHT
	6	26-OCT-10 13:20	25-NOV-10 12:42	28	30	days	EHT
	7	26-OCT-10 13:40	25-NOV-10 12:43	28	30	days	EHT
	8	26-OCT-10 14:10	25-NOV-10 12:44	28	30	days	EHT
	9	26-OCT-10 14:15	25-NOV-10 12:45	28	30	days	EHT
	10	26-OCT-10 15:00	25-NOV-10 12:46	28	30	days	EHT
	11	26-OCT-10 14:25	25-NOV-10 12:47	28	30	days	EHT
	12	26-OCT-10 09:40	25-NOV-10 12:48	28	30	days	EHT
	13	26-OCT-10 10:20	25-NOV-10 12:49	28	30	days	EHT
	14	26-OCT-10 10:40	25-NOV-10 12:50	28	30	days	EHT
	15	26-OCT-10 11:00	25-NOV-10 12:51	28	30	days	EHT
	16	26-OCT-10 13:15	25-NOV-10 12:52	28	30	days	EHT
	17	26-OCT-10 13:30	25-NOV-10 12:53	28	30	days	EHT
	18	26-OCT-10 13:50	25-NOV-10 12:54	28	30	days	EHT
	19	26-OCT-10 13:55	25-NOV-10 12:55	28	30	days	EHT
	20	26-OCT-10 14:35	25-NOV-10 12:56	28	30	days	EHT
	21	26-OCT-10 14:45	25-NOV-10 12:57	28	30	days	EHT
	22	26-OCT-10 13:55	25-NOV-10 12:58	28	30	days	EHT
	23	26-OCT-10 09:50	25-NOV-10 12:59	28	30	days	EHT
	24	26-OCT-10 10:10	25-NOV-10 13:00	28	30	days	EHT
	25	26-OCT-10 10:35	25-NOV-10 13:01	28	30	days	EHT
	26	26-OCT-10 10:50	25-NOV-10 13:02	28	30	days	EHT
	27	26-OCT-10 13:05	25-NOV-10 13:03	28	30	days	EHT
	28	26-OCT-10 13:25	25-NOV-10 13:04	28	30	days	EHT
	29	26-OCT-10 03:45	25-NOV-10 13:05	28	30	days	EHT
	30	26-OCT-10 14:00	25-NOV-10 13:06	28	30	days	EHT
	31	26-OCT-10 14:25	25-NOV-10 13:07	28	30	days	EHT
	32	26-OCT-10 14:55	25-NOV-10 13:08	28	30	days	EHT
	33	26-OCT-10 14:00	25-NOV-10 13:01	28	30	days	EHT

Legend & Qualifier Definitions:

EHTR-FM:	Exceeded ALS recommended hold time prior to sample receipt. Field Measurement recommended.
EHTR:	Exceeded ALS recommended hold time prior to sample receipt.
EHTL:	Exceeded ALS recommended hold time prior to analysis. Sample was received less than 24 hours prior to expiry.
EHT:	Exceeded ALS recommended hold time prior to analysis.
Rec. HT:	ALS recommended hold time (see units).

Notes*:
Where actual sampling date is not provided to ALS, the date (& time) of receipt is used for calculation purposes.
Where actual sampling time is not provided to ALS, the earlier of 12 noon on the sampling date or the time (& date) of receipt is used for calculation purposes. Samples for L948740 were received on 29-OCT-10 12:10.

ALS recommended hold times may vary by province. They are assigned to meet known provincial and/or federal government requirements. In the absence of regulatory hold times, ALS establishes recommendations based on guidelines published by the US EPA, APHA Standard Methods, or Environment Canada (where available). For more information, please contact ALS.

The ALS Quality Control Report is provided to ALS clients upon request. ALS includes comprehensive QC checks with every analysis to ensure our high standards of quality are met. Each QC result has a known or expected target value, which is compared against pre-determined data quality objectives to provide confidence in the accuracy of associated test results.

Please note that this report may contain QC results from anonymous Sample Duplicates and Matrix Spikes that do not originate from this Work Order.

ALS Environmental

Chain of Custody / Analytical Request Form
Canada Toll Free: 1 800 668 9878
www.alsglobal.com

COC # L948740

Page 1 of 3

Report To
Company: Tetra Tech (Wardrop)
Contact: John Guan
Address: 250 Shields Crt #15
Markham, ON L3R 9W7
Phone: 905-470-6570 Fax: 905-470-0958

Report Format / Distribution
Standard Other (specify): email
PDF Excel Digital Fax
Email 1: john.guan@tetratech.com
Email 2: rene.devries@tetratech.com
#3: labresultsON@tetratech.com

Service Requested (Rush for routine analysis subject to availability)
Regular (Default) ✓
Priority (Specify Date Required → →) Surcharges apply
Emergency (1 Business Day) - 100% Surcharge
For Emergency < 1 Day, ASAP or Weekend - Contact ALS

Invoice To Same as Report ? Yes No

THE QUESTIONS BELOW MUST BE ANSWERED FOR WATER SAMPLES (circle Yes or No)
Are any samples taken from a regulated DW System? Yes No
If yes, an authorized Drinking Water COC MUST be used for this submission. N/A
Is the water sampled intended to be potable for human consumption? Yes No

Client / Project Information
Job #: ~~00318721304~~
PO / AFE: 34819
LSD:
1031872400
Quote #:

ALS Contact: Karen Sampler: KO

Lab Work Order # (lab use only)

Analysis Request
Please indicate below Filtered, Preserved or both (F, P, F/P)

Sample #	Sample Identification (This description will appear on the report)	# Containers	Date (dd-mmm-yy)	Time (hh:mm)	Sample Type	BTEX	F1-F4	PHC (g/d)	~~TPH (heavy oil)~~	~~TOC/pH~~	~~Nitrates~~	~~Nitrites~~	~~Nitrogen~~	~~Phosphorus~~	~~Potassium~~	~~Sulfur~~	~~HWS~~	Number of Containers
1	R1-1	2	26-oct-10	9:30	soil	X	X	X										2
2	R1-2	2		10:00		X	X	X										
3	R1-3	2		10:30		X	X	X										
4	R1-4	2		10:45		X	X	X										
5	R1-5	2		1:00		X	X	X										
6	R1-6	2		1:20		X	X	X										
7	R1-7	2		1:40		X	X	X										
8	R1-8	2		2:10		X	X	X										
9	R1-9	2		2:15		X	X	X										
10	R1-10	2		3:00		X	X	X										
11	R1-9 dup	2		2:45		X	X	X										
12	R2-1	2				X	X	X										

CONSUMED

Special Instructions / Regulations / Hazardous Details

Reg 153 Table 1 2 3 TCLP MISA PWQO OTHER (please specify):
Circle one - Note drinking water samples MUST USE DW Chain of Custody

NOT CONSUMED

Failure to complete all portions of this form may delay analysis. Please fill in this form LEGIBLY.
By the use of this form the user acknowledges and agrees with the Terms and Conditions as specified on the back page of the white - report copy.

SHIPMENT RELEASE (client use)			SHIPMENT RECEPTION (lab use only)				SHIPMENT VERIFICATION (lab use only)			
Released by:	Date:	Time:	Received by:	Date:	Time:	Temperature:	Verified by:	Date:	Time:	Observations: Yes / No ? If Yes add SIF
[illegible]	29 OCT 2010	[illegible]	RFB	Oct 29/10	12:10	7.9 °C	RFB	Oct 29/10	13:42	

TYFM014 26-Mar-10

ALS Environmental

Chain of Custody / Analytical Request Form
Canada Toll Free: 1 800 668 9878
www.alsglobal.com

COC # L948740

Report To
Company: Tetra Tech (Wardrop)
Contact: John Guan
Address: 250 Shields Crt #15
Markham, ON L3R 9W7
Phone: 905-470-6570 Fax: 905-470-0958

Report Format / Distribution
Standard Other (specify): email
PDF Excel Digital Fax
Email 1: john.guan@tetratech.com
Email 2: rene.devries@tetratech.com
#3: labresultsON@tetratech.com

Service Requested (Rush for routine analysis subject to availability)
Regular (Default) ✓
Priority (Specify Date Required → →) Surcharges apply
Emergency (1 Business Day) - 100% Surcharge
For Emergency < 1 Day, ASAP or Weekend - Contact ALS

Invoice To Same as Report ? Yes No

THE QUESTIONS BELOW MUST BE ANSWERED FOR WATER SAMPLES (circle Yes or No)
Are any samples taken from a regulated DW System? Yes No
If yes, an authorized Drinking Water COC MUST be used for this submission. N/A
Is the water sampled intended to be potable for human consumption? Yes No

Client / Project Information
Job #: 0031871304
PO / AFE: 34819
LSD:
Quote #:

Lab Work Order # (lab use only)

ALS Contact: Karen Sampler: KO

Analysis Request
Please indicate below Filtered, Preserved or both (F, P, F/P)

Sample #	Sample Identification (This description will appear on the report)	# Containers	Date (dd-mmm-yy)	Time (hh:mm)	Sample Type	BTEX	F1-F4	PHC (gld)	TPH (Heavy oil)	TOC pH	Nitrates	Nitrites	Nitrogen	Phosphorus	Potassium	Sulphate	HUB	Number of Containers
25	R3-3	2	26-Oct-10	10:35	soil	X	X	X	X	X	X	X	X	X	X	X	X	
26	R3-4	2	↓	10:50	↓	X	X	X	X	X	X	X	X	X	X	X	X	
27	R3-5	2		1:05		X	X	X	X	X	X	X	X	X	X	X	X	
28	R3-6	2		1:25		X	X	X	X	X	X	X	X	X	X	X	X	
29	R3-7	2		1:45		X	X	X	X	X	X	X	X	X	X	X	X	
30	R3-8	2		2:00		X	X	X	X	X	X	X	X	X	X	X	X	
31	R3-9	2		2:25		X	X	X	X	X	X	X	X	X	X	X	X	
32	R3-10	2		2:55		X	X	X	X	X	X	X	X	X	X	X	X	
33	R3-8 dup	2		2:00		X	X	X	X	X	X	X	X	X	X	X	X	

Special Instructions / Regulations / Hazardous Details

Reg 153 Table 1 2 3 TCLP MISA PWQO OTHER (please specify):
Circle one - Note drinking water samples MUST USE DW Chain of Custody

NOT CONSUMED

Failure to complete all portions of this form may delay analysis. Please fill in this form LEGIBLY.
By the use of this form the user acknowledges and agrees with the Terms and Conditions as specified on the back page of the white - report copy.

SHIPMENT RELEASE (client use)			SHIPMENT RECEPTION (lab use only)				SHIPMENT VERIFICATION (lab use only)			
Released by:	Date:	Time:	Received by:	Date:	Time:	Temperature:	Verified by:	Date:	Time:	Observations: Yes / No ? If Yes add SIF
Jay Eingold	29 Oct 2010	10:00 a	REB	Oct 29/10	12:10	7.9 °C	REB	Oct 29/10	13:42	

TYFM014 26-Mar-10

ALS Environmental

Chain of Custody / Analytical Request Form
Canada Toll Free: 1 800 668 9878
www.alsglobal.com

COC # 948740

Page 2 of 3

Report To
Company: Tetra Tech (Wardrop)
Contact: John Guan
Address: 250 Shields Crt #15
Markham, ON L3R 9W7
Phone: 905-470-6570 Fax: 905-470-0958

Invoice To Same as Report ? Yes No

THE QUESTIONS BELOW MUST BE ANSWERED FOR WATER SAMPLES (circle Yes or No)
Are any samples taken from a regulated DW System? Yes No
If yes, an authorized Drinking Water COC MUST be used for this submission.
Is the water sampled intended to be potable for human consumption? Yes No
N/A

Lab Work Order # (lab use only)

Report Format / Distribution
Standard Other (specify): email
PDF Excel Digital Fax
Email 1: john.guan@tetratech.com
Email 2: rene.devries@tetratech.com
#3: labresultsON@tetratech.com

Client / Project Information
Job #: 003187 1304
PO AFE: 34819
LSD:

Quote #:

ALS Contact: Karen
Sampler: KO

Service Requested (Rush for routine analysis subject to availability)
Regular (Default) ✓
Priority (Specify Date Required → →) Surcharges apply
Emergency (1 Business Day) - 100% Surcharge
For Emergency < 1 Day, ASAP or Weekend - Contact ALS

Analysis Request
Please indicate below Filtered, Preserved or both (F, P, F/P)

Sample #	Sample Identification (This description will appear on the report)	# Containers	Date (dd-mmm-yy)	Time (hh:mm)	Sample Type	BTEX	F1-F4	PHC (g/d)	TOC/pH	NITRATES	NITRITES	NITROGEN	PHOSPHORUS	POTASSIUM	SULPHUR	H/B	PH (ICAN/OIL)	Number of Containers
13	R2-2	2	26-oct-10	10:20	soil	X	X	X										
14	R2-3	2		10:40		X	X	X										
15	R2-4	2		11:00		X	X	X										
16	R2-5	2		1:15		X	X	X										
17	R2-6	2		1:30		X	X	X										
18	R2-7	2		1:50		X	X	X										
19	R2-8	2		1:55		X	X	X										
20	R2-9	2		2:35		X	X	X										
21	R2-10	2		2:45		X	X	X										
22	R2-8 dup	2		1:55		X	X	X										
23	R3-1	2		9:50		X	X	X										
24	R3-2	2		10:10		X	X	X										

Special Instructions / Regulations / Hazardous Details

Reg 153 Table 1 2 3 TCLP MISA PWQO OTHER (please specify):
Circle one - Note drinking water samples MUST USE DW Chain of Custody

NOT CONSUMED

Failure to complete all portions of this form may delay analysis. Please fill in this form LEGIBLY.
By the use of this form the user acknowledges and agrees with the Terms and Conditions as specified on the back page of the white - report copy.

SHIPMENT RELEASE (client use)			SHIPMENT RECEPTION (lab use only)				SHIPMENT VERIFICATION (lab use only)			
Released by:	Date:	Time:	Received by:	Date:	Time:	Temperature:	Verified by:	Date:	Time:	Observations: Yes / No ? If Yes add SIF
KE JM Eingold	29 OCT 2010	16:00a	REB	Oct 29/10	12:10	7.9 °C	REB	Oct 29/10	13:42	

TYFM014 26-Mar-10

Wardrop Engineering Inc. Lab Data Checklist

ALS Job Number:	L948740	Client:	Hydro One
Chain of Custody #	NA	Location No.:	Bearskin Lake
		Wardrop Project Number:	1031872400

General

Questions	Answers (Y/N)	Comments
Was **Chain of Custody** completed correctly?	Yes	
Was **Temperature** acceptable upon arrival to lab.?	Yes	
Were samples analysed within the **hold time**?	No	Additional analyses requested on 24-Nov-10 exceeded hold times by 1-2 days.
Methanol Extracted within 48 hrs?	No	
Is the **Certificate of Analysis** signed?	Yes	

Laboratory Quality Control Check

Are the following within acceptable criteria?	Answers (Y/N)	Comments
Calibration Verification Standard Recovery	Yes	
Spike blank Recovery (LCS)	Yes	
Matrix Spike Recovery	NA	
Blank (MB) Concentration	Yes	
Matrix Duplicate (MSD) **RPD**	NA	

Field Quality Control Samples

Are the following within alert limits?	Answers (Y/N)	Comments
Field Blank Concentration	NA	No field blank in submission.
Equipment Blank Concentration	NA	No equipment blank in submission.
Trip Blank Concentration	NA	No trip blank in submission.
Field Duplicate RPD	Yes	

Data quality check performed by: Kelly Jones

Date: 11-Nov-10

November 3, 2010 1031872500-REP-V0001-00

Mr. Bob Shine
Environment and Health Coordinator
Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

Dear Mr. Shine,

Subject Hydro One Remote Communities
2010 Annual Report Kasabonika DGS

INTRODUCTION

This report describes the results of monitoring and sampling conducted on June 18, 2010 by Wardrop Engineering Inc. (Wardrop) at the Kasabonika Diesel Generating Station (DGS) in 2010.

BACKGROUND

Site Description

The Kasabonika First Nation is situated on an island located at the south end of Kasabonika Lake, approximately 225 km north-northeast of Pickle Lake, Ontario. It is accessible by air and winter roads. The island community is connected to the mainland by a bridge from the southwest side of the island.

The DGS is located adjacent to the Ministry of Transportation Ontario (MTO) airport on the mainland in provincial jurisdiction west of the community. A Site Plan, Figure 1, shows the features of the DGS and its vicinity. A domestic water well is located east of the staff house. Adjacent land uses include the MTO airport on the north, undeveloped forested land on the south, the PetroKas Tank Farm on the west, and a roadway on the east.

Previous Investigations

In October 1998, Hydro One conducted a Phase I Environmental Site Assessment (Phase I ESA) at the Kasabonika DGS and the details are provided in the report entitled *Phase I*

Environmental Site Assessment at Kasabonika Diesel Generating Station, October 1998. The Phase I ESA identified several areas of known and potential impact and recommended that a Phase II Environmental Site Assessment (Phase II ESA) be conducted.

The Phase II ESA was conducted by Wardrop and consisted of two phases: a preliminary assessment between November 30 and December 3, 1999 and a follow-up assessment between June 15 and 18, 2000. The details are provided in our report entitled: *Phase II Environmental Site Assessment, Diesel Generating Station, Kasabonika, Ontario*, Reference No. 00318702-00, dated April 2001. The assessment identified petroleum hydrocarbon impacts in the soil in the vicinity of the powerhouse, former drum storage area and southwest corner of the property adjacent to PetroKas Tank Farm. The soil impacts were estimated at 650 m^3 *in situ*.

Impacted groundwater was also identified in the southwest corner of the property adjacent to PetroKas Tank Farm.

Groundwater was encountered in 1999 and 2000 at depths ranging between 0.5 m and 2.6 m below ground surface (mbgs). Levels were lower in June 2000 than in December 1999 by an average of 1.1 m. Groundwater appeared to flow toward the east, based on the gradients derived from water level measurements. In the northeast corner of the site, flow turned more northerly. The velocity of groundwater flow was estimated to be approximately 1 m per year.

Site Remediation

In June 2005, soil remediation activities were conducted to remove accessible soil that contained hydrocarbon concentrations exceeding federal residential/parkland guidelines. As detailed in the minutes of the June 7, 2005 meeting between the Kasabonika First Nations, Hydro One and Wardrop, the parties agreed that if the impact identified in the area of the PetroKas Tank Farm, south of the fence line, could not be adequately remediated, samples would be collected to quantify the impacts that remain.

Remediation was undertaken in five affected zones as shown in Figure 1. Elevated hydrocarbon concentrations remained in some areas which could not be remediated due to the presence of site infrastructure:

- Northeast of AST #1 in the former claymax dyke area;
- Along the north side of the powerhouse west and east of the centrally located radiator; and
- Adjacent to the PetroKas tank farm in the southwest corner of the property.

The remaining hydrocarbon impact was considered residual (adhered to soil particles), having a low probability for migration. In order to promote *in-situ* bioremediation, oxygen release compound and *Oilgator* were applied in the zones of residual impact in these excavations.

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Annual monitoring of groundwater was recommended to document water quality and demonstrate that unacceptable dissolved hydrocarbon concentrations were not migrating off the property.

Geology

Based on the borehole drilling logs from the previous Phase II ESA, site remediation and borehole drilling program, the shallow overburden in the vicinity of the DGS site generally consists of sand and gravel fill from the surface to about 1.0 m below grade, which is then underlain by peat (approximately 0.8 m) and then sandy silt to the maximum extent of the investigation. The drilling log for the domestic well near the staff house indicated that the sandy silt continues to a depth of approximately 21 m where bedrock was encountered.

2008 BOREHOLE AND GROUNDWATER MONITORING PROGRAM

2008 Borehole Program

A total of six boreholes (BH201 to BH206) were advanced in the vicinity of MW101 on June 18 and 19, 2008, using Hydro One Remote's Geoprobe 1-inch drill/soil sampler. These are shown on Figure 1.

An additional borehole (BH207) was advanced in the vicinity of a former leaking pipe/valve connecting the PetroKas with the Hydro One tanks near the western edge of the property. This was performed to confirm whether impacted soils from the area had been adequately excavated.

The investigation was to a pre-determined depth of up to 2 m. The soil from each borehole was logged in the field for soil composition, odour, structure, consistency of density, relative moisture content, and evident environmental impacts.

At BH207 (BH207@1.5m) along the western property boundary, concentrations of toluene, ethyl benzene and xylenes were detected above the Canadian Council of Ministers of the Environment Canadian Environmental Quality Guidelines (CEQG). However, the concentrations of toluene and xylenes were below the MOE O. Reg. 153/04 Table 2 standards. Concentrations were not detected in any of the samples from boreholes near MW101 at the eastern property boundary.

Laboratory analyses identified concentrations of PHC fractions F1, F2 and F3 that exceeded the CEQG, the Canadian-Wide Standards (CWS), and the Ontario Ministers of the Environment Soil, Ground Water and Sediment Standards (SGWS) in soil samples near MW101 from BH201 (BH201@1.0m) and BH203 (BH203@1.7m), and in BH207 (BH207@1.5m) near the PetroKas-Hydro One piping at the western boundary.

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At BH201 (BH201@2m), concentrations of PHC F1 and F2 were detected above the CWS and SGWS standards.

2008 Groundwater Monitoring Program

Water levels ranged from 0.16 m below ground surface (mbgs) in MW27 near the southern corner of the site to 1.38 mbgs in MW15 near the northwest corner of the powerhouse.

The groundwater elevations indicated groundwater generally flows southeastward, with a hydraulic gradient of about 3%. Based on a hydraulic conductivity of 6.4 x 10^{-8} m per second (Wardrop, 2001) and an effective porosity of 0.20 for silt to fine sand (Fetter, *Applied Hydrogeology*, 1994), the horizontal groundwater velocity is estimated to be about 0.3 metres per year.

No phase separated hydrocarbon (PSH) was measured in the monitoring wells. Subsurface hydrocarbon vapour concentrations ranged from not detected in MW27, MW102, MW104 and MW105 to 100 ppm in MW101.

Toluene was detected in MW27 and PHC F1+F2 was detected in MW105; however, both were at concentrations below the MOE O.Reg. 153/04 Table 2 standards. Dissolved hydrocarbons were not detected in any other monitoring wells.

2009 GROUNDWATER MONITORING PROGRAM AND REMEDIAL EXCAVATION

2009 Groundwater Monitoring Program

Water levels ranged from 0.42 m below ground surface (mbgs) in MW27 near the southern corner of the site to 1.53 mbgs in MW15 near the northwest corner of the powerhouse.

The shallow groundwater flow direction could not be determined based on the groundwater monitoring results on June 23, 2009.

No phase separated hydrocarbon (PSH) was measured in the monitoring wells. Subsurface hydrocarbon vapour concentrations ranged from not detected in MW104 to 375 ppm in MW105.

One or more of toluene, ethylbenzene and xylenes were detected in MW27, MW103 and MW105; however, all were at concentrations below the MOE O. Reg. 153/04 Table 2 standards. Dissolved hydrocarbons were not detected in any other monitoring wells.

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2009 Remedial Excavation

Three excavations extended to an average depth of 2.0 m below grade and were approximately 27 m^2 in area.

The excavation walls were sampled and profiled in a 3 m x 1 m grid pattern. Floor sampling frequencies were as follows: one field screening sample (using physical observations and OVM readings) every 9 m^2. Selected "worst case" soil samples from each excavation (based upon field screening results) for laboratory analyses. OVM readings were measured in the headspace of soil samples collected from the excavation floors. The OVM readings ranged from 5 ppm to 5% LEL (percentage of lower explosive limit).

In total, twelve confirmatory wall and floor samples including a field duplicate soil sample were submitted for chemical laboratory analyses. These soil samples were deemed to represent the remaining conditions at the limit of the excavation's depth.

The concentrations of BTEX in the analyzed soil samples were below the applicable CCME and MOE O. Reg. 153/04 Table 2 Standards.

Laboratory analyses identified concentrations of one or more of PHC fractions F1, F2 and F3 exceeded the Canadian-Wide Standards (CWS) and the Ontario Ministers of the Environment Soil, Ground Water and Sediment Standards (SGWS) in soil samples collected from a floor sample F1 from Excavation A and a wall sample W37 from Excavation C. The laboratory analysis results of the remaining excavation soil samples and back fill soil sample indicated that, where detected, concentrations were below the applicable CCME and MOE O. Reg. 153/04 Table 2 Standards.

The laboratory analysis results of the back fill soil sample indicated that, where detected, concentrations of metals were below the applicable CCME and MOE O. Reg. 153/04 Table 2 Standards.

METHODOLOGY

2010 Groundwater Investigation

2010 Groundwater Monitoring and Sampling

On June 17, 2010, static water levels and PSH thicknesses, if present, were measured in the monitoring wells. Static water levels were measured using an electronic water level indicator. Depth to the water was recorded.

Subsurface vapour concentrations were also measured in each of the monitoring wells using a GasTech® 1238 ME organic vapour meter (OVM) (calibrated to hexane) set on methane elimination mode.

Prior to obtaining representative groundwater samples, three casing volumes of standing water were removed just below the air-water interface in each monitoring well. If the well did not yield sufficient water, all standing water was purged and a sample collected after sufficient groundwater had recharged.

On June 18, 2010, representative groundwater samples were collected from the following monitoring wells: MW15, MW17, MW18, MW103 and MW106. Samples were not collected from MW101 or MW105, because monitoring well MW101 was destroyed and monitoring well MW105 could not be located. However, alternative monitoring well MW106 was sampled.

The samples were collected and preserved in appropriate containers supplied by the ALS Laboratory Group. Groundwater was transferred directly into bottles from Waterra tubing dedicated to each well. Preservation was performed at the time of sample collection, if necessary. Samples were stored in ice chilled coolers to keep the temperature between 0° to 10°C (with a target of 4°C).

Groundwater Analyses

A total of eight groundwater samples, including one duplicate, one field blank and one trip blank were forwarded on June 18, 2010 to ALS Laboratory Group for analysis. Laboratory analytical parameters included BTEX and PHC fractions F1 to F4.

Quality Assurance/Quality Control

Field QA/QC was established by following the procedures outlined in the MOE's *Guidance on Sampling and Analytical Methods for Use at Contaminated Sites in Ontario (*1996).

Waterra foot valves and polyethylene tubing units were previously provided and installed pre-cleaned and sealed in plastic by the manufacturer. Units were dedicated individually to a single well to prevent sample cross-contamination. New clean, disposable nitrile gloves were worn during purging and sampling, and discarded and replaced after each well was purged and each sample was collected to prevent cross-contamination. Samples were collected in laboratory supplied pre-cleaned bottles with the appropriate preservative.

A duplicate groundwater sample was collected from monitoring well MW106 (DUP MW106).

A field blank was prepared to assess trace level bias. Laboratory supplied sample bottles were filled in the field with reagent grade de-ionized water. A trip blank was also provided by the laboratory.

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ENVIRONMENTAL REGULATORY GUIDELINES

A detailed assessment standards selection process was conducted in accordance with the requirements of Ontario Regulation 153/04 made under the Environmental Protection Act. Based on the results of this process, the Table 2 full Depth Generic Site Condition Standards in a potable groundwater condition with industrial/commercial/community property use and coarse textured soil conditions were selected for assessment purposes. The rationale to support this selection is based on the information provided in Sections A to E. A flow chart showing the selection process is presented in Figure 2.

Because the Site is located in the Federal jurisdiction, the CCME, CSQG for the Protection of Environment and Human Health and for Commercial/Industrial Land Use and Coarse Textured Soil and CCME, CWS for Petroleum Hydrocarbons in Soil for the Protection of Potable Groundwater have been used. It is our understanding that Hydro One would like to assess the site conditions against applicable Federal and Provincial Guidelines and/or Standards. Therefore, the most stringent applicable Federal and provincial Guidelines and/or Standards have been used.

A. Environmentally Sensitive Areas

1. The contaminated site includes, or there is a potential for it to have an adverse effect on, any one of the following:
   a) A provincial park designated by a regulation under the Provincial Parks Act.
   b) A conservation reserve established under the Public Lands Act.
   c) An area of natural and scientific interest (life science) identified by the Ministry of Natural Resources as having provincial significance.
   d) A wetland identified by the Ministry of Natural Resources as having provincial significance.
   e) An area designated by a municipality in its official plan as environmentally significant; however expressed, including designations of areas as environmentally sensitive, as being of environmental concern and as being ecologically significant.
   f) An area designated as an escarpment natural area or an escarpment protection area by the Niagara Escarpment Plan under the Niagara Escarpment Planning and Development Act.
   g) A habitat of endangered or threatened species identified by the Ministry of Natural Resources.
   h) Property within an area designated as a natural core area or natural linkage area within the area to which the Oak Ridges Moraine Conservation Plan under the Oak Ridges Moraine Conservation Act, 2001 applies.

None of above conditions applies to the Site.

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2. The property is a shallow soil property. There are more than 2 m of overburden soil in the study area. Therefore, the property is not a shallow soil property.
3. The soil at the property has a pH less than five or greater than nine for surface soils and/or less than five or greater than 11 for subsurface soils. Soil pH of one soil sample collected in the previous investigation was laboratory measured 7.67.
4. The distance to the nearest water body is more than 30 m. Kasabonika Lake is located approximately 230 m of the Site.

Based on the data above, the Site is not considered a sensitive site.

B. Land Use

The current land use is industrial and the future land use is expected to remain industrial.

C. Geology and Groundwater

A review of published geological information of the area (Surficial Geology of Northern Ontario, Map No. 2518, published by the Ontario Ministry of Northern Development and Mines) indicated that the native stratigraphy would consist of Till, a glacial deposit consisting of an unsorted mixture of boulders, sand, silt and clay. The topography of the Site is relatively flat. Kasabonika Lake is located approximately 230 m of the Site.

Drinking water for the areas is obtained from a domestic well on the site.

D. Depth of Site Condition Standard

The full depth site condition standard was applied.

E. Soil Texture

One soil sample representing at least one-third of the site were collected during the previous environmental assessment and was submitted for grain size analysis. The results of the analysis indicated that greater than 50% by mass of particles were not finer than 75 µm in mean diameter in this soil sample. Subsequently, the coarse textured soil classification was applied.

The First Nation is in the process of extending the reserve boundaries which may include the Hydro One property. For this reason, Hydro One requested we continue to assess compliance against the most stringent of federal guidelines as well as provincial criteria.

For the purposes of assessment of soil and groundwater quality, we applied the same site features as was identified and elected to be used by Hydro One in 2005 (Residential/Parkland property use, Potable Groundwater, Coarse Soil Texture).

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Analytical results were referenced to the following standards and guidelines:

- Ontario Ministry of Environment (MOE), Ontario Regulation 153/04 Soil, Groundwater and Sediment Standards for use under Part XV.1 of the Environmental Protection Act, 2004 (SGWS) Residential/Parkland Property Use and Potable Groundwater Table 2;
- Canadian Council of Ministers of the Environment (CCME) Canadian Environmental Quality Guidelines (2008) (CEQG) Residential/Parkland Property Use and Coarse Soil Texture;
- Canada-Wide Standard for Petroleum Hydrocarbons (PHC) in Soil (CWS) (2008) Residential/Protection of Potable GW/Eco Soil Contact; and
- Health Canada Guidelines for Canadian Drinking Water Quality (CDWQ) (2008).

2010 RESULTS

Groundwater Results

Monitoring Well Conditions

A summary of the condition of each well is provided in Table 1. Monitoring wells MW101 and MW102 have been destroyed and should be replaced.

Groundwater Levels

A summary of groundwater level measurements is provided in Table 2. Water levels ranged from 1.16 m below ground surface (mbgs) in MW18 near the east side of the site to 1.82 mbgs in MW15 near the northwest corner of the powerhouse.

The groundwater elevations were shown on Figure 3. The shallow groundwater flow direction could not be determined based on the groundwater monitoring results on June 17, 2010.

Evidence of Petroleum Hydrocarbons in Groundwater

No PSH was measured in the monitoring wells. Subsurface hydrocarbon vapour concentrations ranged from not detected in MW103 to 100 ppm in MW32 and MW106 as shown in Table 1.

Groundwater Analytical Results

The 2010 analytical results are provided in the attached Certificate of Analysis and on Table 3 along with historical results. Figure 3 presents the 2010 analytical results along with groundwater monitoring results.

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BTEX and PHC F1 to F4 were not detected in any of the monitoring wells sampled and were below the MOE O. Reg. 153/04 Table 2 standards.

Quality Assurance/Quality Control

Laboratory's calibration checks, quality control standard recoveries, spikes, relative percent differences (RPDs), and blanks were within the laboratory's quality control limits. The laboratory certificates are attached.

The analytical results for duplicate samples are compared by calculating the RPD_{DUP}; which is the difference between the results, divided by the average of the results. The RPD_{DUP} can only be calculated if both analytical results are greater than five times the method detection limit.

One duplicate groundwater sample was collected from monitoring well MW106 (DUP MW106) during the groundwater monitoring program. The RPD_{DUP} values could not be calculated since the parameter concentrations were less than five times the method detection limits.

Analytes were not detected in the field blank and trip blank at concentrations exceeding the laboratory detection limits.

CONCLUSIONS

The concentrations of the analysed constituents in groundwater samples collected from the monitoring wells were below the MOE O. Reg. 153/04 Table 2 standards and the CDWQ Guidelines (2007).

RECOMMENDATIONS

Based on the results of the monitoring and sampling activities completed in June 2010, we recommend the following:

- Monitoring wells should be annually inspected to ensure that they are properly secured and are in good condition.
- Monitoring wells MW101 and MW102 were damaged and should be replaced.
- Continued monitoring and sampling of the selected monitoring wells in 2011.

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CLOSURE

We trust that this progress report is sufficient for your current requirements. Should some point require clarification or further discussion, please contact us at your convenience.

Sincerely	Approved by
WARDROP ENGINEERING INC.,	WARDROP ENGINEERING INC.,
John Guan, M.Eng., P.Eng. Project Engineer	Rene de Vries, B.Sc., P.Geo. Sr. Environmental Scientist

Attachments Figures 1 – 3
Tables 1 - 3
Laboratory Certificate of Analysis

SANDY LAKE COMMUNITY DEVELOPMENT SERVICES INC. - HYDRO ONE FORMER DGS SITE REMEDIATION

PHYSICAL / FINANCIAL REPORT

For the period:	December 1 - December 31, 2012
TGCL Reference:	11-230-09

Project Physical Summary:

Completed Previously

- A proposal for the Former DGS Remedial Design (Revised), dated May 31, 2011, was submitted to the project team.
- A project meeting was held on June 29, 2011 in Sandy Lake, Ontario.
- Additional field work, proposed under the Remedial Design proposal, was completed in June 2011.
- A proposal, dated September 29, 2011 (Revised), outlining the 2011 Remedial Actions, was submitted to the project team; field work and reporting on the 2011 Remedial Actions were completed under a different project. The 2011 remedial actions included clearing of the borrow pit and bioremediation cell sites, fence installation activities, and remedial excavation of approximately 2,074 m^3 of petroleum hydrocarbon impacted soil from the former DGS site .
- A proposal, dated February 2, 2012, outlining the 2012 Winter Drilling Program was submitted to the project team.
- The 2012 Winter Drilling field program was completed in March 2012, which included installation of additional groundwater monitoring wells and well sampling.
- A proposed scope of work and cost estimate, dated May 21, 2012, outlining the 2012 Stage 1 Remedial Actions was submitted to the project team.
- TGCL and SLCDS personnel were on site in June 2012 to initiate the 2012 Stage 1 Remedial Actions.
- Construction of borrow pit access road was completed between June 12 and 15, 2012.
- Expansion of biocell access road and upgrading site drainage was completed between June 15 and 19, 2012.
- Construction of a 3,000 m^3 capacity biocell was completed between June 19 and 30, 2012.
- Upgrading of a wooden fence, located along the northern periphery of the former DGS site, was completed between June 14 and July 16, 2012.
- Clearing of trees at the soil laydown area was partially completed between June 25 and 26, 2012.
- The additional assessment and sampling tasks were initiated between June 22 , 2012, and were completed on September 16, 2012.
- A proposed scope of work and cost estimate, dated June 28, 2012, outlining the 2012 Stage II Remedial Actions was submitted to the project team for review.
- Construction of site fencing along the south boundary of the site was completed on August 9 and 17, 2012.
- Repair of the fill borrow pit access road was completed on July 17, 2012.
- Approximately 12.25 L of LPH and 25L of petroleum hydrocarbon impacted water were collected from seven monitoring wells on July 19-20, 2012.
- A project update meeting was held on August 1, 2012.
- Clearing and grubbing of the soil laydown area was completed on August 8 and 9, 2012.
- A project meeting was held on August 15, 2012, prior to the initiation of 2012 Stage II Remedial Actions.
- The remedial excavation activities of the 2012 Stage 2 Remedial Actions were initiated on August 21, 2012.
- Between August 21 and November 30, 2012, approximately 13,069 m^3 of soil has been excavated from the former Hydro One DGS site:
  - Approximately 11,347 m^3 of soil was removed from the site
    - Biocell = 6,097 m^3 (53.7%)
    - Landfill stockpile = 5,250 m^3 (46.3%)
  - Approximately 1,722 m^3 of soil was stockpiled on site for reuse as backfill material.
- Between October 4 and 8, 2012, four treatment sumps were installed along the eastern boundary of the remedial excavation.
- Between November 2 and 5, 2012, six treatment sumps were installed along the eastern boundary of the area of remedial excavation which extended down to bedrock.
- In-situ amendments (urea fertilizer and Regenox™) were applied to areas of exposed bedrock prior to backfilling.
- Under the 2012 Remedial Actions, approximately 73,781L of LPH impacted water was pumped and treated using an on-site treatment system; a total of approximately 1,002 L of LPH and impacted water (LPH = 874 L, Water = 128L) has been recovered and is stored in eight drums on site. An additional 22,700 L of mostly surface water runoff was removed directly to the community sewage lagoon.

Completed This Period

- Between December 1 and 14, 2012, the remedial excavation was backfilled with approximately 3,120 m^3 of clay fill from the borrow pit.
- The remedial excavation completed under the 2012 Remedial Actions was backfilled with a total of approximately 11,107 m^3 of clay fill (1,722 m^3 from soil laydown and 9,385 m^3 from borrow pit).
- The 2012 Remedial Actions were completed for the 2012 field season on December 14, 2012.

To Be Completed

- Some settling of the backfill is expected and will be addressed in 2013 prior to surfacing the top 0.3 m. of the Hydro One Former DGS site with approximately 450 m^3 of stockpiled granular fill material.
- Biocell baseline sampling.

PROGRESS DETAILS

1.0	Project Mgmt, Coord, Admin, Physical/Financial Reporting	- A Financial report was completed on Aug 31, 2011. - A Financial report was completed on Oct 31, 2011. - A Financial report was completed on Mar 31, 2012. TASK COMPLETED
2.0	Remedial Option Evaluation and Costing	Ongoing

PHYSICAL / FINANCIAL REPORT

For the period:		December 1 - December 31, 2012
TGCL Reference:		11-230-09
3.0	Additional Field Work (includes local labour & equipment)	**Completed Previous Period** - TGCL personnel were on site June 29, 2011 to complete the proposed additional field work. - A full site groundwater and LPH monitoring event was completed. - Groundwater samples were collected from select wells for laboratory analysis of BTEX/PHC parameters. - A LPH purge and recovery test was completed on select monitoring wells. TASK COMPLETED
4.0	Remediation Design	**Completed Previous Period** - A proposal for the Former DGS Remedial Design, dated May 31, 2011 was submitted to the project team. - A proposals for the 2011 Remedial Actions (revised), dated September 28, 2011 was submitted to the project team. - A scope of work and cost estimate for the 2012 Winter Drilling Program, dated Feb 7, 2012, was submitted to the project team. - A scope of work and cost estimate for the 2012 Stage 1 Remedial Actions, dated May 21, 2012 was submitted to the project team. - A scope of work and cost estimate for the 2012 Stage 2 Remedial Actions, dated June 28, 2012 was submitted to the project team.
5.0	Project Meetings (in Sandy Lake)	**Completed Previous Period** - Project meeting in Sandy Lake on June 29, 2011 between the First Nation, Hydro One and TGCl. - Project meeting in Sandy Lake on Sept 9, 2011 between the First Nation, Hydro One and TGCL. - Site visit by TGCL and Hydro One on Sept 21, 2011. - Project meeting in Sandy Lake on Nov 25, 2011 between the First Nation, Hydro One and TGCL.
8.0	2012 Winter Drilling Field Program (proposal tasks 2.0 and 3.0)	**Completed Previous Period** - TGCL and SLCDS personnel were on site in March 2012 to complete the 2012 Winter Drilling Field Program; Determination Drilling of Hamilton, Ontario was subcontracted to complete the drilling work. - A total of 12 boreholes were advanced; nine boreholes were advanced to bedrock and installed with monitoring wells; two boreholes were installed with soil vapour monitoring probes. - Soil samples were collected during the drilling program and submitted for laboratory analysis; 10 samples were submitted for BTEX/PHC analysis; three samples were submitted for PAH analysis, six samples were submitted for pH analysis and two were submitted for organic carbon analysis. - Due to cold temperatures and equipment issues, proposed bedrock wells could not be installed. - Two groundwater monitoring events were completed; the first on March 12 and the second on March 21, 2012. - Groundwater samples were collected from the newly installed 200 series monitoring wells (where LPH was not present) and several selected previously installed wells. - A rising head test was completed on two of the newly installed wells. - Soil vapour samples were collected and submitted for laboratory analysis of BTEX and PHC F1/F2 parameters. - The location and elevation of site structures and each test location were surveyed using GPS surveying equipment. TASK COMPLETED
9.0	2012 Winter Drilling Mgmt/Admin/Reporting (proposal tasks 1.0 and 4.0)	**Completed Previous Period** - The 2012 Winter Drilling Program was completed in March 2012. TASK COMPLETED
10.0	2012 Winter Drilling Program Meeting (proposal task 5.0)	- To be completed
11.0	11.0 Risk Assessment	- To be completed

SANDY LAKE COMMUNITY DEVELOPMENT SERVICES INC. - HYDRO ONE FORMER DGS SITE REMEDIATION

PHYSICAL / FINANCIAL REPORT		
For the period:		December 1 - December 31, 2012
TGCL Reference:		11-230-09
12.0	2012 Site Remediation - Coordination & Materials Purchase and Shipping	**<u>Completed Previous Period</u>** - Biocell liner and geotextlie for road construction/upgrade was purchased and shipped into the community in March 2012. - Coordination of the proposed 2012 Stage 1 Remedial Actions was completed in May/June 2012. The field work was initiated June 12, 2012 and continued until June 29, 2012. - Additional supplies for gate construction, monitoring well installation and soil vapour sampling were purchased in May/June 2012. - A geotextile for the rock retaining/filter wall was purchased and shipped in June 2012. TASK COMPLETE
13.0	Project Mgmt/Admin, Coordination, Physical/Financial Reporting (2012 Stage 1)	**<u>Completed Previous Period</u>** - A physical financial report, dated July 19, 2012, was completed for the period of April to June 2012 and submitted to the project team. - A physical financial report, dated September 6, 2012, was completed for the period of July and August 2012 and submitted to the project team. TASK COMPLETE
14.0	Project Construction Meeting (Sandy Lake; assumes Hydro One charter) (2012 Stage 1)	**<u>Completed Previous Period</u>** - A project meeting was held in Sandy Lake on August 1, 2012 between SLCDS, Hydro One and TGCL.
15.0	Completion of Fill Borrow Pit Area (2012 Stage 1)	**<u>Completed Previous Periods</u>** - The proposed location of the fill borrow pit area was cleared and grubbed in fall of 2011. TGCL personnel were on site to oversee borrow pit construction by SLCDS in June 2012. - An access road, including a culvert, spanning a ditch and extending to the truck turnaround location was constructed. - A geotextile was laid down over the access road/truck turn around area and surfaced with approximately 247m^3 of granular fill material and locally available clay; the surficialy granular material and clay was compacted using a sheepsfoot packer. - A section of culvert in the access road which had failed was replaced in July 2012. TASK COMPLETED
16.0	Bioremediation Cell Construction (2012 Stage 1)	**<u>Completed Previous Period</u>** - The proposed location of the biocell was cleared and grubbed in fall of 2011. TGCL personnel were on site to oversee biocell construction by SLCDS in June 2012. - One monitoring well was decommissioned, prior to the expansion of the bioremediation facility. - An access road was constructed to service the proposed biocell. Approximately 180 m^3 of granular fill was used in the construction of the road. - One culvert was installed under the existing biocell access road and one culvert installed in the newly constructed biocell access road. Additionally, a drainage ditch was redirected along the eastern portion of the bioremediation facility. Culverts and ditching were graded to ensure positive site drainage throughout the bioremediation facility. - The construction of the biocell included grading of the biocell floor, forming of berm walls, excavation of a retention pond, installation of the liner and drainage layer and construction of the retaining / filtration wall. Approximately 390m^3 of granular fill was used for the drainage layer and approximately 48m^3 was used for the retaining /filtration wall. - Two hand augered boreholes were advanced and installed with monitoring wells; one along the eastern boundary and one along the southern boundary of the bioremediation facility.
17.0	Preparation of Soil Laydown Area South of DGS (2012 Stage 1)	**<u>Completed Previous Period</u>** - TGCL was on site in June 2012 to supervise the development of the soil laydown area; SLCDS personnel cleared the site using chains saws; trees that were deemed unsafe to cut due to their proximity of the nearby overhead power lines were left for Hydro One forestry crews to assess and determine the safest removal method. - TGCL was on site in August 2012 to supervise the completion of the soil laydown area; SLCDS personnel completed the site clearing and grubbing using heavy equipment and chainsaws. TASK COMPLETED

SANDY LAKE COMMUNITY DEVELOPMENT SERVICES INC. - HYDRO ONE FORMER DGS SITE REMEDIATION

PHYSICAL / FINANCIAL REPORT		
For the period:		December 1 - December 31, 2012
TGCL Reference:		11-230-09
18.0	Former DGS Site Fencing (2012 Stage 1)	**Completed Previous Period** - TGCL was on site in June 2012 to supervise the construction of an access gate installed in the wooden fence constructed along the northern boundary of the site. - TGCL personnel supervised installation of wire mesh along the base of the wooden fence. - TGCL was on site in July and August 2012 to supervised the upgrading of the access gate and the installation of a metal post and wire mesh fence along the south boundary of the site following the development of the soil laydown area. TASK COMPLETED
19.0	Additional Assessment and Sampling (2012 Stage 1)	**Completed Previous Period** -TGCL and SLCDS personnel were on site between June, July and August 2012 to conduct the additional assessment and sampling tasks. - Eight hand augered boreholes (300 series) were advanced, of which, four were installed with monitoring wells; three of the boreholes, advanced in the shoulder of the road, were refused at a very shallow depth and will require stripping of the granualr fill by heavy equipment prior to advancing the boreholes. - Newly installed monitoring wells were surveyed with a rod and level . - A full site monitoring was completed. - Groundwater samples were collected from new monitoring wells and submitted for analysis of BTEX / PHC parameters. - Two surface water samples were collected fron Sandy Lake and submitted for laboratory analysis of BTEX/PHC parameters. - Five boreholes were advanced around the southwest corner of the remedial excavation completed at the former fuel offload location in July 2012. The surficial granular layer from the road was stripped using SLCDS heavy equipment prior to advancing boreholes. - Three soil vapour probes were installed . - Two full site monitoring was completed (July 18 and August 12). - Two rising/falling head tests were completed in the newly installed (300 series) monitoring wells. - A total station survey of the newly installed wells was completed . - On September 16, 2012, three soil vapour probes, installed during the July / August 2012 period, were sampled
20.0	LPH Removal (2012 Stage 1)	**Completed Previous Period** - Olfactory and visual evidence of LPH was noted in six monitoring wells during the June 26, 2012 monitoring event. - A total of 12.25 L of LPH and 25L of petroleum hydrocarbon impacted water were collected from the monitoring wells by TGCL personnel following the July 18 monitoring event. - A total of 2L of LPH and 12 L of petroleum hydrocarbon impacted water were collected from the treatment sumps installed in October and November 2012. TASK COMPLETE
21.0	Project Mgmt/Admin, Coordination, Physical Financial Reporting (2012 Stage II)	**Completed Previous Period** - A physical financial report, dated October 12, 2012, was completed for the period of September 2012 and submitted to the project team. - A physical financial report, dated November 13, 2012, was completed for the period of October 2012 and submitted to the project team. **Completed This Period** - A physical financial report, dated December 10, 2012, was completed for the period of November 2012 and submitted to the project team.
22.0	Project Meetings (2012 Stage II)	**Completed Previous Period** - A project meeting was held in Sandy Lake on August 15, 2012 between SLCDS, Hydro One and TGCl.

SANDY LAKE COMMUNITY DEVELOPMENT SERVICES INC. - HYDRO ONE FORMER DGS SITE REMEDIATION

PHYSICAL / FINANCIAL REPORT

For the period:		December 1 - December 31, 2012
TGCL Reference:		11-230-09
23.0	Remedial Excavation (2012 Stage II)	**Completed Previous Period** - TGCL and SLCDS personnel were on site between August 10 and November 30, 2012, to conduct the 2012 Stage 2 Remedial Actions. - On August 10 - 16, and 21, SLCDS personnel hauled 840 m^3 of granular fill material from the FN aggregate pit and stockpiled it near the former Hydro One DGS site for later use in site sump installation and site restoration. - On August 10 - 11, TGCL personnel completed a resection survey to stake out the former locations of the DGS structures and to layout a grid to aid in orientation during remedial excavation activities. - On August 15, 16 and 20, TGCL personnel directed SLCDS in stripping and stockpiling of non-impacted surface soils from the Former Hydro One DGS site - On August 20, 2012, TGCL and SLCDS personnel were briefed on the overall scope of work and reviewed/signed the respective project health and safety plans. - Remedial excavation of petroleum hydrocarbon impacted soils was completed between August 21 and November 6, 2012. The remedial excavation was directed by TGCL personnel and completed by SLCDS personnel. A total of approximately 13,069 m^3 of soil has been excavated from the former Hydro One DGS site over the course of the 2012 Remedial Actions: - Approximately 11,347 m^3 of soil was removed from the site - Biocell = 6,097 m^3 (53.7%) - Landfill stockpile = 5,250 m^3 (46.3%) - Approximately 1,722 m^3 of soil was stockpiled on site for reuse as backfill material. - On September 1 and 19, SLCDS personnel hauled 16 m^3 of granular fill material from the FN aggregate pit for biocell road maintenance and construction of an access ramp along the east border of the former Hydro One DGS site. - Between September 20 - 26, 2012, the southeast corner of the remedial excavation was backfilled with 1,561 m^3 of clean clay fill excavated from the fill borrow pit. - On October 4, 5 and 8, 2012, SLCDS and TGCL personnel installed the treatment sumps along the eastern edge of the remedial excavation. - On October 12, 2012, approximately 25 kg of urea fertilizer and 30 kg of RegenOx™ was placed on the exposed bedrock of the excavation floor prior to backfilling. - Between October 12 and November 30, 2012 the excavation was backfilled with approximately 7,987 m^3 of clay fill; approximately 1,722 m^3 from the laydown area and approximately 6,265 m^3 from the borrow pit. - Between November 2 and 5, 2012, SLCDS and TGCL personnel installed the treatment sumps along the eastern edge of the area of remedial excavation which extended down to bedrock. - A total of approximately 73,781L of LPH impacted water has been pumped and treated using an on-site treatment system during the 2012 Remedial Actions; a total of approximately 1,002 L of LPH and impacted water (LPH = 874 L, Water = 128L) has been recovered and is stored in eight drums on site. Between November 2 and 5, 2012, an additional 22,700 L (approx.) of mostly surface water runoff from rain/snow events, which occurred during the remedial program, was hauled directly to the community sewage lagoon. - On November 28, approximately 96 m^3 (ex-situ) of granular fill material was removed from the stockpile located near the former Hydro One DGS site for use on a separate project. This material will be replaced by SLCDS. **Completed this Period** - Between December 1 and 14, 2012, the remedial excavation was backfilled wth approximately 3,120 m^3 of clay fill from the borrow pit. - The remedial excavation completed under the 2012 Remedial Actions was backfilled with a total of approximately 11,107 m^3 of clay fill (1,722 m^3 from soil laydown and 9,385 m^3 from borrow pit). - The remedial excavation and site restoration activities proposed under the 2012 Remedial Actions were completed for the 2012 field season on December 14, 2012.
	Lisa Crowe, Sandy Lake Community Development S	Date:
	Randy Edwards, TGCL Project Manager :	Date:

TABLE 1 - SANDY LAKE FORMER HYDRO ONE DGS SITE REMEDIATION PROJECT
CLASS C PRICE ESTIMATES - UPDATED SEPTEMBER 26, 2011

	DESCRIPTION	UNIT	QUANTITY	UNIT PRICE	TOTAL
1.0	**2011 CLASS A COST (Details Presented Separately)**	LS	1	$442,000	**$442,000**
2.0	**2012 CLASS C COST ESTIMATE**				
2.1	Bioremediation Cell Construction (3,000 cu.m. capacity)	LS	1	$130,000	$130,000
2.2	Additional Delineation Drilling	LS	1	$75,000	$75,000
2.3	Site-Specific Risk Assessment	LS	1	$50,000	$50,000
2.4	Impacted Soil Excavation, Haulage, and Backfilling	cu.m.	8400	$120	$1,008,000
2.5	Non-Impacted Soil Excavation, Stockpiling, and Reuse	cu.m.	8400	$30	$252,000
2.6	In-Situ Remediation System Design	LS	1	$40,000	$40,000
2.7	Installation of Extraction/Injection Wells	LS	1	$100,000	$100,000
2.8	Supply & Installation of LPH/Groundwater Pumping System	LS	1	$225,000	$225,000
2.9	System Commissioning and Initial Testing	LS	1	$20,000	$20,000
2.10	In-Situ Remediation System Operation & Monitoring	year	0.25	$70,000	$17,500
2.11	Project Administration, Management & Reporting	LS	1	$50,000	$50,000
2.12	Project Meetings	each	5	$5,000	$25,000
2.13	First Nation Contract Administration, Management, and Training	LS	1	$50,000	$50,000
	Sub-total Section 2.0				**$2,042,500**
3.0	**2013 CLASS C COST ESTIMATE**				
3.1	Ex-Situ Remediation Soil Treatment & Monitoring	year	1	$75,000	$75,000
3.2	In-Situ Remediation System Operation & Monitoring	year	1	$70,000	$70,000
3.3	Project Administration, Management & Reporting	LS	1	$20,000	$20,000
3.4	Project Meetings	each	1	$5,000	$5,000
3.5	First Nation Contract Administration, Management, and Training	LS	1	$7,500	$7,500
	Sub-total Section 3.0				**$177,500**
4.0	**2014 CLASS C COST ESTIMATE**				
4.1	Ex-Situ Remediation Soil Treatment & Monitoring	year	1	$75,000	$75,000
4.2	In-Situ Remediation System Operation & Monitoring	year	1	$70,000	$70,000
4.3	Ex-Situ Remediation Soil Decommissioning	cu.m.	5000	$10	$50,000
4.4	Project Administration, Management & Reporting	LS	1	$20,000	$20,000
4.5	Project Meetings	each	1	$5,000	$5,000
4.6	First Nation Contract Administration, Management, and Training	LS	1	$7,500	$7,500
	Sub-total Section 4.0				**$227,500**
5.0	**2015 CLASS C COST ESTIMATE**				
5.1	In-Situ Remediation System Operation & Monitoring	year	1	$70,000	$70,000
5.2	Project Administration, Management & Reporting	LS	1	$15,000	$15,000
5.3	Project Meetings	each	1	$5,000	$5,000
5.4	First Nation Contract Administration, Management, and Training	LS	1	$5,000	$5,000
	Sub-total Section 5.0				**$95,000**
6.0	**2016 CLASS C COST ESTIMATE**				
6.1	In-Situ Remediation System Operation & Monitoring	year	1	$70,000	$70,000
6.2	Project Administration, Management & Reporting	LS	1	$15,000	$15,000
6.3	Project Meetings	each	1	$5,000	$5,000
6.4	First Nation Contract Administration, Management, and Training	LS	1	$5,000	$5,000
	Sub-total Section 6.0				**$95,000**
7.0	**2017 CLASS C COST ESTIMATE**				
7.1	In-Situ Remediation System Operation & Monitoring	year	1	$70,000	$70,000
7.2	Project Administration, Management & Reporting	LS	1	$15,000	$15,000
7.3	Project Meetings	each	1	$5,000	$5,000
7.4	First Nation Contract Administration, Management, and Training	LS	1	$5,000	$5,000
	Sub-total Section 7.0				**$95,000**
	PROJECT TOTAL				**$3,174,500**

** all volume represent ex-situ volumes

Hydro One Remote Communities Inc.

2012 Site Monitoring Report

Diesel Generating Station

Wapekeka, Ontario

Prepared by:

True Grit Consulting Ltd.
1127 Barton Street
Thunder Bay, ON P7B 5N3
T: 807.626.5640
F: 807.623.5690
Project Number: 12-078-10-5
Contact: Jason Garatti, M.Sc.Eng., P.Geo.

December 19, 2012

Executive Summary

True Grit Consulting Ltd. (TGCL) was retained by Hydro One Remote Communities Inc. (Hydro One) to complete site monitoring at the Wapekeka Diesel Generating Station (DGS) in Wapekeka, Ontario. The purpose of the work was to monitor and sample groundwater for petroleum hydrocarbon (PHC) impacts.

Based on historic subsurface investigation work there were three areas of impact on site: near the west end of the powerhouse building; near the bulk storage tanks; and, the fuel off-load area. In 2002, the fuel off-load area was remediated.

The Wapekeka DGS is owned and operated by Hydro One, a provincial agency and is situated on Wapekeka First Nation land (Federal). Therefore, analytical results were compared to both the Federal and Provincial standards. These include MOE Table 2 potable and Table 3 non-potable criteria, as well as the *Health Canada Guidelines for Canadian Drinking Water Quality* (2008).

Based on soil conditions documented during previous subsurface investigations, the soils at the site generally consist of black peat and organics underlain by clayey silt overlying sandy silt.

On June 28, 2012, TGCL was on site to complete the groundwater monitoring and sampling program.

In June 2012, groundwater at the site ranged in depth from 0.41 to 0.88 m below ground surface (mbgs). The current levels suggest a southeast flow direction with an overall gradient of approximately 0.010. The average hydraulic conductivity at the site is approximately 3.1×10^{-6} m/s. The groundwater velocity is estimated to be 3 m/yr. These results are generally consistent with historical results.

Concentrations of benzene, toluene, ethlybenzene, xylenes (BTEX) and PHCs in groundwater samples collected at the site were generally either below the laboratory's detection limit or below the applicable criteria, with the following exceptions. Concentrations of PHC fractions F2 and F3 at monitoring wells DBW053 and DBW055, both located near the west end of the powerhouse, exceed the applicable criteria. The 2012 results are slightly lower than the 2011 results but are within historic ranges.

In general, on-site impacts is this area are likely localized and the potential for significant migration of impacts in the subsurface is considered low based on the contaminants of concern (i.e. PHCs) and no immediate remediation work is considered warranted.

Based on the 2012 results, TGCL recommends continued groundwater monitoring at the site once annually. Also, Hydro One should consider replacing the monitoring well near the staff house, which was removed during a fuel spill remediation.

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Appendices

1.0 Introduction

True Grit Consulting Ltd. (TGCL) was retained by Hydro One Remote Communities Inc. (Hydro One) to complete a groundwater monitoring and sampling event in June 2012 at a diesel generating station (DGS) located in Wapekeka, Ontario (Figure 1). The following report summarizes the results of the sampling event completed at the site.

1.1 Background Information

Hydro One provided TGCL with the following reports for review:

Phase 1 Environmental Site Assessment of Wapekeka Diesel Generating Station by Ontario Hydro Technologies, dated December 15, 1998;

Draft 2010 Annual Report, Hydro One Wapekeka DGS by Wardrop Engineering Inc. dated August 9, 2010; and,

Draft 2011 Annual Report, Hydro One Wapekeka DGS by Tetra Tech WEI Inc. dated October 7, 2011.

The 2010 and 2011 annual reports provide a summary of previous investigations at the site including: a Phase 1 Environmental Site Assessment (ESA), a Phase 2 ESA, a soil remediation at the fuel offload area and previous groundwater monitoring events.

There were three areas of historic petroleum hydrocarbon (PHC) impact, near the west end of the powerhouse, near the bulk storage tanks and in the fuel off-load area. The fuel off-load area was remediated in 2002.

In 2011, groundwater impacts were observed in monitoring wells DBW053 and DBW055 and were characterized by elevated concentrations of PHC fractions F2 and F3.

1.2 Scope of Work

The scope of work for the 2012 groundwater monitoring program was as follows:

- Measure the static water level of each well and the thickness of free-phase hydrocarbons (if any) using an oil/water interface probe.
- Record the volume of water purged from each well and observations (colour, odour, visible sheens) of purge water and sampled water.
- Collect one water sample from each existing monitoring well.
- Collect one Quality Assurance/Quality Control (QA/QC) blind duplicate for groundwater samples. Label the blind duplicate samples using the next logical identification number.
- Submit all samples to a CALA-accredited laboratory for analysis of benzene, toluene, ethylbenzene and xylene (BTEX) and PHC fractions F1 to F4.
- Prepare a groundwater monitoring report documenting the findings and providing recommendations, if warranted, to minimize the potential for off-site impacts.

2.0 Site Setting

2.1 Site Location and Description

Wapekeka First Nation is located approximately 600 km north of Thunder Bay, Ontario, on the western shore of Angling Lake (Figure 1). Wapekeka First Nation is located approximately 25 km east of Big Trout Lake and is accessible by air or winter road.

The Wapekeka DGS is located north of the community and consists of the following structures and features:

- Powerhouse;
- Two 50,000-L self-contained above ground storage tanks (AST);
- Two storage sheds;
- Staff house;
- Transformer deck;
- Antifreeze storage drums;
- Substation;
- Fuel off-load shed; and,
- Glycol and fuel lines.

Figure 2 illustrates the general site layout and the locations of the aforementioned features. Site photographs are provided in Appendix A.

The DGS site is bounded to the north and east by forested land, to the south by a gravel road and to the west by an outdoor hockey rink. The school is located approximately 75 m to the southwest of the site and the police station and hospital are located to the southeast. Residential properties are located to the south, southwest and southeast of the site.

2.2 Topography and Hydrology

The topography of the DGS site is relatively flat with a slight slope to the south. Surface water runoff at the site is expected to follow site topography and flow south toward Angling Lake.

The nearest surface water receptors are Angling Lake and the Fawn River. Angling Lake is located approximately 400 m south of the DGS site and is the headwaters of the Fawn River.

2.3 Geology and Hydrogeology

Based on the Ministry of Northern Development and Mines (MNDM) *Bedrock Geology of Ontario, Northern Sheet,* Map 2541 (Scale 1:1,000,000), bedrock geology in the area of the site consists of a foliated tonalite suite, composed of tonalite to granodiorite that is foliated to massive, and massive to foliated granodiorite to granite.

Based on the Ministry of Northern Development and Mines (MNDM) *Quaternary Geology of Ontario, Northern Sheet,* Map 2553 (Scale 1:1,000,000), surficial geology in the area of the site consists of undifferentiated till composed predominantly of sand to silty sand matrix with a high content of clasts.

Based on soil conditions documented during previous subsurface investigations, the subsurface soils at the site generally consist of black peat and organics underlain by clayey silt overlying sandy silt.

Based on groundwater conditions documented during previous investigations, the groundwater at the site is shallow, ranging from 0.88 to 2.2 m below ground surface (mbgs), and flows toward the southeast with an estimated flow velocity of 4 m per year (m/yr).

3.0 Methodology

This section documents the field and laboratory investigation methodologies completed for the June 2012 sampling event. On June 28, 2012, TGCL personnel conducted groundwater monitoring and sampling at the site to assess for the presence of PHC impact.

3.1 Hydraulic Conductivity Testing

In-situ hydraulic conductivity testing (rising head tests) was completed on select monitoring wells (DBW052 and DBW057) to assess the characteristics of the overburden aquifer. Following the measurement of the static water levels, the well was rapidly pumped down using the dedicated manual pumping system. The water recovery rate was measured at regular intervals using an electronic water level meter. The recovery data was analyzed to obtain aquifer characteristics (i.e. hydraulic conductivity) using the Bouwer-Rice Method for an unconfined aquifer.

3.2 Groundwater Monitoring and Sampling

Environmental sampling was completed in general accordance with the MOE document *Guidance on Sampling and Analytical Methods for Use at Contaminated Sites in Ontario* (1996).

Prior to sample collection, the static groundwater levels in each of the monitoring wells were measured relative to the top of the riser pipes using a Heron Instruments electronic oil/water interface probe. The probe was rinsed with Alconox Soap, followed by a water rinse between each well to ensure cross-contamination did not occur between sample locations.

Following water level measurements, a minimum of three standing well volumes was purged from each well to obtain fresh formation water for analysis using existing dedicated Waterra tubing. Then groundwater samples from each monitoring well were collected directly from the dedicated sampling equipment into laboratory-supplied cleaned bottles for chemical analysis of BTEX and PHC fractions F1 through F4.

Groundwater samples were stored in insulated containers with ice packs for shipping to a certified and accredited laboratory for chemical analysis.

3.3 Laboratory Analysis

Groundwater samples were submitted under Chain of Custody to Maxxam Analytics (Maxxam) in Mississauga, Ontario, a CALA certified and accredited laboratory, for analysis of BTEX and PHC fractions F1 to F4.

Summary of Samples Submitted for Laboratory Analysis	
Sample Matrix	**Sample ID**
Groundwater	DBW052, DBW053, DBW054, DBW055, DBW056, DBW057, DBW058, DBW059, DBW0550

3.4 Quality Assurance / Quality Control (QA/QC)

Field QA/QC was established by following procedures outlined in the Ontario Ministry of the Environment (MOE) Standards Development Branch *Guidance on Sampling and Analytical Methods for use at Contaminated Sites in Ontario* (December 1996).

Clean disposable nitrile gloves were worn during sampling, and discarded and replaced after collecting each sample to prevent cross-contamination and maintain sample integrity.

Samples were collected in pre-cleaned containers supplied by the laboratory. Following sampling, the containers were carefully packaged to prevent breakage and placed in chilled coolers. The coolers were delivered under Chain of Custody to the analytical laboratory for analysis.

During the June 2012 monitoring and sampling program, the following blind field replicate groundwater sample was collected and submitted for laboratory analysis to check laboratory consistency.

Sample Matrix	Sample ID	Replicate ID
Groundwater	DBW055	DBW0550

Results for internal laboratory QC analyses (such as replicate samples, standards, blanks and matrix spikes) were requested and reviewed.

3.5 Groundwater Assessment Criteria

Assessment criteria for the site were selected using the Generic Approach as found in the MOE *Guideline for Use at Contaminated Sites in Ontario* (1997) and the MOE *Soil, Groundwater and Sediment Standards for Use under Part XV.1 of the Environmental Protection Act,* dated April 15, 2011.

Hydro One is a provincial operating entity in Ontario. The Wapekeka DGS site is situated on Wapekeka First Nation Reserve. Overburden at the site is greater than 2 m deep. No surface water bodies are located within 30 m of the property and there are no sensitive areas located nearby. The site is serviced by a community water system and no wells are located within 100 m of the site.

The site is located within Federal jurisdiction and should be compared to both Federal and Provincial standards. Since no Federal standards exist for a non-potable groundwater condition, the site has been compared to the *Health Canada Guidelines for Canadian Drinking Water Quality* (2008).

Based on site conditions, the applicable provincial assessment criteria are those found in Table 3 of the MOE Standards: Full Depth Generic Site Condition Standards in a Non-Potable Groundwater Condition for all types of property use. Since the site is located within the community, the results have also been compared to the MOE Table 2 criteria: Full Depth Generic Site Condition Standards in a Potable Groundwater Condition for all types of property use. In the event the site is decommissioned in the future, the remediated site would likely need to meet the more stringent MOE Table 2 criteria based on the DGS site's location within the community.

For pre-2005 results, the former Ontario Generic criteria of the *Guidelines for Use at Contaminated Sites in Ontario* (GUCSO, 1997) have been reference for total petroleum hydrocarbons.

4.0 Results

The following sections document the field and laboratory results for the June 2012 groundwater sampling event. Groundwater sampling locations are shown on Figure 2.

4.1 Hydraulic Conductivity Testing Results

Graphs of the hydraulic conductivity analysis are shown in Appendix B.

The average hydraulic conductivity at the site is approximately 3.1×10^{-6} m per second (m/s) based on rising head tests completed at monitoring wells DBW057 and DBW052. The calculated hydraulic conductivity at monitoring wells DBW057 and DBW052 are 1.30×10^{-6} m/s and 4.90×10^{-6} m/s, respectively.

4.2 Field Results

Monitoring well locations are shown on Figure 2. Groundwater levels and elevations in the monitoring wells are presented in Table 1.

All monitoring wells were generally in good condition with the exception of DBW056 which was removed during soil remediation activities following a fuel spill at the staff house AST.

Groundwater levels ranged from 0.41 mbgs at DBW052 to 0.88 mbgs at DBW059. No free phase hydrocarbons were observed.

When plotted on a plan and contoured, the water level elevations indicate the general shape of the groundwater table. Groundwater levels and contours for June 2012 are shown on Figure 3. The groundwater levels suggest a southeast slope with an overall gradient of approximately 0.010. Assuming the average hydraulic conductivity of approximately 3.1×10^{-6} m/s and an effective porosity of 30%, the groundwater velocity at the site is estimated to be 3 m per year (m/yr). The 2012 groundwater velocity is less than the 2011 result (4 m/yr). The 2012 water levels, flow direction and gradient are generally consistent with historic results.

OVCs upon opening well caps were 0 ppm at all wells, except DBW055 which had an OVC of 4.3 ppm.

4.3 Laboratory Results

Groundwater analytical results are summarized in Table 2 and provided in the laboratory Certificates of Analysis in Appendix C. A summary of site impact is shown on Figure 3.

Concentrations of PHC fractions F2 and F3 were above the MOE Table 2 and Table 3 criteria at monitoring wells DBW053 and DBW055 located to the north and south, respectively, of the west end of the powerhouse building.

Detectable concentrations (not exceeding the MOE Table 2 criteria) were measured for xylenes at DBW053 and for BTEX at DBW055. Note that the MOE Table 2 criteria for BTEX are the same as those for the CDWQ.

Concentrations of BTEX and PHC fractions F1 through F4 at all other sampled monitoring wells were below the laboratory's detection limits and the applicable MOE criteria.

4.4 Quality Assurance/Quality Control

The blind field replicates for groundwater sample results are summarized in Table 3. The field and laboratory replicates, blanks and process recoveries are shown on the laboratory Certificates of Analysis in Appendix C.

For groundwater sample DBW055 and its replicate (DBW0550), there was an 8.7%, 140.4% and 151.6% difference for toluene and PHC fractions F2 and F3, respectively. For all other parameters, either the sample or replicate sample concentrations were below the laboratory`s detection limits.

The RPD for toluene is within standard tolerances and is considered acceptable. The RPDs for PHC fractions F2 and F3 are considered elevated but can be attributed to the presence of head space in sample containers or sample heterogeneity.

The laboratory replicates, blanks and process recovery results for groundwater were generally within standard tolerances and are considered acceptable.

5.0 Discussion/Conclusions

On June 28, 2012, TGCL was on site to complete a groundwater monitoring and sampling program.

Groundwater levels ranged from 0.41 mgbs at DBW052 to 0.88 mbgs at DBW059. When plotted on plan and contoured, the groundwater levels suggest a southeast flow direction with an overall slope of 1.0%. The current results are generally consistent with historic results.

Based on rising head tests at wells DBW052 and DBW057 and the Bouwer-Rice Method for an unconfined aquifer, the average hydraulic conductivity of the site is approximately 3.1 x 10^{-6} m/s. The average hydraulic conductivity calculated in 2012 is greater than that hydraulic conductivity assumed in historically (1 x 10^{-6} m/s). Assuming a gradient of 1.0%, the average hydraulic conductivity of 3.1 x 10^{-6} m/s and an effective porosity of 30%, the groundwater velocity is estimated to be 3 m/yr. The 2012 groundwater velocity is less than that reported in 2011 (4 m/yr).

Concentrations of BTEX and PHC fractions F1 through F4 were either below the laboratory's detection limits or the applicable MOE Table 2 criteria with the following exceptions. Concentrations of PHC fraction F2 and F3 at wells DBW053 and DBW055 exceed both the MOE Table 2 and Table 3 criteria. Concentration of PHC fraction F2 and F3 at DBW053 and DBW055, located to the north and south, respectively, of the west end of the powerhouse building, are slightly lower than the 2011 results but are within historic ranges. The source of the impacts in this area is unknown but may be related to leaks from fuel lines exiting the west end of the building.

Based on the current field and analytical results the following conclusions can be made:

- There is one area of PHC impact on site in the vicinity of DBW053 and DBW055.
- In general, on-site impacts described above are likely localized and the potential for significant migration of impacts in the subsurface is considered low based on the contaminants of concern (i.e. PHCs) and no immediate remediation work is considered warranted.

Based on the 2012 results, the following recommendations are presented for consideration:

- Continue groundwater monitoring at the site once annually in June 2013. The monitoring program should include all existing groundwater monitoring wells on site.
- Consider replacing monitoring well DBW056, located adjacent to the staff house AST, which was removed during a fuel spill remediation. The well will serve as a monitor for groundwater impacts that may result from spills or leaks during fueling activities at the staff house AST.

6.0 Closure

The information and data contained in this report, including without limitation, the results of any sampling and analyses conducted by TGCL pursuant to its Agreement with the client, have been developed or obtained through the exercise of TGCL's professional judgment and are set forth to the best of TGCL's knowledge, information and belief. Although every effort has been made to confirm that this information is factual, complete and accurate, TGCL makes no guarantees or warranties whatsoever, whether expressed or implied, with respect to such information or data.

The information and data presented in this report are based on the purpose and scope of the project and form the basis for any conclusions and recommendations presented herein. Any conclusions and recommendations presented herein do not preclude the existence of environmental concerns other than those that may have been identified.

Work performed by TGCL personnel employed sound environmental assessment principles. TGCL cannot guarantee the accuracy and reliability of information provided by others or third parties. Therefore, TGCL does not claim responsibility for undisclosed environmental concerns or conditions that may result in costs for environmental clean-up and/or remediation. This report is intended for information purposes only.

Respectfully submitted by:

True Grit Consulting Ltd.

PROFESSIONAL GEOSCIENTISTS
JASON R. GARATTI
PRACTISING MEMBER
0889
Dec 19/12
ONTARIO

Larissa Mikkelsen, M.Sc.Geol.
Environmental Scientist
lmikkelsen@tgcl.ca

Jason Garatti, M.Sc.Eng., P.Geo.
Principal/Manager, Environmental Services
jgaratti@tgcl.ca

LM/JG:pn

TRUE GRIT CONSULTING LTD

Tables

Figures

Appendix A:
Site Photographs

Appendix B:
Hydraulic Conductivity Analysis Results

Appendix C:
Laboratory Certificates of Analysis

EXECUTIVE SUMMARY

From June to August 1999, Anebeaaki Environmental Inc. (Anebeaaki) conducted a Phase III environmental site assessment (ESA) of the Ontario Hydro Diesel Generator site in Pikangikum, Ontario. The purpose of the ESA was to quantify existing and potential risks to the environment and human health as a result of subsurface impacts at the site, and to identify and evaluate strategies to reduce/maintain the risks at acceptable levels.

The scope of work included: installation of 27 boreholes by manual hand auger (six of which were equipped with groundwater monitoring wells); excavation of seven test pits; collection of soil, groundwater and surface water samples for laboratory analysis; and, evaluation and interpretation of the data. The potential contaminants of concern which were investigated included: petroleum-related compounds; metals and other inorganic parameters; polycyclic aromatic hydrocarbons (PAHs); polychlorinated biphenyls (PCBs); and, glycols.

The results of the analyses have been compared to the corresponding federal remediation criteria from either the *Recommended Canadian Soil Quality Guidelines* (CCME, March 1997) or the *Interim Canadian Environmental Quality Criteria for Contaminated Sites* (CCME, September 1991). Comparison has been made to the criteria for both residential/park and commercial/industrial land use.

In the absence of federal criteria for a given compound, the corresponding provincial criteria from Table A of the *Guideline for Use at Contaminated Sites in Ontario* (MOEE, February 1997) for sites in potable groundwater situations, was used.

The generalized stratigraphy at the site comprises a layer of sand and gravel fill, ranging in thickness from 0.1 m to 1.5 m in thickness, underlain by clay or silty clay. To the west and northwest of the generator compound, a layer of silt, 0.1 to 1.4 m thick, overlies the clay. Depth to bedrock at the site has not been confirmed. Bedrock was not encountered in any of the test pits, excavated to depths up to 3.1 m, however auger refusal was encountered in five boreholes, at depths from 0.6 to 3.7 m.

Saturated conditions were encountered during drilling at depths ranging from 0.6 m to 3.3 m. Depth to groundwater measured in the six monitoring wells approximately 10 days after installation, ranged from 0.63 m below grade (mbg) at the edge of the drainage ditch north of the site, to 3.44 mbg some 40 m east of the site.

In general, the data indicates a groundwater high just east of the site and shallow horizontal groundwater flow appears to be from east to west across the site. Based on the results of field hydraulic testing and an assumed porosity of the native clay, the horizontal linear groundwater velocity has been calculated to be in the order of 0.3 m/yr.

Subsurface petroleum-hydrocarbon impact, in the form of odours, elevated combustible soil vapour concentrations or elevated concentrations of petroleum-related compounds in soil or water samples, were detected at 14 of the 34 boreholes and test pits advanced at the site. Concentrations of one or more petroleum-related compounds exceeded applicable remediation criteria for all land uses in 11 of 16 soil samples analysed. The primary petroleum-related parameter of concern is total light- and mid-distillate petroleum hydrocarbons (TPH(gas/diesel)).

In total, petroleum-hydrocarbon impact has been identified over most of the northern half of the generator site, including beneath the bulk storage tanks and the main generator building. Impact has also been identified in the refuelling area and the drainage ditch north of the generator compound. The estimated area of impact is 3000 m^2.

Based on an average depth of impact of 2 m on and north of the generator compound, and an average depth of impact of 0.7 m in the drainage ditch, it is estimated that approximately 5,200 m^3 (10,400 tonnes) of soil contain petroleum-related compounds at concentrations exceeding applicable criteria.

Other compounds identified in soil at concentrations exceeding applicable criteria include:

- TPH(heavy oils) beneath the generator building;
- glycol beneath the generator building;
- methylnaphthalenes and 1,1-biphenyl north of the generator building; and,
- cresol west of the generator building.

All of these were identified only within in the estimated area of petroleum impact. Therefore, it is our opinion that, depending on the remediation approach selected, remediation of the petroleum hydrocarbons will also address these contaminants.

Concentrations of all metals and other inorganic parameters met the drinking water criteria in three groundwater samples analysed, except for iron in one sample and manganese in two samples. Despite field filtering of the samples, the laboratory reported sediment in the samples which was likely the cause of the elevated concentrations. In any case, the criteria for iron and manganese are based on aesthetic concerns, and the elevated concentrations of manganese and iron measured in the groundwater do not represent a concern at the site.

An organic sheen was observed on the surface of standing water in the drainage ditch north of the site, and on surface water run-off into the ditch during a rainfall event. The concentration of TPH(gas/diesel) in a sample of the surface water exceeded the drinking water criterion. Concentrations of chromium, iron, lead, manganese and selenium also exceeded the drinking water criteria in the surface water sample. However, this sample was not field filtered, and the laboratory reported significant sediment in the sample, which may have resulted in the elevated metals concentrations.

It is our opinion that, again depending on the approach selected, remediation of the contaminated soil would also effect remediation of impacted surface and groundwater and additional separate surface or groundwater remediation would not be required.

On the basis of field observations and the results of laboratory analyses of soil land water samples, the site was classified under the National Classification System for Contaminated Sites as Class 2, with a total score of 65/100. Classification as a Class 2 site indicates that the risk potential for adverse impact on human or environmental health is medium, with action likely required.

Alternative approaches for remediation of the impacts identified at the generator site have been reviewed and evaluated. These approaches include a range of in-situ and ex-situ techniques which may be applicable to the site. In evaluating the approaches, the following criteria were considered:

- site remediation criteria
- effectiveness
- site requirements
- remediation time
- treatment cost
- negative effects on the community
- off-site media treatment criteria
- end product(s)
- availability of equipment/supplies
- technical complexity
- benefits to the community
- risk factors

Based on the evaluation, three feasible remediation strategies have been identified:

- ex-situ bioremediation;
- combined in-situ/ex-situ bioremediation; or,
- in-situ bioremediation.

In order to develop a preferred remediation strategy, detailed input is required from each member of the Project Team. Accordingly, it is recommended that the Project Team review this draft report, consider the options, and jointly develop the preferred strategy at the draft report presentation meeting.

Based on the results of that meeting, Anebeaaki will make the requested revisions to the report, present the recommended remediation strategy (based on Project Team consensus) and provide associated costs in the Final Report.

April 29, 2010 0031870207-WPL-V0001-00

VIA EMAIL

Mr. Bob Shine
Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

Dear Mr. Shine

Subject Proposed 2010 Work Plan
Kasabonika DGS

INTRODUCTION

This letter provides Wardrop Engineering Inc.'s (Wardrop's) proposed work plan with estimated costs to undertake the 2010 monitoring program for the Kasabonika Diesel Generation Station (DGS).

In our 2009 annual report, we recommended the following for the 2010 monitoring year:

- Soil quality assessment to be completed within five years from the areas where PHC impacts have been identified to assess how quickly the PHC impacted soil may attenuate. Alternatively, W37 exceedance can be removed during future remediation work.
- A tap water sample should be collected from the on-site domestic well to confirm the absence of any contaminants of concerns including microbiological parameters.
- Monitoring wells should be annually inspected to ensure that they are properly secured and are in good condition.
- Continued monitoring and sampling of the monitoring wells may not be warranted because there have not been exceedances of any contaminants of concern for the past two successive groundwater sampling events. However, Hydro One may consider conducting groundwater monitoring and sampling of selected monitoring wells for due diligence purposes during soil quality assessment within five years. Wells not being used anymore for monitoring purposes can be decommissioned. The actual wells to be decommissioned should be reviewed in conjunction with planned Hydro One site modification

725 Hewitson Street
Thunder Bay, Ontario P7B 6B5
Canada
Phone: 807-345-5453
Fax: 807-345-8708
E-mail: thunderbay@wardrop.com
Internet: www.wardrop.com

work. The actual well decommissioning work should be completed in accordance with Ontario Regulation 903.

2010 Work Plan

The following provides the proposed 2010 scope of work based on conclusions of the 2009 annual report and the discussions during our meeting held in March 2010:

- Continue annual groundwater monitoring and sampling for monitoring wells MW15 (or MW17), MW18, MW27, MW101, MW103 and MW105. The groundwater samples should be collected and submitted for the following analyses:
    - Benzene, toluene, ethylbenzene, xylenes (BTEX), and petroleum hydrocarbons (PHC) fractions F1 - F4.
    - Collect a tap water sample from the on-site domestic well for the analyses of BTEX and PHC F1 – F4.
- Monitoring wells MW25, MW32, MW102, MW104 and MW106 should be inspected and monitored.

METHODOLOGY – FIELD MONITORING

Monitoring Well Conditions

During the monitoring event, the conditions of the monitoring wells will be assessed and documented. If repairs or modifications are required but cannot be completed while on site, recommendations will be provided to Hydro One.

Monitoring Well Sampling

Monitoring wells will be sampled using dedicated Waterra samplers or disposable bailers. At least three well volumes of groundwater will be purged from the monitoring wells to draw fresh formation water into the well for sampling purposes. Wells which pump dry will be purged a second time following a period of recovery to allow the sand pack to drain and formation water to flush the sand pack. While purging, the groundwater will be physically assessed for evidence of impacts and this information will be documented.

Wells will be sampled immediately following purging or, if recovery is too slow, within 24 hours of purging following standard procedures.

Quality Assurance/Quality Control (QA/QC)

Quality assurance will be established in the field by applying strict material handling, equipment operating, and documentation controls.

New, clean, disposable nitrile gloves will be worn when handling samples and will be discarded and replaced after each sample is collected to prevent cross-contamination. Samples will be collected in laboratory supplied pre-cleaned jars and/or bottles. Water sample bottles will have been provided with the appropriate preservative, where required.

Waterra foot valves and polyethylene tubing were originally provided pre-cleaned and sealed in plastic by the manufacturer and each was dedicated to only one well to prevent sample cross-contamination.

If sampling equipment requires replacing, new equipment that is precleaned and sealed in plastic by the manufacturer will be installed. At no time will dedicated sampling equipment be removed from one well to sample another.

Following sampling, the containers will be carefully packaged to prevent breakage and placed in ice-chilled coolers to keep the temperature between 0°C to 10° C (with a target of 4°C). The coolers will be shipped by overnight courier under chain of custody procedures to the analytical laboratory for analysis.

With each sampling round, a duplicate sample will be collected to check analytical precision. A field blank will be prepared by pouring laboratory supplied deionized and organic free water into the appropriate sample bottles to check low level bias. A travel blank will be prepared and provided by the analytical laboratory and will accompany the sample bottles to and from the site.

A Canadian Association for Environmental Analytical Laboratories (CAEAL) certified and accredited analytical laboratory will perform all analysis following recognized standard methodologies. Copies of internal QC analysis (such as duplicate samples, standards, blanks and matrix spikes) will be requested and reviewed.

DATA ANALYSIS AND REPORTING

Groundwater analytical data will be referenced to the appropriate site condition standard(s) that are identified and agreed to with Hydro One in the task identified above under "2010 Work Plan".

We will provide you with a draft copy of the report for review. Following your review of the report, we will finalize it in accordance with our discussions and provide you with two hard copies.

SCHEDULE

The following are our anticipated key milestone dates for the project:

Item	**Approximate Schedule**
Field Work	June – August 2010
Draft annual report	November – December 2010
Hydro One review	March 2011

Finalize report	Following receipt of comments from Hydro One

Project Team

The key staff to work on this project are listed in the following table:

Name	Assignment
René de Vries, P. Geo.	Project Manager
Jay Eingold, M.Sc.	Client Liaison
John Guan, P.Eng.	Job Manager
Carl Frankruyter	Field Staff
Sharon Elder	Administration Support

ESTIMATED COSTS

Our estimate of costs for the 2010 program is summarized in the attached *Work Plan Acceptance* form. The Goods and Services Tax or other applicable taxes are additional. It should be noted that no cost for a second visit related to the decommissioning of monitoring wells not used any more has been included.

We have assumed that, as in previous years, Wardrop personnel and equipment will be able to mobilize to the site on charter flights that are arranged by and billed directly to Hydro One. In addition, we have assumed that Wardrop personnel can be accommodated on site in the Hydro One residential facilities. We have also assumed that appropriate Hydro One personnel will be on-site to assist with this work.

Project Management

Wardrop will be responsible for the project's management, co-ordination and project administrative services. Wardrop has proven project and quality management systems that Hydro One Remote Communities can count on to deliver the project on time and on budget. Project management services include tasks such as, monitoring schedule, budget and cost performance throughout the duration of the project.

COMMERCIAL TERMS

Changes to Required Services

Wardrop's Thunder Bay office is ISO 9001:2000 registered which requires us to maintain strict project management protocols. This includes close budget tracking, detailed quality control and requirements for signed acceptance of scopes of work and budgets. We do not proceed with work outside defined scopes without the authorization of our clients.

If, during the course of the project, a change in the required services or differences from the specific assumptions has implications for the budget or the schedule, we will call you to discuss the issue, and then issue a written Change Notice to you. If these changes have quantifiable impacts on the budget or schedule, we will provide our opinion of probable cost or schedule change with rationale in the Contract Change Notice. Your written approval will be required for us to proceed under the changed scope.

Payment Schedule

Invoices will be issued on or about the 15th of each month for services provided. Payment is due within 30 days of receipt of the invoice by the client. Interest at a rate of 1.5% per month may be applied to overdue accounts.

Disbursements are charged at cost plus our standard 10% administrative mark up. An administration fee of $6.50/billable hour is applicable to cover the cost of communications, copying and computer related overhead charges.

Validity of Offer

This offer is valid for a period of 60 days.

Contract Terms

This work will be performed in accordance with Hydro One's Terms and Conditions for these projects. For your convenience, we have prepared a *Work Plan Acceptance* form for you to sign and return to us to authorize this work.

CLOSURE

We trust that this work plan will meet with your approval and we look forward to working with you on this project. Should you want to discuss any aspect of this program with us, please feel free to call us at your convenience.

Sincerely

WARDROP ENGINEERING INC.

John Guan, M.Eng., P.Eng.
Environmental Engineer
Infrastructure Division

Reviewed by

WARDROP ENGINEERING INC.

Rene de Vries, P. Geo
Sr. Environmental Scientist
Infrastructure Division

jg/mi

Attachments: - Proposal Acceptance
- Scope of Program

PROPOSAL ACCEPTANCE

Hydro One Remote Communities Inc. agrees to this proposal, price, payment terms, and general terms and conditions, and authorizes Wardrop Engineering Inc. to proceed with the project as described in this letter.

Document Number:	0031870207-WPL-V0001-00
Project Description:	Proposed 2010 Work Plan, Kasabonika DGS
Fee Basis:	Time and Materials
Authorized Budget:	$ 23,800 (plus applicable taxes)

ACCEPTED THIS ________ DAY OF ______________________________, 2010

Authorized Signature: ____

Name: (Please Print): ____

Position: ____

Scope of Program, 2010 Kasabonika DGS

Item	Location	Details	Schedule
Monitoring Wells	MW15 (or MW17), MW18, MW27, MW101, MW103 and MW105 Also, one: Duplicate, Field Blank, Travel Blank.	Measure ground water and phase separated hydrocarbon levels. Samples analyzed for benzene, toluene, ethylbenzene, xylenes (BTEX), and PHC F1 - F4.	One site visit: June - August 2010
Reporting		Draft Report	Nov - Dec 2010
		Final Report	Following receipt of comments from Hydro One

Notes: Read in conjunction with accompanying letter.

Hydro One Remote Communities Inc.

2011 Site Remediation and Monitoring Activities

Diesel Generating Station, Big Trout Lake, Ontario

Prepared by:

True Grit Consulting Ltd.
PO Box 607
Sioux Lookout, ON P8T 1B1
T: 807.737.7132
F: 807.737.1091
Project Number: 11-221-04F
Contact: Randy Edwards, A SC.T

December 31, 2011

Executive Summary

True Grit Consulting Ltd (TGCL) was retained by Kitchenuhmaykoosib Inninuwug (KI) and Hydro One Remote Communities Inc. (Hydro One) to continue on-going remediation and monitoring activities at the Hydro One Diesel Generating Station (DGS) site in Big Trout Lake, Ontario.

In 2001, an environmental assessment of the Hydro One DGS identified subsurface petroleum hydrocarbon (PHC) impact at the site. In 2002 and 2003, a remedial excavation was completed on the property; however, impact remains in areas which were inaccessible to excavation. Ongoing *in-situ* bioremediation is currently underway to reduce the potential for migration of impact downgradient and off site. The *in-situ* program primarily consists of use of an oxygen releasing compound (ORC) to increase subsurface oxygen levels to promote biological degradation of petroleum hydrocarbons.

Remediation and monitoring activities were completed on two events in 2011:

- June 23, 2011, which included well monitoring and replacement of hydrocarbon absorbent pads installed a monitoring well where liquid phase hydrocarbons (LPH) had previously been observed;
- September 19 - 20, 2011, which included well monitoring, replacement of hydrocarbon absorbent pads and collection of groundwater samples for laboratory analysis of PHC parameters.

Addition of ORC slurry into the amendment distribution system had been proposed for the 2011 season; however, due to the observation of residue from previous ORC injection events in the distribution system piping and lack of groundwater in the subsurface, it was decided that injection would not be completed in 2011.

Based on 2011 field and laboratory results the following is concluded:

- PHC impact does not extend off of the DGS property;
- PHC impact in groundwater remains in the area where impacted soils could not be excavated because of the presence of on-site facilities. The presence of PHC impacts is supported by evidence of LPH in MW402, located within the aforementioned area during the 2011 monitoring events;
- The limited groundwater analytical data from the 2011 remedial program does not allow evaluation of the interceptor trench performance;
- Production of oxygen in the amendment distribution system appears to be promoting local degradation of PHCs;
- Dissolved oxygen concentrations suggest that ORC applied in the *in-situ* remediation trench in July 2010 was still producing oxygen at the time of the September 2011 monitoring event; this is likely a result of a low groundwater levels over that period which slowed hydration of the ORC.
- Future injection of ORC to the amendment distribution system will require that rehabilitation measures are undertaken to remove ORC residue build-up in the distribution system piping.

Based on 2011 field and laboratory results and in consideration of the above conclusions, the following recommendations are made for the 2012 field program:

- Monitoring of site wells for depth to water/LPH and temperature/dissolved oxygen concentrations, and change of absorbent pads in MW402, in early summer 2012;

- Total station survey of all monitoring wells to more accurately determine relative groundwater elevations as many of the wells have shifted and/or been repaired since the last site survey conducted in 2008;

- Rehabilitation of the amendment distribution system in early summer of 2012; rehabilitation measures will involve use of a pressure washer and jetting tools to break-up the ORC residue in conjunction with removal of the debris from the piping system using a trash pump;

- Application of ORC to the amendment distribution system in early summer to ensure that elevated dissolved oxygen concentrations are maintained to promote degradation of PHCs;

- Monitoring of site wells for depth to water/LPH and dissolved oxygen concentrations, and change of absorbent pads in MW402, in late fall 2012; and,

- Sampling of select site wells for laboratory analysis of PHC parameters in late fall 2012.

Table of Contents

1.0 Introduction

True Grit Consulting Ltd (TGCL), formerly Anebeaaki Environmental Inc., was retained by Kitchenuhmaykoosib Inninuwug (KI) and Hydro One Remote Communities Inc. (Hydro One) to continue on-going remediation and monitoring activities at the Hydro One Diesel Generating Station (DGS) site in Big Trout Lake, Ontario (Figure 1).

The Project Team for the development and implementation of this project included the following:

- Hydro One
- KI Lands and Environment Office
- KI Chief and Council
- TGCL

This report summarizes the work conducted at the DGS site in 2011.

1.1 Background

In April 2001, TGCL was retained by KI to conduct a Phase II Environmental Site Assessment (ESA) at the Big Trout Hydro One DGS site. The results of this investigation indicated that petroleum hydrocarbon (PHC) impact was present in soil and groundwater in the area around and beneath the former bulk fuel storage area, and extended to the northeast corner of the site. TGCL estimated that approximately 3,246 m^3 of PHC impacted soil was present, of which approximately 1,671 m^3 was accessible to excavation.

In the fall of 2002 and the summer of 2003, TGCL was on site to direct a remedial excavation of accessible impacted soil (1,930 m^3 *in situ*). PHC impact remained in areas where excavation had to be discontinued due to the presence of on-site facilities. As part of the remedial program, an oxygen releasing compound (ORC) was placed in a reactive barrier trench to promote biodegradation of migrating petroleum hydrocarbons from the remaining impacted soil into the newly remediated areas. Monitoring wells installed during remedial activities, and the previous Phase II ESA, were used to monitor groundwater conditions including the effectiveness of the ORC in reducing concentrations and migration of the remaining impact.

Four site monitoring events were conducted between 2003 and 2005. The monitoring indicated there was a need to supply additional oxygen to the subsurface to increase and sustain microbial activity. The results also confirmed that additional measures were required downgradient of the reactive barrier trench to impede any further migration of petroleum hydrocarbon impact.

In 2006, ORC (i.e. calcium peroxide) slurry was injected into the subsurface, in the area of the reactive barrier trench, using steel rods and a high pressure pump. Also, a second in-situ remediation trench, including an amendment distribution system as well as additional ORC, was installed further east (downgradient) of the impacted area, as shown in Figure 2. The distribution system allowed future addition of remediation amendments, as well as ongoing sampling/monitoring of groundwater conditions.

Seven additional groundwater monitoring/injection wells (MW 401 - MW 407), were installed during the 2006 work, bringing the total wells on the site to 22 (although not all are accessible). Also, six sump wells (SW1-SW6) were installed as part of the in-situ amendment distribution system.

As part of the 2006 remedial work, the DGS property was expanded to the east to allow management of PHC impact on site and to provide additional space for DGS operations. The property expansion activities included clearing of trees, grading, and addition of granular fill material to allow for on-site storage and vehicular traffic.

In 2007, a geotextile fabric was installed across the area where granular material was applied in 2006, to permit vehicle traffic and use of this area for storage. In addition, approximately 1,000 seedlings were planted throughout the community to replace trees removed as part of the 2006 DGS site expansion.

Between 2007 and 2010, ORC was injected into the amendment distribution system annually in order to maintain elevated dissolved oxygen concentrations.

Site monitoring conducted in 2009 identified measurable thicknesses of liquid phase hydrocarbon (LPH) in three monitoring wells located within the area of remaining impacted soils.

Installation of an interceptor trench was completed in 2010 to capture the identified LPH. The approximate location of the interceptor trench is shown on Figure 2. The interceptor trench was prepared utilizing Imbiber Bead blankets which is a commercial product containing spherical polymer particles that preferentially absorb and retain organic liquids.

In September 2010, a rolled hydrocarbon absorbent pad was installed in MW402 where significant thicknesses of LPH continued to be measured. The pad is intended to be replaced during each monitoring event.

1.2 Scope of Work

The 2011 scope of work, as outline below, was generally in accordance with TGCL's *2011 Proposed Work Program*, *On-Site In Situ Remediation of Hydro One DGS Site Big Trout Lake, Ontario,* dated May 2011.

- Monitoring of select site wells for LPH thickness, water levels, and headspace vapours;
- Field testing of select site wells for dissolved oxygen and temperature;
- Collection of groundwater samples from selected site wells to be submitted for laboratory analysis of petroleum hydrocarbon parameters; and
- Changing of rolled hydrocarbon absorbent pads installed in MW402.

Addition of ORC slurry into the amendment distribution system had been proposed for the 2011 season; however, due to the observation of residue from previous ORC injection events in the distribution system piping and lack of groundwater in the subsurface, it was decided that injection would not be completed in 2011.

1.3 Site Description

The Hydro One DGS site is located off-Reserve on leased Provincial Crown land, between the residential core of the community and the airport as shown on Figure 1 (attached). The nearest surface water body is Big Trout Lake, located approximately 400 m to the east of the site. The current site layout is shown on Figure 2 (attached).

Site facilities and structures include:

- A generator building;

- A shed, containing a portable generator unit, off of the southeast corner of the generator building;
- Three 50,000 L self-contained above ground fuel storage tanks on concrete pads, to the east of the generator building;
- A fuel offload cabinet immediately south of the tanks;
- Step-up transformers and distribution line poles within a fenced compound in the southwest part of the site;
- Two storage material sheds located in the northwest part of the site;
- Empty 205-L drums, pallets, cable, and other materials immediately southeast of the material sheds;
- A transformer storage area and deck located along the west fenceline;
- Two liquid waste storage sheds located along the south fence;
- A staff house in the eastern part of the property;
- A chain link fence surrounding the site, with three access gates along the south side; and
- Utility pole storage in an open area approximately 20 m west of the site.

2.0 Field Program

On June 23 and September 19 to 20, 2011, TGCL was on site to complete the proposed scope of work.

2.1 Project Meetings

On May 3, 2011, Mr. Adrian Andreacchi of Hydro One and Mr. Randy Edwards of TGCL met with KI Chief and Council and KI Lands and Environment Unit Director Mr. Jacob Ostaman to discuss the 2010 results and the proposed 2011 remedial and monitoring program for the DGS site.

On June 23, 2011, Mr. Andreacchi and Mr. Kramer Coulter of Hydro One and TGCL personnel conducted a project initiation/safety meeting at the DGS site prior to the initiation of the spring field work. Hydro One Contractor Safety and TGCL Health and Safety forms were reviewed at the meeting. Mr. Ben Parkes of TGCL spoke with Mr. Richard Anderson of KI Lands and Environment Unit to provide an update on the project and discuss local resource requirements.

On September 19, 2011, Mr. Andreacchi and TGCL personnel conducted a project initiation/safety meeting at the DGS site prior to initiation of the fall field work.

2.2 Monitoring and Sampling

During both 2011 site visits, the following monitoring/sampling activities were completed at the site.

- Headspace organic vapours were measured in select monitoring locations using a MiniRae 3000 Photoionization Detector;
- Groundwater dissolved oxygen concentrations and temperature were measured in select monitoring locations using an Oakton Dissolved Oxygen 300 meter; and,
- Depth to water and LPH (if any) were measured in select monitoring locations using a Heron oil/water interface probe.
- Prior to sampling, the wells were purged dry using dedicated inertial lift foot valves and polyethylene tubing. Groundwater samples were collected in pre-cleaned laboratory supplied bottles, packaged with ice packs in coolers and shipped with the completed chain of custody form by air to ALS Laboratory (ALS) in Thunder Bay, Ontario for analysis.
- As part of the project quality assurance / quality control (QA/QC) program, a field duplicate and field blank were also submitted for benzene, toluene, ethlybenzene, xylenes (BTEX) and PHCs analysis.

On June 23, 2011, the following monitoring locations were inaccessible or were unable to be monitored.

- MW308 could not be located;
- MW309 is inaccessible beneath site facilities/materials;
- Only vapours could be measured in MW134 as the polyethylene sampling tubing was stuck in the well (possibly frozen);
- Only vapours could be measured in MW129 and MW307, as the wells have an obstruction in them;

- Only vapours could be measured in MW210 and MW401 as the wells were dry.
- Sumps SW1, SW2 and SW6 were dry and all sumps had significant ORC residue build-up in the bottom of the well.

In September 2011, the following monitoring locations were inaccessible or could not be monitored.

- MW308 could not be located;
- MW309 is inaccessible beneath site facilities/materials;
- Only vapours could be measured in MW129 and MW307, as the wells have an obstruction in them;
- Only vapours could be measured in MW141, MW301, MW303, MW304, MW403 and MW404 as the wells were dry.
- Sumps SW1 and SW2 were dry and all sumps had significant ORC residue build-up in the bottom of the well.
- Due to low water levels in the wells, groundwater samples could only be collected from four monitoring wells (MW121, MW134, MW406, and MW407) and two sump wells (SW2, SW5) during the September 2010 site visit. Sufficient water for analysis of both BTEX and PHCs could only be collected from MW407 and the two sump wells. The remaining wells were only sampled for BTEX.

2.3 Groundwater Quality Assessment Criteria

The DGS property is currently on, and immediately surrounded by, Provincial Crown land; however, the KI is actively pursuing addition of the land to its Reserve. It was previously decided by the Project Team that the remediation on the DGS property would be conducted to meet the more stringent of the applicable federal and provincial guidelines. The project remediation criteria are being updated as required due to changes in the federal/provincial guidelines.

The PHC of concern for the remediation is diesel fuel, a mid-distillate PHC. Under the current federal and provincial guidelines the typical indicator used to quantify total light-, mid-, and heavy-distillate PHCs in soil is PHC fractions F1 to F4.

The most common volatile components of light- and mid-distillate PHC products are the monocyclic aromatic hydrocarbons (BTEX), and these are typically used as indicators for the lighter fraction of PHC contaminants in soils.

The selected on-site soil remediation criteria are presented in Table A, below. The remediation criteria for BTEX are from the CCME Environmental Quality Guidelines (1999 or as updated). The remediation criteria for PHC's are from Table 2 of the Ontario Ministry of the Environment (MOE) generic site condition standards (SCS) from the *Soil, Ground Water and Sediment Standards for Use Under Part XV.1 of the Environmental Protection Act* (April 15, 2011, or as updated).

Generic criteria for residential/parkland land use, fine-grained surface soil, and a potable groundwater condition were selected.

Table A: On Site Soil Remediation Criteria for Petroleum Related Contaminants	
Parameters	**Criteria µg/g (ppm)**
Benzene	0.0068
Toluene	0.08
Ethylbenzene	0.018
Xylenes	2.4
PHC Fraction F1, C6 – C10 Hydrocarbons	65
PHC Fraction F2, >C10 – C16 Hydrocarbons	150
PHC Fraction F3, >C16 – C34 Hydrocarbons	1,300
PHC Fraction F4, >C34 Hydrocarbons	5,600

The selected remediation criteria for groundwater are presented in Table B, below. The criteria for BTEX are the community water criteria from the CCME Environmental Quality Guidelines (CCME 1999, or as updated). In the absence of PHC criteria for water in the CCME guidelines, the criteria used are from Table 2 of the MOE generic site condition standards (SCS) from the *Soil, Ground Water and Sediment Standards for Use Under Part XV.1 of the Environmental Protection Act* (April 15, 2011, or as updated).

Table B: On Site Groundwater Remediation Criteria for Petroleum Related Contaminates	
Parameters	**Criterion µg/L (ppb)**
Benzene	5
Toluene	24
Ethylbenzene	2.4
Xylenes	300
PHC Fraction F1, C6 – C10 Hydrocarbons	750
PHC Fraction F2, >C10 – C16 Hydrocarbons	150
PHC Fraction F3, >C16 – C34 Hydrocarbons	500
PHC Fraction F4, >C34 Hydrocarbons	500

2.4 Absorbent Pad Replacement

Rolled hydrocarbon absorbent pads were replaced in monitoring well MW402 in June and September 2011. Staining and odours indicated that the replaced pads had absorbed hydrocarbons. The used pads were disposed of the community waste disposal site.

2.5 ORC Application

Due to the low groundwater conditions and the observation of ORC residue in the amendment distribution system piping it was decided through discussion between TGCL and Hydro One that the proposed injection of ORC during the September site visit would not be productive. Injection was postponed pending more favourable soil moisture conditions and required distribution system rehabilitation measures.

Preliminary distribution system rehabilitation measures were conducted in September 2011. Water was flushed down the sump wells while the ORC residue build-up was disturbed using a long pole. The measures were successful in breaking-up/dissolving the ORC residue down to the bottom of the sumps.

3.0 Results and Discussion

3.1 Field and Laboratory Results

Current and historical well monitoring results are presented in Table 1, attached. Dissolved oxygen and temperature readings are presented in Table 2, attached. Current and historical analytical results are presented in Table 3.0. The 2011 results are presented on Table 3.1.

In September 2011, elevated dissolved oxygen values were measured in the sump wells suggesting that the 2010 ORC application was still producing oxygen at the time of sampling. Product literature indicates that after hydration the ORC will typically produce oxygen for a period of 9-12 months. The elevated dissolved oxygen concentrations measured in September 2011 are likely a result of the low groundwater levels observed at the site, which resulted in incomplete hydration of the ORC over the period. Low groundwater levels also likely contributed to the observed ORC residue build-up in the sumps.

In 2011, measurable thicknesses of LPH were not identified in any wells; however, since September 2010 absorbent pads have been installed in MW402 where LPH has been previously been measured. Evidence of hydrocarbon impact was observed on the pads when replaced during each monitoring event in 2011.

Concentrations of BTEX and PHC fractions F1 to F4 were below the remediation criteria in all groundwater samples submitted for analysis during the September 2011 sampling event. The data is limited due the low number of wells that were able to be sampled due to lack of water in the wells.

3.2 Quality Assurance/Quality Control

The 2011 QA/QC results are shown in Table 4. Laboratory Certificates of Analyses are presented in Appendix B.

The QA/QC program implemented by ALS consisted of the analysis of laboratory replicates, method blanks, matrix spikes, method spikes and surrogate percent recoveries, as appropriate for the particular analysis protocol. Laboratory QA/QC results reported on the Certificates of Analysis (Appendix B) are all within the acceptable ranges set by the laboratories.

A groundwater field duplicate and trip blank were also analyzed as part of the project QA/QC protocol. The field duplicate sample consisted of a sub-sample of the sample collected in the field.

As shown in Table 4, concentrations of PHCs in the original groundwater sample and its duplicate were below laboratory detection limits for all parameters. Concentrations of PHCs in the field blank were below laboratory detection limits, as would be expected.

Considering the above, the results of the QA/QC program support the validity of the sampling and analytical program.

4.0 Conclusions

Based on 2011 field and laboratory results the following is concluded:

- PHC impact does not extend off of the DGS property;
- PHC impact in groundwater remains in the area where impacted soils could not be excavated because of the presence of on-site facilities. The presence of PHC impacts is supported by evidence of LPH in MW402, located within the aforementioned area during the 2011 monitoring events;
- The limited groundwater analytical data from the 2011 remedial program does not allow evaluation of the interceptor trench performance;
- Production of oxygen in the amendment distribution system appears to be promoting local degradation of PHCs;
- Dissolved oxygen concentrations suggest that ORC applied in the *in-situ* remediation trench in July 2010 was still producing oxygen at the time of the September 2011 monitoring event; this is likely a result of a low groundwater levels over that period which slowed hydration of the ORC.
- Future injection of ORC to the amendment distribution system will require that rehabilitation measures are undertaken to remove ORC residue build-up in the distribution system piping.

5.0 Recommendations

Based on 2011 field and laboratory results and in consideration of the above conclusions, the following recommendations are made for the 2012 field program:

- Monitoring of site wells for depth to water/LPH and temperature/dissolved oxygen concentrations, and change of absorbent pads in MW402, in early summer 2012;

- Total station survey of all monitoring wells to more accurately determine relative groundwater elevations as many of the wells have shifted and/or been repaired since the last site survey conducted in 2008;

- Rehabilitation of the amendment distribution system in early summer of 2012; rehabilitation measures will involve use of a pressure washer and jetting tools to break-up the ORC residue in conjunction with removal of the debris from the piping system using a trash pump;

- Application of ORC to the amendment distribution system in early summer to ensure that elevated dissolved oxygen concentrations are maintained to promote degradation of PHCs;

- Monitoring of site wells for depth to water/LPH and dissolved oxygen concentrations, and change of absorbent pads in MW402, in late fall 2012; and,

- Sampling of select site wells for laboratory analysis of PHC parameters in late fall 2012.

6.0 Closure

The work described herein was conducted in accordance with the objectives of the Project Team as outlined in TGCL's *2011 Proposed Work Program*, *On-Site In-Situ Remediation of Hydro One DGS Site Big Trout Lake, Ontario,* dated May 2011.

The information and data contained in this report, including without limitation, the results of any sampling and analyses conducted by TGCL pursuant to its Agreement with the client, have been developed or obtained through the exercise of TGCL's professional judgment and are set forth to the best of TGCL's knowledge, information and belief. Although every effort has been made to confirm that this information is factual, complete and accurate, TGCL makes no guarantees or warranties whatsoever, whether express or implied, with respect to such information or data.

The information and data presented in this report are based on the purpose and scope of the project and form the basis for any conclusions and recommendations presented herein. Any conclusions and recommendations presented herein do not preclude the existence of environmental concerns other than those that may have been identified.

Work performed by TGCL personnel employed sound environmental assessment principles. TGCL cannot guarantee the accuracy and reliability of information provided by others or third parties. Therefore, TGCL does not claim responsibility for undisclosed environmental concerns or conditions that may result in costs for environmental clean-up and/or remediation. This report is intended for information purposes only.

This report has been prepared for the exclusive use of the Project Team, including Kitchenuhmaykoosib Inninuwug and Hydro One as well as Ontario Ministry of Natural Resources and Technical Standards and Safety Authority. It is not to be distributed to parties not listed without the express written consent of True Grit Consulting Ltd.

True Grit Consulting Ltd. accepts no liability for claims arising from the use of this report or from actions taken or decisions made as a result of this report, by parties other than those listed above.

Respectfully submitted by:

True Grit Consulting Ltd.

PROFESSIONAL GEOSCIENTIST
JASON R. GARATTI
PRACTISING MEMBER
0889
ONTARIO
Jan 17/12

Randy Edwards, A Sc.T
Principal/Project Manager
redwards@tgcl.ca

Jason Garatti, M.Sc.Eng., P.Geo.
Principal/Manager, Environmental Services
jgaratti@tgcl.ca

JG/RE:pn/bk

Figures

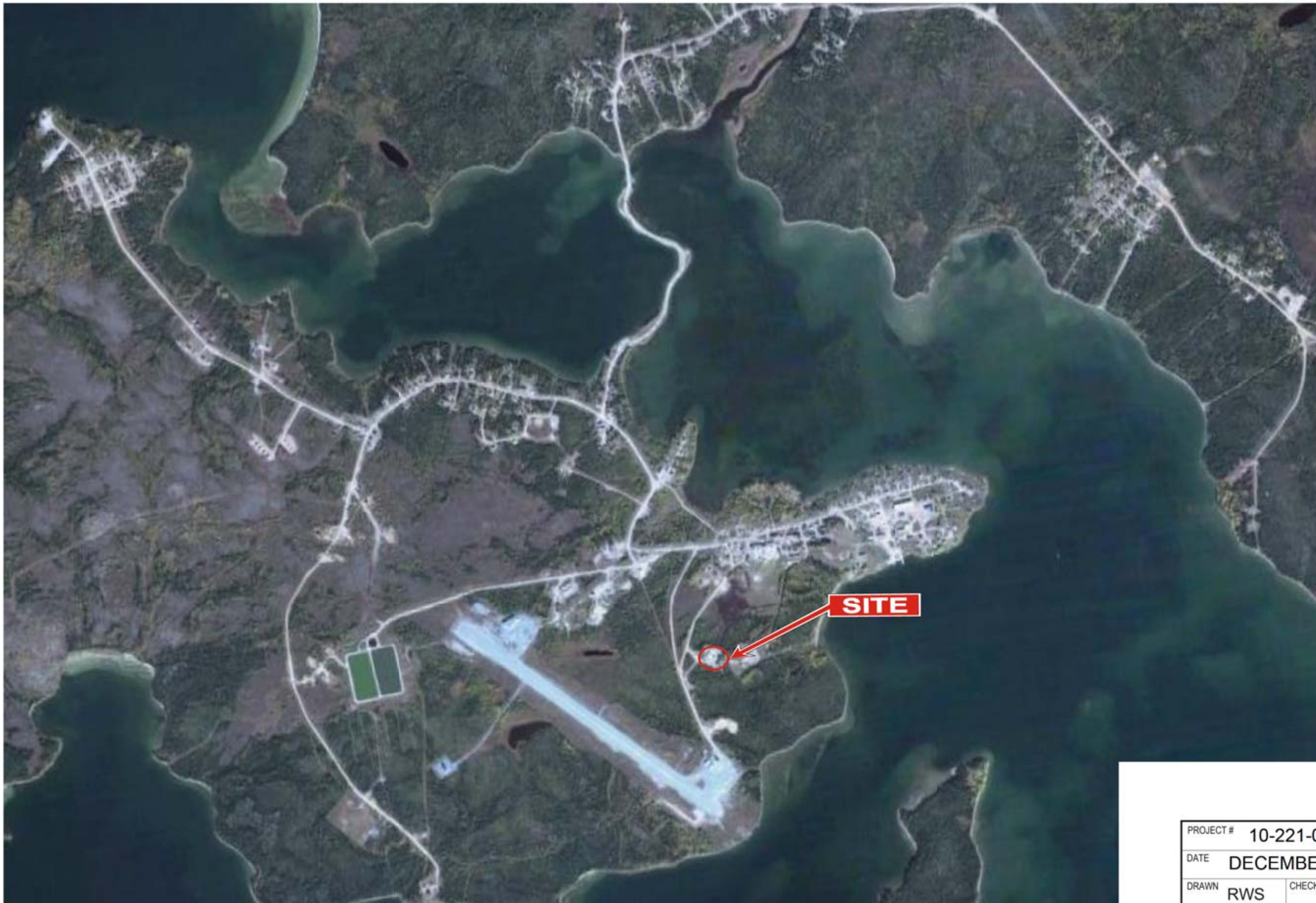
TRUE GRIT
CONSULTING LTD

COMMUNITY LAYOUT AND SITE LOCATION

BIG TROUT LAKE, ONTARIO

CLIENT

KITCHENUHMAYKOOSIB INNINUWUG



PROJECT #	10-221-04F
DATE	DECEMBER 2011
DRAWN RWS	CHECKED WRE
DRAWING #	FIGURE 1

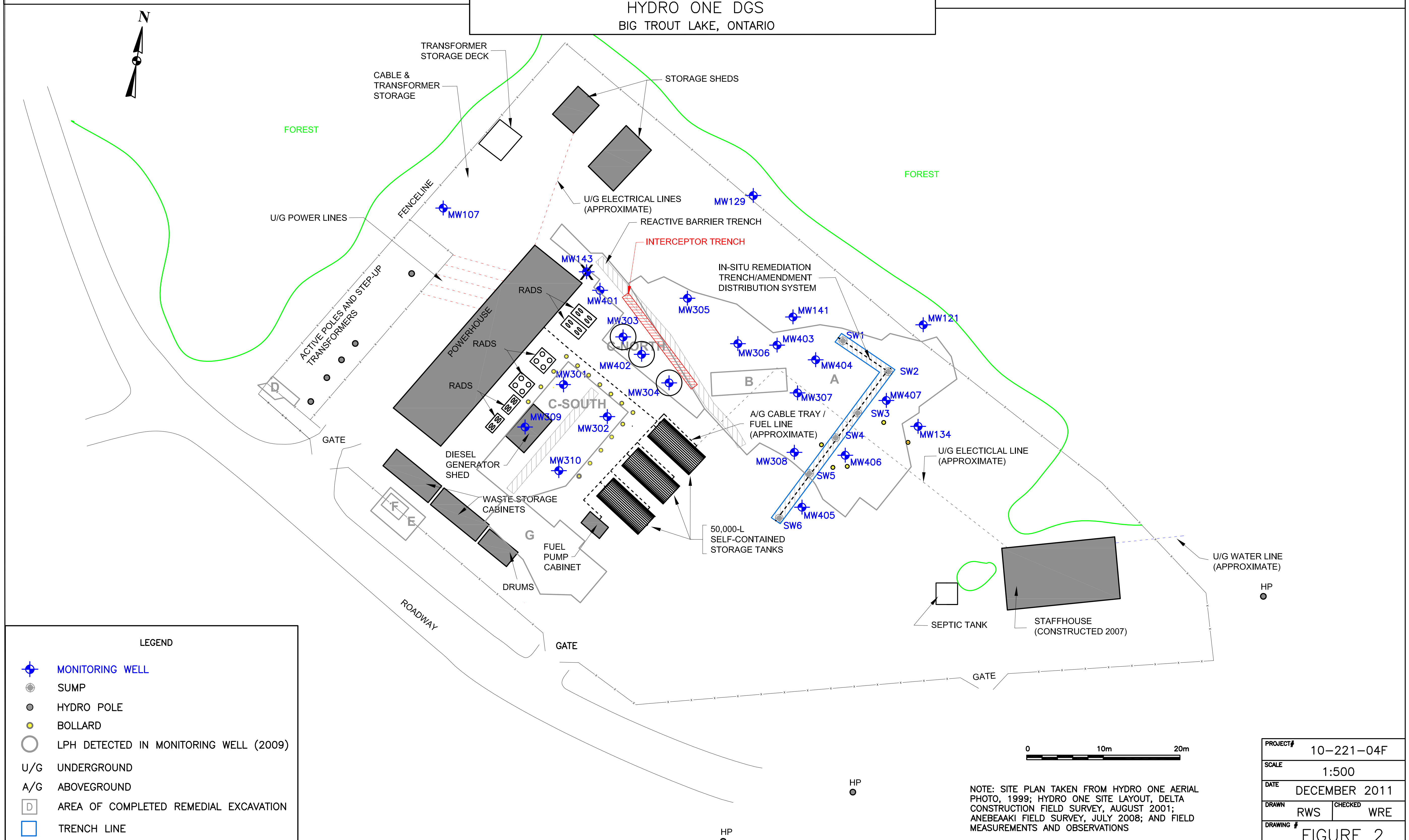
TRUE GRIT CONSULTING LTD

SITE LAYOUT AND PROPOSED LOCATION OF INTERCEPTOR TRENCH

HYDRO ONE DGS

BIG TROUT LAKE, ONTARIO

KITCHENUHMAYKOOSIB INNINUWUG



Tables

TABLE 1 GROUNDWATER MONITORING DATA
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE

WELL	CURRENT WELL CONDITION STATUS	DATE MONITORED	HEADSPACE VAPOUR (ppm or %LEL) *	RELATIVE ELEVATION[1] (ground level)	RELATIVE ELEVATION[2] (top of pipe)	WELL STICKUP (m)	TOTAL WELL DEPTH (top of pipe)	DEPTH TO WATER (from grade) (m)	DEPTH TO WATER[3] (top of pipe) (m)	RELATIVE WATER ELEVATION	DEPTH TO LPH (m) (from TOP)	LPH THICKNESS (m)
		2-Jul-08	30 ppm					2.07	2.855	99.571	-	0.000
		7-Jul-09	50 ppm					1.16	1.947	100.479	-	0.000
		13-Oct-09	NM					3.84	4.62	97.806	-	0.000
MW107	EXISTING	26-Jul-10	45 ppm	101.642	102.426	0.78	4.91	3.45	4.239	98.187	-	0.000
		28-Sep-10	35 ppm					2.91	3.694	98.732	-	0.000
		23-Jun-11	0.5 ppm					3.13	3.911	98.515	-	0.000
		19-Sep-11	0.0 ppm					4.08	4.867	97.559	-	0.000
		2-Jul-08	NM					0.50	1.4	98.805	-	0.000
		7-Jul-09	200 ppm					0.16	1.06	99.145	-	0.000
		13-Oct-09	NM					1.83	2.73	97.475	-	0.000
MW121	EXISTING	27-Jul-10	70 ppm	99.301	100.205	0.90	3.79	0.67	1.577	98.628	-	0.000
		28-Sep-10	15 ppm					0.61	1.517	98.688	-	0.000
		23-Jun-11	0.3 ppm					1.18	2.081	98.124	-	0.000
		19-Sep-11	0.0 ppm					2.93	3.835	96.370	-	0.000
		2-Jul-08	NM					NM	NM	NM	NM	NM
		7-Jul-09	75 ppm					NM	NM	NM	NM	NM
		13-Oct-09	NM					2.32	3.61	97.740	-	0.000
MW129	OBSTRUCTED	26-Jul-10	60 ppm	100.064	101.35	1.29	4.79	NM	NM	NM	NM	NM
		28-Sep-10	3 ppm					NM	NM	NM	NM	NM
		23-Jun-11	0.2 ppm					DRY	DRY	DRY	DRY	DRY
		19-Sep-11	0.0 ppm					NM	NM	NM	NM	NM
		2-Jul-08	10 ppm					NM	1.445	99.270	-	0.000
		7-Jul-09	50 ppm					NM	NM	NM	NM	NM
		13-Oct-09	NM					2.41	2.985	97.730	-	0.000
MW134	EXISTING	26-Jul-10	75 ppm	100.144	100.715	0.57	3.35	1.91	2.484	98.231	-	0.000
		28-Sep-10	75 ppm					1.45	2.024	98.691	-	0.000
		23-Jun-11	0.4 ppm					NM	NM	NM	NM	NM
		19-Sep-11	0.0 ppm					2.67	3.243	97.472	-	0.000
		2-Jul-08	50 ppm					0.79	1.83	99.292	-	0.000
		7-Jul-09	40 ppm					0.38	1.422	99.700	-	0.000
		13-Oct-09	NM					2.47	3.515	97.607	-	0.000
MW141	EXISTING	26-Jul-10	70 ppm	100.078	101.122	1.04	4.22	1.62	2.659	98.463	-	0.000
		28-Sep-10	75 ppm					1.45	2.496	98.626	-	0.000
		23-Jun-11	0.1 ppm					1.90	2.948	98.174	-	0.000
		19-Sep-11	0.0 ppm					DRY	DRY	DRY	DRY	DRY
		2-Jul-08	200 ppm					NM	NM	NM	NM	NM
		7-Jul-09	100 ppm					0.75	0.68	101.045	-	0.000
		13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY
MW301	EXISTING	26-Jul-10	125 ppm	101.79	101.725	-0.07	3.24	2.73	2.665	99.060	-	0.000
		28-Sep-10	NM					NM	NM	NM	NM	NM
		23-Jun-11	0.2 ppm					2.92	2.851	98.874	-	0.000
		19-Sep-11	0.0 ppm					DRY	DRY	DRY	DRY	DRY
		2-Jul-08	60 ppm					NM	NM	NM	NM	NM
		7-Jul-09	25 ppm					0.33	0.265	101.279	-	0.000
		13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY
MW302	EXISTING	27-Jul-10	50 ppm	101.613	101.544	-0.07	2.59	1.83	1.758	99.786	-	0.000
		28-Sep-10	30 ppm					1.48	1.482	100.062	-	0.000
		23-Jun-11	0.2 ppm					2.20	2.133	99.411	-	0.000
		19-Sep-11	0.0 ppm					2.676	2.676	98.868	-	0.000
		2-Jul-08	60 ppm					1.41	2.19	99.670	-	0.000
		7-Jul-09	200 ppm					0.23	1.016	100.844	-	0.000
		13-Oct-09	NM					3.36	4.14	97.728	4.13	0.010
MW303	EXISTING	26-Jul-10	75 ppm	101.079	101.86	0.78	4.60	2.68	3.461	98.399	-	0.000
		28-Sep-10	100 ppm					2.15	2.928	98.934	2.925	0.003
		23-Jun-11	14.1 ppm					2.59	3.374	98.486	-	0.000
		19-Sep-11	1.5					DRY	DRY	DRY	DRY	DRY
		2-Jul-08	50 ppm					0.86	1.535	99.946	-	0.000
		7-Jul-09	30 ppm					0.20	0.872	100.610	0.871	0.001
		13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY
MW304	EXISTING	26-Jul-10	25 ppm	100.81	101.481	0.67	3.21	2.08	2.754	98.727	-	0.000
		28-Sep-10	NM					1.59	2.26	99.221	-	0.000
		23-Jun-11	NM					2.01	2.678	98.803	-	0.000
		19-Sep-11	0.4 ppm					DRY	DRY	DRY	DRY	DRY
		4-Nov-06	NM					0.52	1.24	98.689	-	0.000
		7-Jul-09	>100% LEL					0.10	0.815	99.114	-	0.000
		13-Oct-09	NM					2.25	2.965	96.964	-	0.000
MW305	EXISTING	27-Jul-10	0 ppm	99.214	99.929	0.72	4.29	1.56	2.271	97.658	-	0.000
		28-Sep-10	5 ppm					1.22	1.938	97.991	-	0.000
		23-Jun-11	0.1 ppm					1.55	2.261	97.668	-	0.000
		19-Sep-11	0.0 ppm					3.07	3.781	96.148	-	0.000
		2-Jul-08	10 ppm					1.28	1.92	99.237	-	0.000
		7-Jul-09	30 ppm					0.51	1.15	100.007	-	0.000
		13-Oct-09	NM					2.87	3.505	97.652	-	0.000
MW306	EXISTING	26-Jul-10	10 ppm	100.518	101.157	0.64	3.99	2.14	2.779	98.378	-	0.000
		28-Sep-10	50 ppm					1.86	2.494	98.663	-	0.000
		23-Jun-11	0.0 ppm					2.19	2.831	98.326	-	0.000
		19-Sep-11	NM					3.43	4.065	97.092	-	0.000
		2-Jul-08	NM					1.07	1.65	99.295	-	0.000
		7-Jul-09	25 ppm					0.18	0.76	100.185	-	0.000
		13-Oct-09	NM					2.90	3.48	97.465	-	0.000
MW307	OBSTRUCTED	26-Jul-10	5 ppm	100.361	100.945	0.58	4.02	1.51	2.097	98.848	-	0.000
		28-Sep-10	NM					0.66	1.241	99.704	-	0.000
		23-Jun-11	0.0 ppm					NM	NM	NM	NM	NM
		19-Sep-11	NM					NM	NM	NM	NM	NM
		4-Nov-06	NM					NM	NM	NM	NM	NM
		7-Jul-09	NM					NM	NM	NM	NM	NM
		13-Oct-09	NM					NM	NM	NM	NM	NM
MW308	CNL	26-Jul-10	NM	99.190	100.109	0.92	3.02	NM	NM	NM	NM	NM
		28-Sep-10	NM					NM	NM	NM	NM	NM
		23-Jun-11	NM					NM	NM	NM	NM	NM
		19-Sep-11	NM					NM	NM	NM	NM	NM
		2-Jul-08	20 ppm					NM	NM	NM	NM	NM
		7-Jul-09	25 ppm					NM	NM	NM	NM	NM
		13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY
MW310	EXISTING	26-Jul-10	0 ppm	101.795	101.783	-0.01	2.04	0.59	0.581	101.202	-	0.000
		28-Sep-10	5 ppm					DRY	DRY	DRY	DRY	DRY
		23-Jun-11	0.3 ppm					DRY	DRY	DRY	DRY	DRY
		19-Sep-11	0.0 ppm					1.90	1.891	99.892	-	0.000
		2-Jul-08	10 ppm					NM	NM	NM	NM	NM
		7-Jul-09	40 ppm					0.44	1.467	101.134	-	0.000
		13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY
MW401	EXISTING	26-Jul-10	30 ppm	101.577	102.601	1.02	2.65	DRY	DRY	DRY	DRY	DRY
		28-Sep-10	25 ppm					DRY	DRY	DRY	DRY	DRY
		23-Jun-11	0.9 ppm					DRY	DRY	DRY	DRY	DRY
		19-Sep-11	0.0 ppm					1.67	2.689	99.912	-	0.000
		2-Jul-08	400 ppm					1.69	2.83	99.337	-	0.000
		7-Jul-09	15 % LEL					0.75	1.886	100.281	-	0.000
		13-Oct-09	NM					3.34	4.475	97.704	4.46	0.015
MW402	EXISTING	26-Jul-10	3 % LEL	101.03	102.167	1.14	4.15	2.94	4.079	98.126	4.031	0.048
		28-Sep-10	1% LEL					2.36	3.495	98.726	3.428	0.067
		23-Jun-11	70.1 ppm					2.68	3.813	98.354	-	0.000
		19-Sep-11	28.5 ppm					3.53	4.663	97.504	-	0.000
		2-Jul-08	50 ppm					0.76	1.925	99.544	-	0.000
		7-Jul-09	300 ppm					0.43	1.595	99.874	-	0.000
		13-Oct-09	NM					2.04	3.202	98.267	-	0.000
MW403	EXISTING	26-Jul-10	100 ppm	100.302	101.469	1.17	3.20	1.46	2.625	98.844	-	0.000
		28-Sep-10	105 ppm					1.26	2.422	99.047	-	0.000
		23-Jun-11	0.1 ppm					1.69	2.853	98.616	-	0.000
		19-Sep-11	0.0 ppm					DRY	DRY	DRY	DRY	DRY

TABLE 1 **GROUNDWATER MONITORING DATA**
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE

WELL	CURRENT WELL CONDITION STATUS	DATE MONITORED	HEADSPACE VAPOUR (ppm or %LEL) *	RELATIVE ELEVATION[1] (ground level)	RELATIVE ELEVATION[2] (top of pipe)	WELL STICKUP (m)	TOTAL WELL DEPTH (top of pipe)	DEPTH TO WATER (from grade) (m)	DEPTH TO WATER[3] (top of pipe) (m)	RELATIVE WATER ELEVATION	DEPTH TO LPH (m) (from TOP)	LPH THICKNESS (m)
		2-Jul-08	30 ppm					NM	NM	NM	NM	NM
		7-Jul-09	150 ppm					0.24	1.448	99.825	-	0.000
		13-Oct-09	NM		101.273	1.21	3.52	2.15	3.36	97.913	-	0.000
MW404**	EXISTING	27-Jul-10	80 ppm	100.063				1.70	2.912	98.361	-	0.000
		28-Sep-10	75 ppm					0.92	2.129	99.144	-	0.000
		23-Jun-11	0.0 ppm		101.083	1.02	3.33	1.75	2.765	98.508	-	0.000
		19-Sep-11	0.0 ppm					DRY	DRY	DRY	DRY	DRY
		4-Nov-06	NM					NM	NM	NM	NM	NM
		7-Jul-09	NM					NM	NM	NM	NM	NM
		13-Oct-09	NM					1.66	2.55	98.533	-	0.000
MW405	EXISTING	27-Jul-10	80 ppm	99.590	100.481	0.89	2.64	1.55	2.445	98.036	-	0.000
		28-Sep-10	75 ppm					1.26	2.147	98.334	-	0.000
		23-Jun-11	1.3 ppm					1.47	2.361	98.12	-	0.000
		19-Sep-11	0.0 ppm					1.60	2.486	97.995	-	0.000
		2-Jul-08	20 ppm					0.96	1.395	99.724	-	0.000
		7-Jul-09	250 ppm					0.65	1.089	100.030	-	0.000
		13-Oct-09	NM					2.39	2.825	98.294	-	0.000
MW406	EXISTING	26-Jul-10	55 ppm	100.681	101.119	0.44	3.63	2.47	2.909	98.210	-	0.000
		28-Sep-10	50 ppm					1.70	2.137	98.982	-	0.000
		23-Jun-11	4.0 ppm					2.23	2.664	98.455	-	0.000
		19-Sep-11	0.2 ppm					2.60	3.041	98.078	-	0.000
		2-Jul-08	10 ppm					0.25	1.19	99.483	-	0.000
		7-Jul-09	30 ppm					0.05	0.988	99.685	-	0.000
		13-Oct-09	NM					0.59	1.53	99.143	-	0.000
MW407	EXISTING	26-Jul-10	75 ppm	99.733	100.673	0.94	3.71	1.36	2.295	98.378	-	0.000
		28-Sep-10	75 ppm					0.17	1.108	99.565	-	0.000
		23-Jun-11	0.5 ppm					1.96	2.903	97.770	-	0.000
		19-Sep-11	0.0 ppm					0.12	1.055	99.618	-	0.000
		2-Jul-08	<10 ppm					NM	NM	NM	NM	NM
		7-Jul-09	25 ppm					-0.23	0.625	99.755	-	0.000
		13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY
SW1	EXISTING	26-Jul-10	NM	99.526	100.38	0.85	2.77	1.66	2.512	97.868	-	0.000
		28-Sep-10	NM					0.88	1.735	98.645	-	0.000
		23-Jun-11	NM					DRY	DRY	DRY	DRY	DRY
		19-Sep-11	0.0 ppm					DRY	DRY	DRY	DRY	DRY
		2-Jul-08	<10 ppm					NM	NM	NM	NM	NM
		7-Jul-09	25 ppm					NS	1.015	99.612	-	0.000
		13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY
SW2	EXISTING	26-Jul-10	NM	NS	100.627	NS	3.37	NS	2.757	97.870	-	0.000
		28-Sep-10	NM					NS	1.375	99.252	-	0.000
		23-Jun-11	0.2 ppm					DRY	DRY	DRY	DRY	DRY
		19-Sep-11	0.0 ppm					NS	1.164	99.463	-	0.000
		2-Jul-08	<10 ppm					NM	NM	NM	NM	NM
		7-Jul-09	25 ppm					0.26	1.315	99.732	-	0.000
		13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY
SW3	EXISTING	26-Jul-10	NM	99.99	101.047	1.06	3.53	2.18	3.235	97.812	-	0.000
		28-Sep-10	NM					0.75	1.81	99.237	-	0.000
		23-Jun-11	0.1 ppm					DRY	DRY	DRY	DRY	DRY
		19-Sep-11	0.0 ppm					DRY	DRY	DRY	DRY	DRY
		2-Jul-08	<10 ppm					NM	NM	NM	NM	NM
		7-Jul-09	10 ppm					0.05	1.05	100.188	-	0.000
		13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY
SW4	EXISTING	26-Jul-10	NM	100.241	101.238	1.00	3.40	DRY	DRY	DRY	DRY	DRY
		28-Sep-10	NM					DRY	DRY	DRY	DRY	DRY
		23-Jun-11	0.1 ppm					1.44	2.433	98.805	-	0.000
		19-Sep-11	0.0 ppm					1.24	2.234	99.004	-	0.000
		2-Jul-08	NM					NM	NM	NM	NM	NM
		7-Jul-09	25 ppm					0.51	0.33	100.223	-	0.000
		13-Oct-09	NM					NM	NM	NM	NM	NM
SW5	EXISTING	26-Jul-10	NM	100.737	100.553	-0.18	3.61	2.69	2.51	98.043	-	0.000
		28-Sep-10	10 ppm					0.37	0.19	100.363	-	0.000
		23-Jun-11	0.9 ppm					1.53	1.342	99.211	-	0.000
		19-Sep-11	0.0 ppm					0.66	0.481	100.072	-	0.000
		2-Jul-08	NM					NM	NM	NM	NM	NM
		7-Jul-09	NM					NM	NM	NM	NM	NM
		13-Oct-09	NM					NM	NM	NM	NM	NM
SW6	EXISTING	26-Jul-10	NM	NS	100.827	NS	2.95	DRY	DRY	DRY	DRY	DRY
		28-Sep-10	25 ppm					NS	1.755	99.072	-	0.000
		23-Jun-11	0.2 ppm					DRY	DRY	DRY	DRY	DRY
		19-Sep-11	0.0 ppm					NS	1.100	99.73	-	0.000

1 Elevation of ground level in metres, relative to on-site benchmark.
2 Elevation of top of well pipe in metres, relative to on-site benchmark.
3 Depth to groundwater in metres from top of pipe.
4 Elevation of groundwater in metres from ground level, relative to on-site benchmark.
5 Elevation of groundwater in metres from top of pipe, relative to on-site benchmark.
NS Not Surveyed
NM Not Monitored
DRY Well was dry
CNL Can Not Locate
* Headspace combustible vapours measured using a Gastechtor Model 1258ME Hydrocarbon Surveyor prior to 2011; Headspace organic vapour measured using a MiniRAE Lite TM PGM-7300 Volatile Organic Compound detector since June 2011.
** MW404 repaired due to frost heaving, 0.19m cut off of stand pipe during the June 2011 monitoring event.

TABLE 2.0 DISSOLVED OXYGEN CONCENTRATIONS
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2011)

Parameter	Date Sampled	Temperature °C	Dissolved Oxygen	
			% saturation	mg/L
MW107 BHW107	May 27/04	3.1	72.00	9.11
	Oct 14/04	6.5	58.10	7.08
	Aug 24/05	9.1	59.50	6.14
	Nov 6/06	3.9	71.20	9.36*
	Sept 19/07	10.5	107.30	13.28
	July 2/08	2.7	40.16*	5.45
	Dec 2/08	3.5	61.75*	8.2
	July 7/09	7.77	70.10	8.58
	Oct 13/09	4.3	53.68*	6.98
	July 26/10	18.8	46.30	4.25
	Sept 28/10	6.5	73.50	9.08
	June 23/11	2.1	55.00	7.17
	Sept 19/11	9.7	68.10	7.72
MW121 BHW121	Aug 29/03	12.9	100.80	10.37
	May 27/04	2.0	46.60	5.80
	Nov 6/06	3.9	61.00	8.02*
	Sept 19/07	10.2	34.67	3.94
	Dec 2/08	2.5	23.97*	3.27
	July 7/09	9.2	17.50	2.03
	Oct 13/09	5.4	5.40	0.67
	July 27/10	16.7	39.60	4.16
	Sept 28/10	6	69.50	8.77
	June 23/11	5.3	6.80	0.81
	Sept 19/11	8.2	63.60	7.53
MW129 BHW129	May 27/04	2.7	79.10	9.60
	Nov 6/06	4.5	103.10	12.94*
	Sept 19/07	10.3	66.00	7.47
	July 7/09	10.5	80.02	8.92
	July 26/10	NM	NM	NM
	Sept 28/10	NM	NM	NM
	June 23/11	DRY	DRY	DRY
	Sept 19/11	NM	NM	NM
MW134 BHW134	May 27/04	1.2	44.30	5.90
	Oct 14/04	5.5	11.70	1.65
	Aug 24/05	11.3	13.10	1.32
	Nov 6/06	3.3	64.50	8.61*
	Sept 19/07	11.6	22.60	2.44
	July 3/08	8.9	6.37	0.74
	Dec 2/08	2.8	9.31*	1.26
	July 7/09	9.8	20.90	2.17
	Oct 13/09	7.4	2.20	0.11
	July 26/10	17	13.50	1.88
	Sept 28/10	11.1	24.40	2.65
	June 23/11	NM	NM	NM
	Sept 19/11	10.4	59.50	6.9
MW141 BHW141	Aug 29/03	12.7	71.00	7.29
	May 27/04	3.5	25.70	3.24
	Oct 14/04	9.4	26.40	3.28
	Nov 6/06	3.1	45.90	6.16*
	Sept 19/07	11.1	9.80	1.07
	July 2/08	7.2	16.29*	1.97
	Dec 2/08	2.3	16.33*	2.24
	July 7/09	10	62.30	7.01
	Oct 13/09	7.4	6.10	0.74
	July 26/10	14.3	18.30	2.06
	Sept 28/10	7.7	42.50	4.93
	June 23/11	9.3	7.90	0.88
	Sept 19/11	DRY	DRY	DRY
MW301 BH301	Oct 14/04	6.9	29.10	3.60
	Nov 6/06	4.7	66.60	8.57*
	Sept 19/07	DRY	DRY	DRY
	July 7/09	11	15.70	1.52
	July 26/10	14.3	28.70	5.81
	Sept 28/10	NM	NM	NM
	June 23/11	7.1	32.00	3.88
	Sept 19/11	DRY	DRY	DRY

TABLE 2.0 DISSOLVED OXYGEN CONCENTRATIONS
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2011)

Parameter	Date Sampled	Temperature ^oC	Dissolved Oxygen % saturation	Dissolved Oxygen mg/L
MW302 BH302	Aug 24/05	13.6	18.30	1.80
	Nov 6/06	3.8	68.30	9.00*
	Sept 19/07	DRY	DRY	DRY
	Dec 2/08	FROZEN	FROZEN	FROZEN
	July 7/09	10.6	18.20	1.87
	July 27/10	16.8	18.70	1.93
	Sept 28/10	8.8	46.20	5.24
	June 23/11	7.3	3.90	0.46
	Sept 19/11	10.4	17.70	1.23
MW303 BHW303	Aug 29/03	11.4	76.00	7.82
	May 27/04	3.1	21.50	2.73
	Oct 14/04	6.0	12.90	1.67
	Nov 6/06	3.5	33.40	4.10*
	Sept 19/07	10.4	11.20	1.46
	July 2/08	5.4	17.48*	2.21
	Dec 2/08	3.5	10.84*	1.44
	July 7/09	9.2	6.20	0.7
	July 26/10	14.3	17.60	2.09
	Sept 28/10	NM	NM	NM
	June 23/11	NM	NM	NM
	Sept 19/11	DRY	DRY	DRY
MW304 BHW304	Oct 14/04	6.3	12.80	1.60
	Aug 24/05	12.9	38.70	3.63
	Nov 6/06	1.5	67.90	9.52*
	Sept 19/07	10.6	10.70	1.18
	July 2/08	7.5	8.25*	0.99
	July 26/10	12.1	14.40	2.31
	Sept 28/10	7.5	88.50	10.56
	June 23/11	6.8	6.60	0.79
	Sept 19/11	DRY	DRY	DRY
MW305 BHW305	Nov 6/06	2.7	24.80	3.37*
	Sept 19/07	10.8	3.20	0.36
	July 7/09	8.9	7.00	0.81
	Oct 13/09	7.1	1.90	0.23
	July 27/10	18.6	59.70	5.87
	Sept 28/10	7.7	91.00	10.92
	June 23/11	4.4	29.00	3.84
	Sept 19/11	10.3	54.40	6.06
MW306 BHW306	Nov 6/06	2.9	27.20	3.67*
	Sept 19/07	11.0	16.80	1.85
	July 2/08	7.4	27.51*	3.31
	July 7/09	9.7	66.80	7.6
	Oct 13/09	7.3	16.10	1.91
	July 26/10	15.6	80.00	8.32
	Sept 28/10	7.9	78.50	9.37
	June 23/11	5.8	11.40	1.72
	Sept 19/11	NM	NM	NM
MW307 BHW307	Aug 24/05	12.8	25.80	2.36
	Nov 6/06	2.5	33.30	4.54*
	Sept 19/07	11.3	12.30	1.32
	July 2/08	11.5	13.45	1.47
	Dec 2/08	2.3	79.08*	10.85
	July 7/09	10.1	31.60	3.54
	Oct 13/09	6.2	6.20	0.79
	July 26/10	NM	NM	NM
	Sept 28/10	NM	NM	NM
	June 23/11	NM	NM	NM
	Sept 19/11	NM	NM	NM
MW308 BHW308	Nov 6/06	3.6	73.80	9.77*
	Sept 19/07	9.8	11.20	1.27
	July 26/10	NM	NM	NM
	Sept 28/10	NM	NM	NM
	June 23/11	CNL	CNL	CNL
	Sept 19/11	CNL	CNL	CNL
MW310 BHW310	Sept 19/07	DRY	DRY	DRY
	July 7/09	10.1	56.90	6.4
	July 26/10	17.9	71.20	7.27
	Sept 28/10	DRY	DRY	DRY
	June 23/11	DRY	DRY	DRY
	Sept 19/11	10.0	25.70	2.86
MW401 BHW401	July 7/09	7.7	14.40	1.67
	July 26/10	DRY	DRY	DRY
	Sept 28/10	DRY	DRY	DRY
	June 23/11	DRY	DRY	DRY
	Sept 19/11	NM	NM	NM

TABLE 2.0 DISSOLVED OXYGEN CONCENTRATIONS
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2011)

Parameter	Date Sampled	Temperature °C	Dissolved Oxygen % saturation	Dissolved Oxygen mg/L
MW402 BHW402	Nov 6/06	2.7	47.00	6.38*
	Sept 19/07	10.6	9.80	1.05
	July 2/08	6.9	1.81*	0.22
	July 7/09	9.4	3.90	0.44
	July 26/10	12.6	15.20	1.67
	Sept 28/10	NM	NM	NM
	June 23/11	NM	NM	NM
	Sept 19/11	9.6	19.70	2.03
MW403 BHW403	Nov 6/06	1.3	55.90	7.88*
	Sept 19/07	11.2	17.60	1.92
	July 2/08	10.4	6.07*	0.68
	Dec 2/08	-	4.10	-
	July 7/09	10.10	7.40	0.82
	Oct 13/09	7.20	0.80	0.10
	July 26/10	14.80	12.10	1.63
	Sept 28/10	7.00	51.00	6.09
	June 23/11	9.50	11.60	1.31
	Sept 19/11	DRY	DRY	DRY
MW404 BHW404	Nov 6/06	1.6	37.80	5.28*
	Sept 19/07	12.1	14.50	1.52
	July 2/08	9.9	8.11*	0.92
	Dec 2/08	2.3	29.00	4.3
	July 7/09	10.1	28.00	3.12
	Oct 13/09	5.9	1.50	0.21
	July 27/10	17.1	34.70	3.7
	Sept 28/10	7.9	59.90	7.08
	June 23/11	10.6	16.00	3.42
	Sept 19/11	DRY	DRY	DRY
MW405 BHW405	Nov 6/06	0.8	116.90	16.72*
	Sept 19/07	DRY	DRY	DRY
	Oct 13/09	6	0.00	0.01
	July 27/10	18.1	19.70	2.2
	Sept 28/10	8.2	97.50	11.66
	June 23/11	8.2	19.50	2.19
	Sept 19/11	10.9	31.70	3.33
MW406 TPW406	Nov 6/06	0.7	110.70	15.87*
	Sept 19/07	10.1	21.00	2.36
	July 3/08	8.8	8.86*	1.03
	July 7/09	9.8	27.70	2.98
	Oct 13/09	7.6	16.20	1.9
	July 26/10	13.9	12.20	1.63
	Sept 28/10	8.9	52.50	6.07
	June 23/11	7.9	13.60	1.29
	Sept 19/11	11.4	56.10	6.06
MW407 TPW407	Nov 6/06	1.1	61.40	8.71*
	Sept 19/07	11	41.10	4.48
	July 3/08	11	47.38*	5.24
	Dec 2/08	NA	NA	NA
	July 7/09	9.8	20.60	1.74
	Oct 13/09	7.3	20.60	2.49
	July 26/10	14.1	10.00	1.8
	Sept 28/10	9.4	55.00	6.37
	June 23/11	8.1	15.30	1.89
	Sept 19/11	11.9	93.40	10.05
SUMP 1	Sept 19/07	DRY	DRY	DRY
	July 3/08	14.4	63.94*	6.56
	July 7/09	NA	>160	NA
	Oct 13/09	DRY	DRY	DRY
	July 26/10	23.6	>160	>20.0
	Sept 28/10	7.9	150.00	18.99
	June 23/11	NM	NM	NM
	Sept 19/11	NM	NM	NM
SUMP 2	Sept 19/07	10.3	45.10	4.4
	July 3/08	14	20.39	2.1
	Dec 2/08	2.2	180.20	24.78*
	Oct 13/09	DRY	DRY	DRY
	July 26/10	21.5	106.00	9.31
	Sept 28/10	7.2	>160	>20.0
	June 23/11	DRY	DRY	DRY
	Sept 19/11	8.7	105.30	12.61

TABLE 2.0 DISSOLVED OXYGEN CONCENTRATIONS
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2011)

Parameter	Date Sampled	Temperature °C	Dissolved Oxygen	
			% saturation	mg/L
SUMP 3	Sept 19/07	DRY	DRY	DRY
	July 3/08	12.6	15.00*	1.6
	Dec 2/08	2.5	195.01	26.6*
	July 7/09	10.5	>160	>17.89*
	Oct 13/09	DRY	DRY	DRY
	July 26/10	19.7	>160	>20
	Sept 28/10	6.6	>160	>20
	June 23/11	NM	NM	NM
	Sept 19/11	DRY	DRY	DRY
SUMP 4	Sept 19/07	DRY	DRY	DRY
	July 3/08	10.6	40.68*	4.54
	July 7/09	10.5	>160	>17.89*
	Oct 13/09	DRY	DRY	DRY
	July 26/10	DRY	DRY	DRY
	Sept 28/10	DRY	DRY	DRY
	June 23/11	11.4	>160	>20.0
	Sept 19/11	9.7	109.50	12.46
SUMP 5	July 7/09	9.9	70.40	8.72
	July 26/10	20.3	55.00	5.02
	Sept 28/10	8	112.20	13.56
	June 23/11	7.9	67.30	7.85
	Sept 19/11	10.2	93.50	10.13
SUMP 6	July 26/10	DRY	DRY	DRY
	Sept 28/10	8.3	131.00	15.75
	June 23/11	DRY	DRY	DRY
	Sept 19/11	10.6	85.80	9.59

DRY Well was dry

* Value estimated based on theoretical relationship between temperature and oxygen dissolution in water at 1 atmosphere

NA Not Available

% saturation from Sept 28/10 sampling event was back calculated as it was not recorded while on site

TABLE 3.0 COMPARISON OF PETROLEUM HYDROCARBON CONCENTRATIONS IN GROUNDWATERS TO REMEDIATION CRITERIA
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2011)
All values in μg/L unless noted.

Parameter	Date Sampled	Benzene	Toluene	Ethyl Benzene	Xylenes	Purgeable	Extractable	TPH (gas/diesel)	PHC F1 C6-10	PHC F2 >C10-16	PHC F3 >C16-34	PHC F4 >C34-50
Potable Remediation Criteria		5 [1, 2]	24 [1, 2]	2.4 [1, 2]	300 [1, 2]	N/C	N/C	1000 [3]	750 [2]	150 [2]	500 [2]	500 [2]
Non-potable Remediation Criteria		140 [4]	83 [4]	11,000 [4]	3,900 [4]	N/C	N/C	N/C	810 [4]	1,300 [4]	N/C	N/C
MW107 BHW107	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 29/10	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
MW121 BHW121	Aug 29/03	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 29/10	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	N/A*	N/A*	N/A*	N/A*
MW129 BHW129	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<200	<200	<200
MW134 BHW134	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Oct 14/04	<0.2	19.9	0.52	< 0.6	<100	162	262	-	-	-	-
	Aug 24/05	<0.2	13.3	<0.2	< 0.6	<100	340	440	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Dec 2/08	<0.2	0.5	0.4	1.7	-	-	-	<100	**370**	<100	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 29/10	<0.50	0.63	0.74	<1.5	-	-	-	<100	100	<250	<250
	Sept 20/11	<0.50	<0.50	0.87	<1.5	-	-	-	N/A*	N/A*	N/A*	N/A*
MW141 BHW141	Aug 29/03	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Oct 14/04	2.75	<0.2	**4.55**	6.7	<100	175	275	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 29/10	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
MW301 BH301	Oct 14/04	4.46	0.44	1.12	36.0	<100	1,510	**1,610**	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	2,100	**2,200**	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	110	<100
MW302 BH302	Oct 14/04	**11.9**	22.2	**52.4**	**314.0**	9,850	130,000	**139,850**	-	-	-	-
	Aug 24/05	**6.6**	<0.2	1.0	137.0	3,300	280,000	**283,300**	-	-	-	-
	Nov 6/06	<20	<20	<20	< 40	-	-	-	**100,000**	**76,000**	**17,000**	<100
MW303 BHW303	Aug 29/03	<0.2	0.57	**2.56**	11.1	480	36,200	**36,480**	-	-	-	-
	May 27/04	<0.2	<0.2	<0.2	TR	<100	9,600	**9,600**	-	-	-	-
	Oct 14/04	<0.2	<0.2	**14.2**	155.7	3,560	174,000	**177,560**	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	23,000	**23,000**	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	3.4	-	-	-	<100	**22,000**	**11,000**	<100
	Sept 19/07	<0.2	<0.2	<0.2	1.2	-	-	-	120	**11,000**	**6,400**	<100
	Dec 2/08	3.3	<0.2	**3.3**	8.5	-	-	-	100	**21,000**	**12,000**	<100
MW304 BHW304	Oct 14/04	<0.2	<0.2	1.13	8.6	166	4,030	**4,196**	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	4,900	**5,000**	-	-	-	-
	Nov 6/06	<2	<2	<2	< 4	-	-	-	< 1,000	**1,500**	**650**	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	120	**42,000**	**23,000**	<200
MW305 BHW305	Aug 29/03	<0.2	<0.2	<0.2	< 0.6	<100	221	321	-	-	-	-
	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 29/10	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
MW306 BHW306	Aug 29/03	<0.2	<0.2	<0.2	< 0.6	<100	208	308	-	-	-	-
	May 27/04	1.42	<0.2	**2.64**	5.4	<100	TR	TR	-	-	-	-
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 29/10	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250

TABLE 3.0 COMPARISON OF PETROLEUM HYDROCARBON CONCENTRATIONS IN GROUNDWATERS TO REMEDIATION CRITERIA
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2011)
All values in µg/L unless noted.

Parameter	Date Sampled	Benzene	Toluene	Ethyl Benzene	Xylenes	Purgeable	Extractable	TPH (gas/diesel)	PHC F1 C6-10	PHC F2 >C10-16	PHC F3 >C16-34	PHC F4 >C34-50
Potable Remediation Criteria		5 [1, 2]	24 [1, 2]	2.4 [1, 2]	300 [1, 2]	N/C	N/C	1000 [3]	750 [2]	150 [2]	500 [2]	500 [2]
Non-potable Remediation Criteria		140 [4]	83 [4]	11,000 [4]	3,900 [4]	N/C	N/C	N/C	810 [4]	1,300 [4]	N/C	N/C
MW307 BHW307	Aug 29/03	<0.2	<0.2	<0.2	2.3	N/A*	N/A*	N/A*	-	-	-	-
	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	215	315	-	-	-	-
	Oct 14/04	0.69	<0.2	**11.5**	65.7	2,770	61,000	**63,770**	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	25,000	**25,100**	-	-	-	-
	Nov 6/06	<2	<2	<2	6	-	-	-	**17,000**	**19,000**	**9,600**	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	**16,000**	**12,000**	<100
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	**3,100**	**2,400**	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	510	530	<100
MW308 BHW308	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	-	-	-	-
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
MW310 BHW310	Aug 24/05	N/A*	N/A*	N/A*	N/A*	N/A*	<100	<200	-	-	-	-
MW401 BHW401	Sept 19/07	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY
MW402 BHW402	Nov 6/06	4.2	<0.2	<0.2	1.4	-	-	-	<100	**1,900**	420	<100
MW403 BHW403	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
MW404 BHW404	Nov 6/06	<0.2	0.3	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
MW405 BHW405	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	220	<100
MW406 TPW406	Nov 6/06	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	170	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	220	<100
	Sept 29/10	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	**400**	620	<250
	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	N/A*	N/A*	N/A*	N/A*
MW407 TPW407	Nov 6/06	<2	<2	<2	< 4	-	-	-	**1,100**	**1,900**	**1,300**	<100
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 29/10	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
SUMP 1	Sept 29/10	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
SUMP 2	Sept 19/07	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	110	740	260
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	-	-	-	<100	<100	<100	<100
	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
SUMP 3	Sept 19/07	N/A*	N/A*	N/A*	N/A*	-	-	-	N/A*	N/A*	N/A*	N/A*
SUMP 4	Sept 19/07	N/A*	N/A*	N/A*	N/A*	-	-	-	N/A*	N/A*	N/A*	N/A*
SUMP 5	Sept 29/10	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
SUMP 6	Sept 19/07	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*

1 Guidelines for Canadian Drinking Water Quality (Health Canada, 2010); based on Aesthetic Objectives / or Operational Guidance Values; or based on Maximum Acceptable Concentrations.
2 Remediation Criteria for potable groundwater from Table 2 of the Ministry of the Environment (MOE) Generic site condition standards (SCS) from the Soil, Groundwater and Sediment Standards for Use Under Part XV.1 of the Environmental Protection Act (updated 2011)
3 Remediation criteria from Table A of the MOE Guideline for Use at Contaminated sites in Ontario (1997)
4 Remediation Criteria from Tier 1 (Table 2/Residential/Coarse Soils) of the Federal Interim Groundwater Quality Guidelines For Federal Contaminated Sites (Environment Canada 2010).
TR Trace levels less than Estimated Quantitation Limit
N/C No criterion
N/A Not analyzed
* Insufficient water in well on date of sampling
DRY Well was dry
BOLD Exceeds potable criteria
Highlight Exceeds non-potable criterion
TPH Total Petroleum Hydrocarbons
PHC Petroleum Hydrocarbons

TABLE 3.1 COMPARISON OF PETROLEUM HYDROCARBON CONCENTRATIONS IN GROUNDWATERS TO REMEDIATION CRITERIA
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE 2011
All values in µg/L unless noted.

Parameter	Date Sampled	Benzene	Toluene	Ethyl Benzene	Xylenes	Purgeable	Extractable	TPH (gas/diesel)	PHC F1 C6-10	PHC F2 >C10-16	PHC F3 >C16-34	PHC F4 >C34-50
Potable Remediation Criteria		5 [1, 2]	24 [1, 2]	2.4 [1, 2]	300 [1, 2]	N/C	N/C	1000 [3]	750 [2]	150 [2]	500 [2]	500 [2]
Non-potable Remediation Criteria		140 [4]	83 [4]	11,000 [4]	3,900 [4]	N/C	N/C	N/C	810 [4]	1,300 [4]	N/C	N/C
MW1291 BHW121	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	N/A*	N/A*	N/A*	N/A*
MW134 BHW134	Sept 20/11	<0.50	<0.50	0.87	<1.5	-	-	-	N/A*	N/A*	N/A*	N/A*
MW406 TPW406	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	N/A*	N/A*	N/A*	N/A*
MW407 TPW407	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
SUMP 2	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250
SUMP5	Sept 20/11	<0.50	<0.50	<0.50	<1.5	-	-	-	<100	<100	<250	<250

1 Guidelines for Canadian Drinking Water Quality (Health Canada, 2010); based on Aesthetic Objectives / or Operational Guidance Values; or based on Maximum Acceptable Concentrations.
2 Remediation Criteria for potable groundwater from Table 2 of the Ministry of the Environment (MOE) Generic site condition standards (SCS) from the Soil, Groundwater and Sediment Standards for Use Under Part XV.1 of the Environmental Protection Act (updated 2011)
3 Remediation criteria from Table A of the MOE Guideline for Use at Contaminated sites in Ontario (1997)
4 Remediation Criteria from Tier 1 (Table 2/Residential/Coarse Soils) of the Federal Interim Groundwater Quality Guidelines For Federal Contaminated Sites (Environment Canada 2010).
N/C No criterion
N/A Not analyzed
* Insufficient water in well on date of sampling
BOLD Exceeds potable criteria
Highlight Exceeds non-potable criterion
TPH Total Petroleum Hydrocarbons
PHC Petroleum Hydrocarbons

TABLE 4 COMPARISON OF PETROLEUM HYDROCARBON CONCENTRATIONS IN FIELD DUPLICATE / BLANK GROUNDWATER SAMPLES
ON-SITE IN-SITU REMEDIATION - BIG TROUT LAKE, ONTARIO - 2011
All Values in µg/L unless noted.

Parameter	Benzene	Toluene	Ethyl Benzene	Xylenes	PHC F1 C6-10	PHC F2 C10-16	PHC F3 C16-34	PHC F4 C34-50
Duplicate Samples								
MW500	<0.50	<0.50	<0.50	<1.5	<100	<100	<250	<250
MW407	<0.50	<0.50	<0.50	<1.5	<100	<100	<250	<250
Percent Difference	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*
Trip Blank								
MW501	<0.50	<0.50	<0.50	<1.5	<100	<100	<250	<250

Percent Difference Calculation $|(x_1 - x_2)| / ((x_1 + x_2) / 2) * 100$

na not applicable

Appendix A:
Laboratory Certificate of Analysis

TRUE GRIT CONSULTING LTD.
ATTN: BEN PARKES
1127 BARTON STREET
THUNDER BAY ON P7B 5N3

Date Received: 21-SEP-11
Report Date: 03-OCT-11 14:33 (MT)
Version: FINAL

Client Phone: 807-626-5640

Certificate of Analysis

Lab Work Order #: L1061635

Project P.O. #: NOT SUBMITTED
Job Reference: JOB#11-221-04F (KI HYDRO ONE DGS)
C of C Numbers: L1061635
Legal Site Desc:

Tricia Sampson
Account Manager Supervisor

ALS ENVIRONMENTAL ANALYTICAL REPORT

	Sample ID	L1061635-1	L1061635-2	L1061635-3	L1061635-4	L1061635-5
	Description	GROUNDWATER	GROUNDWATER	GROUNDWATER	GROUNDWATER	GROUNDWATER
	Sampled Date	20-SEP-11	20-SEP-11	20-SEP-11	20-SEP-11	20-SEP-11
	Sampled Time					
	Client ID	MW121	MW134	MW406	MW407	SW2
Grouping	**Analyte**					
WATER						
Volatile Organic Compounds	Benzene (ug/L)	<0.50	<0.50	<0.50	<0.50	<0.50
	Ethyl Benzene (ug/L)	<0.50	<0.50	<0.50	<0.50	<0.50
	Toluene (ug/L)	<0.50	0.87	<0.50	<0.50	<0.50
	o-Xylene (ug/L)	<0.50	<0.50	<0.50	<0.50	<0.50
	m+p-Xylenes (ug/L)	<1.0	<1.0	<1.0	<1.0	<1.0
	Xylenes (Total) (ug/L)	<1.5	<1.5	<1.5	<1.5	<1.5
	Surrogate: 2,5-Dibromotoluene (%)	96	108	115	114	117
Hydrocarbons	F1 (C6-C10) (ug/L)				<100	<100
	F1-BTEX (ug/L)				<100	<100
	F2 (C10-C16) (ug/L)				<100	<100
	F3 (C16-C34) (ug/L)				<250	<250
	F4 (C34-C50) (ug/L)				<250	<250
	Total Hydrocarbons (C6-C50) (ug/L)				<250	<250
	Chrom. to baseline at nC50				YES	YES
	Surrogate: 2-Bromobenzotrifluoride (%)				64	61
	Surrogate: Octacosane (%)				88	88

ALS ENVIRONMENTAL ANALYTICAL REPORT

	Sample ID	L1061635-6	L1061635-7	L1061635-8		
	Description	GROUNDWATER	GROUNDWATER	GROUNDWATER		
	Sampled Date	20-SEP-11	20-SEP-11	20-SEP-11		
	Sampled Time					
	Client ID	SW5	MW500	MW501		
Grouping	**Analyte**					
WATER						
Volatile Organic Compounds	Benzene (ug/L)	<0.50	<0.50	<0.50		
	Ethyl Benzene (ug/L)	<0.50	<0.50	<0.50		
	Toluene (ug/L)	<0.50	<0.50	<0.50		
	o-Xylene (ug/L)	<0.50	<0.50	<0.50		
	m+p-Xylenes (ug/L)	<1.0	<1.0	<1.0		
	Xylenes (Total) (ug/L)	<1.5	<1.5	<1.5		
	Surrogate: 2,5-Dibromotoluene (%)	103	115	114		
Hydrocarbons	F1 (C6-C10) (ug/L)	<100	<100	<100		
	F1-BTEX (ug/L)	<100	<100	<100		
	F2 (C10-C16) (ug/L)	<100	<100	<100		
	F3 (C16-C34) (ug/L)	<250	<250	<250		
	F4 (C34-C50) (ug/L)	<250	<250	<250		
	Total Hydrocarbons (C6-C50) (ug/L)	<250	<250	<250		
	Chrom. to baseline at nC50	YES	YES	YES		
	Surrogate: 2-Bromobenzotrifluoride (%)	67	73	67		
	Surrogate: Octacosane (%)	83	86	81		

Reference Information

Test Method References:

ALS Test Code	Matrix	Test Description	Method Reference**
BTX-R153-WT	Water	BTEX (O.Reg.153/04)	MOE DECPH-E3421/CCME TIER 1
BTX-WT	Water	BTEX	SW846 8260
F1-F4-CALC-WT	Water	CCME Total Hydrocarbons	CCME CWS-PHC DEC-2000 - PUB# 1310-L

Analytical methods used for analysis of CCME Petroleum Hydrocarbons have been validated and comply with the Reference Method for the CWS PHC.

In cases where results for both F4 and F4G are reported, the greater of the two results must be used in any application of the CWS PHC guidelines and the gravimetric heavy hydrocarbons cannot be added to the C6 to C50 hydrocarbons.
In samples where BTEX and F1 were analyzed , F1-BTEX represents a value where the sum of Benzene, Toluene, Ethylbenzene and total Xylenes has been subtracted from F1.

In samples where PAHs, F2 and F3 were analyzed, F2-Naphth represents the result where Naphthalene has been subtracted from F2. F3-PAH represents a result where the sum of Benzo(a)anthracene, Benzo(a)pyrene, Benzo(b)fluoranthene, Benzo(k)fluoranthene, Dibenzo(a,h)anthracene, Fluoranthene, Indeno(1,2,3-cd)pyrene, Phenanthrene, and Pyrene has been subtracted from F3.

Unless otherwise qualified, the following quality control criteria have been met for the F1 hydrocarbon range:
1. All extraction and analysis holding times were met.
2. Instrument performance showing response factors for C6 and C10 within 30% of the response factor for toluene.
3. Linearity of gasoline response within 15% throughout the calibration range.

Unless otherwise qualified, the following quality control criteria have been met for the F2-F4 hydrocarbon ranges:
1. All extraction and analysis holding times were met.
2. Instrument performance showing C10, C16 and C34 response factors within 10% of their average.
3. Instrument performance showing the C50 response factor within 30% of the average of the C10, C16 and C34 response factors.
4. Linearity of diesel or motor oil response within 15% throughout the calibration range.

F1-WT	Water	F1 (O.Reg.153/04)	MOE DECPH-E3421/CCME TIER 1

The F1 fraction, nC6 to nC10 hydrocarbons, is determined by purging a known volume or weight of the original sample. The sample is analyzed by purge and trap, gas chromatography (GC) with a 100% poly(dimethylsiloxane) (DB-1 or equivalent) column and a combination of a flame ionization detector (FID) and a mass selective detector (MSD). All area counts from the FID are integrated from the beginning of the nC6 peak to the apex of the nC10 peak to give F1. Standards containing nC6, nC10 and toluene are run at least once daily. Toluene is used as the calibration standard for the F1 fraction. The nC6 and nC10 response factors must be within 30% of the response factor for toluene.

F2-F4-WT	Water	F2-F4 (O.Reg.153/04)	MOE DECPH-E3421/CCME TIER 1

The petroleum hydrocarbons are extracted from the aqueous samples using solvent partition. The extracts are treated with silica gel to remove polar contaminants. The final concentrated extract is analyzed by gas chromatography (GC) using flame ionization detection (FID) and a 100% polydimethylsiloxane column.

The F2 fraction is determined by integrating the area in the chromatogram from the apex of nC10 to the apex nC16 and quantitating using external calibration using a standard mix containing nC10, nC16 and nC34. Similarly, the F3 fraction extends from the apex of nC16 to the apex nC34 and the F4 fraction covers the area from the apex nC34 to the apex nC50. If the chromatogram does not return to the baseline by the time nC50 elutes, a gravimetric determination of the F4 is performed.

** ALS test methods may incorporate modifications from specified reference methods to improve performance.

The last two letters of the above test code(s) indicate the laboratory that performed analytical analysis for that test. Refer to the list below:

Laboratory Definition Code	Laboratory Location
WT	ALS ENVIRONMENTAL - WATERLOO, ONTARIO, CANADA

Chain of Custody Numbers:

L1061635

Reference Information

GLOSSARY OF REPORT TERMS

Surrogate - A compound that is similar in behaviour to target analyte(s), but that does not occur naturally in environmental samples. For applicable tests, surrogates are added to samples prior to analysis as a check on recovery.
mg/kg - milligrams per kilogram based on dry weight of sample.
mg/kg wwt - milligrams per kilogram based on wet weight of sample.
mg/kg lwt - milligrams per kilogram based on lipid-adjusted weight of sample.
mg/L - milligrams per litre.
< - Less than.
D.L. - The reported Detection Limit, also known as the Limit of Reporting (LOR).
N/A - Result not available. Refer to qualifier code and definition for explanation.

Test results reported relate only to the samples as received by the laboratory.
UNLESS OTHERWISE STATED, ALL SAMPLES WERE RECEIVED IN ACCEPTABLE CONDITION.
Analytical results in unsigned test reports with the DRAFT watermark are subject to change, pending final QC review.

ALS Lab
ANALYTICAL GROUP
Environmental

L1061635

Chain of Custody / Analytical Request Form

Canada Toll Free: 1 800 668 9878

www.alsglobal.com

COC #

Report To		Report Format / Distribution	Service Requested (Rush for routine analysis subject to availability)
Company:	True Grit Consulting Ltd	☑ Standard ☐ Other (specify):	☑ Regular (Default)
Contact:	Ben Parkes	☑ PDF ☑ Excel ☐ Digital ☐ Fax	○ Priority (Specify Date Required → →) Surcharges apply
Address:	1127 Barton St, Thunder Bay, ON P7B 5N3	Email 1: jgaratti@tgcl.ca,pnistico@tgcl.ca	○ Emergency (1 Business Day) - 100% Surcharge
		Email 2: bparkes@tgcl.ca , recwards@tgcl...	○ For Emergency < 1 Day, ASAP or Weekend - Contact ALS
Phone:	807-626-5640 Fax: 807-623-5690		Analysis Request
Invoice To	Email all invoices to ~~ldrager@tgcl.ca~~ aseej.wilke@tgcl.ca	Client / Project Information	Please indicate below Filtered, Preserved or both (F, P, F/P)

THE QUESTIONS BELOW MUST BE ANSWERED FOR WATER SAMPLES (circle Yes or No)

Are any samples taken from a regulated DW System? Yes No

If yes, an authorized Drinking Water COC MUST be used for this submission.

Is the water sampled intended to be potable for human consumption? Yes No

Job #: Job #11-221-04F (KI Hydro One DGS)

PO / AFE:

LSD:

Quote #:

Lab Work Order # (lab use only)

ALS Contact: Tricia Sampson

Sampler: BEN PARKES

Sample #	Sample Identification (This description will appear on the report)	Date (dd-mmm-yy)	Time (hh:mm)	Sample Type	~~BTX F1-F4~~ F1-F4	BTEX											Number of Containers
1	[redacted], MW121	20-SEPT-...		GW		X											2
2	[redacted], MW134	↓		↓		X											2
3	[redacted], MW406					X											3
4	[redacted], MW407				X	X											4
5	[redacted], SW2				X	X											4
6	[redacted], SW5				X	X											~~4~~ 3
7	[redacted], MW500				X	X											4
8	[redacted], MW501				X	X											4
	[redacted]																
	[redacted]																
	[redacted]																
	[redacted]																

Special Instructions / Regulations / Hazardous Details

Reg 153 Table 1 2 3 TCLP MISA PWQO OTHER (please specify)

Circle one - Note drinking water samples MUST USE DW Chain of Custody

See SIF

Failure to complete all portions of this form may delay analysis. Please fill in this form LEGIBLY.

By the use of this form the user acknowledges and agrees with the Terms and Conditions as specified on the back page of the white - report copy.

SHIPMENT RELEASE (client use)			SHIPMENT RECEPTION (lab use only)				SHIPMENT VERIFICATION (lab use only)			
Released by: BEN PARKES	Date: SEPT 21, 2011	Time:	Received by: KLM	Date: Sept 21/11	Time: 6:50	Temperature: 9.9°C	Verified by: KLM	Date: Sept. 21/11	Time: 6:25	Observations: Yes / No ? If Yes add SIF

GENF 20.00 v.1 Analytical 11-March-11 TS Page 1 of 1

TYFM014 26-Mar-10

8, 6, 11.1

Hydro One
Remote Communities Inc.
680 Beaverhall Place
Thunder Bay ON P7E 6G9
Tel: (807) 474-2800
Billing: Toll Free 1-800-465-5085
Operations Toll Free 1-888-825-8707
Fax: (807) 475-8123

Hydro One Remote Communities Inc. & Webequie First Nation

Memorandum of Understanding re. Former Webequie DGS Site Remediation

The intent of this memo is to document the initial understanding reached between Webequie First Nation and Hydro One Remote Communities Inc. (Remotes) in forming a working partnership with regards to remedial action planning for the cleanup of the former Webequie Hydro One Diesel Generating Station (DGS).

On April 4, 2012, Bob Shine of Remotes met with Webequie First Nation Chief and Council in Webequie, ON, to discuss starting the remedial action planning for the old DGS site. Adrian Andreacchi of Remotes and Lindsay Jupp of Matawa Technical Services joined the meeting via teleconference from Hydro One's Thunder Bay operations centre. Meeting minutes, outlining these discussions, are attached for reference and records purposes.

Webequie First Nation has identified that they would like some time to examine their options with regards to taking on the General Contractor/Project Manager role for the former DGS site remediation. Hydro One has indicated that while the First Nation examines these options, Hydro One would like to move forward with their Environmental Consultant to plan and undertake an updated Phase 2 ESA in order to identify current environmental site conditions for the purpose of researching and identifying viable remedial options.

It is understood that upon completion of the P2ESA and after all viable remediation options are identified, the project stakeholders *(Webequie First Nation, Matawa, Hydro One and environmental consultant)* would meet to determine the best course of action in proceeding with remediation of the former DGS site and to discuss the options that Webequie First Nation and Matawa will be working towards with regards to Project Management and General Contractor roles for the project.

It is understood that all stakeholders will maintain clear and transparent communication between all other parties throughout the P2ESA, project development and project planning stages in order to ensure that a viable partnership be maintained.

Current & Upcoming Project Steps

- Webequie First Nation and Matawa Technical Services to identify and examine the potential for the First Nation to take on the project management and general contractor roles of the project, inclusive of all insurance, liability, WSIB, Health and Safety Policies & Procedures, as well as any other operational/administrative requirements. Please note that Remotes is willing to assist in any way they can to help accommodate this process and opportunity.

- Matawa Technical Services to contact other potential stakeholders (i.e. MTO) and facilitate multi-stakeholder/agency aspects of project planning.

- Webequie First Nation to provide an updated heavy equipment inventory and pricing schedule to Hydro One for the purposes of P2ESA and remediation planning/budgeting.

- Hydro One to commission True Grit Consulting Ltd. to plan, design and complete an updated P2ESA on site at the former DGS property.

- Hydro One to commission True Grit Consulting Ltd. to identify/research/plan/design viable remediation options for the DGS property.

- All stakeholders to meet/conference call/e-mail to keep dialogue open and all informed about progress and addressing issues that may arise.

HYDRO ONE REMOTE COMMUNITIES INC.:

Print Name	Signature	Date
Bob Shire	Bob Shire	Aug 30/12

WEBEQUIE FIRST NATION:

Name	Signature	Date
Chief Cornelius Wabasse	C Wabasse	Aug 27/12
Councillor Elsie MacDonald	Elsie MacDonald	Aug 29/12
Councillor Donald Shewaybick	Donald Shewaybick	Aug 27/12
Councillor Randy Jacob	Randy Jacob	Aug 28/12
Councillor Tommy Shewaybick	[signature]	Aug 27/12

True Grit Consulting Ltd.
1127 Barton St.
Thunder Bay, ON, P7B 5N3
T 807.626.5640 F 807.623.5690 www.tgcl.ca

October 9, 2012 Proposal No. 12-078-06

VIA EMAIL (bob.shine@HydroOne.com; Adrian.ANDREACCHI@HydroOne.com)

Mr. Bob Shine
Mr. Adrian Andreacchi
Hydro One Remotes Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7B 6G9

Dear Mr. Shine and Mr. Andreacchi

Re: Work Plan for Supplemental Investigations and Development of a Remedial Action Plan Hydro One Remotes Former DGS Site, Webequie, Ontario

True Grit Consulting Ltd. (TGCL) is pleased to provide this work plan and cost estimate to complete a Supplemental Environmental Investigation and develop a Remedial Action Plan at the former Hydro One Remotes Diesel Generation Station (DGS) in Webequie, Ontario.

Background

Site Location

Webequie First Nation is located approximately 370 km north of Geraldton, Ontario, on the north end of Eastwood Island in Winisk Lake. The area surrounding the community is part of the Winisk River Provincial Park.

Webequie can be accessed throughout the year by regular air service. During the winter months, the community is accessible by a winter/ice road.

The former DGS is located on First Nation Reserve land about 5 km south of the community on the southeast corner of the airport apron.

Site Description

According to local sources, the site was undeveloped prior to the construction of the DGS facility. The Settlement Committee approved the location of the DGS facility by issuing a Band Council Resolution (489/30209) in 1979. The former Webequie DGS facility was constructed and began operations in 1980/81.

During the assessment work completed by TGCL (2011) in June and August 2010, the site facilities comprised the following:

- DGS building comprised of a single storey steel framed building with a concrete slab-on-grade floor; 2 x 1,100-L above ground storage tanks (ASTs) were reportedly located within the building (Wardrop 2002);
- 2 x 22,700-L steel single-walled ASTs located west of the building and situated within a containment berm; aboveground fuel distribution piping extended east from the ASTs to the building;
- An empty containment berm was observed immediately west of the 22,700-L ASTs;
- A 47,500-L steel single-walled AST was located west of the empty containment berm in a separate containment berm; aboveground piping extended north from the AST to a pump for heavy equipment fuel supply activities;
- 2 x 47,500-L steel single-walled ASTs were located west of the other 47,500-L AST; these tanks were used for bulk fuel storage;

- Two new, unused ASTs (4,100-L and 2,200-L), a 2,300-L steel single-wall AST (empty) and a 10,000-L mobile AST were observed immediately north of the containment berms; and,
- Four abandoned/decommissioned ASTs (4,300-L, 21,000-L and 2 x 7,200-L) were observed south of the DGS building.

It is TGCLs understanding that the former Webequie DGS was decommissioned in June 2011 and demolition and removal of the DGS facilities occurred in October 2011.

On July 12 and 13, 2012, TGCL was on site to complete a groundwater monitoring program. During the work TGCL observed an old fuel kiosk, a pile of concrete, a number of ASTs of varying models and sizes, sheds, vehicles and other debris on the site and at the adjacent MTO property.

Previous Environmental Work

Previous environmental investigations have been completed for at the former Webequie DGS site including:

- *Phase 1 Environmental Site Assessment of Webequie Diesel Generating Station* completed by Ontario Hydro Technologies (OH) and dated December 2, 1998.
- *Phase 2 Environmental Site Assessment of Webequie Diesel Generating* Station completed in June 2001 by Wardrop Engineering Inc. (Wardrop) and dated January 2002.
- *Webequie Diesel Generating Station 2007 Progress Report* completed by Wardrop and dated March 2008.
- *Hydro One Remote Communities Webequie Diesel Generation Station, 2009 Progress Report* completed by Wardrop and dated March 2010.
- *Hydro One Remote Communities Webequie Diesel Generation Station, 2010 Progress Report* completed by Wardrop and dated February 2011.
- *Webequie First Nation Remedial Investigation and Options Analysis (RIOA) – 11 Sites, Webequie First Nation Draft Report* completed by TGCL and dated June 30, 2011.

Results of the previous environmental investigations by Wardrop and TGCL indicate five areas of petroleum hydrocarbon (PHC) impacts in soil and groundwater at the former Webequie DGS, including:

- Zone A - on the west side of the DGS building and bulk fuel storage area;
- Zone B - in the vicinity of the culvert discharge area located to the east of the former DGS; and,
- Zone C - in the vicinity of the south ditch discharge area;
- Zone D – at the north side of the former MTO building, north of the DGS site; and,
- Zone E - at the staff house AST;

The impacted areas are shown on Figure 1, attached.

A total of 12 groundwater monitoring wells were installed at the site by Wardrop in 2001, and two groundwater monitoring wells were installed north of the site near the former MTO building by TGCL in 2010. As of July 2012, all of the wells remained on-site.

Soil stratigraphy generally includes fill material (up to 2.9 m) overlying a layer of organic soil (representing original grade), underlain by silt till with trace cobbles and boulders to at least 4.4 mbg. Bedrock was not encountered. Static water levels ranged from between approximately 1 mbg (south portion of the site) and 5.5

mbg (north portion of the site) in 2010. In 2011, groundwater levels ranged from between approximately 1 mbg and 3.5 mbg.

Summary of Impact

Five zones of soil impact haven been identified around the former DGS facility and surrounding area and are described in OH (1998), Wardrop (2002), and TGCL (2011). Groundwater impact was identified within one area of soil impact, west of the former DGS building.

A brief summary of the impacted areas and their extents is provided below.

<u>Zone A - Tank Farm and Power House</u>

The area of impact around the tank farm and power house extends across much of the former DGS site around the fuel offloads, bulk diesel storage tank farms and storage sheds. Impact in this area is likely a result of historical accidental fuel spills. The Wardrop report estimates that soil impact appears to be limited to the upper 1 m to 2 m of soil/fill over most of the area, however, based on additional sampling by TGCL in 2010, it appears that soil impact may extend deeper in parts of this area. Wardrop estimated approximately 1,950 m^3 of impacted soil in this area, while TGCL estimated approximately 3,817 m^3. Additional soil sampling is required.

<u>Zone B - Culvert Discharge Area</u>

The area of impact around the culvert discharge area has been attributed to a 1995 fuel spill at the MTO tank farm. Ground staining was observed extending east and northeast from the discharge point. The impacts are interpreted to extend from surface to 1.5 mbg. Wardrop estimated approximately 375 m^3 of impacted soil in this area, while TGCL estimated approximately 509 m^3. Additional soil sampling is required.

<u>Zone C - South Discharge Area</u>

The area of impact surrounding the south ditch discharge has been attributed to runoff containing diesel fuel released from the tank farm during accidental spills in 1994 and 1995. The area of impact is limited to the vicinity of monitoring well DBW040 and appears to extend to approximately 1 mbg. TGCL estimated approximately 65 m^3 of impacted soil in this area. Additional soil sampling is required.

<u>Zone D – Former MTO Building</u>

An area of impact was identified immediately north of the MTO garage. Impact is likely attributed to fuelling and repair activities in and outside of the garage. Impact appears limited to the upper approximately 1.0 m of soil, but no delineation of impact has been completed. Additional soil sampling is recommended between this impacted area and the DGs site, in the former building footprint.

<u>Zone E - Staff House</u>

An area of impact was identified immediately adjacent to the staff house, around the day tank. Impact is attributed to tank filling activities. Impact appears limited to the upper 0.5 m to 1.0 m of soil and appears localized to the immediate vicinity of the AST. TGCL estimated approximately 35 m^3 of impacted soil in this area. Additional soil sampling is required.

Objectives

The purpose of the work is to further define the degree and extent of soil impacts, and subsequently to develop a remedial action plan for the site. Based on the existing information, groundwater impact at the site appears to be limited to within identified areas of soil impact, and gaps are present in soil data with respect to aerial and vertical extent of soil impact.

Once the degree and extent of impact is defined, the requirements for site remediation will be confirmed, and a proposed approach will be developed. At this point discussions will take place between Hydro One and the Webequie First Nation to determine project roles and responsibilities, soil treatment facility citing, excavation contracting, and future treatment and monitoring requirements.

Scope of Work

The Supplemental Investigation will be completed in general accordance with Canadian Standards Association Standard (CSA) Z768-01. The Supplemental Investigation and Remedial Plan will include the following general tasks:

- Information Review
- Supplementary Environmental Site Investigation – Test Pitting Program
- Groundwater Monitoring and Sampling Program
- Remedial work Plan

The subsequent Site Remediation project will likely include the following general tasks:

- Bioremediation Cell Construction (likely)
- Remedial Excavation and Backfilling
- Soil Treatment

Records Review

TGCL has completed a review of the available Phase 1 and Phase 2 reports. As part of this task, the results of the sampling have been reviewed and compared to current regulatory criteria. In addition, all historical groundwater results will be presented in conjunction with updated results.

Supplementary Investigations

The data from the original Phase 2 ESA is over 10 years old and may not represent current site conditions. Some additional sampling was conducted in 2010, however gaps in the data have been identified.

To fill in the data gaps identified in the information review and to update site conditions in the context of the current applicable remediation criteria, a supplementary environmental investigation is proposed.

The supplementary investigation will include a groundwater monitoring and sampling program and a soil sampling program.

A soil sampling program by test pitting is proposed to update site information and delineate the current lateral and vertical extent of soil impact. For costing purposes we have assumed excavation of approximately 20 test pits, including 15 throughout the DGS site, and an accommodation for five more as required for additional delineation based on field observations. The proposed locations of 15 test pits are shown in Figure 1, attached. In addition, the rationale for the placement of the 15 test pits is included in Table 1 below.

It is anticipated that test pits will extend to between 4 m to 5 m below grade, and will generally be installed to the maximum reach of the excavator. Based on information in the Phase 2 ESA, this will not reach bedrock, however it will reach the local water table, and as a result should be sufficient to identify the vertical extent of soil impact.

Soil conditions are generally rocky and not conducive to hand-augering, however an attempt will be made to advance some shallow boreholes around the day tank at the residence to try to delineate impact in that area.

Table 1 – Test Pit Program Summary

Test Pit	Location	Rationale
TP201 to TP207	Former Tank Farms	• In order to determine if fuel migrated through clay lined berms; • To confirm the aerial and vertical extent of soil impact; • Analyze for petroleum hydrocarbons.
TP208 to TP210	Beneath Former Power House	• To confirm the eastern limit of contamination from the tank farm area and the depth of impact; • Analyze for petroleum hydrocarbons, metals, PAHs.
TP211	Beneath Former MTO Building	• To confirm north extent of impacts from DGS site tank farms; • To determine if any impact from garage activities; • Analyze for petroleum hydrocarbons, metals, PAHs.
TP212	East of DGS Rads	• To confirm the east extent of impact from powerhouse; • To assess potential glycol impact from rads; • Analyze for petroleum hydrocarbons, metals, PAHs, glycol.
TP213 and TP214	Culvert Discharge Area to East	• To confirm the east, northeast and southeast extents of impact and depth of impact; may require additional pits; • Analyze for petroleum hydrocarbons, metals, and glycol.
TP215	Pole Storage and Material Laydown Area	• To confirm the presence/absence of petroleum hydrocarbon impact and/or wood preservative impact; • Analyze for petroleum hydrocarbons, metals, PAHs, phenols.

Upon completion of the sampling program, a total station survey will be completed at the site to tie in the test pit locations and remaining site features which will be overlaid onto the previous investigation drawings. In addition, the relative well elevations will be resurveyed to ensure that groundwater elevations are accurate.

Soil Sampling

Soil samples will be collected from each sampling location at regular intervals or at the direction of TGCL personnel to assess soil conditions and for potential laboratory analysis. New clean nitrile gloves will be worn when handling samples and/or sample containers and will be changed between samples to prevent sample cross-contamination.

Soil samples collected from each sampling location will be immediately placed in new polyethylene bags for on-site organic vapour screening. Soil samples with the potential to be submitted for laboratory analysis will be split between polyethylene bags and new laboratory-supplied containers. All soil samples collected for laboratory analysis will be immediately placed in chilled coolers for transportation to the laboratory.

All collected soil samples will be field screened for organic vapour concentrations using a Photoionization Detector (PID). Samples will be field-screened by allowing the sample to warm to room temperature for approximately 10 minutes, then gently agitating the sample bag to release the organic vapours. The pump intake probe will be inserted through the sample bag and the highest meter reading will be recorded.

If there is evidence of petroleum hydrocarbon, or other contaminant impact in the soil (visual, olfactory. elevated organic soil vapour concentrations), samples representative of the highest degree of impact will be selected for laboratory analysis. Where significant evidence of petroleum hydrocarbon impact is encountered, two or more samples may be selected to provide vertical delineation. If impact is not observed in the soil during sampling representative soil samples may be selected to provide comprehensive coverage of the area of investigation.

All samples will be submitted for laboratory analysis in chilled coolers (where applicable) and under Chain of Custody.

Groundwater Monitoring and Sampling

All of the groundwater monitoring wells remaining at the site will be monitored and sampled. Wells will be monitored for combustible head space vapours as well as depth to groundwater and the presence of liquid-phase petroleum hydrocarbons (LPH).

Prior to sample collection, at least three well volumes of groundwater will be purged from each monitoring well to draw fresh formation water into the well for sampling purposes using dedicated sampling equipment. Wells which pump dry will be purged dry a second time following an appropriate period of recovery to allow the sand pack to drain into the well and formation water to flush the sand pack. While purging, the groundwater will be physically assessed for evidence of hydrocarbon impact, such as a hydrocarbon sheen or odour, and documented.

If free-phase hydrocarbon is encountered in any well, the purge water will be collected into sealed pails, and stored at the new DGS site for future removal.

Samples will be collected from each monitoring well using a dedicated polyethylene sampling tubing and foot valve installed in each well. In addition, the domestic water well at the residence will be sampled.

Water samples will be collected directly into new laboratory-supplied containers. All water samples collected for laboratory analysis will be immediately placed in chilled coolers for transportation to the laboratory. All samples will be submitted for laboratory analysis in chilled coolers (where applicable) and under Chain of Custody.

Laboratory Analysis

To quantify current concentrations of petroleum hydrocarbons in the soil and groundwater to current regulatory criteria, samples will be submitted for laboratory analyses of benzene, toluene, ethlybenzene, xylenes (BTEX) and PHCs. The PHC analytical results are presented in the following fractions: F1 (C6-C10), F2 (>C10-C16), F3 (>C16-C34), and F4 (>C34) as prescribed in the CCME Canada-Wide Standards for PHC in Soil (2008). A minimum of 10% of the samples will be analyzed as part of the project QA/QC program.

Selected samples will also be submitted for analysis of a suite of metals and inorganic parameters, phenols, and PAHs, from areas that were identified as containing historical waste oil/liquid storage and/or pole storage.

In addition to contaminant characterization, a soil sample representative of impacted soil to be remediated will be analyzed for additional parameters to establish the physical and chemical properties, as well as the biotreatability of the soil. The sample will be analyzed for effective grain size, organic carbon content, pH, moisture content; plate counts and tests of microbial colony-forming units (CFU) and hydrocarbon utilizing bacteria (HUB), and metals content.

Remedial Plan

Using all of the information collected and compiled from the previous tasks, we will prepare a detailed Remedial Plan containing all necessary details of the proposed work plan. The Remedial Plan will include the following:

- a general description of the proposed work plan;
- the project objectives, including specific site and soil treatment criteria to be achieved;
- a description of regulatory approval requirements, and federal and provincial environmental compliance/conformance requirements;

- a public communication/consultation plan;
- a description of all preparation and construction activities;
- the quality, quantity, source locations, haul distances and costs of all fill materials to be used for backfilling the excavation during the remedial work;
- a description of the confirmatory and verification sampling plans;
- requirements for site restoration and landscaping;
- a description of on-site supervision and field service requirements;
- project schedule/duration;
- a site-specific health and safety plan;
- Quality Assurance/Quality programs;
- a description of operations and maintenance plans for the post-construction ex-situ treatment phase;
- a description of site monitoring, risk management, in-situ remediation programs (if required);
- requirements for reporting/documentation including as-built drawings, completion certificates, etc.; and,
- Class “B” Cost estimates.

Meetings

We understand that the Webequie First Nation may be interested in conducting the work using own forces. In this case, we anticipate that a meeting will be required to present the remediation plan to the First Nation, and to discuss options for treatment facility citing, and also for project implementation responsibilities.

Once the approach is finalized, another meeting will likely be required to present the finalized plan.

Based on this, we have included two meetings in the community in the proposed budget.

If it is determined that additional Health & Safety consulting is required to assist the First Nation in setting up its contracting company, a proposal for the additional work will be provided.

Schedule

We have tentatively scheduled the field work for the week of October 15, 2012. The work is anticipated to take four days on-site to complete. Results should be available within two weeks of completion of the field work. The draft report and preliminary remedial plan will be completed before the end of December 2012. Refinement of the plan and any further negotiations with the First Nation can take place during the winter, and site remediation can be planned for spring/summer 2013.

Cost Estimate

TGCL is prepared to complete the work on a time and materials basis, with an upset limit of **$48,802.45 plus HST**. This cost includes all costs to date for site monitoring work completed in 2012. A breakdown of the cost is attached.

TRUE GRIT CONSULTING LTD

Closure

Thank you for the opportunity to provide environmental services to Hydro One Remote Communities Inc. If you have any questions or require clarification on any point, please contact the undersigned at 807-626-5640. We look forward to working with you on this assignment.

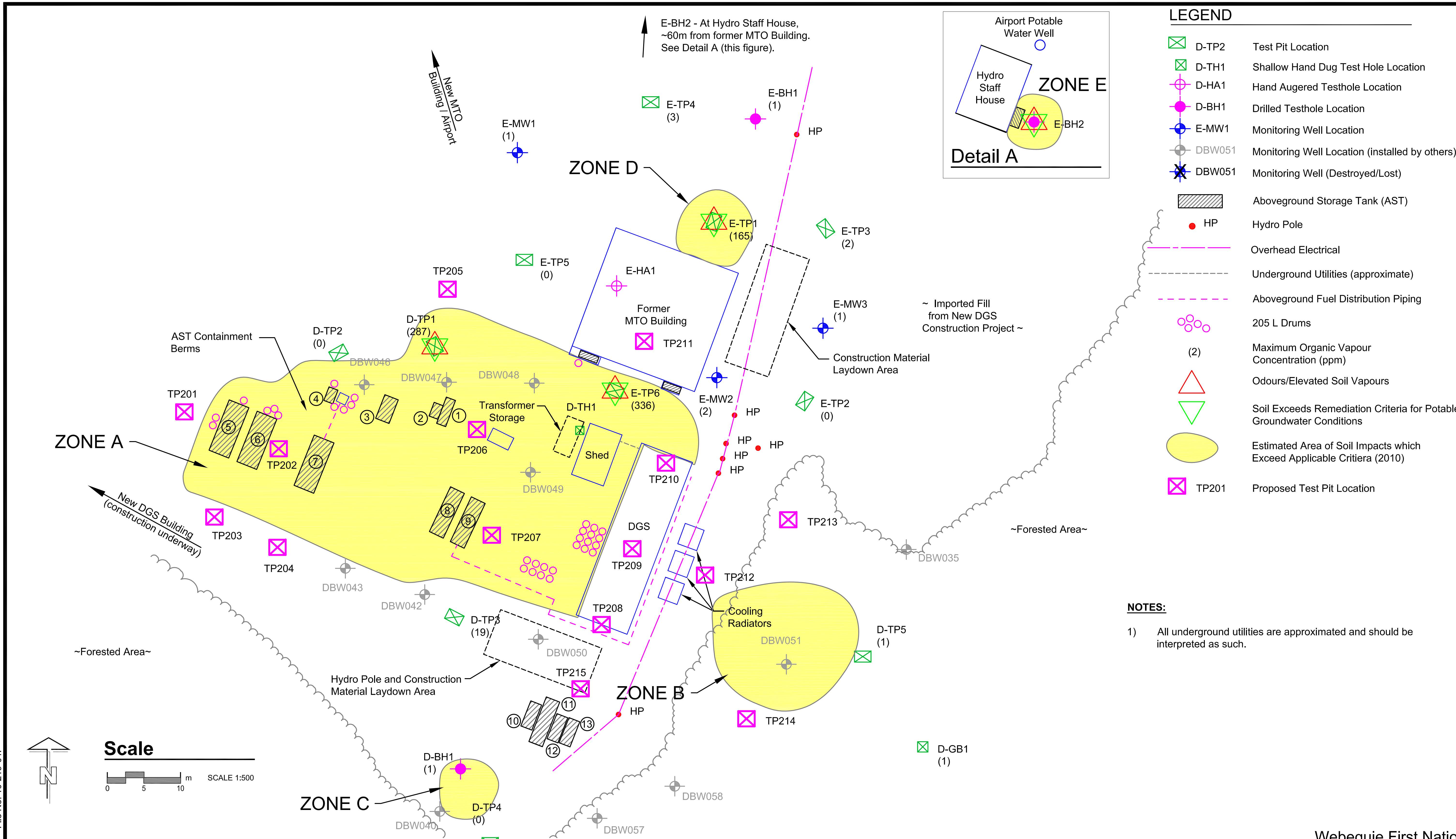
Sincerely,

True Grit Consulting Ltd.

Jason Garatti, MScEng, P.Geo.
Principal/Manager, Environmental Services
jgaratti@tgcl.ca

JG:pn

Attachments



TRUE GRIT CONSULTING LTD

Designed By: CT
Approved By: DRC
Date: October 2012

Webequie First Nation
Former DGS Building

Proposed Test Pit Program

FIGURE 1

TABLE A - 2012 SITE MONITORING, INVESTIGATION, AND RAP COST ESTIMATE BREAKDOWN - WEBEQUIE

TASK	ESTIMATED DAYS / EVENTS	TGCL FEES	TGCL DISBURSEMENTS	LABORATORY	FIRST NATION LABOUR & EQUIP.	SUBCONTRACTORS	TOTALS
TASK 1 - COORDINATION / MANAGEMENT (completed to Aug. 31/12)		-	-	-	-	-	**$1,051.68**
TASK 2 - MONITORING EVENT #1 (completed to Aug. 31/12)		-	-	-	-	-	**$5,300.77**
TASK 3 - SUPPLEMENTAL INVESTIGATIONS (incl. Mob time)	**4.00**	$10,434.00	$1,413.00	$9,625.00	$7,084.00	$0.00	**$28,556.00**
TASK 4 - DATA ASSESSMENT & REPORTING (ESA & RAP)		$9,682.00	$100.00	-	-	$0.00	**$9,782.00**
TASK 5 - MEETINGS (in Webequie)	**2**	$4,012.00	$100.00	-	-	$0.00	**$4,112.00**
TOTAL		**$ 24,128.00**	**$ 1,613.00**	**$ 9,625.00**	**$ 7,084.00**	**$ 0.00**	**$ 48,802.45**

MATAWA FIRST NATIONS

MEETING MINUTES

October 26, 2012
1:00 – 3:00 pm
MTO Boardroom 2A
Sampling & Remediation at Webequie Airport

In attendance:

James Suganaqueb, WFN
Donald Shewaybick, WFN
Elsie MacDonald, WFN
Elder, WFN
Moe Fenelon, MTO
Kelly Cross, MTO
Tyler Manning, MTO
Robin Beveridge, AANDC
Bob Shine, HORCI
Adrian Andreacchi, HORCI
Lindsey Jupp, Matawa

(Items underlined require Action by designated person)

Introductions done around the table

LJ – Introduction to the Remedial Investigations and Options Anaylsis (RIOA) project in Webequie (WFN) conducted by True Grit Consulting Ltd (TGCL); still in draft

- By coming together like this with all the major parties involved in testing and remediating any soil and/or water contamination at the Webequie airport; put our efforts together to collaborate and reduce costs in the end

BS – Summary of HORCI's Phase 2 work being completed by TGCL

Matawa First Nations 233 S. Court Street Thunder Bay, ON P7B 2X9 Tel: (807) 344-4575 Fax: (807) 344-2977
Toll Free: 1-800-463-2249
www.matawa.on.ca

- Adrian and TGCL were in WFN last week doing preliminary sampling by test pitting because too many large boulders and old trees for borehole drilling.
- Area has been fenced to keep people off the site in order to avoid any further contamination – however slight
- TGCL should have a report completed in Jan / Feb 2013 at which time it will be shared with WFN & MFNM
- TGCL designed sampling program off the RIOA, but with alterations since the site buildings were demolished & removed
- Last Phase I & II were done in 2001, so this will be an update
- Completed some confirmation digging, as per FN request (Gilbert Roundhead, memory of machine spill)
- Arnasson equipment is not on the HORCI site, but are on MTO
- Zone B (as in RIOA figures) has no hint of downgrade travel
- Zone C (as in RIOA figures) is rough terrain and difficult to access with excavator; did not pursue such a small area – not certain history was HORCIs

MF – confirmation is needed regarding water well connected to waiting room

BS – will confirm if drinking well was sampled (Wardrop, 2001, report was positive for contamination; RIOA, 2010, was clear)

TM – last assessment of the airport was completed in February 2012, but only included areas for new garage & waiting room

  - PHC surface staining was confirmed in new garage location
  - Oil cans, filters etc were found in testpits
  - Other uses may have used the site and they need to decide what the scope of the clean-up should be
  - Will come up with a plan to determine what contamination is MTO and what is not MTO

- Other users have been on old property since MTO left for new buildings
- Nov 2011 concern for mobile tanks was documented due to staining
- need to secure site while investigations are undertaken to avoid incidents

RB – how long was the old site operated by MTO?

MF/KC/JS/EM : 1976 – 2008; until new buildings were put up

AA – two old single walled tanks *were* on the map & marked as "MTC"; observed staining; MTO's old tanks

KC – these old tanks were shipped out last winter road

LJ – mentioned former spill James had recalled during visit

JS - ~1000L mobile tank spilled a long time ago, just inside the fence

- This was area over top of water line from well to new buildings; would have probably dug a portion of it up during that time

<u>RB – If there is an issue with water testing results at the airport then Health Canada should be notified.</u>

<u>MF – First Nation equipment will have to be moved so investigations can start</u>

JS – what about looking at old equipment storage area a long side the runway / on the hill?

- Old abandoned equipment on the tree line

<u>MF – will put together a tender to get best price to haul materials away over winter road; community vehicles etc.</u>

- LJ mentioned Penn-co supposed to contract MTO to haul old DGS items away; MF not aware; <u>Matawa to inform AANDC Chris Rohr</u>

<u>TM – will look at site & then start phase 2 assessments</u>

RB – will MTO be sharing assessment plan with the group so that everyone knows what areas are/are not including?

<u>MF – TM to communicate with LJ & AA about sampling areas</u>

LJ – First Nation will not be doing any more sampling programs to the same degree as RIOA so will identify other potential areas of interest

BS – cost sharing is the next level of this relationship

- TGCL will be including options in their report for remediation; most likely is a biocell, but where to build & how to excavate (boulders/trees etc) is the challenge; will not be an easy clean-up and could be quite costly

MF – must also keep in mind future development plans of First Nation; for example new cargo apron application; no area has yet been designated, so would benefit from assessment program

JS – future development is reliant on clean areas for warehousing and air park; must stay away from contaminated areas

MF – must keep other parties off these potentially contaminated areas; ie: Arnasson has to relocate their equipment

<u>KC – will speak to them about moving</u>

JS – used to have their equipment stored at the landfill, but moved back to airport

- All the First Nation storage tanks will be moved to the new cargo area when ready

RB – does MTO have a lease with INAC?

KC – no, only an agreement with the First Nation; usually 10 years to operate; has grey areas about permits & clean-up; land used to be Provincial Park & in the land transfer a lot was missed in the case of environmental procedures (ie: EA); INAC encouraged operating agreements between MTO & FN

LJ – what about MTO agreements with 3rd parties?

KC – have agreements in place with environmental responsibilities to the user, not MTO

TM – is there an MTO boundary for which sampling should be kept in?

MF – check with geomatics to see if they've surveyed the area & delineated the extent

LJ – can Draft RIOA be shared with MTO, as well as any updates as that project moves to final stages?

JS – can share so long as updates are sent; Matawa to do

BS – in the future must discuss the clean-up criteria depending on end land-use; industrial, commercial, residential

JS – LJ to send summary for community members' information

AGREEMENT IN PRINCIPLE

Between

JAMES BAY GENERAL HOSPITAL

And

HYDRO ONE REMOTE COMMUNITIES INC.

This Agreement in principle is intended to document our mutual understanding regarding the agreement made at the December 13, 2007 meeting in Timmins, Ontario.

This agreement in principle will be forwarded to the JBGH Board of Directors and the CEO of Hydro One Remote Communities Inc. for approval.

JAMES BAY GENERAL HOSPITAL UNDERTAKING:

1/ James Bay General Hospital agree to pay for 80% of the costs to decommission the 50,000 gallon vertical aboveground storage tank in Attawapiskat.

2/ James Bay General Hospital agree to pay for 66.66% of the costs to remediate the soil associated with the 50,000 gallon vertical aboveground storage tank fuel handling activities in Attawapiskat.

HYDRO ONE REMOTE COMMUNITIES INC. UNDERTAKING:

1/ Hydro One Remote Communities Inc. agree to pay for 20% of the costs to decommission the 50,000 gallon vertical aboveground storage tank in Attawapiskat.

2/ Hydro One Remote Communities Inc. agree to pay for 33.33% of the costs to remediate the soil associated with the 50,000 gallon vertical aboveground storage tank fuel handling activities in Attawapiskat.

Agreed by:	Agreed by:
______________________	______________________
Derrick Gourley	Tim Lindsay
James Bay General Hospital	Hydro One Remote Communities Inc.

ATTAWAPISKAT FIRST NATION REMEDIATION PROJECT – VAST SITE
CLASS A PRICE ESTIMATES – UPDATED OCTOBER 12, 2012

	DESCRIPTION	TOTAL
1.1	ADDITIONAL CONSTRUCTION COSTS	
A.	MOBILIZATION/DEMOBILIZATION	$120,000
B.	ON-SITE INSPECTION AND SAMPLING	$147,095
C.	ACCESS ROADWAY CONSTRUCTION, UPGRADES &MAINTENANCE	$51,526
D.	PREPARATION OF BACKFILL BORROW SITE & MATERIAL PREPARATION	$117,067
E.	BIOREMEDIATION CELL CONSTRUCTION	$0.00
F.	PREPARATION OF IMPACTED SOIL STORAGE AREA	$12,581
K.	SOIL EXCAVATION AND HAULAGE – SITE 3 VASTs	$508,404
N.	EX-SITU BIOREMEDIATION OPERATION & MONITORING	$89,750
O.	EX-SITU BIOREMEDIATION DECOMMISSIONING	$49,977
	Construction Sub-Total	$1,096,400
	Contingency (10%)	$109,640
	Construction Total	$1,206,040
1.2	ADDITIONAL NON-CONSTRUCTION COSTS	$ 123,490

TOTAL ADDITIONAL COST	$1,329,530
PRE-CONSTRUCTION CONTRIBUTION BY ATTAWPISKAT FIRST NATION OF BIOREMEDIATION CELL	$664,765
TOTAL PROJECT COST	$1,994,295

<u>COST SHARE;</u>

HYDRO ONE	$664,765
WAHA	$664,765
ATTAWAPISKAT	$664,765

ON-SITE IN SITU REMEDIATION
OF
HYDRO ONE DGS SITE
BIG TROUT LAKE, ONTARIO

2009 MONITORING REPORT

JANUARY 2010

DISTRIBUTION:	**KITCHENUHMAYKOOSIB INNINUWUG**	**2 COPIES**	**PROJ. # CS68.06**
	HYDRO ONE REMOTE COMMUNITIES INC.	**4 COPIES**	
	ANEBEAAKI ENVIRONMENTAL INC.	**1 COPY**	

EXECUTIVE SUMMARY

An environmental assessment of the Big Trout Lake Hydro One diesel generating station (DGS) conducted in 2001 identified subsurface petroleum hydrocarbon impact at the site. A remedial excavation was completed on the property in 2002 and 2003; however, impact remains in areas which were inaccessible to excavation. Ongoing *in-situ* bioremediation is currently underway to reduce the potential for migration of impact down-gradient and off-site. The *in-situ* program consists of increasing subsurface oxygen levels to promote biological degradation of petroleum hydrocarbons.

Two site visits were completed in 2009:

- July 7 - 9, 2009, which included well monitoring and addition of oxygen releasing compound (ORC) into the existing amendment distribution system; and,

- October 13 - 15, 2009, which included well monitoring and collection of groundwater samples for laboratory analysis of petroleum hydrocarbon parameters.

Based on observations made in the field and the results of field and laboratory analyses, the following was concluded:

- petroleum hydrocarbon impact does not extend off of the DGS property;

- groundwater petroleum hydrocarbon impact, expressed as the presence of liquid phase hydrocarbons, continues to be present in the area where petroleum hydrocarbon impacted soils could not be excavated;

- groundwater petroleum hydrocarbon concentrations within the previously completed remedial excavation have continued to declined over the past three sampling events, and no longer exceeds the applicable remediation criteria;

- dissolved oxygen concentrations from July 2009 were generally consistent with previous monitoring events; where lower concentrations were measured in areas where petroleum hydrocarbon impact is present, or immediately down-gradient, and higher concentrations measured in wells located away from the impacted areas;

- dissolved oxygen concentrations in the sump wells located within the amendment distribution system were elevated at the time of the July 2009 monitoring event, suggesting that the ORC applied in July 2008 was still producing oxygen;,

- the injection of ORC appears to be continuing to promote local degradation of petroleum hydrocarbons.

Based on observations made in the field, results of field and laboratory analyses, and in consideration of the above conclusions, the following recommendations are made for the 2010 field season:

- well monitoring in summer 2010, to update water/LPH levels and dissolved oxygen concentrations;

- installation of an interceptor trench in early summer 2010, which will use Imbiber Beads™ to capture liquid phase petroleum hydrocarbons (LPH) as it potentially moves along the migration pathway between the area of remaining impacted soils and the area of completed remedial excavation;

- application of oxygen releasing compound to the amendment distribution system in early summer 2010, to ensure that dissolved oxygen concentrations are maintained thereby promoting degradation of the petroleum hydrocarbon impact in the groundwater; and,

- well monitoring in the fall 2010, along with collection of groundwater samples from select wells for laboratory analysis of petroleum hydrocarbon concentrations.

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1.0 INTRODUCTION

Anebeaaki Environmental Inc. (Anebeaaki) was retained by Kitchenuhmaykoosib Inninuwug (KI) and Hydro One Remote Communities Inc. (Hydro One) to continue on-going remediation measures at the Hydro One Diesel Generating Site (DGS) in the community of Big Trout Lake, Ontario.

The Project Team for the development and implementation of this project included the following:

- Hydro One Remote Communities Inc.
- Kitchenuhmaykoosib Inninuwug Lands and Environment Office
- Kitchenuhmaykoosib Inninuwug Chief and Council
- Anebeaaki Environmental Inc.

This report summarizes the work conducted at the DGS site in 2009. The scope of work was generally in accordance with that outlined in the On-Site In Situ Remediation of Hydro One DGS Site Big Trout Lake, Ontario, 2008 Monitoring Report, dated April, 2009.

1.1 SITE DESCRIPTION

The Hydro One DGS site is located off-Reserve on leased Provincial Crown land, between the residential core of the community and the airport as shown in Figure 1, in Appendix I. The nearest surface water body is Big Trout Lake, located approximately 400 m to the east of the site. The current site layout, including the limits of a 2006 property line expansion, is shown on Figure 2. Site facilities and structures include:

- a generator building;
- a shed, containing a portable generator unit, off of the southeast corner of the generator building;
- three 50,000 L self-contained fuel storage tanks on concrete pads, to the east of the generator building;
- a fuel offload cabinet immediately south of the tanks;
- step-up transformers and distribution line poles within a fenced compound in the southwest part of the site;
- two storage material sheds located in the northwest part of the site;
- empty 205-L drums, pallets, cable, and other materials immediately southeast of the material sheds;
- a transformer storage area and deck located along the west fence;
- two liquid waste storage sheds located along the south fence;
- a staff house in the eastern part of the property;
- a chain link fence surrounding the site, with three access gates along the south side;
- utility pole storage in an open area approximately 20 m west of the site.

1.2 BACKGROUND

In April 2001, Anebeaaki was retained by KI to conduct a Phase II Environmental Site Assessment (ESA) at the Hydro One DGS site in Big Trout Lake, Ontario. The results of this investigation indicated that petroleum hydrocarbon (PHC) impact was present in soil and groundwater in the area around and beneath the former bulk fuel storage area, and extended to the northeast corner of the site. Anebeaaki estimated that approximately 3,246 m^3 of PHC impacted soil was present, of which approximately 1,671 m^3 was accessible to excavation.

In the fall of 2002 and the summer of 2003, Anebeaaki was on site to direct a remedial excavation of accessible impacted soil (1,930 m^3 *in situ*). Petroleum hydrocarbon impact remained in areas where excavation had to be discontinued due to facilities. As part of the remedial program, an oxygen releasing compound was placed in a reactive barrier trench to promote biodegradation of migrating petroleum hydrocarbons from the remaining impacted soil into the newly remediated areas. Monitoring wells installed during remedial activities, and the previous Phase II environmental site assessment, were used to monitor groundwater conditions including the effectiveness of the oxygen releasing compound in reducing concentrations and migration of the remaining impact.

Four site monitoring events were conducted between 2003 and 2005. The monitoring indicated there was a need to supply additional oxygen to the subsurface to increase and sustain microbial activity. The results also confirmed that additional measures were required down-gradient of the reactive barrier trench to impede any further migration of petroleum hydrocarbon impact.

In 2006, oxygen releasing compound (calcium peroxide) slurry was injected into the subsurface, in the area of the reactive barrier trench, using steel rods and a high pressure pump. Also, a second in-situ remediation trench, including additional oxygen releasing compound as well as an amendment distribution system, was installed further east (down-gradient) of the impacted area, as shown in Figure 2. The distribution system allowed future addition of remediation amendments, as well as ongoing sampling/monitoring of groundwater conditions.

Seven additional groundwater monitoring/injection wells (MW 401 - MW 407), were installed during the 2006 work, bringing the total wells on the site to 22 (one well is inaccessible beneath a shed). Also, six sump wells (SW1-SW6) were installed as part of the in-situ amendment distribution system.

As part of the 2006 remedial work, the DGS property was expanded to the east to allow management of petroleum hydrocarbon impact on-site and to provide additional space for DGS operations. The property expansion activities included clearing of trees, grading, and addition of granular fill material to allow for on-site storage and vehicular traffic.

In 2007, a geotextile fabric was installed across the area where granular material was applied in 2006, to permit vehicle traffic and use of this area for storage. In addition, approximately 1,000 seedlings were planted throughout the community to replace trees removed as part of the 2006 DGS site expansion.

Site monitoring and sampling conducted in 2007 and 2008 indicated that petroleum hydrocarbon impact did not extend off of the DGS property, as well as the need to supply additional oxygen releasing compound to the sub-surface in order to maintain elevated dissolved oxygen concentrations and microbial activity.

1.3 SELECTED CRITERIA

The DGS property is currently on, and immediately surrounded by Provincial Crown land; however the First Nation is actively pursuing addition of the land to its Reserve. It was previously decided by the Project Team that the remediation on the DGS property would be conducted to meet the more stringent of the applicable federal and provincial guidelines.

The petroleum hydrocarbon of concern for the remediation is diesel fuel, a mid-distillate petroleum hydrocarbon. Under the current federal and provincial guidelines the typical indicator used to quantify total light-, mid-, and heavy-distillate petroleum hydrocarbons in soil is PHC (petroleum hydrocarbons), which is divided into four fractions (F1-F4).

The most common volatile components of light- and mid-distillate petroleum hydrocarbon products are the monocyclic aromatic hydrocarbons (benzene, toluene, ethylbenzene, and xylenes (BTEX)), and these are typically used as indicators for the lighter fraction of petroleum hydrocarbon contaminants in soils.

The selected on-site soil remediation criteria are presented in Table A. The remediation criteria for BTEX are from the CCME Environmental Quality Guidelines (1999 or as updated). The remediation criteria for PHC's are from the CCME Canada-Wide Standards for Petroleum Hydrocarbons in Soil (2008). Tier 1 generic criteria for residential/parkland land use, fine-grained surface soil, and potable groundwater were selected.

TABLE A ON-SITE SOIL REMEDIATION CRITERIA FOR PETROLEUM RELATED CONTAMINANTS (All concentrations are in µg/g (ppm))

PARAMETERS	CRITERION
Benzene	0.0068
Toluene	0.08
Ethylbenzene	0.018
Xylenes	2.4
F1, C6 - C10 Hydrocarbons	170
F2, >C10 - C16 Hydrocarbons	150
F3, >C16 - C34 Hydrocarbons	1,300
F4, >C34 Hydrocarbons	5,600

The selected remediation criteria for groundwater are presented in Table B. The criteria for BTEX are the community water criteria from the CCME Environmental Quality Guidelines (CCME 1999, or as updated). In the absence of PHC criteria for water in the CCME guidelines, the criteria used are from Table 2 of the Ontario Ministry of the Environment (MOE) generic site condition standards (SCS) from the *Soil, Ground Water and Sediment Standards for Use Under Part XV.1 of the Environmental Protection Act* (March 9, 2004, or as updated) ,

TABLE B ON-SITE GROUNDWATER REMEDIATION CRITERIA FOR PETROLEUM-RELATED CONTAMINANTS (All concentrations are in μg/L (ppb))

PARAMETER	CRITERION
Benzene	5
Toluene	24
Ethylbenzene	2.4
Xylenes	300
F1, C6 - C10 Hydrocarbons	1,000 [a]
F2, >C10 - C16 Hydrocarbons	
F3, >C16 - C34 Hydrocarbons	1,000 [b]
F4, >C34 Hydrocarbons	

[a] The sum of F1 and F2 must be less than 1,000
[b] The sum of F3 and F4 must be less than 1,000

1.4 SCOPE OF WORK

The following tasks were completed during the 2009 field season:

- Monitoring select site wells for liquid phase petroleum hydrocarbon (LPH) thickness, water levels, and headspace combustible vapours;
- Field testing select site wells for dissolved oxygen and temperature;
- Addition of oxygen releasing compound slurry into the amendment distribution system; and,
- Collection of groundwater samples from selected site wells to be submitted for laboratory analysis of petroleum hydrocarbon parameters.

2.0 FIELD PROGRAM

Anebeaaki was on-site from July 7 to 9, and October 13 to 15, 2009, to conduct the proposed scope of work.

2.1 PROJECT MEETINGS

On July 7 and October 13, 2009, Mr. Tim Lindsay of Hydro One, and Anebeaaki personnel conducted a project initiation/safety meeting at Big Trout Lake Hydro One DGS prior to field work. Hydro One Contractor Safety and Environment Pre-Job Meeting Checklist forms were reviewed at the meetings.

2.2 MONITORING AND SAMPLING

Select site wells were monitored during the July and October 2009 site visits. The following data was collected:

- Headspace combustible vapours measured in select wells using a Gastechtor Model 1258ME Hydrocarbon Surveyor;
- Groundwater dissolved oxygen and temperature measured in select wells using an Oakton Dissolved Oxygen 300 meter; and,
- Depth to water and liquid-phase petroleum hydrocarbons (if any) measured in select monitoring and sump wells using a Heron™ oil/water interface probe.

On July 7, 2009, headspace combustible vapours and depth to water/liquid phase petroleum hydrocarbons were measured in 19 of the 21 existing accessible monitoring wells and five of the six sump wells. Field parameters (temperature and dissolved oxygen) were measured in 18 wells and four sump wells.

On October 13, 2009, the depth to water/liquid phase petroleum hydrocarbon was monitored in 20 wells and four sump wells. Field parameters (temperature and dissolved oxygen) were measured in 12 wells.

The 2009 monitoring data is presented in Table 1 in Appendix III. Current and historical results for dissolved oxygen concentrations are presented in Table 2.

Groundwater samples were collected from 10 monitoring wells during the October site visit. Prior to sampling, the wells were purged dry using dedicated inertial lift foot valves and polyethylene tubing. Groundwater samples were collected in precleaned laboratory supplied bottles, packaged with ice packs in coolers and shipped with the completed chain of custody form by air to Maxxam Analytics Inc. (Maxxam) for analysis of BTEX and PHCs. Analytical results from current and past sampling events are presented in Table 3. As part of the project quality assurance / quality control (QA/QC) program, a field duplicate and field blank were also submitted for BTEX and PHCs analysis. QA/QC results for the current data are shown in Table 4.

Laboratory Certificates of Analyses are presented in Appendix IV.

2.3 ORC APPLICATION

On July 8, 2009, following monitoring of site wells and sumps, oxygen releasing compound OxyClean-18SR™ was applied into the existing amendment distribution system. OxyClean-18SR™ is a calcium peroxide based product which decomposes slowly in contact with water releasing in the order of 17% oxygen by weight.

The distribution piping and associated trench was full of water, which had to be pumped out to allow for injection of the ORC. The pumped water was discharged back onto the area of remaining petroleum hydrocarbon impacted soils.

The ORC was mixed in a drum at a rate of approximately 0.2 kg of OxyClean™ per L of water and pumped into the amendment distribution system using a submersible pump. To provide even distribution of the ORC throughout the system, the mixture was pumped down all six vertical sumps.

A total of 350 kg of ORC had been purchased and mobilized to the site for the 2009 injection program. The amendment distribution system was able to accept approximately 200 kg, mixed with approximately 1,000 L of water. The remaining 150 kg of ORC remains stored at the site in a locked shed.

Photographs of ORC application activities are included in Appendix II.

3.0 RESULTS AND DISCUSSION

Measurable thicknesses of LPH were identified in monitoring well MW304 (1 mm) during the July monitoring event and in monitoring wells MW303 (10 mm) and MW402 (15 mm) during the October monitoring event.

Although LPH has not been detected in these wells prior to this monitoring season, historical PHC concentrations in groundwater samples collected from MW303 and MW304 have been at levels indicative of the presence of LPH. These wells are installed in the area where complete remedial excavation of petroleum hydrocarbon impacted soil was not possible due to site facilities.

Groundwater levels during the October 2009 monitoring event were low, even when compared to previous fall/winter monitoring events. Six of the monitoring wells and all sump wells monitored were dry.

Dissolved oxygen levels were higher in the background well (MW107) than in wells within the petroleum hydrocarbon impacted area (MW303, MW304, MW402), which is consistent with the previous monitoring events, and suggest that biological activity within the impacted area is reducing the available oxygen.

The dissolved oxygen values measured in sump wells in the July 2009 monitoring event were elevated and suggest that the ORC applied in 2008 was still producing oxygen at that time.

Generally, dissolved oxygen concentrations measured in the monitoring wells during the October 2009, were significantly lower than previous monitoring events; the oxygen concentrations in six of the 12 wells monitored were the lowest values recorded since the treatment was initiated. The apparent decrease in dissolved oxygen concentrations is suspect, especially in consideration of the injection of additional ORC the previous July. The low concentrations measured may be attributable to instrument error and will be confirmed in the next monitoring event.

Dissolved oxygen concentrations could not be measured in the sump wells during the October 2009 monitoring event as they were dry. It is expected that the ORC injected during July 2009 still has considerable capacity for oxygen generation.

Concentrations of BTEX and PHC (F1 - F2/F2 - F3) were below the remediation criteria in all groundwater samples submitted for analysis during the October 2009 sampling event. Samples were not submitted from MW303 and MW402 as LPH was detected.

As in the 2007 and 2008 field seasons, concentrations of PHC measured in MW307 during the 2009 field season were significantly lower than in previous sampling events. This well is significant as it is located down gradient of area of remaining impacted soil and upgradient of the amendment distribution system. The continuous reduction over the past three years may be a reflection of reduced migration of petroleum hydrocarbon impact across the area or migration of oxygenated water from the amendment distribution system located approximately 8 m to the east.

Measurable concentrations of BTEX and PHC had been measured in MW134 during the 2008 sampling event, but were below laboratory detection limits during the 2009 sampling event. MW134 is located down-gradient of the amendment distribution system.

3.1 QUALITY ASSURANCE/QUALITY CONTROL

Maxxam's quality assurance/quality control (QA/QC) program consisted of the analysis of laboratory replicates, method blanks, matrix spikes, method spikes and surrogate percent recoveries, as appropriate for the particular analysis protocol. Laboratory QA/QC results reported on the Certificates of Analysis (in Appendix IV) are all within the acceptable ranges set by the laboratories.

A groundwater field duplicate and field blank were also analyzed as part of the project QA/QC protocol. The field duplicate sample consisted of a sub-sample of the sample collected in the field. The QA/QC results, including the calculated percent difference between results, is shown in Table 4.

As shown in Table 4, concentrations of petroleum hydrocarbons in the original groundwater sample and its duplicate were below laboratory detection limits for all parameters. Concentrations of petroleum hydrocarbons in the field blank were below laboratory detection limits, as would be expected.

Considering the above, the results of the QA/QC program support the validity of the laboratory analytical results.

4.0 CONCLUSIONS/ RECOMMENDATIONS

4.1 CONCLUSIONS

Based on observations made in the field and the results of field and laboratory analyses, the following is concluded:

- Petroleum hydrocarbon impact does not extend off of the DGS property;

- Petroleum hydrocarbon impact in groundwater remains in the area where impacted soils could not be excavated because of site facilities; this is evidenced by the observation of LPH in two monitoring wells during the October 2009 monitoring event;

- Concentrations of petroleum hydrocarbons in groundwater within the area of completed remedial excavation have progressively decreased over the past three sampling events;

- Dissolved oxygen concentrations within the areas of petroleum hydrocarbon impact appear to be being depleted by microbial activity;

- Production of oxygen in the amendment distribution system appears to be promoting local degradation of petroleum hydrocarbons;

- Dissolved oxygen concentrations suggest that ORC applied in the *in-situ* remediation trench in 2008 was still producing oxygen at the time of the July 2009 monitoring event, which suggests that a treatment rate of 350 kg of ORC per year is suitable to maintain elevated concentrations of oxygen over the course of one year;

- Oxygen release from the ORC applied in July 2009 is likely to have stagnated in October 2009, as dry conditions were encountered in the sump wells and hydration of the product is required for the release of oxygen; oxygen release is expected to resume in spring of 2010 following snow melt;

- The dry subsurface conditions observed in October 2009 also indicated that little migration of petroleum hydrocarbon impact will likely occur during the winter months;

- Based on historical data and anticipated delay of ORC degradation due to dry subsurface conditions, it is expected that the 200 kg of ORC, injected to the *in-situ* remediation trench in July 2009, will be sufficient to generate oxygen until the following field season.

4.2 RECOMMENDATIONS

Based on observations made in the field, results of field and laboratory analyses, and in consideration of the above conclusions, the following recommendations are made for the 2010 field season:

- monitoring of site wells for depth to water/LPH and temperature/dissolved oxygen concentrations in late June 2010;

- application of ORC to the amendment distribution system in late June 2010, to ensure that elevated dissolved oxygen concentrations are maintained to promote degradation of petroleum hydrocarbons;

- implementation of remedial measures to address the potential for migration of the observed LPH into the area of completed remedial excavation;

- monitoring of site wells for depth to water/LPH and dissolved oxygen concentrations in late fall 2010; and,

- sampling of select site wells for laboratory analysis of petroleum hydrocarbon parameters in late fall 2010.

5.0 PROPOSED 2010 SCOPE OF WORK

5.1 PROJECT KICKOFF MEETING

Prior to starting work on the site, a project kickoff and health and safety meeting will take place. All Anebeaaki, Hydro One, and First Nation workers who will be involved in the project will participate in the meeting. The following will be discussed at the meeting:

- a review of the project scope in the work plan, and the project schedule;
- a review of a completed project Health and Safety Plan and Hydro One Contractor Safety and Environment Pre-Job Meeting Checklist form; and,
- identification of roles and responsibilities with respect to direction of work, and health and safety issues.

5.2 DESIGNATION OF WORK AREA

Immediately after the kickoff and health and safety meeting, a site office / support zone will be established. A line storage shed located in the northwest part of the site will be designated as site meeting place and support zone. Daily tailgate meetings will be held in this location. This location will also be used for first aid, coffee breaks, and drinking water storage.

5.3 SITE MONITORING

The proposed site monitoring (summer and fall) includes:

- monitoring the existing accessible 21 on-site wells for LPH thickness, water levels, and headspace combustible vapours;

- sampling 15 select wells for field parameters (dissolved oxygen and temperature).

5.4 INJECTION OF OXYGEN RELEASING COMPOUND

The in-situ distribution piping system installed in 2006 will be utilized to apply the ORC to the subsurface. The distribution system consists of 150 mm screen PVC piping, installed immediately above bedrock, connected to vertical sumps consisting of 150 mm solid PVC pipe. The location of the distribution system is shown on Figure 2.

The results from the 2009 monitoring suggest that 350 kg of ORC is sufficient to ensure an elevated concentration of oxygen in the *in-situ* amendment distribution system over the course of the year; therefore, a similar rate is proposed to be reapplied in 2010. A total of 150 kg is currently stored on-site.

The ORC will be installed generally as follows:

- the ORC and water will be mixed in a 205-L drum to form a slurry with a consistency of approximately 20% solids (approximately 0.2 kg of powder to 1 L of water);

- an injection hose will be fed down the existing vertical sumps and through the horizontal distribution pipes; and,

- the slurry mixture will be pumped into the distribution piping using an electric submersible pump.

5.5 INSTALLATION OF LPH INTERCEPTOR TRENCH

In discussions with Hydro One, KI and Anebeaaki, it was decided that remedial measures should be implemented in an effort to collect the identified LPH and reduce the potential for subsurface migration.

Based on information gathered from previous assessment and remedial activities, it is known that the three wells where LPH was identified in 2009 are located within a bedrock depression/trench, which is a preferential pathway for migration of the remaining petroleum hydrocarbon impact. The wells are installed to bedrock which was encountered between approximately 3 m and 3.8 m below grade in the area.

The installation of an interceptor trench is proposed across the bedrock depression/migration pathway to capture LPH as it moves along this migration pathway. The trench would be approximately 15 m long and excavated down to bedrock, which is anticipated to range between approximately 1.6 m and 4 m below grade across this area. The proposed location of the interceptor trench is shown on Figure 2.

Capture of the LPH would be effected by the use of Imbiber Beads™. Imbiber Beads™ are a commercial product consisting of spherical polymer particles that absorb and retain organic liquids, in this case, diesel fuel. Product information has been attached in Appendix V. Approximately 180 Imbiber Beads™ blankets will be overlapped to produce a continuous barrier from the bedrock to approximately 1 m below grade, on the down-gradient wall of the interceptor trench.

Diesel fuel impacted soil encountered during trench excavation would be hauled and placed into the First Nation's existing soil treatment facility. Non impacted soils would be stockpiled on-site for reuse as backfill material. Following installation of the Imbiber Beads ™ blankets, the trench would be backfilled with imported clean granular fill material and the stockpiled non-impacted site soils.

Samples will be collected from any soil placed into the First Nation's soil treatment facility and submitted for laboratory analysis to characterize petroleum hydrocarbon concentrations.

5.6 GROUNDWATER SAMPLING

Groundwater samples will be collected from 10 monitoring wells and two sump wells during the fall site visit. Prior to sampling, each well will be either purged dry or until a minimum of three standing wells volumes are removed. Groundwater samples will be collected using dedicated inertial-lift foot valves and polyethylene tubing. Samples will be collected into pre-cleaned laboratory supplied bottles. Sample bottles will be packed with completed chain of custody forms into coolers with ice packs, and shipped by air to the laboratory.

A total of 12 samples, plus two QA/QC duplicates, and one field blank, will be submitted for laboratory analysis of benzene, toluene, ethylbenzene, and xylenes (BTEX) and petroleum hydrocarbons (PHCs).

5.7 PROJECT MANAGEMENT AND REPORTING

The project will be administered by a project team comprised of the Kitchenuhmaykoosib Inninuwug Lands and Environment Office and Hydro One Remote Communities Inc. Once this proposed scope of work is approved, a Letter of Understanding will form the agreement between Hydro One and KI. Anebeaaki will be contracted by KI to oversee the project. Mr. Bob Shine will be the primary contact for Hydro One. All correspondence between the project team including Anebeaaki, Hydro One, and KI will be copied to each party.

A project kickoff meeting will be scheduled for the start of the field work. At this meeting, the project requirements, scope, schedule and budget will be reviewed/confirmed. Also, a Health and Safety meeting will take place.

The project duration is anticipated to be approximately seven days on-site, over two site visits. Verbal communication will be constant, and a brief written progress report will be completed, and submitted to the Steering Committee members by email.

The Anebeaaki Field Supervisor and KI Project Manager will monitor the equipment and labour requirements daily, and will track anticipated and actual usage on daily tracking forms.

Any major changes to the project identified in the field will be communicated immediately to the KI Project Manager, and as soon as possible thereafter to the Hydro One Project Manager. Any change significantly altering the scope and/or cost of the project, will be documented on a field change order form once discussed and agreed.

Approximately six weeks after completion, a project completion report will be submitted. The report will include details of the work completed, site plans, and monitoring results.

A formal agreement between Anebeaaki and KI Lands and Environment will be signed. This agreement will include payment terms.

5.8 COST ESTIMATE

The estimated cost to complete the above scope of work is presented in Appendix VI.

Anebeaaki will invoice KI, and KI will invoice Hydro One for overall project costs, based on actual quantities, verified by Anebeaaki.

The project will be will be invoiced by Anebeaaki and KI following completion of each of the two proposed site visits and at submission of the report.

6.0 CLOSURE

The work described herein was conducted in accordance with the objectives of the Project Team as outlined in Anebeaaki's *On-Site In Situ Remediation Of Hydro One DGS Site Big Trout Lake, Ontario - 2008 Monitoring Report,* dated April 2009.

The reported information is believed to provide a reasonable representation of the general environmental conditions at the site; however, the data were collected at discrete locations and conditions may vary at other locations. The remediation was also limited to those chemical parameters specifically addressed in this report.

This report has been prepared for the exclusive use of the Project Team, including Kitchenuhmaykoosib Inninuwug and Hydro One as well as Ontario Ministry of Natural Resources and Technical Standards and Safety Authority. It is not to be distributed to parties not listed without the express written consent of Anebeaaki Environmental Inc.

Anebeaaki Environmental Inc. accepts no liability for claims arising from the use of this report or from actions taken or decisions made as a result of this report, by parties other than those listed above.

Randy Edwards, A.Sc.T., CCEP	Dave Cronier
Project Manager	Senior Project Manager

APPENDIX I
FIGURES

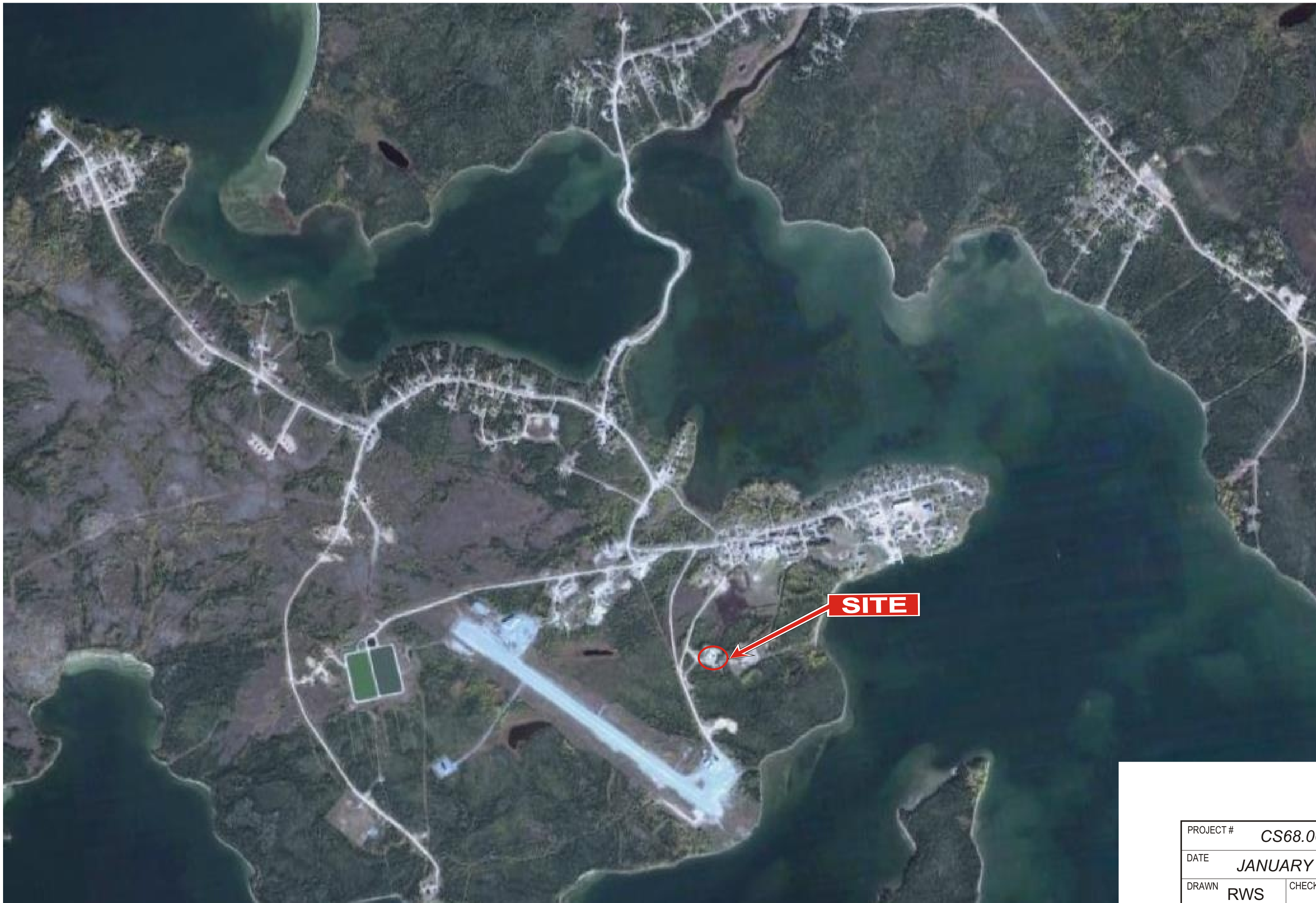
ANEBEAAKI ENVIRONMENTAL INC.

COMMUNITY LAYOUT AND SITE LOCATION

BIG TROUT LAKE, ONTARIO

CLIENT

KITCHENUHMAYKOOSIB INNINUWUG



SATELLITE IMAGE TAKEN FROM GOOGLE EARTH
IMAGE COPYRIGHTS RESERVED BY DIGITALGLOBE AND EUROPA TECHNOLOGIES

PROJECT #	CS68.06		
DATE	JANUARY 2010		
DRAWN	RWS	CHECKED	WRE
DRAWING #	FIGURE 1		

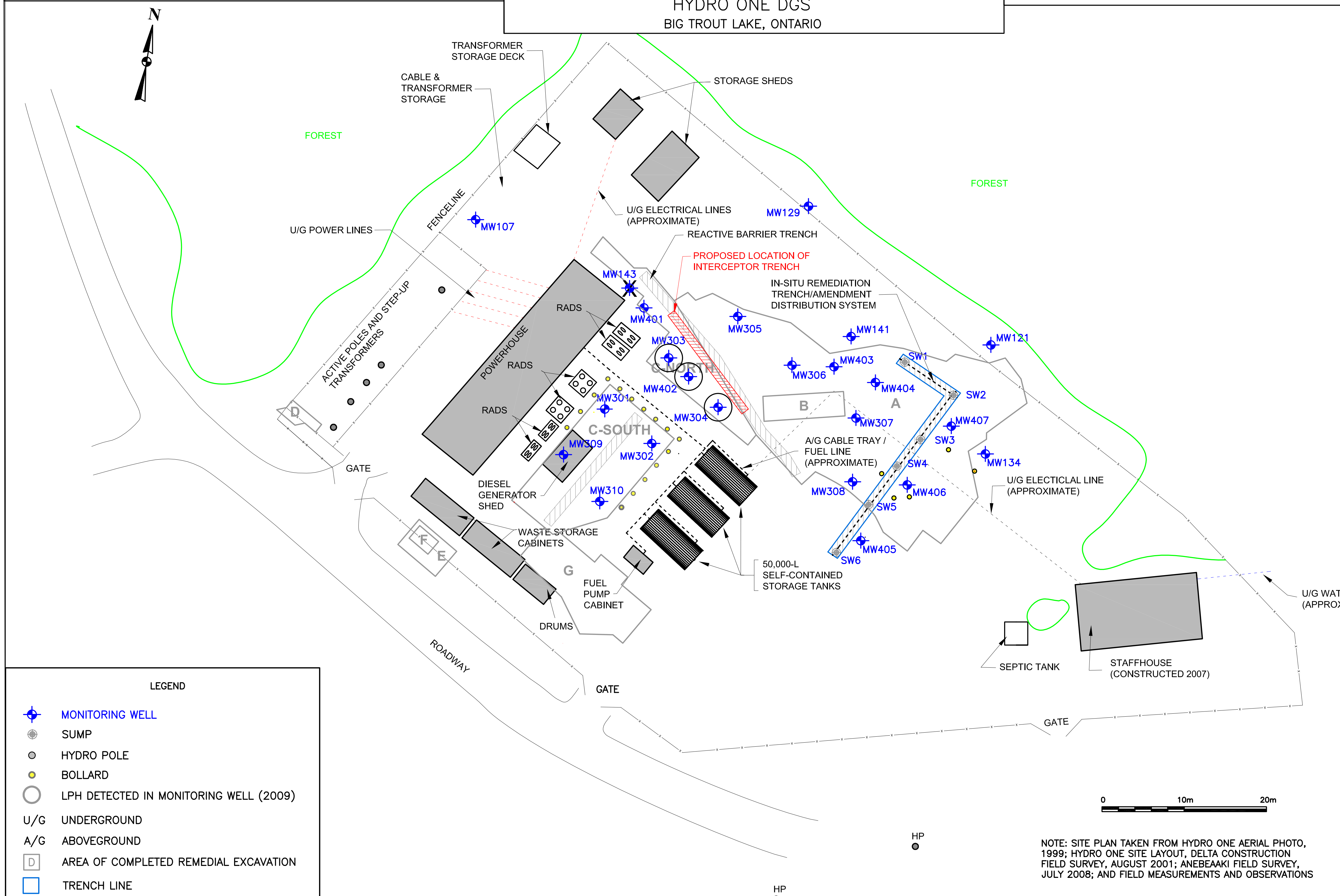
ANEBEAAKI ENVIRONMENTAL INC.

SITE LAYOUT AND PROPOSED LOCATION OF INTERCEPTOR TRENCH

HYDRO ONE DGS

BIG TROUT LAKE, ONTARIO

KITCHENUHMAYKOOSIB INNINUWUG



LEGEND

- MONITORING WELL
- SUMP
- HYDRO POLE
- BOLLARD
- LPH DETECTED IN MONITORING WELL (2009)
- U/G UNDERGROUND
- A/G ABOVEGROUND
- D AREA OF COMPLETED REMEDIAL EXCAVATION
- TRENCH LINE

NOTE: SITE PLAN TAKEN FROM HYDRO ONE AERIAL PHOTO, 1999; HYDRO ONE SITE LAYOUT, DELTA CONSTRUCTION FIELD SURVEY, AUGUST 2001; ANEBEAAKI FIELD SURVEY, JULY 2008; AND FIELD MEASUREMENTS AND OBSERVATIONS

PROJECT#	CS68.06
SCALE	1:500
DATE	JANUARY 2010
DRAWN	RWS
CHECKED	WRE
DRAWING #	FIGURE 2

APPENDIX II
PHOTOGRAPHS

Photo 1: Preparing ORC slurry prior to pumping into amendment distribution system

Photo 2: Pumping ORC solution into amendment distribution system

ANEBEAAKI ENVIRONMENTAL INC.

CLIENT	KITCHENUHMAYKOOSIB INNINUWUG / HYDRO ONE REMOTE COMMUNTIES		
PROJECT	BIG TROUT LAKE HYDRO ONE		
DRAWN	CKN	CHECKED	WRE
APROVED	WRE	DRAWING NO.	PHOTOS 1 & 2

APPENDIX III
TABLES

TABLE 1 **GROUNDWATER MONITORING DATA 2009**
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE

WELL	WELL CONDITION STATUS	WELL SURVEYED DATE	HEADSPACE VAPOUR (ppm or %LEL)	RELATIVE ELEVATION[1] (ground level)	RELATIVE ELEVATION[2] (top of pipe)	WELL STICKUP (m)	TOTAL WELL DEPTH (top of pipe)	DEPTH TO WATER (from grade) (m)	DEPTH TO WATER[3] (top of pipe) (m)	RELATIVE WATER ELEVATION	DEPTH TO LPH (m) (from TOP)	DEPTH TO LPH (m) (from grade)	LPH THICKNESS (m)
MW107	EXISTING	7-Jul-09	50 ppm	101.642	102.426	0.78	4.915	1.16	1.947	100.479	-	-	0.000
	EXISTING	13-Oct-09	NM					3.84	4.62	97.806	-	-	0.000
MW121	EXISTING	7-Jul-09	200 ppm	99.301	100.205	0.90	3.794	0.16	1.06	99.145	-	-	0.000
	EXISTING	13-Oct-09	NM					1.83	2.73	97.475	-	-	0.000
MW129	EXISTING	7-Jul-09	75 ppm	100.064	101.35	1.29	4.798	NM	NM	NM	NM	NM	NM
	EXISTING	13-Oct-09	NM					2.32	3.61	97.740	-	-	0.000
MW134	DAMAGED / REPAIRED	7-Jul-09	50 ppm	100.144	100.715	0.57	3.357	NM	NM	NM	NM	NM	NM
	EXISTING	13-Oct-09	NM					2.41	2.985	97.730	-	-	0.000
MW141	EXISTING	7-Jul-09	40 ppm	100.078	101.122	1.04	4.229	0.38	1.422	99.700	-	-	0.000
	EXISTING	13-Oct-09	NM					2.47	3.515	97.607	-	-	0.000
MW301	EXISTING	7-Jul-09	100 ppm	101.79	101.725	-0.07	3.245	0.75	0.68	101.045	-	-	0.000
	EXISTING	13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY	DRY
MW302	EXISTING	7-Jul-09	25 ppm	101.613	101.544	-0.07	2.598	0.33	0.265	101.279	-	-	0.000
	EXISTING	13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY	DRY
MW303	EXISTING	7-Jul-09	200 ppm	101.079	101.86	0.78	4.603	0.23	1.016	100.844	-	-	0.000
	EXISTING	13-Oct-09	NM					3.36	4.14	97.720	4.13	3.35	0.010
MW304	EXISTING	7-Jul-09	30 ppm	100.81	101.481	0.67	3.218	0.20	0.872	100.609	0.871	0.09	0.001
	EXISTING	13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY	DRY
MW305	EXISTING	7-Jul-09	>100% LEL	99.214	99.929	0.72	4.296	0.10	0.815	99.114	-	-	0.000
	EXISTING	13-Oct-09	NM					2.25	2.965	96.964	-	-	0.000
MW306	EXISTING	7-Jul-09	30 ppm	100.518	101.157	0.64	3.997	0.51	1.15	100.007	-	-	0.000
	EXISTING	13-Oct-09	NM					2.87	3.505	97.652	-	-	0.000
MW307	EXISTING	7-Jul-09	25 ppm	100.361	100.945	0.58	4.023	0.18	0.76	100.185	-	-	0.000
	EXISTING	13-Oct-09	NM					2.90	3.48	97.465	-	-	0.000
MW308	EXISTING	7-Jul-09	NM	99.190	100.109	0.92	3.020	NM	NM	NM	NM	NM	NM
	EXISTING	13-Oct-09	NM					NM	NM	NM	NM	NM	NM
MW310	EXISTING	7-Jul-09	25 ppm	101.795	101.783	-0.01	2.035	NM	NM	NM	NM	NM	NM
	EXISTING	13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY	DRY
MW401	EXISTING	7-Jul-09	40 ppm	101.577	102.601	1.02	2.648	0.44	1.467	101.134	-	-	0.000
	EXISTING	13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY	DRY
MW402	EXISTING	7-Jul-09	15 % LEL	101.03	102.167	1.14	4.153	0.75	1.886	100.281	-	-	0.000
	EXISTING	13-Oct-09	NM					3.34	4.475	97.692	4.46	3.32	0.015
MW403	EXISTING	7-Jul-09	300 ppm	100.302	101.469	1.17	3.204	0.43	1.595	99.874	-	-	0.000
	EXISTING	13-Oct-09	NM					2.04	3.202	98.267	-	-	0.000
MW404	EXISTING	7-Jul-09	150 ppm	100.063	101.273	1.21	3.517	0.24	1.448	99.825	-	-	0.000
	EXISTING	13-Oct-09	NM					2.15	3.36	97.913	-	-	0.000
MW405	EXISTING	7-Jul-09	NM	99.590	100.481	0.89	2.635	NM	NM	NM	NM	NM	NM
	EXISTING	13-Oct-09	NM					1.66	2.55	97.931	-	-	0.000
MW406	EXISTING	7-Jul-09	250 ppm	100.681	101.119	0.44	3.630	0.65	1.089	100.030	-	-	0.000
	EXISTING	13-Oct-09	NM					2.39	2.825	98.294	-	-	0.000
MW407	EXISTING	7-Jul-09	30 ppm	99.733	100.673	0.94	3.705	0.05	0.988	99.685	-	-	0.000
	EXISTING	13-Oct-09	NM					0.59	1.53	99.143	-	-	0.000
SW1	EXISTING	7-Jul-09	25 ppm	99.526	100.38	0.85	2.765	-0.23	0.625	99.755	-	-	0.000
	EXISTING	13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY	DRY
SW2	EXISTING	7-Jul-09	25 ppm	NS	100.627	NS	3.370	NS	1.015	99.612	-	-	0.000
	EXISTING	13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY	DRY
SW3	EXISTING	7-Jul-09	25 ppm	99.99	101.047	1.06	3.530	0.26	1.315	99.732	-	-	0.000
	EXISTING	13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY	DRY
SW4	EXISTING	7-Jul-09	10 ppm	100.241	101.238	1.00	3.400	0.05	1.05	100.188	-	-	0.000
	EXISTING	13-Oct-09	NM					DRY	DRY	DRY	DRY	DRY	DRY
SW5	EXISTING	7-Jul-09	25 ppm	100.737	100.553	-0.18	3.610	0.51	0.33	100.223	-	-	0.000
	EXISTING	13-Oct-09	NM					NM	NM	NM	NM	NM	NM
SW6	EXISTING	7-Jul-09	NM	NS	100.827	NS	2.950	NM	NM	NM	NM	NM	NM
	EXISTING	13-Oct-09	NM					NM	NM	NM	NM	NM	NM

1 Elevation of ground level in metres, relative to on-site benchmark.
2 Elevation of top of well pipe in metres, relative to on-site benchmark.
3 Depth to groundwater in metres from top of pipe.
4 Elevation of groundwater in metres from ground level, relative to on-site benchmark.
5 Elevation of groundwater in metres from top of pipe, relative to on-site benchmark.
NS Not Surveyed
NM Not Monitored

TABLE 2	DISSOLVED OXYGEN CONCENTRATIONS ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2009)			
Parameter	**Date Sampled**	**Temperature ^{o}C**	**Dissolved Oxygen**	
			% saturation	**mg/L**
MW107 BHW107	May 27/04	3.1	72.00	9.11
	Oct 14/04	6.5	58.10	7.08
	Aug 24/05	9.1	59.50	6.14
	Nov 6/06	3.9	71.20	9.36*
	Sept 19/07	10.5	107.30	13.28
	July 2/08	2.7	40.16*	5.45
	Dec 2/08	3.5	61.75*	8.2
	July 7/09	7.77	70.10	8.58
	Oct 13/09	4.3	53.68*	6.98
MW121 BHW121	Aug 29/03	12.9	100.80	10.37
	May 27/04	2.0	46.60	5.80
	Nov 6/06	3.9	61.00	8.02*
	Sept 19/07	10.2	34.67	3.94
	Dec 2/08	2.5	23.97*	3.27
	July 7/09	9.2	17.50	2.03
	Oct 13/09	5.4	5.40	0.67
MW129 BHW129	May 27/04	2.7	79.10	9.60
	Nov 6/06	4.5	103.10	12.94*
	Sept 19/07	10.3	66.00	7.47
	July 7/09	10.5	80.02	8.92
MW134 BHW134	May 27/04	1.2	44.30	5.90
	Oct 14/04	5.5	11.70	1.65
	Aug 24/05	11.3	13.10	1.32
	Nov 6/06	3.3	64.50	8.61*
	Sept 19/07	11.6	22.60	2.44
	July 3/08	8.9	6.37	0.74
	Dec 2/08	2.8	9.31*	1.26
	July 7/09	9.8	20.90	2.17
	Oct 13/09	7.4	2.20	0.11
MW141 BHW141	Aug 29/03	12.7	71.00	7.29
	May 27/04	3.5	25.70	3.24
	Oct 14/04	9.4	26.40	3.28
	Nov 6/06	3.1	45.90	6.16*
	Sept 19/07	11.1	9.80	1.07
	July 2/08	7.2	16.29*	1.97
	Dec 2/08	2.3	16.33*	2.24
	July 7/09	10	62.30	7.01
	Oct 13/09	7.4	6.10	0.74
MW301 BH301	Oct 14/04	6.9	29.10	3.60
	Nov 6/06	4.7	66.60	8.57*
	Sept 19/07	DRY	DRY	DRY
	July 7/09	11	15.70	1.52
MW302 BH302	Aug 24/05	13.6	18.30	1.80
	Nov 6/06	3.8	68.30	9.00*
	Sept 19/07	DRY	DRY	DRY
	Dec 2/08	FROZEN	FROZEN	FROZEN
	July 7/09	10.6	18.20	1.87

Table 2: Continued

TABLE 2	DISSOLVED OXYGEN CONCENTRATIONS ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2009)			
Parameter	**Date Sampled**	**Temperature °C**	**Dissolved Oxygen**	
			% saturation	**mg/L**
MW303 BHW303	Aug 29/03	11.4	76.00	7.82
	May 27/04	3.1	21.50	2.73
	Oct 14/04	6.0	12.90	1.67
	Nov 6/06	3.5	33.40	4.10*
	Sept 19/07	10.4	11.20	1.46
	July 2/08	5.4	17.48*	2.21
	Dec 2/08	3.5	10.84*	1.44
	July 7/09	9.2	6.20	0.7
MW304 BHW304	Oct 14/04	6.3	12.80	1.60
	Aug 24/05	12.9	38.70	3.63
	Nov 6/06	1.5	67.90	9.52*
	Sept 19/07	10.6	10.70	1.18
	July 2/08	7.5	8.25*	0.99
MW305 BHW305	Nov 6/06	2.7	24.80	3.37*
	Sept 19/07	10.8	3.20	0.36
	July 7/09	8.9	7.00	0.81
	Oct 13/09	7.1	1.90	0.23
MW306 BHW306	Nov 6/06	2.9	27.20	3.67*
	Sept 19/07	11.0	16.80	1.85
	July 2/08	7.4	27.51*	3.31
	July 7/09	9.7	66.80	7.6
	Oct 13/09	7.3	16.10	1.91
MW307 BHW307	Aug 24/05	12.8	25.80	2.36
	Nov 6/06	2.5	33.30	4.54*
	Sept 19/07	11.3	12.30	1.32
	July 2/08	11.5	13.45	1.47
	Dec 2/08	2.3	79.08*	10.85
	July 7/09	10.1	31.60	3.54
	Oct 13/09	6.2	6.20	0.79
MW308 BHW308	Nov 6/06	3.6	73.80	9.77*
	Sept 19/07	9.8	11.20	1.27
MW310 BHW310	Sept 19/07	DRY	DRY	DRY
	July 7/09	10.1	56.90	6.4
MW401 BHW401	July 7/09	7.7	14.40	1.67
MW402 BHW402	Nov 6/06	2.7	47.00	6.38*
	Sept 19/07	10.6	9.80	1.05
	July 2/08	6.9	1.81*	0.22
	July 7/09	9.4	3.90	0.44
MW403 BHW403	Nov 6/06	1.3	55.90	7.88*
	Sept 19/07	11.2	17.60	1.92
	July 2/08	10.4	6.07*	0.68
	Dec 2/08	-	4.10	-
	July 7/09	10.10	7.40	0.82
	Oct 13/09	7.20	0.80	0.10
MW404 BHW404	Nov 6/06	1.6	37.80	5.28*
	Sept 19/07	12.1	14.50	1.52
	July 2/08	9.9	8.11*	0.92
	Dec 2/08	2.3	29.00	4.3
	July 7/09	10.1	28.00	3.12
	Oct 13/09	5.9	1.50	0.21

TABLE 2	DISSOLVED OXYGEN CONCENTRATIONS ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2009)			
Parameter	**Date Sampled**	**Temperature °C**	**Dissolved Oxygen**	
			% saturation	**mg/L**
MW405 BHW405	Nov 6/06	0.8	116.90	16.72*
	Sept 19/07	DRY	DRY	DRY
	Oct 13/09	6	0.00	0.01
MW406 TPW406	Nov 6/06	0.7	110.70	15.87*
	Sept 19/07	10.1	21.00	2.36
	July 3/08	8.8	8.86*	1.03
	July 7/09	9.8	27.70	2.98
	Oct 13/09	7.6	16.20	1.9
MW407 TPW407	Nov 6/06	1.1	61.40	8.71*
	Sept 19/07	11	41.10	4.48
	July 3/08	11	47.38*	5.24
	Dec 2/08	NA	NA	NA
	July 7/09	9.8	20.60	1.74
	Oct 13/09	7.3	20.60	2.49
SUMP 1	Sept 19/07	DRY	DRY	DRY
	July 3/08	14.4	63.94*	6.56
	July 7/09	NA	>160	NA
	Oct 13/09	DRY	DRY	DRY
SUMP 2	Sept 19/07	10.3	45.10	4.4
	July 3/08	14	20.39	2.1
	Dec 2/08	2.2	180.20	24.78*
	Oct 13/09	DRY	DRY	DRY
SUMP 3	Sept 19/07	DRY	DRY	DRY
	July 3/08	12.6	15.00*	1.6
	Dec 2/08	2.5	195.01	26.6*
	July 7/09	10.5	>160	>17.89*
	Oct 13/09	DRY	DRY	DRY
SUMP 4	Sept 19/07	DRY	DRY	DRY
	July 3/08	10.6	40.68*	4.54
	July 7/09	10.5	>160	>17.89*
	Oct 13/09	DRY	DRY	DRY
SUMP 5	July 7/09	9.9	70.40	8.72

DRY Well was dry

* Value estimated based on theoretical relationship between temperature and oxygen dissolution in water at 1 atmosphere

NA Not Available

TABLE 3 COMPARISON OF PETROLEUM HYDROCARBON CONCENTRATIONS IN GROUNDWATERS TO REMEDIATION CRITERIA
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2009)
All values in μg/L unless noted.

Parameter	Date Sampled	Benzene	Toluene	Ethyl Benzene	Xylenes	Purgeable	Extractable	TPH (gas/diesel)	PHC F1 C6-10	PHC F2 >C10-16	SUM OF F1 - F2	PHC F3 >C16-34	PHC F4 >C34-50	SUM OF F3 - F4
Remediation Criteria		5 [1]	24 [1]	2.4 [1]	300 [1]	N/C	N/C	1000 [2]	1000 [3 a]			1000 [3 b]		
MW107 BHW107	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
MW121 BHW121	Aug 29/03	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
MW129 BHW129	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<200	<300	<200	<200	<400
MW134 BHW134	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	<0.2	19.9	0.52	< 0.6	<100	162	262	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	13.3	<0.2	< 0.6	<100	340	440	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Dec 2/08	<0.2	0.5	0.4	1.7	N/A	N/A	N/A	<100	370	<470	<100	<100	<200
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
MW141 BHW141	Aug 29/03	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	2.75	<0.2	**4.55**	6.7	<100	175	275	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
MW301 BH301	Oct 14/04	4.46	0.44	1.12	36.0	<100	1,510	**1,610**	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	2,100	**2,200**	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	110	<100	<210
	Sept 19/07	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY
MW302 BH302	Oct 14/04	**11.9**	22.2	**52.4**	**314.0**	9,850	130,000	**139,850**	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	**6.6**	<0.2	1.0	137.0	3,300	280,000	**283,300**	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<20	<20	<20	< 40	N/A	N/A	N/A	**100,000**	**76,000**	**176,000**	**17,000**	<100	**17,000**
	Sept 19/07	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY
MW303 BHW303	Aug 29/03	<0.2	0.57	**2.56**	11.1	480	36,200	**36,480**	N/A	N/A	N/A	N/A	N/A	N/A
	May 27/04	<0.2	<0.2	<0.2	TR	<100	9,600	**9,600**	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	<0.2	<0.2	**14.2**	155.7	3,560	174,000	**177,560**	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	23,000	**23,000**	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	3.4	N/A	N/A	N/A	<100	**22,000**	**22,000**	**11,000**	<100	**11,000**
	Sept 19/07	<0.2	<0.2	<0.2	1.2	N/A	N/A	N/A	**120**	**11,000**	**11,120**	**6,400**	<100	**6,400**
	Dec 2/08	3.3	<0.2	**3.3**	8.5	N/A	N/A	N/A	**100**	**21,000**	**21,100**	**12,000**	<100	**12,000**
MW304 BHW304	Aug 29/03	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	<0.2	<0.2	1.13	8.6	166	4,030	**4,196**	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	4,900	**5,000**	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<2	<2	<2	< 4	N/A	N/A	N/A	< 1,000	**1,500**	**1,500**	650	<100	<750
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	**120**	**42,000**	**42,120**	**23,000**	<200	**23,000**
MW305 BHW305	Aug 29/03	<0.2	<0.2	<0.2	< 0.6	<100	221	321	N/A	N/A	N/A	N/A	N/A	N/A
	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
MW306 BHW306	Aug 29/03	<0.2	<0.2	<0.2	< 0.6	<100	208	308	N/A	N/A	N/A	N/A	N/A	N/A
	May 27/04	1.42	<0.2	**2.64**	5.4	<100	TR	TR	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Sept 19/07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
MW307 BHW307	Aug 29/03	<0.2	<0.2	<0.2	2.3	N/A*	N/A*	N/A*	N/A	N/A	N/A	N/A	N/A	N/A
	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	215	315	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	0.69	<0.2	**11.5**	65.7	2,770	61,000	**63,770**	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	25,000	**25,100**	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<2	<2	<2	6	N/A	N/A	N/A	**17,000**	**19,000**	**36,000**	**9,600**	<100	**9,600**
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	**16,000**	**16,000**	**12,000**	<100	**12,000**
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	**3,100**	**3,100**	**2,400**	<100	**2,400**
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	510	<610	530	<100	<630
MW308 BHW308	Aug 29/03	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A	N/A	N/A	N/A	N/A	N/A
	May 27/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/04	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Aug 24/05	<0.2	<0.2	<0.2	< 0.6	<100	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200

TABLE 3 COMPARISON OF PETROLEUM HYDROCARBON CONCENTRATIONS IN GROUNDWATERS TO REMEDIATION CRITERIA
ON-SITE IN-SITU REMEDIATION - HYDRO ONE DGS - BIG TROUT LAKE (2004 - 2009)
All values in µg/L unless noted.

Parameter	Date Sampled	Benzene	Toluene	Ethyl Benzene	Xylenes	Purgeable	Extractable	TPH (gas/diesel)	PHC F1 C6-10	PHC F2 >C10-16	SUM OF F1 - F2	PHC F3 >C16-34	PHC F4 >C34-50	SUM OF F3 - F4
Remediation Criteria		5 [1]	24 [1]	2.4 [1]	300 [1]	N/C	N/C	1000 [2]	1000 [3 a]			1000 [3 b]		
MW310	Aug 24/05	N/A*	N/A*	N/A*	N/A*	N/A*	<100	<200	N/A	N/A	N/A	N/A	N/A	N/A
BHW310	Sept 19/07	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY
MW401 BHW401	Sept 19/07	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY
MW402 BHW402	Nov 6/06	4.2	<0.2	<0.2	1.4	N/A	N/A	N/A	<100	**1,900**	**1,900**	420	<100	<520
MW403	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
BHW403	Sept 19/07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
MW404	Nov 6/06	<0.2	0.3	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
BHW404	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
MW405	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	220	<100	<320
BHW405	Sept 19/07	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY	DRY
MW406 TPW406	Nov 6/06	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	170	<100	<270
	Sept 19/07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	220	<100	<320
MW407 TPW407	Nov 6/06	<2	<2	<2	< 4	N/A	N/A	N/A	**1,100**	**1,900**	**3,000**	**1,300**	<100	**1,300**
	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
	Oct 14/09	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
SUMP 1	Sept 19/07	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*
SUMP 2	Sept 19/07	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	110	<210	740	260	1000
	Dec 2/08	<0.2	<0.2	<0.2	<0.4	N/A	N/A	N/A	<100	<100	<200	<100	<100	<200
SUMP 3	Sept 19/07	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*
SUMP 4	Sept 19/07	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*
SUMP 5	Sept 19/07	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*
SUMP 6	Sept 19/07	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*	N/A*

1 Remediation criteria for community water from *Canadian Environmental Quality Guidelines* (CCME 1999)
2 Remediation criteria from Table A of the MOE Guideline for Use at Contaminated sites in Ontario (1997)
3 Remediation criteria from Table 2 of the Ontario Ministry of the Environment (MOE) generic site condition standards (SCS) from the Soil, Ground Water and Sediment Standards for Use Under Part XV.1 of the Environmental Protection Act (2004), for sites in a potable water condition and fine-textured soils
a The sum of F1 and F2
b The sum of F3 and F4
TR Trace levels less than Estimated Quantitation Limit
N/C No criterion
N/A Not analyzed
* Insufficient water in well on date of sampling
DRY Well was dry
BOLD Exceeds applicable criterion
TPH Total Petroleum Hydrocarbons
PHC Petroleum Hydrocarbons

TABLE 4 **COMPARISON OF PETROLEUM HYDROCARBON CONCENTRATIONS IN FIELD DUPLICATE / BLANK GROUNDWATER SAMPLES**
ON-SITE IN-SITU REMEDIATION - BIG TROUT LAKE, ONTARIO - 2009
All Values in µg/L unless noted.

Parameter	Benzene	Toluene	Ethyl Benzene	Xylenes	PHC F1 C6-10	PHC F2 C10-16	PHC F3 C16-34	PHC F4 C34-50
Duplicate Samples								
Dup 1	<0.2	<0.2	<0.2	<0.4	<100	<100	<100	<100
MW141	<0.2	<0.2	<0.2	<0.4	<100	<100	<100	<100
Percent Difference	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*	*NA*
Trip Blank								
MW300	<0.2	<0.2	<0.2	<0.4	<100	<100	<100	<100

Percent Difference Calculation $|(x_1 - x_2)|/ ((x_1 + x_2) / 2) * 100$

na not applicable

APPENDIX IV
LABORATORY CERTIFICATES OF ANALYSIS

Your Project #: CS68.09
Site: BIG TROUT LAKE, ON
Your C.O.C. #: 16413905, 164139-0

Attention: Dave Cronier
Anebeaaki Enviromental
8 Lincoln Park
PO BOX 2047
Sioux Lookout, ON
P8T 1J7

Report Date: 2009/10/26

CERTIFICATE OF ANALYSIS

MAXXAM JOB #: A9E0343
Received: 2009/10/20, 09:34

Sample Matrix: Water
Samples Received: 10

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Petroleum Hydro. CCME F1 & BTEX in Water	10	N/A	2009/10/23	CAM SOP-00315	CCME CWS
Petroleum Hydrocarbons F2-F4 in Water	2	2009/10/23	2009/10/25	CAM SOP-00316	CCME Hydrocarbons
Petroleum Hydrocarbons F2-F4 in Water	8	2009/10/23	2009/10/26	CAM SOP-00316	CCME Hydrocarbons

* RPDs calculated using raw data. The rounding of final results may result in the apparent difference.

Encryption Key

Please direct all questions regarding this Certificate of Analysis to your Project Manager.

KRISTEN BURMEISTER, Project Manager
Email: Kristen.Burmeister@maxxamanalytics.com
Phone# (905) 817-5700 Ext:5816

==
Maxxam has procedures in place to guard against improper use of the electronic signature and have the required "signatories", as per section 5.10.2 of ISO/IEC 17025:2005(E), signing the reports. SCC and CALA have approved this reporting process and electronic report format.

For Service Group specific validation please refer to the Validation Signature Page

Total cover pages: 1

Maxxam Job #: A9E0343
Report Date: 2009/10/26

Anebeaaki Enviromental
Client Project #: CS68.09
Project name: BIG TROUT LAKE, ON

PETROLEUM HYDROCARBONS (CCME)

Maxxam ID		EB9961	EB9962	EB9963		
Sampling Date		2009/10/14 14:00	2009/10/14 14:15	2009/10/14 14:30		
COC Number		164139-0	164139-0	164139-0		
	Units	**MW107**	**MW407**	**MW141**	**RDL**	**QC Batch**
BTEX & F1 Hydrocarbons						
Benzene	ug/L	ND	ND	ND	0.2	1982654
Toluene	ug/L	ND	ND	ND	0.2	1982654
Ethylbenzene	ug/L	ND	ND	ND	0.2	1982654
o-Xylene	ug/L	ND	ND	ND	0.2	1982654
p+m-Xylene	ug/L	ND	ND	ND	0.4	1982654
Total Xylenes	ug/L	ND	ND	ND	0.4	1982654
F1 (C6-C10)	ug/L	ND	ND	ND	100	1982654
F1 (C6-C10) - BTEX	ug/L	ND	ND	ND	100	1982654
F2-F4 Hydrocarbons						
F2 (C10-C16 Hydrocarbons)	ug/L	ND	ND	ND	100	1982554
F3 (C16-C34 Hydrocarbons)	ug/L	ND	ND	ND	100	1982554
F4 (C34-C50 Hydrocarbons)	ug/L	ND	ND	ND	100	1982554
Reached Baseline at C50	ug/L	Yes	Yes	Yes		1982554
Surrogate Recovery (%)						
1,4-Difluorobenzene	%	101	99	101		1982654
4-Bromofluorobenzene	%	99	98	102		1982654
D10-Ethylbenzene	%	91	89	92		1982654
D4-1,2-Dichloroethane	%	107	102	104		1982654
o-Terphenyl	%	99	98	99		1982554

ND = Not detected
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

Maxxam Analytics International Corporation o/a Maxxam Analytics 6740 Campobello Road, Mississauga, Ontario, L5N 2L8 Tel: (905) 817-5700 Toll-Free: 800-563-6266 Fax: (905) 817-5777 www.maxxam.ca

Maxxam Job #: A9E0343
Report Date: 2009/10/26

Anebeaaki Enviromental
Client Project #: CS68.09
Project name: BIG TROUT LAKE, ON

PETROLEUM HYDROCARBONS (CCME)

Maxxam ID		EB9964	EB9965	EB9966		
Sampling Date		2009/10/14 14:45	2009/10/14 14:50	2009/10/14 15:00		
COC Number		164139-0	164139-0	164139-0		
	Units	**MW307**	**MW121**	**MW406**	**RDL**	**QC Batch**
BTEX & F1 Hydrocarbons						
Benzene	ug/L	ND	ND	ND	0.2	1982654
Toluene	ug/L	ND	ND	ND	0.2	1982654
Ethylbenzene	ug/L	ND	ND	ND	0.2	1982654
o-Xylene	ug/L	ND	ND	ND	0.2	1982654
p+m-Xylene	ug/L	ND	ND	ND	0.4	1982654
Total Xylenes	ug/L	ND	ND	ND	0.4	1982654
F1 (C6-C10)	ug/L	ND	ND	ND	100	1982654
F1 (C6-C10) - BTEX	ug/L	ND	ND	ND	100	1982654
F2-F4 Hydrocarbons						
F2 (C10-C16 Hydrocarbons)	ug/L	510	ND	ND	100	1982554
F3 (C16-C34 Hydrocarbons)	ug/L	530	ND	220	100	1982554
F4 (C34-C50 Hydrocarbons)	ug/L	ND	ND	ND	100	1982554
Reached Baseline at C50	ug/L	Yes	Yes	Yes		1982554
Surrogate Recovery (%)						
1,4-Difluorobenzene	%	101	103	105		1982654
4-Bromofluorobenzene	%	96	99	104		1982654
D10-Ethylbenzene	%	89	92	92		1982654
D4-1,2-Dichloroethane	%	104	108	110		1982654
o-Terphenyl	%	99	99	98		1982554

ND = Not detected
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

Maxxam Job #: A9E0343
Report Date: 2009/10/26

Anebeaaki Enviromental
Client Project #: CS68.09
Project name: BIG TROUT LAKE, ON

PETROLEUM HYDROCARBONS (CCME)

Maxxam ID		EB9967	EB9968		
Sampling Date		2009/10/14 15:30	2009/10/14 15:45		
COC Number		164139-0	164139-0		
	Units	**MW306**	**MW305**	**RDL**	**QC Batch**

BTEX & F1 Hydrocarbons					
Benzene	ug/L	ND	ND	0.2	1982654
Toluene	ug/L	ND	ND	0.2	1982654
Ethylbenzene	ug/L	ND	ND	0.2	1982654
o-Xylene	ug/L	ND	ND	0.2	1982654
p+m-Xylene	ug/L	ND	ND	0.4	1982654
Total Xylenes	ug/L	ND	ND	0.4	1982654
F1 (C6-C10)	ug/L	ND	ND	100	1982654
F1 (C6-C10) - BTEX	ug/L	ND	ND	100	1982654
F2-F4 Hydrocarbons					
F2 (C10-C16 Hydrocarbons)	ug/L	ND	ND	100	1982554
F3 (C16-C34 Hydrocarbons)	ug/L	ND	ND	100	1982554
F4 (C34-C50 Hydrocarbons)	ug/L	ND	ND	100	1982554
Reached Baseline at C50	ug/L	Yes	Yes		1982554
Surrogate Recovery (%)					
1,4-Difluorobenzene	%	101	102		1982654
4-Bromofluorobenzene	%	98	103		1982654
D10-Ethylbenzene	%	85	97		1982654
D4-1,2-Dichloroethane	%	105	108		1982654
o-Terphenyl	%	97	95		1982554

ND = Not detected
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

Maxxam Job #: A9E0343
Report Date: 2009/10/26

Anebeaaki Enviromental
Client Project #: CS68.09
Project name: BIG TROUT LAKE, ON

PETROLEUM HYDROCARBONS (CCME)

Maxxam ID		EB9969		EB9970		
Sampling Date		2009/10/14 16:00				
COC Number		164139-0		164139-0		
	Units	**MW129**	**RDL**	**MW134**	**RDL**	**QC Batch**
BTEX & F1 Hydrocarbons						
Benzene	ug/L	ND	0.2	ND	0.2	1982654
Toluene	ug/L	ND	0.2	ND	0.2	1982654
Ethylbenzene	ug/L	ND	0.2	ND	0.2	1982654
o-Xylene	ug/L	ND	0.2	ND	0.2	1982654
p+m-Xylene	ug/L	ND	0.4	ND	0.4	1982654
Total Xylenes	ug/L	ND	0.4	ND	0.4	1982654
F1 (C6-C10)	ug/L	ND	100	ND	100	1982654
F1 (C6-C10) - BTEX	ug/L	ND	100	ND	100	1982654
F2-F4 Hydrocarbons						
F2 (C10-C16 Hydrocarbons)	ug/L	ND	200	ND	100	1982856
F3 (C16-C34 Hydrocarbons)	ug/L	ND	200	ND	100	1982856
F4 (C34-C50 Hydrocarbons)	ug/L	ND	200	ND	100	1982856
Reached Baseline at C50	ug/L	Yes		Yes		1982856
Surrogate Recovery (%)						
1,4-Difluorobenzene	%	101		103		1982654
4-Bromofluorobenzene	%	96		100		1982654
D10-Ethylbenzene	%	92		89		1982654
D4-1,2-Dichloroethane	%	106		105		1982654
o-Terphenyl	%	115		107		1982856

ND = Not detected
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

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GENERAL COMMENTS

Sample EB9969-01: F2-F4 Analysis.
Due to limited amount of sample available for analyses. a smaller than usual portion of the sample was used . Reporting limits were adjusted accordingly.

Results relate only to the items tested.

Anebeaaki Enviromental
Attention: Dave Cronier
Client Project #: CS68.09
P.O. #:
Project name: BIG TROUT LAKE, ON

Quality Assurance Report

Maxxam Job Number: MA9E0343

QA/QC Batch Num Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	Recovery	Units	QC Limits
1982554 BLZ	Matrix Spike	o-Terphenyl	2009/10/26		95	%	30 - 130
		F2 (C10-C16 Hydrocarbons)	2009/10/26		88	%	60 - 130
		F3 (C16-C34 Hydrocarbons)	2009/10/26		88	%	60 - 130
		F4 (C34-C50 Hydrocarbons)	2009/10/26		88	%	60 - 130
	Spiked Blank	o-Terphenyl	2009/10/26		99	%	30 - 130
		F2 (C10-C16 Hydrocarbons)	2009/10/26		82	%	60 - 130
		F3 (C16-C34 Hydrocarbons)	2009/10/26		82	%	60 - 130
		F4 (C34-C50 Hydrocarbons)	2009/10/26		82	%	60 - 130
	Method Blank	o-Terphenyl	2009/10/26		100	%	30 - 130
		F2 (C10-C16 Hydrocarbons)	2009/10/26	ND, RDL=100		ug/L	
		F3 (C16-C34 Hydrocarbons)	2009/10/26	ND, RDL=100		ug/L	
		F4 (C34-C50 Hydrocarbons)	2009/10/26	ND, RDL=100		ug/L	
	RPD	F2 (C10-C16 Hydrocarbons)	2009/10/26	NC		%	50
		F3 (C16-C34 Hydrocarbons)	2009/10/26	NC		%	50
		F4 (C34-C50 Hydrocarbons)	2009/10/26	NC		%	50
1982654 DCA	Matrix Spike	1,4-Difluorobenzene	2009/10/23		100	%	70 - 130
		4-Bromofluorobenzene	2009/10/23		97	%	70 - 130
		D10-Ethylbenzene	2009/10/23		92	%	70 - 130
		D4-1,2-Dichloroethane	2009/10/23		103	%	70 - 130
		Benzene	2009/10/23		86	%	70 - 130
		Toluene	2009/10/23		86	%	70 - 130
		Ethylbenzene	2009/10/23		91	%	70 - 130
		o-Xylene	2009/10/23		96	%	70 - 130
		p+m-Xylene	2009/10/23		95	%	70 - 130
		F1 (C6-C10)	2009/10/23		107	%	70 - 130
	Spiked Blank	1,4-Difluorobenzene	2009/10/23		104	%	70 - 130
		4-Bromofluorobenzene	2009/10/23		102	%	70 - 130
		D10-Ethylbenzene	2009/10/23		95	%	70 - 130
		D4-1,2-Dichloroethane	2009/10/23		102	%	70 - 130
		Benzene	2009/10/23		96	%	70 - 130
		Toluene	2009/10/23		95	%	70 - 130
		Ethylbenzene	2009/10/23		95	%	70 - 130
		o-Xylene	2009/10/23		98	%	70 - 130
		p+m-Xylene	2009/10/23		99	%	70 - 130
		F1 (C6-C10)	2009/10/23		119	%	70 - 130
	Method Blank	1,4-Difluorobenzene	2009/10/23		104	%	70 - 130
		4-Bromofluorobenzene	2009/10/23		98	%	70 - 130
		D10-Ethylbenzene	2009/10/23		91	%	70 - 130
		D4-1,2-Dichloroethane	2009/10/23		104	%	70 - 130
		Benzene	2009/10/23	ND, RDL=0.2		ug/L	
		Toluene	2009/10/23	ND, RDL=0.2		ug/L	
		Ethylbenzene	2009/10/23	ND, RDL=0.2		ug/L	
		o-Xylene	2009/10/23	ND, RDL=0.2		ug/L	
		p+m-Xylene	2009/10/23	ND, RDL=0.4		ug/L	
		Total Xylenes	2009/10/23	ND, RDL=0.4		ug/L	
		F1 (C6-C10)	2009/10/23	ND, RDL=100		ug/L	
		F1 (C6-C10) - BTEX	2009/10/23	ND, RDL=100		ug/L	
	RPD	Benzene	2009/10/23	NC		%	40
		Toluene	2009/10/23	NC		%	40
		Ethylbenzene	2009/10/23	NC		%	40
		o-Xylene	2009/10/23	NC		%	40
		p+m-Xylene	2009/10/23	NC		%	40
		Total Xylenes	2009/10/23	NC		%	40
		F1 (C6-C10)	2009/10/23	NC		%	40
		F1 (C6-C10) - BTEX	2009/10/23	NC		%	40

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Anebeaaki Enviromental
Attention: Dave Cronier
Client Project #: CS68.09
P.O. #:
Project name: BIG TROUT LAKE, ON

Quality Assurance Report (Continued)

Maxxam Job Number: MA9E0343

QA/QC Batch Num Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	Recovery	Units	QC Limits
1982856 ZZ	Matrix Spike	o-Terphenyl	2009/10/25		106	%	30 - 130
		F2 (C10-C16 Hydrocarbons)	2009/10/25		87	%	60 - 130
		F3 (C16-C34 Hydrocarbons)	2009/10/25		87	%	60 - 130
		F4 (C34-C50 Hydrocarbons)	2009/10/25		87	%	60 - 130
	Spiked Blank	o-Terphenyl	2009/10/25		112	%	30 - 130
		F2 (C10-C16 Hydrocarbons)	2009/10/25		89	%	60 - 130
		F3 (C16-C34 Hydrocarbons)	2009/10/25		89	%	60 - 130
		F4 (C34-C50 Hydrocarbons)	2009/10/25		89	%	60 - 130
	Method Blank	o-Terphenyl	2009/10/24		103	%	30 - 130
		F2 (C10-C16 Hydrocarbons)	2009/10/24	ND, RDL=100		ug/L	
		F3 (C16-C34 Hydrocarbons)	2009/10/24	ND, RDL=100		ug/L	
		F4 (C34-C50 Hydrocarbons)	2009/10/24	ND, RDL=100		ug/L	
	RPD	F2 (C10-C16 Hydrocarbons)	2009/10/25	NC		%	50
		F3 (C16-C34 Hydrocarbons)	2009/10/25	NC		%	50
		F4 (C34-C50 Hydrocarbons)	2009/10/25	NC		%	50

Duplicate: Paired analysis of a separate portion of the same sample. Used to evaluate the variance in the measurement.
Matrix Spike: A sample to which a known amount of the analyte of interest has been added. Used to evaluate sample matrix interference.
Spiked Blank: A blank matrix to which a known amount of the analyte has been added. Used to evaluate analyte recovery.
Method Blank: A blank matrix containing all reagents used in the analytical procedure. Used to identify laboratory contamination.
Surrogate: A pure or isotopically labeled compound whose behavior mirrors the analytes of interest. Used to evaluate extraction efficiency.
NC (RPD): The RPD was not calculated. The level of analyte detected in the parent sample and its duplicate was not sufficiently significant to permit a reliable calculation.

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Validation Signature Page

Maxxam Job #: A9E0343

The analytical data and all QC contained in this report were reviewed and validated by the following individual(s).

JEEVARAJ JEEVARATRNAM, Senior Analyst

MAMDOUH SALIB, Analyst, Hydrocarbons

==

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Your Project #: CS68.06
Site: BIG TROUT LAKE, ON
Your C.O.C. #: 16413906, 164139-0

Attention: Dave Cronier
Anebeaaki Enviromental
8 Lincoln Park
PO BOX 2047
Sioux Lookout, ON
P8T 1J7

Report Date: 2009/10/26

CERTIFICATE OF ANALYSIS

MAXXAM JOB #: A9E0319
Received: 2009/10/20, 09:34

Sample Matrix: Water
Samples Received: 2

Analyses	Quantity	Date Extracted	Date Analyzed	Laboratory Method	Method Reference
Petroleum Hydro. CCME F1 & BTEX in Water	2	N/A	2009/10/24	CAM SOP-00315	CCME CWS
Petroleum Hydrocarbons F2-F4 in Water	2	2009/10/23	2009/10/25	CAM SOP-00316	CCME Hydrocarbons

* RPDs calculated using raw data. The rounding of final results may result in the apparent difference.

Encryption Key

Please direct all questions regarding this Certificate of Analysis to your Project Manager.

KRISTEN BURMEISTER, Project Manager
Email: Kristen.Burmeister@maxxamanalytics.com
Phone# (905) 817-5700 Ext:5816

==
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For Service Group specific validation please refer to the Validation Signature Page

Total cover pages: 1

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Maxxam Job #: A9E0319
Report Date: 2009/10/26

Anebeaaki Enviromental
Client Project #: CS68.06
Project name: BIG TROUT LAKE, ON

PETROLEUM HYDROCARBONS (CCME)

Maxxam ID		EB9902	EB9903		
Sampling Date		2009/10/14	2009/10/14		
COC Number		164139-0	164139-0		
	Units	**DUP1**	**MW300**	**RDL**	**QC Batch**
BTEX & F1 Hydrocarbons					
Benzene	ug/L	ND	ND	0.2	1983239
Toluene	ug/L	ND	ND	0.2	1983239
Ethylbenzene	ug/L	ND	ND	0.2	1983239
o-Xylene	ug/L	ND	ND	0.2	1983239
p+m-Xylene	ug/L	ND	ND	0.4	1983239
Total Xylenes	ug/L	ND	ND	0.4	1983239
F1 (C6-C10)	ug/L	ND	ND	100	1983239
F1 (C6-C10) - BTEX	ug/L	ND	ND	100	1983239
F2-F4 Hydrocarbons					
F2 (C10-C16 Hydrocarbons)	ug/L	ND	ND	100	1982856
F3 (C16-C34 Hydrocarbons)	ug/L	ND	ND	100	1982856
F4 (C34-C50 Hydrocarbons)	ug/L	ND	ND	100	1982856
Reached Baseline at C50	ug/L	Yes	Yes		1982856
Surrogate Recovery (%)					
1,4-Difluorobenzene	%	96	99		1983239
4-Bromofluorobenzene	%	100	100		1983239
D10-Ethylbenzene	%	107	107		1983239
D4-1,2-Dichloroethane	%	102	106		1983239
o-Terphenyl	%	99	99		1982856

ND = Not detected
RDL = Reportable Detection Limit
QC Batch = Quality Control Batch

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Maxxam Job #: A9E0319
Report Date: 2009/10/26

Anebeaaki Enviromental
Client Project #: CS68.06
Project name: BIG TROUT LAKE, ON

GENERAL COMMENTS

Results relate only to the items tested.

Maxxam Analytics International Corporation o/a Maxxam Analytics 6740 Campobello Road, Mississauga, Ontario, L5N 2L8 Tel: (905) 817-5700 Toll-Free: 800-563-6266 Fax: (905) 817-5777 www.maxxam.ca

Anebeaaki Enviromental
Attention: Dave Cronier
Client Project #: CS68.06
P.O. #:
Project name: BIG TROUT LAKE, ON

Quality Assurance Report

Maxxam Job Number: MA9E0319

QA/QC Batch Num Init	QC Type	Parameter	Date Analyzed yyyy/mm/dd	Value	Recovery	Units	QC Limits
1982856 ZZ	Matrix Spike	o-Terphenyl	2009/10/25		106	%	30 - 130
		F2 (C10-C16 Hydrocarbons)	2009/10/25		87	%	60 - 130
		F3 (C16-C34 Hydrocarbons)	2009/10/25		87	%	60 - 130
		F4 (C34-C50 Hydrocarbons)	2009/10/25		87	%	60 - 130
	Spiked Blank	o-Terphenyl	2009/10/25		112	%	30 - 130
		F2 (C10-C16 Hydrocarbons)	2009/10/25		89	%	60 - 130
		F3 (C16-C34 Hydrocarbons)	2009/10/25		89	%	60 - 130
		F4 (C34-C50 Hydrocarbons)	2009/10/25		89	%	60 - 130
	Method Blank	o-Terphenyl	2009/10/24		103	%	30 - 130
		F2 (C10-C16 Hydrocarbons)	2009/10/24	ND, RDL=100		ug/L	
		F3 (C16-C34 Hydrocarbons)	2009/10/24	ND, RDL=100		ug/L	
		F4 (C34-C50 Hydrocarbons)	2009/10/24	ND, RDL=100		ug/L	
	RPD	F2 (C10-C16 Hydrocarbons)	2009/10/25	NC		%	50
		F3 (C16-C34 Hydrocarbons)	2009/10/25	NC		%	50
		F4 (C34-C50 Hydrocarbons)	2009/10/25	NC		%	50
1983239 GRU	Matrix Spike	1,4-Difluorobenzene	2009/10/24		95	%	70 - 130
		4-Bromofluorobenzene	2009/10/24		102	%	70 - 130
		D10-Ethylbenzene	2009/10/24		108	%	70 - 130
		D4-1,2-Dichloroethane	2009/10/24		108	%	70 - 130
		Benzene	2009/10/24		96	%	70 - 130
		Toluene	2009/10/24		100	%	70 - 130
		Ethylbenzene	2009/10/24		102	%	70 - 130
		o-Xylene	2009/10/24		107	%	70 - 130
		p+m-Xylene	2009/10/24		100	%	70 - 130
		F1 (C6-C10)	2009/10/24		71	%	70 - 130
	Spiked Blank	1,4-Difluorobenzene	2009/10/24		95	%	70 - 130
		4-Bromofluorobenzene	2009/10/24		100	%	70 - 130
		D10-Ethylbenzene	2009/10/24		112	%	70 - 130
		D4-1,2-Dichloroethane	2009/10/24		109	%	70 - 130
		Benzene	2009/10/24		102	%	70 - 130
		Toluene	2009/10/24		105	%	70 - 130
		Ethylbenzene	2009/10/24		106	%	70 - 130
		o-Xylene	2009/10/24		111	%	70 - 130
		p+m-Xylene	2009/10/24		104	%	70 - 130
		F1 (C6-C10)	2009/10/24		77	%	70 - 130
	Method Blank	1,4-Difluorobenzene	2009/10/24		97	%	70 - 130
		4-Bromofluorobenzene	2009/10/24		101	%	70 - 130
		D10-Ethylbenzene	2009/10/24		120	%	70 - 130
		D4-1,2-Dichloroethane	2009/10/24		106	%	70 - 130
		Benzene	2009/10/24	ND, RDL=0.2		ug/L	
		Toluene	2009/10/24	ND, RDL=0.2		ug/L	
		Ethylbenzene	2009/10/24	ND, RDL=0.2		ug/L	
		o-Xylene	2009/10/24	ND, RDL=0.2		ug/L	
		p+m-Xylene	2009/10/24	ND, RDL=0.4		ug/L	
		Total Xylenes	2009/10/24	ND, RDL=0.4		ug/L	
		F1 (C6-C10)	2009/10/24	ND, RDL=100		ug/L	
		F1 (C6-C10) - BTEX	2009/10/24	ND, RDL=100		ug/L	
	RPD	Benzene	2009/10/24	NC		%	40
		Toluene	2009/10/24	NC		%	40
		Ethylbenzene	2009/10/24	NC		%	40
		o-Xylene	2009/10/24	NC		%	40
		p+m-Xylene	2009/10/24	NC		%	40
		Total Xylenes	2009/10/24	NC		%	40
		F1 (C6-C10)	2009/10/24	NC		%	40
		F1 (C6-C10) - BTEX	2009/10/24	NC		%	40

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Anebeaaki Enviromental
Attention: Dave Cronier
Client Project #: CS68.06
P.O. #:
Project name: BIG TROUT LAKE, ON

Quality Assurance Report (Continued)

Maxxam Job Number: MA9E0319

Duplicate: Paired analysis of a separate portion of the same sample. Used to evaluate the variance in the measurement.
Matrix Spike: A sample to which a known amount of the analyte of interest has been added. Used to evaluate sample matrix interference.
Spiked Blank: A blank matrix to which a known amount of the analyte has been added. Used to evaluate analyte recovery.
Method Blank: A blank matrix containing all reagents used in the analytical procedure. Used to identify laboratory contamination.
Surrogate: A pure or isotopically labeled compound whose behavior mirrors the analytes of interest. Used to evaluate extraction efficiency.
NC (RPD): The RPD was not calculated. The level of analyte detected in the parent sample and its duplicate was not sufficiently significant to permit a reliable calculation.

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Validation Signature Page

Maxxam Job #: A9E0319

The analytical data and all QC contained in this report were reviewed and validated by the following individual(s).

JEEVARAJ JEEVARATRNAM, Senior Analyst

Suzana Popović

SUZANA POPOVIC, Supervisor, Hydrocarbons

==

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APPENDIX V
IMBIBER BEADS ™
PRODUCT INFORMATION

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WHAT ARE IMBIBER BEADS® | SORBENT DEFINITIONS | CHEMICAL COMPATIBILITY | GOV'T ENVIRONMENTAL FACT SHEETS

Imbiber Beads® (demo packet) 'drink' compatible liquids into their molecular structure. There is no practical way to make the Imbiber Beads® release a liquid once it has been "Imbibed."

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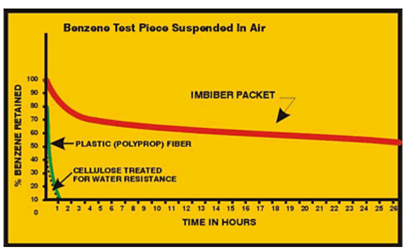
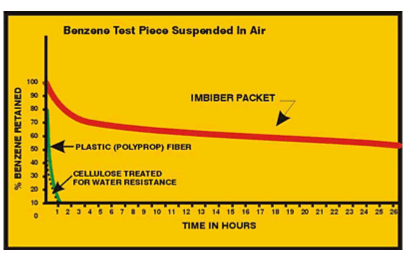
Rate of Vapor Release

(Safety of Personnel and the Environment)



Volume to Volume Comparison

22 – 27 Volumes Liquid per Volume of Imbiber Beads® - Environment Canada



What are Imbiber Beads?

Imbiber Beads ® are spherical plastic particles that 'IMBIBE', drink - in or absorb a very broad cross section of the organic chemical spectrum. The polymer particles are solid (about the size of a salt or sugar granule). There are no pores or voids to fill (as in a sponge). Once contact has been made with a compatible liquid, the Imbiber Beads® drink the liquid into their solid structure and in so doing, swell. This can be up to 27 volumes per original Imbiber Beads® volume with some liquids. The Imbiber Beads ® will not release liquid, not through compression, gravitational pull, not even when cut in half. The liquid is held in the molecular structure - not in droplets.

Advantages

The advantages to using the true absorbing system of IMBIBER BEADS® ARE MANY:

Efficient capture of organic liquids
Total containment of captured organic liquids
Safer storage and handling of hazardous materials
Drastic reduction of potentially dangerous vapour release
Effective seperation of oil/water (unaffected by water)

Imbiber Beads® (demo packet) 'drink' compatible liquids into their molecular structure. There is no practical way to make the Imbiber Beads® release a liquid once it has been "Imbibed."

ADsorbent vs ABsorbent

Absorb - "to take in and incorporate; assimilate; to suck up; drink in; to take up or receive a chemical by molecular action i.e. bring within, enclose, engulf, consume".

Adsorb - "to collect a gas, liquid, or dissolved substance in a condensed form on a surface". Adsorbents do not encapsulate or stabilize spilled substances. They are primarily useful for picking up and transporting the spilled material. ADsorbents are materials that retain liquids on the surface of their particles by capillary action and surface tension. The problem is that the spilled substance is still there on the surface of the particles and will leach back into the environment.

IMBTEC

IMBIBER BEADS®
THE ONLY TRUE ABSORBANT ENGINEERED FOR ORGANIC LIQUIDS
TEL: 1-888-843-2323

American Society for Testing and Materials (ASTM)

Definitions: taken from "Standard Test Methods for Sorbent Performance of Adsorbents – ASTM Designation F726-99

Sorbent:
"An insoluble material or mixture of materials used to recover liquids through the mechanisms of Absorption or Adsorption or both"

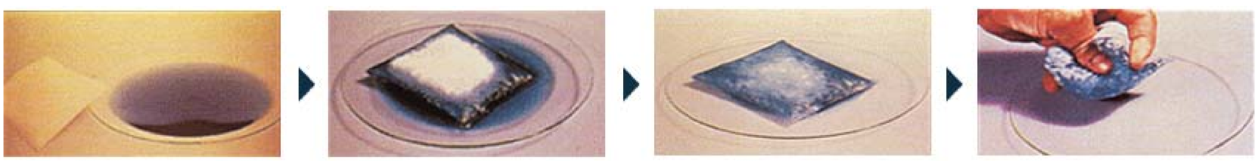
Adsorbent:
"An insoluble material that is coated by a liquid on its' surface including pores and capillaries without the solid swelling more than 50% in excess liquid."

Absorbent:
" A material that picks up and retains a liquid distributed throughout its' molecular structure the solid to swell (50% or more). The absorbent must be at least 70% insoluble in excess fluid".

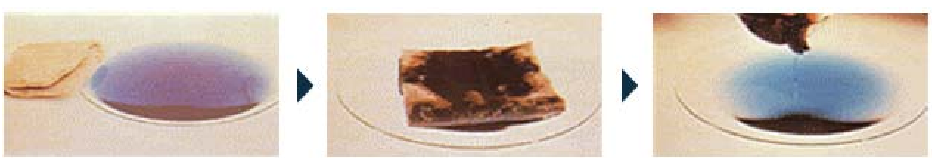
Thickener:
" as a material (usually of higher molecular weight) that is soluble in excess liquid. These go from dry to gummy (viscoelastic) to flowable and then soluble. The final viscosity depends only on solid ratio."

Imbiber Beads® is the only product available that meets ASTM PERFORMANCE SPEC'S F716 & " EPA OIL PROGRAM " definitions for AB-SORPTION.

Imbiber Beads ®ABsorbent -True ABsorbent products
(demo packet) 'drink' compatible liquids into their molecular structure. There is no practical way to make the Imbiber Beads® release once it has been "Imbibed."



Typical Adsorbents - ADsorbent - Products include plastic fibre, cellulosic fibre, mats & product
will release their contents under pressure, gravitational pull, or will leach their contents in water.



IMPORTANT: Imbibitive Technologies Corporation does not recommend the use of Imbiber Beads® or any other finely divided organic sorbent material with oxidizers.

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Compatibility Hazardous Organic Chemicals

There are literally millions of organic chemicals in the world....Please find below a representative list only, of some of the organics that IMBIBER BEADS® are compatible with ....

Absorption (Immobilization within 10 minutes)

Allybromide	Diphenyloxide	Dimethoxypropane	Toluene
n-Amylbenzene	Epichlorohydrin	Dioxane	1,1,2-Trichloroethane
Amyl Acetate	1 2-Epoxydodecane	1 1-Diphenylethylene	aaa-Trichlorotoluene;
Amylene	Ethylbenzene	Dipropylamine	Benzotrichloride
Benzene	Ethylbromide	Ethlyacetate	Valeronitrille
Benzyl Chloride	Ethylchloride	Ethyl Acrylate	Vinylpyridine
2 Bromoethylbenzene	Ethylenedichloride	Ethylbromobenzene	Ethlyoxazolene
Bromotrichloro Methane	2-Ethylhexylamine	Ethylbutyrate	Freon 113
Butyl Acrylate	Allychloride	2-Ethylhexyl Acrylate	Heptane
t-Butylbenzene	t-Amylbenzene	Ethyliodide	Hexane
sec-Butylbenzene	Amyl Chloride	Ethylpropyl Ether	Iodomethane
Butyl Cellosolve	Benzaldehyde	Ethylisobutyl Ether	Isobutylamine
t-Butylstyrene	Bromobenzene	Ethylenebromide	Isopropyl Acetate
Butyraldehyde	Butyl Acetate	Ethyllaurate	Mesitylene
Carbon Disulfide	Butylbutyrate	Ethyltoluene	Methylacrylate
Cellosolve Acetate	n-Butylbenzene	#2 Fuel Oil	Methybenzoate
2-Chlorobenzaldehyde	Butylbenzoate	Gasoline	Methylcyclohexane
Chorobenzol	Butyric Acid	2-Heptanone	Methylethylketone
o-Chloroethylbenzene	Carbon Tetrachloride	Iodohexane	Methylisopropyl Ketone
Choro-2-Methyl Propene	m-Chloroaniline	Isobutylacetate	Methylpropionate
Chloropentanes	Chlorobenzene	Isopar E	Naphtha
1-Chloronaphthalene	Chlorobromomethane	Isooctane	Nitrobenzene
3-Chloropropenyl Benzene	Chloroform	Isopropylbenzene	2-Octane-1
chloroform	3-Chloro-2-Methyl Propene	Methoxynaphthalene	Pentane
Cyclohexane	a-Chloro-m-Xylene	Methylamylacetate	Perchloroetheylene
Cyclooctone	2-Chloropropene	Methylbutylamine	2-Phenylethylamine
Decahydronaphthalene (Decalin)	Chlorostyrene	Methylene Chloride	Propylacetate
1 5-Dibromopentane	2-Chlorotoluene	Methylisobutylketone	Propylene Oxide
Dibutyl Ether	Cyclohexyl Chloride	Methylmethacrylate	Quinoline
1 2-Dichloroethylene	p-Cymene	Mineral Spirits	Styrene Oxide
aa-Dichloro-m-Xylene	1 2-Dibromopentane	Naphtha 107-142	Tetrachloroethane
Diethyl Carbonate	1 2-Dibromopropane	Octane	Thiophene
Diisobutylamine	Dichlorobenzene	Oil of Citronella	Trichlorobenzene
Diisobutylketone	Dichloroisopropyl Ether	3-Pentanone	1,1,2-Trichloroethylene
Diisopropyl Ketone	Diethylbenzene	Petroleum Ether 32-59	Trichloropropane
N,N,-Dimethyl Benzylamine	| Diethylketone	Propylenedichloride	Turpentine
1 2-Dimethyl Cyclohexane	Diisobutylene	Pyridine	Vinyl Acetate
Dimethylsulfide	p-Diisopropyl Benzene	Styrene	Vinyl Toluene
Dipentene	Dimethoxymethane	Tetrahydrofuran	VMSP Naphtha
	N,N,-Dimethylcaproamide	Thionyl Chloride	Xylene

Absorption (Immobilization within 15 minutes)

Acetophenone	Ethyloctynol	50 Aniline/50 Nitrobenzene	1-Ethynyl-1-Cyclo-Hexanol
Benzensulfonyl Chloride	Flourobenzene	n-Butylsterate	#1 Fuel Oil
Chloroacetone	Isoamylisovalerate	2-Chlorothiazone	Isopropylacetrophenone
Diacetone	Kerosene	#2 Diesel	Methylacetate
#2 Diesel Union-Prem.	2-Methylbenzothiazole	Dimethyldodecylamine	Pentylacetate

Stearoyl Chloride	Ethyleneimine	m-Toluidine	2 Amino 2 Methyl Propanol
			Cyclopentanol
			Dimethylaniline
			Dodecyltoluene
			2-Ethylhexanoic Acid
Isomylnitrite	Dimethylhexynol	Nitrooctane	
Methylacetoacetate	Dodecylbenzene	Wesson Oil	
Naphtol	Ethylbenzoate		
Oleic Acid	# Fuel Oil (mixture)		
Benzylacetate	Modified # 4 Fuel & Oil		

APPENDIX VI
COST ESTIMATE
2010 PROPOSED SCOPE OF WORK

TABLE 5: SUMMARY OF PROJECT COSTS - BIG TROUT LAKE - 2010 HYDRO DGS SITE REMEDIATION
January 2010

SUMMARY OF COSTS					
Anebeaaki	**Fees**	**Disburs.**	**Rem. Supp.**	**Lab**	**Total**
1.0 Project Development / Coordination	$3,410	$100	$0	$0	$3,510
2.0 Administration, Management, Reporting	$6,870	$100	$0	$0	$6,970
3.0 Mob/Demob Shipping	$2,730	$5,418	$0	$0	$8,148
4.0 Site Monitoring Event	$2,580	$720	$0	$0	$3,300
5.0 In-Situ Injection	$5,160	$745	$5,830	$0	$11,735
6.0 Interceptor Trench	$10,320	$2,240	$14,300	$0	$26,860
7.0 Follow Up Site Monitoring/Sampling Event	$4,140	$2,545	$0	$2,002	$8,687
Anebeaaki Subtotal	**$35,210**	**$11,868**	**$20,130**	**$2,002**	**$69,210**
First Nation	**Labour**	**Equipment**	**Backfill**		**Total**
1.0 Project Development / Coordination	$0	$0	$0		$0
2.0 Administration, Management, Reporting	$0	$0	$0		$0
3.0 Mob/Demob Shipping	$0	$0	$0		$0
4.0 Site Monitoring Event	$480	$0	$0		$480
5.0 In-Situ Injection	$960	$0	$0		$960
6.0 Interceptor Trench	$1,280	$9,840	$4,400		$15,520
7.0 Follow Up Site Monitoring/Sampling Event	$960	$0	$0		$960
First Nation Subtotal	**$3,680**	**$9,840**	**$4,400**		**$17,920**
SUMMARY					
1.0 Project Development / Coordination					$3,510
2.0 Administration, Management, Reporting					$6,970
3.0 Mob/Demob Shipping					$8,148
4.0 Site Monitoring Event					$3,780
5.0 In-Situ Injection					$12,695
6.0 Interceptor Trench					$42,380
7.0 Follow Up Site Monitoring/Sampling Event					$9,647
Project Subtotal					**$87,130**
First Nation Administration / Management (10%)					$8,713
Project Total					**$95,842**

True Grit Consulting Ltd.
1127 Barton Street
Thunder Bay, ON P7B 5N3
T 807.626.5640 F 807.623.5690 www.tgcl.ca

March 3, 2011 Project No. 10-222-04F

VIA EMAIL (georgekakekaspan@knet.ca)

Mr. George Kakekaspan
Fort Severn First Nation
General Delivery
Fort Severn, Ontario
P0V 1W0

Dear: Mr. Kakekaspan

Re: Summary of 2010 Site Work
Hydro One DGS, Fort Severn, Ontario

Introduction

True Grit Consulting Ltd. (TGCL) is pleased to provide Fort Severn First Nation (FSFN) with this report summarizing the results of the 2010 site work conducted at the Hydro One Remote Communities Inc. (HORC) DGS in Fort Severn, Ontario.

The purpose of the work was to assess soil and groundwater quality, and to inspect and start-up the in-situ groundwater remediation system at the site.

The scope of work for the July and October 2010 site visits included the following tasks:

- Advance five boreholes to be completed as monitoring wells at the site to further assess soil and groundwater quality.
- Collect soil and groundwater samples for laboratory analysis of benzene, toluene, ethlybenzene and xylenes (BTEX) and petroleum hydrocarbon (PHC) fractions F1 to F4.
- Complete rising head tests on selected monitoring wells to assess aquifer characteristics (i.e. hydraulic conductivity, groundwater flow rate).
- Complete a survey of the locations and elevations of the new and existing monitoring wells.
- Inspect and start-up the in-situ groundwater remediation system.

Site Setting

Site Description

The community of Fort Severn is located approximately 850 km north of Thunder Bay, Ontario (Figure 1). The community is situated on the west side of the Severn River, approximately 6 km upstream of where the river discharges into Hudson Bay. Access to the community is by air, summer barge and by seasonal winter road.

The DGS site is located near the northwest corner of the community with site access from Street G to the southeast and from the community landfill access road to the northeast. The property is occupied by the HORC powerhouse, transformer compound, staff house, four bulk above ground storage tanks and four sheds used for HORC equipment and non-hazardous liquid waste storage. A site plan illustrating site features, layout and infrastructure is provided as Figure 2.

Background

In September 2000, Anebeaaki Environmental Inc. (Anebeaaki) was retained by the Fort Severn First Nation to conduct a Phase II Environmental Site Assessment (ESA) at the Fort Severn Hydro One DGS site. The project was administered by a steering committee comprised of the Fort Severn First Nation and Hydro One. The results of the Phase II ESA indicated that petroleum hydrocarbon (PHC) impact was present in soil and groundwater in two distinct areas at the site, including:

- the area around and beneath the bulk fuel storage facilities, extending east of the facility to the area of the fuel off-load, and north of the facility along the migration route of past drainage of impacted water from the former secondary containment berm; and,

- a smaller area of impact near the northwest corner of the generator building, at the location where the day tank vents exit and a fuel distribution line enters the building.

In July 2003, Anebeaaki mobilized to Fort Severn to conduct the excavation of impacted soil at the site. Excavation of accessible soil was completed at this time. In October 2003, several large-diameter sump wells were installed within the remaining impacted area to enhance natural attenuation by installing oxygen releasing compound (ORC) socks into the wells. The site conditions were monitored biannually between 2004 and 2007.

In 2008, an alternative approach, designed to increase the rate of remediation by natural attenuation, while demonstrating innovative approaches to site remediation was proposed. In July and October 2008, an in-situ groundwater remediation system was installed to augment the use of ORC socks. The system included a groundwater extraction pump powered by photovoltaic (solar) panels, and a biofilter and diffuser to treat impacted water.

The system operation and site conditions have been monitored biannually in 2009 and 2010.

Methodology

Monitoring Well Installations

Between July 14 and 15, 2010, five boreholes (MW700, MW701, MW702, MW703 and MW704) were manually advanced at the site with all five completed as monitoring wells to assess soil and groundwater conditions at the site. Monitoring well locations are shown on Figure 2. Photos of the borehole drilling and monitoring well installations are provided in Appendix A (Photos 1 through 4).

An experienced TGCL environmental field technician supervised the drilling and monitoring well installations. Representative soil samples were collected directly from the hand auger bit at regular intervals and logged to document the soil conditions encountered (i.e. soil type, texture, moisture, colour, odour, etc). Representative soil samples were also collected for field testing purposes and potential laboratory analysis. During the borehole drilling, soil samples were immediately placed in new polyethylene bags for on-site organic vapour concentration (OVC) screening to assess for PHC impacts. Field screening of OVCs was carried out in each sample bag using a MiniRAE 2000 PID, calibrated to a 100 ppm isobutylene standard prior to sample assessment. Samples were allowed to equilibrate in polyethylene bags, and then agitated prior to inserting the intake probe to measure the OVC. The maximum OVC from each sample location was recorded. These results were used for assisting in the selection of soil samples for potential laboratory analysis. A summary of the soil conditions and well installations are provided on the borehole logs in Appendix B.

Each well was constructed of 38 mm diameter threaded Schedule 40 PVC pipe and No. 10 machine-slotted screen. Commercial grade, clean silica sand was placed around the screened section to provide a filter pack around the screen. A bentonite clay seal was placed atop the filter sand pack. The wells were completed with flush mount well protectors completed approximately 0.1 to 0.15 m below ground surface and secured with concrete.

All boreholes and wells were installed by Drilltec Environmental Inc., an Ontario Ministry of the Environment (MOE)-licensed water well driller, using a shovel and a hand auger. Each well was supplied with new dedicated Waterra foot valves and polyethylene tubing to facilitate well development and groundwater sample collection for laboratory analysis.

Groundwater Monitoring and Sampling

Immediately upon opening each monitoring well cap, the highest hydrocarbon vapour level (HCVL) was measured and recorded using a MiniRAE 2000 Photo-Ionization Detector (PID), calibrated to a 100 parts per million (ppm) isobutylene standard at the start of each field day.

Following HCVL measurements, static groundwater levels in the monitoring wells were measured relative to the top of the riser pipes using an electronic oil/water interface meter and recorded. The thickness of free-phased hydrocarbon in each well, if present, was also measured and recorded.

Following water level measurements, standing water was purged from the wells to obtain fresh formation water for collection and laboratory analysis. Dedicated Waterra foot valves and polyethylene tubing were used to develop new wells and to purge existing and new wells of approximately three well casing volumes of groundwater from each well prior to sample collection. Where wells were purged dry, the well was allowed to recover to within 80% of the initial static water level, then purged dry a second time prior to sample collection.

Following purging, groundwater samples were collected directly from the pumping system into laboratory-supplied cleaned bottles for chemical analysis.

Hydraulic Conductivity Testing

On July 15, 2010, in-situ hydraulic conductivity testing (rising head tests) was completed on existing monitoring well MW201 and new monitoring well MW701 to assess the hydraulic conductivity of the overburden aquifer. Water levels were measured and referenced to the top of the well casing.

Following the measurement of the static water level, the well was rapidly pumped down using the manual dedicated pumping system. The water recovery rate was measured at regular intervals during recovery until the water level had recovered to at least 90% of the initial static water level. All field measurements were recorded on field data logging sheets.

The recovery data was analyzed to obtain aquifer characteristics using Aquifer Test software and the Bouwer-Rice method for an unconfined aquifer.

Laboratory Analysis

Based on field observations and screening results, the following soil and groundwater samples were submitted under Chain of Custody to ALS Laboratory Group (ALS) in Thunder Bay, Ontario, a CALA-certified and accredited laboratory, for analysis.

Analytical Program	
Sample ID	**Parameters**
Soil	
BH700-S2A, BH701-S2, BH702-S4, BH703-S2 and BH704-S1	BTEX, PHC F1 to F4
Groundwater	
Monitoring Wells - BHW105, BHW106, MW201, MW202, MW203, MW204, MW206, MW301, MW700, MW701, MW702, MW703, MW704, Sump Wells SW1, SW2, SW4, SW5 and SW6	BTEX, PHC F1 to F4

Groundwater samples were not collected from sump well SW3 in July and monitoring well BHW115 in July and October. Sump well SW3 contained an oxygen releasing compound (ORC) sock that appeared frozen in place and could not be removed and monitoring well BHW115 could not be located.

Quality Assurance/Quality Control

In order to ensure that a high level of quality was maintained throughout the sampling and analytical program, a number of controls and procedures were implemented. These procedures include cleaning all soil and groundwater sampling equipment between samples and using new clean nitrile gloves to collect each sample.

New dedicated Waterra foot valves and tubing were installed and used to sample each new well and existing dedicated Waterra sampling systems were used to sample each existing well.

The following blind replicate samples were submitted to the laboratory in July and October for quality control purposes to check analytical consistency.

Sample ID	Replicate ID
Sump well SW1	MW707
Sump well SW4	MW705

A field blank sample (MW706-July) prepared in the field with laboratory provided distilled water, and a laboratory prepared travel blank sample (Travel Blank-July, October), were also submitted for quality control purposes. A field blank sample was not prepared during the October 2010 site visit as the sample set broke during transit to the community.

All samples were collected, transported, and stored under conditions that maintained sample integrity using the general protocols presented in the MOE manual *Guidance on Sampling and Analytical Methods for Use at Contaminated Sites in Ontario*, 1996.

ALS provided pre-cleaned sampling bottles and jars. All samples submitted for analysis were labelled with a distinct sample identification number, placed directly into chilled coolers, and delivered under Chain of Custody to the analytical laboratory well within the analytical hold times specified for the parameters being analyzed.

Assessment Criteria for Soil and Groundwater

Soil

Soil analytical results for BTEX and PHC fractions F1 to F4 are compared to the Tier I generic remediation criteria for surface soil from the *Canada-Wide Standard for Petroleum Hydrocarbons in Soil* (PHC CWS), June 2008.

The PHC CWS is a 3-tiered, risk-based standard developed for four generic land uses – agriculture, residential/parkland, commercial, and industrial. The standard can be applied at Tier 1 – generic numerical levels that are protective of human health and the environment; Tier 2 – adjustments to Tier 1 level based on site specific information, and Tier 3 – levels that are developed from a site specific ecological or human health based risk assessment.

The Tier 1 generic criteria were selected as they are protective of human health and the environment, and allow that the recommended ambient soil quantity level be considered as protective for the site unconditionally. In both Tiers 2 and 3, decisions may be taken in calculating a site-specific level that even minor future changes to the specified land use may alter the protection afforded by the recommended ambient soil quality level.

As the site is located within the community core, and to avoid restriction of future use of the property, the Tier 1 generic criteria for residential/parkland land use was selected. The specific criteria applicable to sites with coarse grained soil were selected based on soil conditions observed at the site during this and historical assessments.

Groundwater

Groundwater analytical results for BTEX are compared to the community water criteria from the federal Canadian Environmental Quality Guidelines (CCME 1999, or as updated). In the absence of applicable federal criteria, results for PHC fractions F1 to F4 were compared to the Table 2 potable groundwater criteria of the MOE *Soil, Ground Water and Sediment Standards for Use Under Part XV.1 of the Environmental Protection Act*, March 9, 2004.

Remediation System Inspection, Start-up and Winterization

The remediation system was inspected during the July 2010 site work. The inspection included a visual assessment of the following system components:

- Solar panels,
- Groundwater extraction pump controller and batteries,
- Groundwater extraction pump (contained in sump well SW5) and tubing,
- Biofilter and diffuser, and
- Preliminary re-injection point connection (contained in sump well SW1).

Prior to system start-up, a flow meter was installed in-line with the pump tubing prior to the biofilter to assess the flow rate prior to groundwater treatment. During the start-up process, the groundwater extraction pump was found damaged and requiring replacement.

An additional, unscheduled site visit was proposed to replace the pump and start the system. Due to scheduling conflicts, system repair and activation did not take place and the flow meter was disconnected during the October site visit and stored on-site.

Summary of Results

Soil Conditions

The subsurface soils at the site generally consist of sand and gravel fill to approximately 0.9 m, underlain by peat to 1.2 m, followed by silt and sand to the maximum depth investigated of 2.1 m.

OVCs in soil samples ranged from 0.3 to 168.9 ppm in samples BH702-S1 and BH702-S3, respectively, located near the northeast corner of the site.

Soil results are summarized in Table 1 and the laboratory reports are provided in Appendix C. Parameter concentrations in exceedances of the CCME PHC CWS remediation criteria are provided in the below table.

CCME PHC CWS Criteria Exceedances for Soil Samples			
Parameter	**Soil Sample ID**	**CCME Tier 1 Criteria (ug/g)**	**Results (ug/g)**
PHC Fraction F2	BH702-S4	150	431

Monitoring Well Conditions and Repairs

The monitoring wells were generally in good condition with the exception of BHW101 and MW205 which were found destroyed, and monitoring wells MW202, MW203, MW204 and MW301 which were observed to have been damaged by frost heaving resulting in the pipes lifting. Damaged wells were repaired by cutting down the riser pipes as required and re-fitting the pipes with existing plastic caps and/or j-plugs. Destroyed well BHW101 was replaced with new monitoring well MW704, and MW205 could not be repaired due to time constraints experienced when completing the site work.

Following the new well installation and existing well repairs, an elevation survey was completed and measurements were taken relative to existing site features and infrastructure.

Groundwater Conditions

A summary of the 2010 groundwater levels is provided in Table 2 and the groundwater contours for July 2010 are shown on Figure 3. No measurable free phase petroleum hydrocarbons were present in any of the existing or new on-site monitors in 2010.

Groundwater was encountered at the site at depths ranging from 0.1 m below ground surface (mbgs) at MW206 in July to 1.4 mbgs at SW1 in July. Based on the rising head tests completed at MW201 and MW701, the average hydraulic conductivity of the local soil profile was estimated to be approximately 94 cm/sec. A copy of the rising head test analysis report is provided in Appendix D.

Due to underground infrastructure (i.e. polyethylene barrier) upgradient of SW1 and SW2, groundwater levels at these wells do not appear to reflect the static water level of the aquifer; therefore, the levels were not considered in the development of the groundwater contours.

The groundwater water levels suggest a northwest flow direction with a gradient of approximately 0.012. Using the hydraulic gradient (assuming flow to be in the direction of the gradient), the average hydraulic conductivity, and an effective porosity of 0.2 for sand, gravel and silt (Fetter, 1994), the groundwater flow rate is estimated to be 6 m/year. However, due to permafrost conditions in the area, shallow groundwater would be frozen and not mobile for several months of the year.

Groundwater results are summarized in Table 3 and the laboratory reports are provided in Appendix C. Parameter concentrations in exceedance of the CCME Community Water criteria for BTEX and the MOE Table 2 criteria for PHC fractions F1 - F4 are provided in the below table.

CCME and MOE Criteria Exceedances for Groundwater				
Parameter	**Date**	**Groundwater Sample ID**	**CCME Community Water & MOE Table 2 Criteria (ug/L)**	**Results (ug/L)**
Benzene	14-Jul-10	SW1	5	6.21
	13-Oct-10			5.56
Ethylbenzene	14-Jul-10	SW1	2.4	10.5
	13-Oct-10			22.6
PHC Fractions F1& F2	14-Jul-10	SW1, SW5, MW301, MW702	1000	14860, 1070, 1620, 14900
	13-Oct-10	SW1, MW702		4370, 5200
PHC Fractions F3 & F4	14-Jul-10	SW1, MW702	1000	3270, 1630
	13-Oct-10	SW1		1130

All other parameter concentrations were below the applicable CCME and MOE Table 2 criteria.

Groundwater in sump well SW3 could not be accessed in July due to the presence of an ORC sock that appeared to be frozen in the well and could not be removed and monitoring well BHW115 was not sampled in July or October as it could not be located. Through internal HORC communications during the site work, TGCL understands from HORC that a location sensor was installed near BHW115 approximately 0.3 to 0.45 mbgs to assist in locating the well due to the depth it was installed below grade. HORC owns the locating equipment and will need to bring the equipment to permit monitoring and sampling of BHW115 in 2011.

Quality Assurance/Quality Control

The replicate groundwater sample results are summarized in Table 3, and the travel, field and laboratory blanks and process recoveries are shown on the laboratory Analytical Reports in Appendix C.

In general, field replicate results compared well with the exception of PHC fraction F2 and F3 results in July from sump well SW1 (F2 – 14500 ug/L, F3 – 3270 ug/L) and it's replicate MW707 (F2 – 6670 ug/L, F3 – 1740 ug/L). The elevated PHC conditions measured in the water is likely the cause of this level of variability between samples.

Field and travel blank results were below the laboratory's detection limit and are considered acceptable.

The laboratory replicates, blanks and process recovery results for the soil and groundwater samples were generally within standard tolerances and are considered acceptable.

Remediation System Inspection, Start-Up and Winterization

The remediation system components were inspected during the July site visit and observed to be in good condition, with the exception of the groundwater extraction pump and tubing. The groundwater extraction pump and associated tubing was found plugged with sediment preventing pump operation. The tubing was replaced and the pump was rinsed and cleaned of sediment with distilled water; however, the pump would still not operate.

An additional, unscheduled site visit was proposed to install a new pump and start-up the system; however, due to scheduling conflicts this site visit did not occur. Since the remediation system could not be started, flow meter readings were not measured and the flow rate could not be assessed. The flow meter was disconnected during the October site visit and stored on-site pending system repair and start-up in 2011.

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Discussions/Conclusions

Based on the new well installations, the subsurface soils at the site generally consist of sand and gravel fill underlain by peat and followed by silt and sand, which was consistent with historical observations.

An exceedance of the CCME criterion for PHC fraction F2 was measured in soil near the groundwater table from new location MW702, located in the northeast corner of the site. Measurable concentrations of PHC fraction F2 was detected in samples BH701-S2 and BH703-S2, and concentrations of benzene, toluene, ethylbenzene and/or xylenes were measured in all samples; however, all results were well below the applicable CCME PHC CWS criteria.

Based on groundwater levels from the new and existing wells, the groundwater levels suggest a northwest flow direction with an estimated groundwater flow rate of 6 m/yr.

In July and October 2010, there was no measurable free phase PHCs present on the groundwater in any of the existing or new on-site monitoring wells.

Exceedances of the CCME and MOE criteria were measured for benzene and ethlybenzene at SW1, for PHC fractions F1 and F2 at SW1, SW5, and MW702, and for PHC fractions F3 and F4 at SW1. In July only, exceedances for PHC fractions F1 and F2 at MW301 and F3 and F4 at MW702 were also measured. With the exception of MW702, PHC impacts appear to be present adjacent to (SW1 and SW5) and downgradient of (MW301) the DGS fuel storage area. PHC impacts from MW702, which is located cross gradient of the DGS, appear to be from another off-site source.

The remediation system groundwater extraction pump and tubing was found to be plugged with sediment preventing pump operation. Although the tubing was replaced and the pump rinsed and cleaned of sediment, the pump would still not operate. The replacement of the groundwater extraction pump will be required before the system can be started. Following system maintenance and start-up, an assessment of the groundwater flow rate into the system can be completed using the newly installed flow meter.

Recommendations

Based on the results of the 2010 site work, the following recommendations are provided for consideration:

- Continue twice annual on-going site monitoring, sampling and groundwater treatment.
- Complete a remediation system inspection and replace the system pump to permit system activation.
- During remediation system start-up, reconnect the flow meter prior to the system biofilter to assess the flow rate prior to groundwater treatment.
- Decommission abandoned monitoring well MW205 in accordance with Reg 903. To save on costs to complete the work, attempts should be made to schedule the decommissioning in conjunction with other nearby northern HORC work involving a licensed well contractor.
- Monitoring well BHW115 should be located using HORCs locating equipment to permit assessment of groundwater quality at this location.
- Obtain information from investigation work completed on adjacent property to assess potential source of impacts at MW702.

Closure

We trust that the above summary of results meets with your current requirements. Should you have any questions or require further information, please do not hesitate to contact us at 626.5640.

Sincerely,

True Grit Consulting Ltd.

Selena Contardo
Senior Environmental Technologist
scontardo@tgcl.ca

Jason Garatti, M.Sc.Eng., P.Geo.
Principal/Manager, Environmental Services
jgaratti@tgcl.ca

SC/JG:mg

Attachments: Tables
Figures
Appendix A: Photographs
Appendix B: Borehole Logs
Appendix C: Laboratory Reports
Appendix D: Hydraulic Conductivity Testing

Tables

Figures

Appendix A:
Photographs

Appendix B:
Borehole Logs

Appendix C:
Laboratory Reports

Appendix D:
Hydraulic Conductivity Testing

P.O. BOX 12
SANDY LAKE, Ontario
_P0V 1V0_

Phone: (807) 774-3421
(807) 774-5121
FAX: (807) 774-1040

June 29, 2009

Ralph Falcioni, P.Eng, MBA, (Acting) Customer Service Manager
Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, Ontario
P7E 6G9

Dear Ralph Falcioni,

Subject: Letter of Understanding – DGS Site Remediation

The Council of the Sandy Lake First Nation (SLFN) is in receipt of the draft "Letter of Understanding" (LOU) submitted by Hydro One Remote Communities Inc. (HORCI) with respect to the proposed agreement between HORCI and SLFN for the remediation of contaminated soils on the site identified in the agreements dated 1984/1988 between Her Majesty the Queen, represented by the Minister of Indian Affairs and Northern Development and Ontario Hydro. The agreement for the provision of electrical services to the community of SLFN provided that Ontario Hydro (and/or its successor) must meet certain requirements in the event of the closure of the operation of the diesel generating station (DGS) on the site designated.

The LOU proposed by HORCI reflects discussion undertaken by HORCI in the fulfillment of its obligations to Her Majesty under the provisions of the 1984/1988 Agreements. The draft sets out the proposed terms related to a contract between the two parties to remediate the former DGS site and dispose of the hydro carbon contaminated soil in such manner as to meet the remediation plan prepared by Anebeaaki Environmental Inc.

The Council of SLFN wishes to clarify its position with respect to this project. SLFN was not, and is not a party to the Agreements concluded between Her Majesty the Queen and Ontario Hydro including but not limited to the agreement made in 1984 and amended in 1988. The obligations under those Agreements are obligations of Ontario Hydro/HORCI to Her Majesty to leave the site substantially in the condition it was in before the establishment of the DGS operation.

HORCI requested that SLFN undertake, under contract to HORCI, the removal and disposition of the contaminated soils as specified in the Anebeaaki Site Remediation Plan. Our community has the experience and has carried out this kind of work in the community in the past. SLFN is prepared to undertake such an assignment subject to the understanding that our role is limited to that of a contractor engaged in the removal and disposition of the contaminated materials only.

SLFN wants to be clear that the obligations of Ontario Hydro/HORCI are obligations to Her Majesty who in turn is obligated to SLFN in ensuring that the quality of what is done meets the requirements of Her Majesty the Queen and the community under the 1984/1988 agreements. The community will require that Her Majesty the Queen confirm to the community that the obligations have been successfully met.

On the matter of accepting a transfer of title to the contaminated soils and those elements of the agreement related that, in effect, assume the responsibilities for the fulfillment of the obligations of Ontario Hydro/HORCI including assuming the liabilities there under, we would suggest that this is beyond the capabilities of the SLFN. The degree of contamination in situations of this nature can be the subject of estimates of volume and the disposition of contaminants and future leaching and further contamination an uncertain science. To the extent that SLFN, as the contractor for collection, removal and deposit of the material limits its liability to the handling and transport of the material not the long-term ownership and responsibility for future contamination.

Our relationship in this matter is confined solely to providing a service as the contractor for the collection, transportation, and deposit of the material as required under the plan for remediation as set out. The responsibility of Ontario Hydro/HORCI for the remediation and disposal is a matter for Her Majesty the Queen.

SLFN is prepared to enter into an agreement with HORCI for contract services specific to the removal and deposit of contaminated soils as indicated herein.

Yours truly,

SANDY LAKE FIRST NATION COUNCIL:

Chief Adam Fiddler

Deputy Chief Bart Meekis

Sidney Fiddler

c.c. Myles D'Arcy, President, Hydro One Remote Communities Inc.
John Cornell, CMO, INAC
Gloria Lalman, Lands and Trust, INAC
Bob Shine, Hydro One Remote Communities Inc.
Joseph C. Meekis, Executive Director, Sandy Lake First Nation
Harry Meekis, A/Capital Projects Manager, Sandy Lake First Nation

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

Cost of remediation of contaminated land

Reference: Exhibit C2 / 5/ 1 / Attachment A

Remotes is applying for a tax provision of ($187,000).

Interrogatory

Please explain why Remotes is forecasting a negative tax provision to be included in rates, considering that Remotes has a zero return on equity. Please include the regulatory basis that Remotes is relying on when applying for a negative tax provision that reduces the revenue requirement that will be applicable until Remotes' next cost-of-service application.

Response

Remotes conducts its operations under a cost recovery model applied to achieve an after-tax breakeven operation result.

To the extent that Regulatory Net Income (before tax) is negative and the resultant tax loss can be utilized by applying it to reduce future or previous year's taxable income, Remotes has reflected the tax benefit by reducing its future revenue requirement.

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

Generation Capital Programs – 2009

Reference: Attachment 4 –Capital Projects, 2009

The table for 2009 Capital Projects shows:

- investment of $125,000 for Lighting Improvement at Armstrong; and
- Investments of $367,000 for Lighting Improvements for 11 Locations which averages out to be $33,364 per location.

Interrogatory

Please explain the reason for the higher than average cost ($33,364) of implementing the Lighting Improvement at Armstrong reported ($125,000)?

Response

Lighting projects were required as a result of poor lighting conditions in several plants. A scope of work and budget estimate was developed for all of the lighting projects and no two locations had the same scope of work or cost. In Armstrong, new ‘T5’ fixtures and bulbs were installed as replacements to offer better lighting and improved energy efficiency. Most sites simply required fixture and bulb replacements resulting in a lower project cost than Armstrong. The Armstrong site also required a complete rewiring of the lighting system to relocate the lighting from the plant walls to an overhead position, and included the introduction of more appropriate zone lighting. Given the height of the Armstrong plant, this work required higher than average set-up time related to scaffolding and working from heights.

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

Generation Capital Programs – 2011 & 2012

Reference:
- Attachment 4 –Capital Projects, 2011 & 2012

The following amounts are shown:
- for 2011 there is a project under "Facilities", called "Beaverhall Mezzanine" with capital cost of $227,000
- for 2012 there is a project under "Facilities", called "Civil Shop Beaverhall Place" with capital cost of $176,000

Interrogatory

a) Where is the Beaverhall facility located, and what is its purpose?
b) Does the facility belong to Remotes, or does Remotes make these expenditures under an arrangement with the owner such as a leasehold improvement?

Response

a) The Beaverhall facility is located at 680 Beaverhall Place, Thunder Bay. It is the service centre for Remotes' operations, including finance, billing, customer service, trades, administrative and management staff. The building is zoned light industrial, with office, stores, shop and yard space.

b) Remotes owns the Beaverhall facility.

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

Smart Meters

Reference:
- Decision / EB-2008-0232 / pp.6-7
- Exhibit D1 / 2 / 1

Interrogatory

In its previous Decision, the Board approved Remotes' proposed treatment of the cost of acquiring and installing Smart Meters as a normal component of its rate base, rather than through the deferral accounts prescribed for most other distributors at the time.

a) Please describe the extent to which Remotes installed Smart Meters in 2009 and 2010, and describe the functionality of the meters in comparison with Smart Meters installed by other distributors such as Hydro One Distribution.

b) Please indicate whether the cost of changing meters in 2011 (Exh D1 / 2 / 1 / p. 10, line 7) involved recently-installed Smart Meters, and if so please explain why this cost would be required of nearly-new meters.

Response

a) In 2009 and 2010, smart meters were installed when meters were required to be replaced (broken meters, meter reverification). The smart meters are used only for the collection of manually read monthly readings. The functionality to collect meter reads remotely is currently not used as the required infrastructure in the communities has not been installed. Additionally, the communities do not currently have the communications infrastructure required to transmit meter data reliably, if at all.

b) Remotes did not replace all of its meters in 2009 and 2010. Meter changes in 2011 and 2012 are largely associated with Measurement Canada meter reverification requirements. Because the community electrical distribution systems were installed at one time, most of the meters are required to be changed at one time. The meter replacements do not involve more recently-installed Smart Meters unless the meter is found to be defective. Meter changes in 2013 are also based on Measurement Canada requirements, and, as noted in D1, Tab 2, Schedule 1, page 10, also reflect anticipated deployment of new meters in Pikangikum and Cat Lake.

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

Smart Meters

References:
Exhibit D1 / 2 / 1 / p. 11
Exhibit E1 / 1 / 1 / p. 3

Amongst the factors in Remotes' request for an increase in tis revenue requirement are three factors related to extending the service area to include Cat Lake and Pikangikum:

i. Electricity purchases: $1,368,000
ii. Clearing Transmission right-of–way to Cat Lake: $1,200,000
iii. Distribution Services in Pikangikum: $380,000

Interrogatory

a) Is the second item a one-off expenditure, as opposed to an annual expenditure? If so, would it not be more appropriate to include in the rate base, or alternatively at a fraction such as 25% so that the cost would be recovered over a period of years with a lesser effect on Remotes' annual revenue requirement?

b) Does the third item include the amount of $60 thousand mentioned in the reference in Exh D1?

c) Is this list of three factors comprehensive? If not, please provide a more detailed and comprehensive listing of incremental costs associated with extending the service area. For example, are there costs of distribution service in Cat Lake analogous to those in Pikangikum? Are there costs of operating the transmission system in addition to the clearing expenditure?

Response

a) The transmission right-of-way clearance to Cat Lake is not an annual expenditure, but would be required on a cyclical basis, once every six to eight years depending on the growth rate of the vegetation. Forestry by the nature of the work is a current year expenditure and does not meet the definition of a capital asset; accordingly, Remotes does not believe that the right-of-way clearance could be included in rate base. Any difference between forecast and actual expenditures will be captured in the Remote Rate Protection Variance Account. Remotes notes that some work to maintain the line is also likely required and would be expected to commence once a line clearance is established.

b) No the above amounts are strictly OMA related. There is $60 thousand in gross capital expenditures budgeted for distribution system improvements in Cat Lake and Pikangikum and an additional $60 thousand in gross capital associated with metering and minor storm damage. These expenditures would have a very minor impact on revenue requirement.

c) The costs are Remotes' best estimate of what is required to serve the communities. The costs are expected to be proportional to the number of customers. The operating and maintenance costs related to the community distribution system in Cat Lake are expected to be approximately $135 thousand annually. Remotes expects that there will be some maintenance costs associated with the long distribution line to the community of Cat Lake once the line clearance is established, but does not have an estimate of those costs at this time.

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

Smart Meters

Reference: Exhibit F1 / 1 / 1
Remotes has listed three Regulatory Accounts, and does not include Account 1562 'Deferred Payments In Lieu of Taxes' Board staff is aware that Hydro One has submitted argument in EB-2012-0136, dated January 31 and February 25 2013, that the requirement for Account 1562 is not applicable.

Interrogatory

Does Remotes consider that the same arguments apply to it as Hydro One has submitted in EB-2012-0136? Please explain.

Response

Yes. Remotes takes the position that it should be treated the same as Hydro One Networks with respect to Account 1562.

Remotes has been making payment in lieu of corporate income taxes to the Ontario Electricity Finance Corporation relating to taxable income earned by its distribution and generation business, under section 89 of the *Electricity Act, 1998*. As confirmed by the Board in its Decision in EB-2012-0136, Account 1562 applies to only distributors which are subject to section 93 of the Act. Therefore, Remotes is not required to use Account 1562.

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

IFRS Transition Costs

Reference: Exhibit F1 / 1 / 1 / p. 1
Remotes has recorded a $ zero balance in the Impact for USGAAP account as at December 31, 2012.

Interrogatory

a) Is Remotes proposing to continue this account in this application? Please explain.

b) Has Remotes identified any significant differences between CGAAP and USGAAP at this time? Please explain.

c) Please explain if any of the differences noted in the answer to part a) of this interrogatory would be incorporated into the Impact for USGAAP regulatory account or the proposed revenue requirements for 2013.

d) If there are no differences identified, please state why Remotes requires the continuance of the Impact for USGAAP regulatory account.

e) Remotes' adoption of USGAAP is a one-time occurrence. Please explain why Remotes would need continuance of the Impact for Changes in USGAAP variance account, when USGAAP was adopted by Remotes for financial reporting purposes on January 1, 2012.

Response

a) No. US GAAP transition is complete and the account was not used.

b) No. There were no impacts to Remotes' revenue requirement or rate base as a result of transitioning from Canadian GAAP to US GAAP. The only significant impacts related to presentation of information in the Financial Statements.

c) N/A.

d) Refer to a) above. Remotes no longer requires the continuance of this account.

e) Refer to a) above.

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

IFRS Transition Costs

Reference: Exhibit F1/1/1/ Page 1

Interrogatory

a) Please disclose the estimated USGAAP incremental transition costs embedded in the proposed 2013 test year.

b) Please explain if Remotes is seeking to recover USGAAP incremental transition costs in the 2013 test year when the adoption of USGAAP occurred in 2012.

Response

a) There are no USGAAP transition costs embedded in the 2013 test year.

b) N/A

Ontario Energy Board (Board Staff) INTERROGATORY #27 List 1

IFRS Transition Costs

Reference: Exhibit F1/Tab1/1/Page 1

Remotes has recorded a $72,000 balance in the IFRS Transition Costs account as at December 31, 2012. Remotes is proposing to recover the balance in this account from customers in 2013 rates.

Interrogatory

a) Please list reasons why the Board should approve Remotes' request to recover the balance in the IFRS Transition Costs account, when Remotes has transitioned to USGAAP and not IFRS.

b) Is Remotes proposing to continue this account in this application? Please explain.

Response

a) Management has made the determination that they will not seek recovery of the $72,000 balance in the IFRS Transition Cost account.

b) No. Remotes does not anticipate further costs associated with adopting IFRS.

Ontario Energy Board (Board Staff) INTERROGATORY #28 List 1

Deferral and Variance Accounts

Reference: Exhibit F1/1/1

Remotes is required to provide explanations for the nature and amounts of any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding)

Interrogatory

a) Please provide a statement as to whether Remotes has made any adjustments that were previously approved

b) Please provide any supporting documentation of the adjustments.

Response

a) Yes, Remotes has made an adjustment, as ordered by the board in EB 2011-0427, to its regulatory accounts increasing the IFRS Transition Costs Variance account and reducing the RRRP account by the same amount.

b) Please refer to page 8 of the OEB decision and order to EB 2011-0427, dated April 3, 2012 as support for the adjusting entry made.

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

Deferral and Variance Accounts

References:
- Exhibit A / 11 / 1 / Attachment 3 / pp. 15, 17 & 18
- Exhibit C1 /4 / 1 / Page 3
- Exhibit F1 / 1 / 1

As per Exhibit A / 11 / 1, Attachment 3, page 15, Hydro One Remotes 2011 audited financial statements includes the following as note # 7:

> **"REGULATORY ASSET AND LIABILITIES**
> The Company records a liability (Note 11) for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2011, the carrying value of the regulatory asset was increased by $7,043 thousand to reflect a revaluation adjustment in the Company's environmental liabilities.
>
> This environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of the Company's actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been lower by $7,043 thousand (2010 - higher by $356 thousand). In addition, amortization expense in 2011 would have been lower by $1,017 thousand (2010 - $1,268 thousand) and financing charges would have been higher by $261 thousand (2010 - $495 thousand)."

As per Exhibit A / 11 / 1, Attachment 3 / page 17 & 18, Hydro One Remotes 2011 audited financial statements includes as note # 11:

> **"ENVIRONMENTAL LIABILITIES**
> Estimated future environmental expenditures for each of the five years subsequent to December 31, 2011 and in total thereafter are as follows: 2012 - $3,402 thousand; 2013 - $2,603 thousand; 2014 - $1,401 thousand; 2015 - $1,468 thousand; 2016 - $1,027 thousand; and thereafter - $5,519.
>
> Consistent with its accounting policy for environmental costs, the Company records a liability for the estimated future expenditures associated with the Company's land assessment and remediation (LAR) program. The Company's LAR liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations. The revaluation

adjustments in 2010 and 2011 were the result of net changes in the estimated timing and amount of future expenditures.

There are uncertainties in estimating future environmental expenditures due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A longterm inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.57% to 6.25%, depending on the appropriate rate for the period when the obligations were first recorded."

As per Exhibit F1/Tab1/1, Remotes has incurred several debits to the RRRP variance account for Environmental Asset Amortization, as follows:

2009	$983,000
2010	$1,268,000
2011	$1,017,000
2012	$3,474,000

Interrogatory

a) Please explain why the carrying value of the regulatory asset was increased by approximately $7 million in 2011 to reflect a revaluation adjustment in Remotes' environmental liabilities. Please outline the circumstances and the assumptions used, including the choice of discount rates, timing and amount of future expenditures, etc.

b) Are there any changes to the accounting for the environmental regulatory asset or environmental liability as a result of the adoption of USGAAP?

i. Please explain and indicate the regulatory implications. For example, please describe if the environmental regulatory asset is within the scope of ASC 410 Asset Retirement Obligations.

ii. Please provide any analysis performed by Remotes and an external third party (e.g. external auditor opinion) regarding the impact of the adoption of USGAAP on the accounting of the environmental regulatory asset and environmental liability. Please explain both financial and regulatory accounting implications.

c) Please provide a schedule of the expected environmental asset amortization expense and its calculation from 2013 through 2017, in addition to the actual amounts incurred from 2009 to 2012, as shown in Exhibit F1/1/1.

i. Please explain why the amount of $2.713 million included in the test year revenue requirement for environmental asset amortization, as per Exhibit C1/4/1/Page 3, is an appropriate amount for both the test year and IRM periods, when the amount included in 2009 rates was approximately $1 million.

ii. Please explain the variation from year to year and the large increase 2012 in the audited actual amounts included in the RRRP Variance account, as shown in Exhibit F1/1/1.

Response

a) Hydro One Remotes reviews and updates its environmental liability pertaining to its land assessment and remediation program on an annual basis. In 2011, the provision assumptions were reviewed for significant changes in work program plans (e.g. quantity of contaminated sites, extent of contamination, cost estimates to remediate) or in regulations. No major regulatory changes occurred in 2011.

Hydro One Remotes confirmed significant increases to the provision consistent with changes in the scope and timing of remediation work. The scope of required work can change when field work shows that contamination was more extensive than originally expected. Similarly, monitoring costs increase when the remediation project does not start as expected. The Remotes LAR provision was been increased in 2011 by about $7 million (present value) to recognize an increase in projected spending of more than $8 million due to various factors. The duration of the program was also extended a further five years to the period ending 2020 to accommodate the additional work.

The major factors contributing to the change in the annual pattern of estimated future expenditures were as per the following table:

Community	Increased Spend	Years Extended	Reason
Sandy Lake	$3.4M	6	Revised estimate based on new information obtained from 2010 remedial planning and field work. Actual volume and depth of impacted soil is much greater and deeper than originally expected, thereby changing scope of work drastically. Impacted ground water becoming an issue therefore, the project will be more complicated and prolonged.
Big Trout Lake	$0.85M	5	Total site remediation is initiated during the station upgrade; however, the upgrade has been delayed indefinitely by AANDC. Source point of impacted soil is situated under the station and therefore inaccessible until station upgrade occurs necessitating prolonged remedial measures.
Sachigo Lake	$0.77M	5	The effectiveness of subsurface remedial efforts has been less than desired which has initiated a review of the current program and further examination of remedial options.
Deer Lake	$0.69M	5	Total site remediation is initiated during the station upgrade; however, the upgrade has been delayed indefinitely by AANDC resulting in a prolonged program and increased costs.
Kingfisher Lake	$0.70M	5	As per Deer Lake.
Fort Severn	$0.48M	5	As per Deer Lake.
Weagamow	$0.46M	5	As per Deer Lake.
Cat Lake	$0.40M	4	Negotiations with the First Nation on the project have not been completed as quickly as planned.
Kasabonika Lake	$0.24M	5	As per Deer Lake.
Webequie	$0.15M	2	Delays in construction of new DGS pushed remedial efforts back. Negotiations with First Nation were not completed as quickly as planned.
Total	$8.14		

b)

i. The environmental liability is not an ARO.

ii. On transitioning to US GAAP, there were no accounting changes affecting environmental liabilities compared to legacy CGAAP (per Part V of the CICA Handbook).

c) The following schedule summarizes expected environmental expenditures, which equate to regulatory asset amortization expense, for the years 2013 through 2017, as well as actual expenditures/amortization from 2009 to 2012.

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

The 2009 rates included expected environmental spending that included 4 larger projects: Attawapiskat, Big Trout Lake, Sandy Lake and Sachigo Lake. Due to delayed negotiations, Attawapiskat was deferred and is now included in the 2013 test year. Sandy Lake was also deferred due to negotiations and, subsequently, Sandy Lake Development getting set up as the primary contractor. The project did not start until 2010 and as a result of new information obtained from the remedial planning field work, the estimate and scope of work was revised. Actual volume and depth of impacted soil was much greater and deeper than originally expected thereby changing the scope of work drastically. Impacted ground water has become an issue therefore the project is much more complicated and prolonged. While spending on these projects was minimal in 2009, progress was made on other projects such as spot cleaning of residual areas in Kasabonika and Fort Severn Phase 2 study. Test year 2013 includes Pikangikum which was forecasted to be complete in 2010 but was deferred due to slowed negotiations. Webequie old station site remediation is new to this test year.

i. The $2.713 million included in the test year revenue requirement for environmental asset amortization is the expected remediation costs in 2013.

ii. Please see the table below.

Remotes LAR Amortization Expense Year over Year Variances $ Thousand		
Year	**Year over Year Variance**	**Explanation**
2010	285	Bearskin old station site remediation underway in 2010, work commences in Sandy Lake with a Letter of Understanding and remedial planning field work. This is partially offset by Kasabonika and Fort Severn projects which were substantially complete in 2009.
2011	(251)	Sachigo Lake work lower in 2011 as in-situ remediation was determined to be ineffective and an alternative method to assist with control of off-site impact was examined. Work to prevent cross contamination was completed in Big Trout Lake in 2010. In 2011 Sandy Lake bio-cell installation and further site investigation.
2012	1,498	Sandy Lake work ramps up with excavation of the site. Webequie remediation commences with further evaluation of site and Sachigo work resumes with further drilling for setting up potential future pump and treat system.
2013	198	In 2013 Attawapiskat remediation should begin and assuming successful negotiations, remediation in Pikangikum and Webequie will proceed. With the majority of remediation completed in 2012, some further assessment and work will continue for Sandy Lake and Sachigo including new well installations to assist with better delineation and water sampling; as well installation for further assessment in Cat Lake in 2013.
2014	(1,226)	Attawapiskat, Pikangikum and Webequie are expected to be substantially completed in 2013. This is partially offset with increases associated with work in Cat Lake and the pump and treat system installation in Sandy Lake and possibly Sachigo.
2015	102	Cat Lake project ramps up. Sandy Lake project winds down with on-going bio-cell remediation of soil and ground water pump operation.
2016	(455)	Remediation in Cat Lake substantially completed.
2017	150	Big Trout Lake and Wapekeka remediation commences assuming station upgrade(s) take place.

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

RRRP Variance Account – Taxes

References:
- Exhibit F1 / 1 / 1
- Decision, EB-2008-0232
- Exhibit C2 / 5 / 1 / Attachment 3

As per Exhibit F1/Tab1/1, Remotes has incurred several debits and credits to the RRRP variance account for Income and Capital Tax, as follows:

2009: $2,944,000
2010: $1,353,000
2011: ($158,000)
2012: ($1,372,000)

The Decision in Remotes previous rebasing application, EB-2008-0232, states at p. 11:

"..the Board does not consider it appropriate to make provision for a PILs liability which has no reasonable prospect of being realized."

Interrogatory

a) Please provide the supporting calculations and basis for the tax amounts included in the RRRP variance account.

b) Please explain why different amounts for the years 2009, 2010, and 2011 are shown on Exhibit C2/Tab/1/Attachment 3 (2009 - $1,826,000, 2010 - $731,000, 2011 ($164,000)). Please state which are the correct numbers to include in the RRRP variance account and provide reasons to support these numbers.

c) Please explain why the amount of taxes shown in Exhibit F1/1/1 shown in the "Approved" column is $152,000 when the Board approved a zero amount of taxes or PILs liability in rates in EB-2008-0232.

Response

a) The tax amounts included in the RRRP variance account are per the audited financial statements for the respective years. Copies of the financial statements previously submitted can be summarized as follows:

	2009	2010	2011	2012*
Income tax (note 5 of F/S)	2,824,000	1,324,000	(127,000)	(1,436,000)
Capital tax expense (recovery) in OM&A	120,000	29,000	(31,000)	(0)
Total per Exhibit F1	2,944,000	1,353,000	(158,000)	(1,436,000)

* 2012 number included herein is updated according to final Audited Financial Statements. Capital Tax expense was discontinued by the Province of Ontario on July 1, 2010.

b) The amounts shown on Exhibit C2, Tab 5, Schedule 1, Attachment 3 (2009 - $1,826,000, 2010 -$731,000, 2011 ($164,000)) reflect the tax returns filed. The financial statement amounts are being used for the RRRP variance account as certain tax return adjustments to financial statement income before tax, such as the impact of RRRP have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. Please see Exhibit C1, Tab 5, Schedule 1 for an explanation of the difference between Regulatory income and taxable income per tax returns as well as the treatment of deferral accounts.

c) Remotes agrees that the amount reflected in Exhibit F1, Tab1, Schedule 1 shown in the “Approved” column should be zero as per EB-2008-0232.

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

Proposed Rate Increase in Existing Communities

Reference: Exhibit G1 / 1 / 1 / pp. 1-2

Interrogatory

Please provide the calculation that Remotes has used as the basis for the proposed distribution rate increase of 3.45%, in an Excel spreadsheet format if available. Please sort the distributors from the largest 2011 distribution rate increase to the lowest, and if available please indicate which 2011 applications were cost-of-service applications and which were IRM applications.

Response

Following the methodology approved in the Board's Decision with Reasons for EB-2008-0232, Hydro One Remotes has calculated the average 2010 to 2011 rate increase of 3.45% as shown in the spreadsheet included here as Attachment 1.

The bill increases for the Residential and General Service Energy customers of Ontario LDCs have been calculated using data from the 2010 and 2011 Electricity Distribution Rates Databases available on the Board's website. The Electricity Rates Databases do not indicate if the rates shown are based on a cost-of-service or an IRM application, and Hydro One Remotes does not have this information.

Applicant	Service_Territory	DX_Base (11/10)	Total bill (11/10)
Atikokan Hydro Inc.	Residential	0.12%	3.83%
Atikokan Hydro Inc.	General Service Less Than 50 kW	0.15%	3.99%
Bluewater Power Distribution Corporation	Residential	0.07%	2.71%
Bluewater Power Distribution Corporation	General Service Less Than 50 kW	-1.82%	2.67%
Brant County Power Inc.	Residential	6.13%	5.65%
Brant County Power Inc.	General Service Less Than 50 kW	-5.05%	3.24%
Brantford Power Inc.	Residential	0.09%	1.75%
Brantford Power Inc.	General Service Less Than 50 kW	0.13%	2.30%
Burlington Hydro Inc.	Residential	-0.43%	2.67%
Burlington Hydro Inc.	General Service Less Than 50 kW	-0.48%	3.07%
Cambridge and North Dumfries Hydro Inc.	Residential	0.09%	3.57%
Cambridge and North Dumfries Hydro Inc.	General Service Less Than 50 kW	-4.59%	3.22%
Canadian Niagara Power Inc. - Eastern Ontario Power	Residential	0.94%	2.25%
Canadian Niagara Power Inc. - Eastern Ontario Power	General Service Less Than 50 kW	-2.99%	1.64%
Canadian Niagara Power Inc. - Fort Erie	Residential	0.94%	3.09%
Canadian Niagara Power Inc. - Fort Erie	General Service Less Than 50 kW	-2.99%	2.39%
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	Residential	0.00%	2.93%
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	General Service Less Than 50 kW	-0.02%	3.30%
Centre Wellington Hydro Ltd.	Residential	-1.48%	1.36%
Centre Wellington Hydro Ltd.	General Service Less Than 50 kW	-1.30%	1.96%
Chapleau Public Utilities Corporation	Residential	0.00%	3.03%
Chapleau Public Utilities Corporation	General Service Less Than 50 kW	-0.02%	3.45%
Chatham-Kent Hydro Inc.	Residential	0.28%	3.07%
Chatham-Kent Hydro Inc.	General Service Less Than 50 kW	0.23%	3.40%
COLLUS Power Corporation	Residential	-4.99%	1.78%
COLLUS Power Corporation	General Service Less Than 50 kW	0.00%	3.52%
Cooperative Hydro Embrun Inc.	Residential	0.08%	3.67%
Cooperative Hydro Embrun Inc.	General Service Less Than 50 kW	0.08%	4.00%
E.L.K. Energy Inc.	Residential	-0.23%	2.35%
E.L.K. Energy Inc.	General Service Less Than 50 kW	-0.28%	3.06%
Enersource Hydro Mississauga Inc.	Residential	0.09%	2.21%
Enersource Hydro Mississauga Inc.	General Service Less Than 50 kW	0.11%	2.40%
ENWIN Utilities Ltd.	Residential	0.30%	2.83%
ENWIN Utilities Ltd.	General Service Less Than 50 kW	0.09%	3.14%
Erie Thames Powerlines Corporation	Residential	0.00%	6.30%
Erie Thames Powerlines Corporation	General Service Less Than 50 kW	0.00%	6.85%
Espanola Regional Hydro Distribution Corporation	Residential	0.10%	3.48%
Espanola Regional Hydro Distribution Corporation	General Service Less Than 50 kW	0.06%	3.75%
Essex Powerlines Corporation	Residential	0.08%	3.10%
Essex Powerlines Corporation	General Service Less Than 50 kW	25.73%	7.56%
Festival Hydro Inc.	Residential Average	5.96%	4.15%
Festival Hydro Inc.	General Service Less Than 50 kW	-0.31%	2.97%

Fort Frances Power Corporation	Residential	0.21%	4.07%
Fort Frances Power Corporation	General Service Less Than 50 kW	0.22%	4.31%
Greater Sudbury Hydro Inc.	Residential	0.00%	2.74%
Greater Sudbury Hydro Inc.	General Service Less Than 50 kW	-1.62%	2.73%
Grimsby Power Inc.	Residential	-0.27%	1.69%
Grimsby Power Inc.	General Service Less Than 50 kW	-0.22%	2.18%
Guelph Hydro Electric Systems Inc.	Residential	0.08%	2.86%
Guelph Hydro Electric Systems Inc.	General Service Less Than 50 kW	0.05%	3.40%
Haldimand County Hydro Inc.	Residential	0.08%	3.56%
Haldimand County Hydro Inc.	General Service Less Than 50 kW	0.07%	4.09%
Halton Hills Hydro Inc.	Residential	0.09%	3.55%
Halton Hills Hydro Inc.	General Service Less Than 50 kW	0.11%	3.88%
Hearst Power Distribution Company Limited	Residential	0.00%	2.76%
Hearst Power Distribution Company Limited	General Service Less Than 50 kW	0.00%	3.32%
Horizon Utilities Corporation	Residential	13.00%	7.39%
Horizon Utilities Corporation	General Service Less Than 50 kW	16.43%	7.49%
Hydro 2000 Inc.	Residential	0.23%	2.54%
Hydro 2000 Inc.	General Service Less Than 50 kW	0.22%	2.76%
Hydro Hawkesbury Inc.	Residential	0.16%	3.99%
Hydro Hawkesbury Inc.	General Service Less Than 50 kW	0.21%	4.17%
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%
Hydro Ottawa Limited	Residential	0.08%	2.57%
Hydro Ottawa Limited	General Service Less Than 50 kW	0.06%	2.95%
Innisfil Hydro Distribution Systems Limited	Residential	0.09%	3.09%
Innisfil Hydro Distribution Systems Limited	General Service Less Than 50 kW	-7.47%	2.21%
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%
Kitchener-Wilmot Hydro Inc.	Residential	0.52%	3.19%
Kitchener-Wilmot Hydro Inc.	General Service Less Than 50 kW	0.20%	3.38%
Lakefront Utilities Inc.	Residential	0.60%	3.21%
Lakefront Utilities Inc.	General Service Less Than 50 kW	-4.33%	2.75%
Lakeland Power Distribution Ltd.	Residential	0.11%	2.42%
Lakeland Power Distribution Ltd.	General Service Less Than 50 kW	0.13%	2.83%
London Hydro Inc.	Residential	0.08%	2.68%
London Hydro Inc.	General Service Less Than 50 kW	0.11%	3.09%
Middlesex Power Distribution Corporation	Residential	0.12%	3.53%
Middlesex Power Distribution Corporation	General Service Less Than 50 kW	0.14%	4.24%
Middlesex Power Distribution Corporation - Dutton	Residential	0.18%	2.84%

Middlesex Power Distribution Corporation - Dutton	General Service Less Than 50 kW	0.21%	3.35%
Middlesex Power Distribution Corporation - Newbury	Residential	0.19%	0.67%
Middlesex Power Distribution Corporation - Newbury	General Service Less Than 50 kW	0.16%	1.31%
Midland Power Utility Corporation	Residential	0.07%	2.70%
Midland Power Utility Corporation	General Service Less Than 50 kW	0.07%	3.24%
Milton Hydro Distribution inc.	Residential	7.89%	4.20%
Milton Hydro Distribution inc.	General Service Less Than 50 kW	7.60%	4.19%
Newmarket - Tay Power Distribution Ltd.	Residential	4.85%	5.85%
Newmarket - Tay Power Distribution Ltd.	General Service Less Than 50 kW	17.11%	8.74%
Niagara Peninsula Energy Inc.	Residential	4.99%	4.40%
Niagara Peninsula Energy Inc.	General Service Less Than 50 kW	-5.50%	1.81%
Niagara-on-the-Lake Hydro Inc.	Residential	0.11%	2.40%
Niagara-on-the-Lake Hydro Inc.	General Service Less Than 50 kW	0.11%	2.65%
Norfolk Power Distribution Inc.	Residential	0.11%	2.26%
Norfolk Power Distribution Inc.	General Service Less Than 50 kW	0.12%	2.71%
North Bay Hydro Distribution Limited	Residential	0.21%	3.91%
North Bay Hydro Distribution Limited	General Service Less Than 50 kW	0.51%	4.29%
Northern Ontario Wires Inc.	Residential	0.53%	1.58%
Northern Ontario Wires Inc.	General Service Less Than 50 kW	0.58%	2.16%
Oakville Hydro Electricity Distribution Inc.	Residential	-1.25%	3.18%
Oakville Hydro Electricity Distribution Inc.	General Service Less Than 50 kW	-1.21%	3.37%
Orangeville Hydro Limited	Residential	-0.44%	2.76%
Orangeville Hydro Limited	General Service Less Than 50 kW	0.11%	3.36%
Orillia Power Distribution Corporation	Residential	0.08%	3.04%
Orillia Power Distribution Corporation	General Service Less Than 50 kW	0.09%	3.21%
Oshawa PUC Networks Inc.	Residential	0.11%	4.11%
Oshawa PUC Networks Inc.	General Service Less Than 50 kW	0.05%	4.30%
Ottawa River Power Corporation	Residential	0.00%	2.78%
Ottawa River Power Corporation	General Service Less Than 50 kW	0.00%	3.23%
Parry Sound Power Corporation	Residential	28.35%	10.85%
Parry Sound Power Corporation	General Service Less Than 50 kW	27.12%	9.50%
Peterborough Distribution Incorporated	Residential	0.10%	3.31%
Peterborough Distribution Incorporated	General Service Less Than 50 kW	0.11%	3.56%
PowerStream Inc. - Barrie	Residential	-0.80%	2.88%
PowerStream Inc. - Barrie	General Service Less Than 50 kW	0.06%	3.50%
PowerStream Inc. - South	Residential	0.09%	3.30%
PowerStream Inc. - South	General Service Less Than 50 kW	0.10%	3.53%
PUC Distribution Inc.	Residential	0.10%	3.46%
PUC Distribution Inc.	General Service Less Than 50 kW	0.06%	3.72%
Renfrew Hydro Inc.	Residential	-2.35%	2.40%
Renfrew Hydro Inc.	General Service Less Than 50 kW	0.55%	3.53%
Rideau St. Lawrence Distribution Inc.	Residential	0.10%	1.90%
Rideau St. Lawrence Distribution Inc.	General Service Less Than 50 kW	0.10%	2.49%

Sioux Lookout Hydro Inc.	Residential	0.12%	1.92%
Sioux Lookout Hydro Inc.	General Service Less Than 50 kW	0.14%	2.47%
St. Thomas Energy Inc.	Residential	3.80%	3.61%
St. Thomas Energy Inc.	General Service Less Than 50 kW	5.69%	4.20%
Thunder Bay Hydro Electricity Distribution Inc.	Residential	-2.99%	3.31%
Thunder Bay Hydro Electricity Distribution Inc.	General Service Less Than 50 kW	0.07%	4.32%
Tillsonburg Hydro Inc.	Residential	-6.70%	1.47%
Tillsonburg Hydro Inc.	General Service Less Than 50 kW	0.07%	3.34%
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%
Veridian Connections Inc.	Residential	0.08%	3.46%
Veridian Connections Inc.	General Service Less Than 50 kW	0.00%	3.77%
Veridian Connections Inc. - Gravenhurst	Residential Average	6.34%	2.95%
Veridian Connections Inc. - Gravenhurst	General Service Less Than 50 kW	-5.61%	0.65%
Wasaga Distribution Inc.	Residential	0.04%	2.93%
Wasaga Distribution Inc.	General Service Less Than 50 kW	0.02%	3.44%
Waterloo North Hydro Inc.	Residential	16.93%	7.70%
Waterloo North Hydro Inc.	General Service Less Than 50 kW	12.83%	6.17%
Welland Hydro-Electric System Corp.	Residential	0.12%	1.87%
Welland Hydro-Electric System Corp.	General Service Less Than 50 kW	0.10%	2.44%
Wellington North Power Inc.	Residential	0.08%	1.13%
Wellington North Power Inc.	General Service Less Than 50 kW	0.10%	1.87%
West Coast Huron Energy Inc.	Residential	0.00%	2.40%
West Coast Huron Energy Inc.	General Service Less Than 50 kW	-0.02%	2.83%
Westario Power Inc.	Residential	0.09%	-0.26%
Westario Power Inc.	General Service Less Than 50 kW	0.10%	0.42%
Whitby Hydro Electric Corporation	Residential	-0.52%	3.28%
Whitby Hydro Electric Corporation	General Service Less Than 50 kW	5.19%	4.54%
Woodstock Hydro Services Inc.	Residential	14.68%	5.73%
Woodstock Hydro Services Inc.	General Service Less Than 50 kW	14.61%	5.32%
		1.83%	**3.45%**

Applicant	Service_Territory	DX_Base (11/10)	Total bill (11/10)
Kenora Hydro Electric Corporation Ltd.	Residential	38.60%	11.66%
Parry Sound Power Corporation	Residential	28.35%	10.85%
Kenora Hydro Electric Corporation Ltd.	General Service Less Than 50 kW	42.91%	9.90%
Parry Sound Power Corporation	General Service Less Than 50 kW	27.12%	9.50%
Newmarket - Tay Power Distribution Ltd.	General Service Less Than 50 kW	17.11%	8.74%
Waterloo North Hydro Inc.	Residential	16.93%	7.70%
Essex Powerlines Corporation	General Service Less Than 50 kW	25.73%	7.56%
Horizon Utilities Corporation	General Service Less Than 50 kW	16.43%	7.49%
Horizon Utilities Corporation	Residential	13.00%	7.39%
Kingston Hydro Corporation	Residential	19.26%	7.32%
Erie Thames Powerlines Corporation	General Service Less Than 50 kW	0.00%	6.85%
Erie Thames Powerlines Corporation	Residential	0.00%	6.30%
Waterloo North Hydro Inc.	General Service Less Than 50 kW	12.83%	6.17%
Newmarket - Tay Power Distribution Ltd.	Residential	4.85%	5.85%
Woodstock Hydro Services Inc.	Residential	14.68%	5.73%
Brant County Power Inc.	Residential	6.13%	5.65%
Woodstock Hydro Services Inc.	General Service Less Than 50 kW	14.61%	5.32%
Hydro One Networks Inc.	Residential Average	6.97%	4.82%
Kingston Hydro Corporation	General Service Less Than 50 kW	6.17%	4.63%
Whitby Hydro Electric Corporation	General Service Less Than 50 kW	5.19%	4.54%
Hydro One Networks Inc.	General Service Average	5.96%	4.53%
Niagara Peninsula Energy Inc.	Residential	4.99%	4.40%
Thunder Bay Hydro Electricity Distribution Inc.	General Service Less Than 50 kW	0.07%	4.32%
Fort Frances Power Corporation	General Service Less Than 50 kW	0.22%	4.31%
Oshawa PUC Networks Inc.	General Service Less Than 50 kW	0.05%	4.30%
North Bay Hydro Distribution Limited	General Service Less Than 50 kW	0.51%	4.29%
Middlesex Power Distribution Corporation	General Service Less Than 50 kW	0.14%	4.24%
St. Thomas Energy Inc.	General Service Less Than 50 kW	5.69%	4.20%
Milton Hydro Distribution inc.	Residential	7.89%	4.20%
Milton Hydro Distribution inc.	General Service Less Than 50 kW	7.60%	4.19%
Hydro Hawkesbury Inc.	General Service Less Than 50 kW	0.21%	4.17%
Festival Hydro Inc.	Residential Average	5.96%	4.15%
Oshawa PUC Networks Inc.	Residential	0.11%	4.11%
Haldimand County Hydro Inc.	General Service Less Than 50 kW	0.07%	4.09%
Fort Frances Power Corporation	Residential	0.21%	4.07%
Cooperative Hydro Embrun Inc.	General Service Less Than 50 kW	0.08%	4.00%
Atikokan Hydro Inc.	General Service Less Than 50 kW	0.15%	3.99%
Hydro Hawkesbury Inc.	Residential	0.16%	3.99%
North Bay Hydro Distribution Limited	Residential	0.21%	3.91%
Halton Hills Hydro Inc.	General Service Less Than 50 kW	0.11%	3.88%
Atikokan Hydro Inc.	Residential	0.12%	3.83%
Veridian Connections Inc.	General Service Less Than 50 kW	0.00%	3.77%

Espanola Regional Hydro Distribution Corporation	General Service Less Than 50 kW	0.06%	3.75%
PUC Distribution Inc.	General Service Less Than 50 kW	0.06%	3.72%
Cooperative Hydro Embrun Inc.	Residential	0.08%	3.67%
St. Thomas Energy Inc.	Residential	3.80%	3.61%
Cambridge and North Dumfries Hydro Inc.	Residential	0.09%	3.57%
Haldimand County Hydro Inc.	Residential	0.08%	3.56%
Peterborough Distribution Incorporated	General Service Less Than 50 kW	0.11%	3.56%
Halton Hills Hydro Inc.	Residential	0.09%	3.55%
PowerStream Inc. - South	General Service Less Than 50 kW	0.10%	3.53%
Renfrew Hydro Inc.	General Service Less Than 50 kW	0.55%	3.53%
Middlesex Power Distribution Corporation	Residential	0.12%	3.53%
COLLUS Power Corporation	General Service Less Than 50 kW	0.00%	3.52%
PowerStream Inc. - Barrie	General Service Less Than 50 kW	0.06%	3.50%
Espanola Regional Hydro Distribution Corporation	Residential	0.10%	3.48%
PUC Distribution Inc.	Residential	0.10%	3.46%
Veridian Connections Inc.	Residential	0.08%	3.46%
Chapleau Public Utilities Corporation	General Service Less Than 50 kW	-0.02%	3.45%
Wasaga Distribution Inc.	General Service Less Than 50 kW	0.02%	3.44%
Chatham-Kent Hydro Inc.	General Service Less Than 50 kW	0.23%	3.40%
Guelph Hydro Electric Systems Inc.	General Service Less Than 50 kW	0.05%	3.40%
Kitchener-Wilmot Hydro Inc.	General Service Less Than 50 kW	0.20%	3.38%
Oakville Hydro Electricity Distribution Inc.	General Service Less Than 50 kW	-1.21%	3.37%
Orangeville Hydro Limited	General Service Less Than 50 kW	0.11%	3.36%
Middlesex Power Distribution Corporation - Dutton	General Service Less Than 50 kW	0.21%	3.35%
Tillsonburg Hydro Inc.	General Service Less Than 50 kW	0.07%	3.34%
Hearst Power Distribution Company Limited	General Service Less Than 50 kW	0.00%	3.32%
Peterborough Distribution Incorporated	Residential	0.10%	3.31%
Thunder Bay Hydro Electricity Distribution Inc.	Residential	-2.99%	3.31%
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	General Service Less Than 50 kW	-0.02%	3.30%
PowerStream Inc. - South	Residential	0.09%	3.30%
Whitby Hydro Electric Corporation	Residential	-0.52%	3.28%
Brant County Power Inc.	General Service Less Than 50 kW	-5.05%	3.24%
Midland Power Utility Corporation	General Service Less Than 50 kW	0.07%	3.24%
Ottawa River Power Corporation	General Service Less Than 50 kW	0.00%	3.23%
Cambridge and North Dumfries Hydro Inc.	General Service Less Than 50 kW	-4.59%	3.22%
Orillia Power Distribution Corporation	General Service Less Than 50 kW	0.09%	3.21%
Lakefront Utilities Inc.	Residential	0.60%	3.21%
Kitchener-Wilmot Hydro Inc.	Residential	0.52%	3.19%
Oakville Hydro Electricity Distribution Inc.	Residential	-1.25%	3.18%
ENWIN Utilities Ltd.	General Service Less Than 50 kW	0.09%	3.14%
Essex Powerlines Corporation	Residential	0.08%	3.10%
Canadian Niagara Power Inc. - Fort Erie	Residential	0.94%	3.09%
Innisfil Hydro Distribution Systems Limited	Residential	0.09%	3.09%

London Hydro Inc.	General Service Less Than 50 kW	0.11%	3.09%
Chatham-Kent Hydro Inc.	Residential	0.28%	3.07%
Burlington Hydro Inc.	General Service Less Than 50 kW	-0.48%	3.07%
E.L.K. Energy Inc.	General Service Less Than 50 kW	-0.28%	3.06%
Orillia Power Distribution Corporation	Residential	0.08%	3.04%
Chapleau Public Utilities Corporation	Residential	0.00%	3.03%
Festival Hydro Inc.	General Service Less Than 50 kW	-0.31%	2.97%
Veridian Connections Inc. - Gravenhurst	Residential Average	6.34%	2.95%
Hydro Ottawa Limited	General Service Less Than 50 kW	0.06%	2.95%
Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	Residential	0.00%	2.93%
Wasaga Distribution Inc.	Residential	0.04%	2.93%
PowerStream Inc. - Barrie	Residential	-0.80%	2.88%
Guelph Hydro Electric Systems Inc.	Residential	0.08%	2.86%
Middlesex Power Distribution Corporation - Dutton	Residential	0.18%	2.84%
ENWIN Utilities Ltd.	Residential	0.30%	2.83%
Lakeland Power Distribution Ltd.	General Service Less Than 50 kW	0.13%	2.83%
West Coast Huron Energy Inc.	General Service Less Than 50 kW	-0.02%	2.83%
Ottawa River Power Corporation	Residential	0.00%	2.78%
Orangeville Hydro Limited	Residential	-0.44%	2.76%
Hearst Power Distribution Company Limited	Residential	0.00%	2.76%
Hydro 2000 Inc.	General Service Less Than 50 kW	0.22%	2.76%
Lakefront Utilities Inc.	General Service Less Than 50 kW	-4.33%	2.75%
Greater Sudbury Hydro Inc.	Residential	0.00%	2.74%
Greater Sudbury Hydro Inc.	General Service Less Than 50 kW	-1.62%	2.73%
Bluewater Power Distribution Corporation	Residential	0.07%	2.71%
Norfolk Power Distribution Inc.	General Service Less Than 50 kW	0.12%	2.71%
Midland Power Utility Corporation	Residential	0.07%	2.70%
London Hydro Inc.	Residential	0.08%	2.68%
Bluewater Power Distribution Corporation	General Service Less Than 50 kW	-1.82%	2.67%
Burlington Hydro Inc.	Residential	-0.43%	2.67%
Niagara-on-the-Lake Hydro Inc.	General Service Less Than 50 kW	0.11%	2.65%
Hydro Ottawa Limited	Residential	0.08%	2.57%
Hydro 2000 Inc.	Residential	0.23%	2.54%
Rideau St. Lawrence Distribution Inc.	General Service Less Than 50 kW	0.10%	2.49%
Sioux Lookout Hydro Inc.	General Service Less Than 50 kW	0.14%	2.47%
Welland Hydro-Electric System Corp.	General Service Less Than 50 kW	0.10%	2.44%
Lakeland Power Distribution Ltd.	Residential	0.11%	2.42%
West Coast Huron Energy Inc.	Residential	0.00%	2.40%
Enersource Hydro Mississauga Inc.	General Service Less Than 50 kW	0.11%	2.40%
Niagara-on-the-Lake Hydro Inc.	Residential	0.11%	2.40%
Renfrew Hydro Inc.	Residential	-2.35%	2.40%
Canadian Niagara Power Inc. - Fort Erie	General Service Less Than 50 kW	-2.99%	2.39%
E.L.K. Energy Inc.	Residential	-0.23%	2.35%

Brantford Power Inc.	General Service Less Than 50 kW	0.13%	2.30%
Norfolk Power Distribution Inc.	Residential	0.11%	2.26%
Canadian Niagara Power Inc. - Eastern Ontario Power	Residential	0.94%	2.25%
Toronto Hydro-Electric System Limited	Residential Regular	-1.35%	2.22%
Enersource Hydro Mississauga Inc.	Residential	0.09%	2.21%
Innisfil Hydro Distribution Systems Limited	General Service Less Than 50 kW	-7.47%	2.21%
Grimsby Power Inc.	General Service Less Than 50 kW	-0.22%	2.18%
Northern Ontario Wires Inc.	General Service Less Than 50 kW	0.58%	2.16%
Toronto Hydro-Electric System Limited	General Service Less Than 50 kW	-0.66%	2.08%
Centre Wellington Hydro Ltd.	General Service Less Than 50 kW	-1.30%	1.96%
Sioux Lookout Hydro Inc.	Residential	0.12%	1.92%
Rideau St. Lawrence Distribution Inc.	Residential	0.10%	1.90%
Welland Hydro-Electric System Corp.	Residential	0.12%	1.87%
Wellington North Power Inc.	General Service Less Than 50 kW	0.10%	1.87%
Niagara Peninsula Energy Inc.	General Service Less Than 50 kW	-5.50%	1.81%
COLLUS Power Corporation	Residential	-4.99%	1.78%
Brantford Power Inc.	Residential	0.09%	1.75%
Grimsby Power Inc.	Residential	-0.27%	1.69%
Canadian Niagara Power Inc. - Eastern Ontario Power	General Service Less Than 50 kW	-2.99%	1.64%
Northern Ontario Wires Inc.	Residential	0.53%	1.58%
Tillsonburg Hydro Inc.	Residential	-6.70%	1.47%
Centre Wellington Hydro Ltd.	Residential	-1.48%	1.36%
Middlesex Power Distribution Corporation - Newbury	General Service Less Than 50 kW	0.16%	1.31%
Hydro One Brampton Networks Inc.	Residential	-7.41%	1.19%
Wellington North Power Inc.	Residential	0.08%	1.13%
Middlesex Power Distribution Corporation - Newbury	Residential	0.19%	0.67%
Veridian Connections Inc. - Gravenhurst	General Service Less Than 50 kW	-5.61%	0.65%
Westario Power Inc.	General Service Less Than 50 kW	0.10%	0.42%
Hydro One Brampton Networks Inc.	General Service Less Than 50 kW	-12.81%	0.24%
Westario Power Inc.	Residential	0.09%	-0.26%
		1.83%	**3.45%**

2010

Applicant	**Atikokan Hydro Inc.**	**Atikokan Hydro Inc.**	**Bluewater Power Distribution Corporation**	**Bluewater Power Distribution Corporation**	**Brant County Power Inc.**	**Brant County Power Inc.**	**Brantford Power Inc.**	**Brantford Power Inc.**	**Burlington Hydro Inc.**
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	30.53	69.89	13.66	24.48	10.95	16.51	11.34	24.54	12.15
Volumetric Charge	0.0121	0.0089	0.0186	0.0172	0.0216	0.0186	0.0137	0.0064	0.0166
RTSR_Network	0.0054	0.0049	0.006	0.0055	0.0052	0.0048	0.0075	0.0067	0.0061
RTSR_Connection	0.0024	0.0021	0.0053	0.0047	0.0039	0.0034	0.0057	0.0051	0.0054
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0753	1.0753	1.0356	1.0356	1.0495	1.0495	1.042	1.042	1.0405
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	600	750	600	750	600	750	600	750	600
Consumption-Tier2	215	1344	207	1295	210	1312	208	1303	208
DX_Base	$ 40.21	$ 87.69	$ 28.54	$ 58.88	$ 28.23	$ 53.71	$ 22.30	$ 37.34	$ 25.43
Retail TX Service Charges	$ 6.71	$ 15.05	$ 9.36	$ 21.13	$ 7.64	$ 17.21	$ 11.00	$ 24.59	$ 9.57
Commodity Charge	$ 55.13	$ 149.56	$ 54.53	$ 145.84	$ 54.74	$ 147.14	$ 54.63	$ 146.44	$ 54.61
Regulatory charges (WMSR+RRRP)	$ 5.59	$ 13.98	$ 5.39	$ 13.46	$ 5.46	$ 13.64	$ 5.42	$ 13.55	$ 5.41
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	0.12%	0.15%	0.07%	-1.82%	6.13%	-5.05%	0.09%	0.13%	-0.43%
Total bill (11/10)	3.83%	3.99%	2.71%	2.67%	5.65%	3.24%	1.75%	2.30%	2.67%

2011

Applicant	**Atikokan Hydro Inc.**	**Atikokan Hydro Inc.**	**Bluewater Power Distribution Corporation**	**Bluewater Power Distribution Corporation**	**Brant County Power Inc.**	**Brant County Power Inc.**	**Brantford Power Inc.**	**Brantford Power Inc.**	**Burlington Hydro Inc.**
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	30.58	70.02	13.68	24.01	11	17	11.36	24.59	12.12
Volumetric Charge	0.0121	0.0089	0.0186	0.0169	0.0237	0.017	0.0137	0.0064	0.0165
RTSR_Network	0.006	0.0054	0.0062	0.0057	0.0065	0.006	0.0071	0.0064	0.0063
RTSR_Connection	0.0037	0.0032	0.0053	0.0047	0.0043	0.0038	0.005	0.0044	0.0054
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0753	1.0753	1.0356	1.0356	1.0482	1.0482	1.042	1.042	1.0405
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	600	750	600	750	600	750	600	750	600
Consumption-Tier2	215	1344	207	1295	210	1310	208	1303	208
DX_Base	$ 40.26	$ 87.82	$ 28.56	$ 57.81	$ 29.96	$ 51.00	$ 22.32	$ 37.39	$ 25.32
Retail TX Service Charges	$ 8.34	$ 18.50	$ 9.53	$ 21.54	$ 9.06	$ 20.54	$ 10.09	$ 22.51	$ 9.74
Commodity Charge	$ 57.79	$ 157.19	$ 57.16	$ 153.27	$ 57.36	$ 154.51	$ 57.26	$ 153.90	$ 57.24
Regulatory charges (WMSR+RRRP)	$ 5.59	$ 13.98	$ 5.39	$ 13.46	$ 5.45	$ 13.63	$ 5.42	$ 13.55	$ 5.41
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	Burlington Hydro Inc.	Cambridge and North Dumfries Hydro Inc.	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc. - Eastern Ontario Power	Canadian Niagara Power Inc. - Eastern Ontario Power	Canadian Niagara Power Inc. - Fort Erie
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	25.24	9.93	12.33	17.81	21.42	17.81
Volumetric Charge	0.0136	0.0161	0.0131	0.015	0.0231	0.015
RTSR_Network	0.0057	0.0045	0.004	0.0047	0.0044	0.0058
RTSR_Connection	0.0047	0.0032	0.003	0.0039	0.0036	0.0053
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0405	1.0286	1.0286	1.0719	1.0719	1.0391
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600
Consumption-Tier2	1301	206	1286	214	1340	208
DX_Base	$ 52.44	$ 22.81	$ 38.53	$ 29.81	$ 67.62	$ 29.81
Retail TX Service Charges	$ 21.64	$ 6.34	$ 14.40	$ 7.37	$ 17.15	$ 9.23
Commodity Charge	$ 146.30	$ 54.43	$ 145.18	$ 55.08	$ 149.24	$ 54.59
Regulatory charges (WMSR+RRRP)	$ 13.53	$ 5.35	$ 13.37	$ 5.57	$ 13.93	$ 5.40
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	-0.48%	0.09%	-4.59%	0.94%	-2.99%	0.94%
Total bill (11/10)	3.07%	3.57%	3.22%	2.25%	1.64%	3.09%

2011

Applicant	Burlington Hydro Inc.	Cambridge and North Dumfries Hydro Inc.	Cambridge and North Dumfries Hydro Inc.	Canadian Niagara Power Inc. - Eastern Ontario Power	Canadian Niagara Power Inc. - Eastern Ontario Power	Canadian Niagara Power Inc. - Fort Erie
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	25.19	9.95	11.76	18.01	20.8	18.01
Volumetric Charge	0.0135	0.0161	0.0125	0.0151	0.0224	0.0151
RTSR_Network	0.0059	0.0052	0.0046	0.0044	0.0041	0.0062
RTSR_Connection	0.0047	0.0034	0.0032	0.0035	0.0033	0.0053
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0405	1.0286	1.0286	1.0719	1.0719	1.0391
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600
Consumption-Tier2	1301	206	1286	214	1340	208
DX_Base	$ 52.19	$ 22.83	$ 36.76	$ 30.09	$ 65.60	$ 30.09
Retail TX Service Charges	$ 22.06	$ 7.08	$ 16.05	$ 6.77	$ 15.86	$ 9.56
Commodity Charge	$ 153.75	$ 57.05	$ 152.57	$ 57.74	$ 156.85	$ 57.22
Regulatory charges (WMSR+RRRP)	$ 13.53	$ 5.35	$ 13.37	$ 5.57	$ 13.93	$ 5.40
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	Canadian Niagara Power Inc. - Fort Erie	Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	Centre Wellington Hydro Ltd.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chapleau Public Utilities Corporation
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	21.42	15.46	30.69	13.99	15.43	18.46	30.01
Volumetric Charge	0.0231	0.0219	0.0144	0.0129	0.0161	0.0102	0.0122
RTSR_Network	0.0053	0.0052	0.0044	0.0062	0.0057	0.0053	0.0047
RTSR_Connection	0.0046	0.0042	0.0038	0.0048	0.0043	0.0015	0.0014
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0391	1.0382	1.0382	1.0449	1.0449	1.0654	1.0654
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800	2000
Consumption-Tier1	750	600	750	600	750	600	750
Consumption-Tier2	1299	208	1298	209	1306	213	1332
DX_Base	$ 67.62	$ 32.98	$ 59.49	$ 24.31	$ 47.63	$ 26.62	$ 54.41
Retail TX Service Charges	$ 20.57	$ 7.81	$ 17.03	$ 9.20	$ 20.90	$ 5.80	$ 13.00
Commodity Charge	$ 146.17	$ 54.57	$ 146.08	$ 54.67	$ 146.71	$ 54.98	$ 148.63
Regulatory charges (WMSR+RRRP)	$ 13.51	$ 5.40	$ 13.50	$ 5.43	$ 13.58	$ 5.54	$ 13.85
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00
DX_Base (11/10)	-2.99%	0.00%	-0.02%	-1.48%	-1.30%	0.00%	-0.02%
Total bill (11/10)	2.39%	2.93%	3.30%	1.36%	1.96%	3.03%	3.45%

2011

Applicant	Canadian Niagara Power Inc. - Fort Erie	Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	Canadian Niagara Power Inc. - Port Colborne Hydro Inc.	Centre Wellington Hydro Ltd.	Centre Wellington Hydro Ltd.	Chapleau Public Utilities Corporation	Chapleau Public Utilities Corporation
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	20.8	15.46	30.68	13.79	15.21	18.46	30
Volumetric Charge	0.0224	0.0219	0.0144	0.0127	0.0159	0.0102	0.0122
RTSR_Network	0.0057	0.0055	0.0046	0.0054	0.005	0.0057	0.0051
RTSR_Connection	0.0046	0.0045	0.004	0.0045	0.004	0.0015	0.0014
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0391	1.0382	1.0382	1.0449	1.0449	1.0654	1.0654
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800	2000
Consumption-Tier1	750	600	750	600	750	600	750
Consumption-Tier2	1299	208	1298	209	1306	213	1332
DX_Base	$ 65.60	$ 32.98	$ 59.48	$ 23.95	$ 47.01	$ 26.62	$ 54.40
Retail TX Service Charges	$ 21.41	$ 8.31	$ 17.86	$ 8.28	$ 18.81	$ 6.14	$ 13.85
Commodity Charge	$ 153.61	$ 57.20	$ 153.52	$ 57.31	$ 154.18	$ 57.63	$ 156.21
Regulatory charges (WMSR+RRRP)	$ 13.51	$ 5.40	$ 13.50	$ 5.43	$ 13.58	$ 5.54	$ 13.85
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00

2010

Applicant	Chatham-Kent Hydro Inc.	Chatham-Kent Hydro Inc.	COLLUS Power Corporation	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	E.L.K. Energy Inc.	Enersource Hydro Mississauga Inc.
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	18.03	33.1	9.4	17.86	13.49	20.02	11.17	11.1	11.75
Volumetric Charge	0.0084	0.0112	0.0178	0.0112	0.0126	0.0166	0.0079	0.0017	0.0118
RTSR_Network	0.0053	0.0047	0.0054	0.005	0.0051	0.0047	0.0061	0.0055	0.0069
RTSR_Connection	0.0045	0.004	0.0033	0.0028	0.0046	0.0041	0.0046	0.0042	0.0057
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0428	1.0428	1.075	1.075	1.0579	1.0579	1.0791	1.0791	1.036
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	600	750	600	750	600	750	600	750	600
Consumption-Tier2	209	1304	215	1344	212	1322	216	1349	207
DX_Base	$ 24.75	$ 55.50	$ 23.64	$ 40.26	$ 23.57	$ 53.22	$ 17.49	$ 14.50	$ 21.19
Retail TX Service Charges	$ 8.18	$ 18.14	$ 7.48	$ 16.77	$ 8.21	$ 18.62	$ 9.24	$ 20.93	$ 10.44
Commodity Charge	$ 54.64	$ 146.51	$ 55.13	$ 149.53	$ 54.87	$ 147.93	$ 55.19	$ 149.92	$ 54.54
Regulatory charges (WMSR+RRRP)	$ 5.42	$ 13.56	$ 5.59	$ 13.98	$ 5.50	$ 13.75	$ 5.61	$ 14.03	$ 5.39
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	0.28%	0.23%	-4.99%	0.00%	0.08%	0.08%	-0.23%	-0.28%	0.09%
Total bill (11/10)	3.07%	3.40%	1.78%	3.52%	3.67%	4.00%	2.35%	3.06%	2.21%

2011

Applicant	Chatham-Kent Hydro Inc.	Chatham-Kent Hydro Inc.	COLLUS Power Corporation	COLLUS Power Corporation	Cooperative Hydro Embrun Inc.	Cooperative Hydro Embrun Inc.	E.L.K. Energy Inc.	E.L.K. Energy Inc.	Enersource Hydro Mississauga Inc.
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	18.1	33.23	8.94	17.86	13.51	20.06	11.13	11.06	11.77
Volumetric Charge	0.0084	0.0112	0.0169	0.0112	0.0126	0.0166	0.0079	0.0017	0.0118
RTSR_Network	0.0057	0.0051	0.0056	0.0052	0.006	0.0056	0.0057	0.0051	0.0066
RTSR_Connection	0.0045	0.004	0.0034	0.0029	0.0048	0.0043	0.0045	0.0041	0.0054
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0428	1.0428	1.075	1.075	1.0579	1.0579	1.0791	1.0791	1.036
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	600	750	600	750	600	750	600	750	600
Consumption-Tier2	209	1304	215	1344	212	1322	216	1349	207
DX_Base	$ 24.82	$ 55.63	$ 22.46	$ 40.26	$ 23.59	$ 53.26	$ 17.45	$ 14.46	$ 21.21
Retail TX Service Charges	$ 8.51	$ 18.98	$ 7.74	$ 17.42	$ 9.14	$ 20.95	$ 8.81	$ 19.86	$ 9.95
Commodity Charge	$ 57.28	$ 153.98	$ 57.79	$ 157.16	$ 57.51	$ 155.47	$ 57.85	$ 157.56	$ 57.17
Regulatory charges (WMSR+RRRP)	$ 5.42	$ 13.56	$ 5.59	$ 13.98	$ 5.50	$ 13.75	$ 5.61	$ 14.03	$ 5.39
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	**Enersource Hydro Mississauga Inc.**	**ENWIN Utilities Ltd.**	**ENWIN Utilities Ltd.**	**Erie Thames Powerlines Corporation**	**Erie Thames Powerlines Corporation**	**Espanola Regional Hydro Distribution Corporation**	**Espanola Regional Hydro Distribution Corporation**	**Essex Powerlines Corporation**
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	39.51	10.7	25.17	14.19	18.94	9.94	17.92	12.55
Volumetric Charge	0.0115	0.0199	0.0162	0.0126	0.009	0.012	0.0147	0.0148
RTSR_Network	0.0064	0.0066	0.006	0.0049	0.0045	0.0053	0.0049	0.0058
RTSR_Connection	0.0053	0.0043	0.004	0.0053	0.0048	0.0039	0.0035	0.0051
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.036	1.0377	1.0377	1.0427	1.0427	1.0543	1.0543	1.0602
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1295	208	1297	209	1303	211	1318	212
DX_Base	$ 62.51	$ 26.62	$ 57.57	$ 24.27	$ 36.94	$ 19.54	$ 47.32	$ 24.39
Retail TX Service Charges	$ 24.24	$ 9.05	$ 20.75	$ 8.51	$ 19.39	$ 7.76	$ 17.71	$ 9.24
Commodity Charge	$ 145.88	$ 54.57	$ 146.03	$ 54.64	$ 146.50	$ 54.81	$ 147.59	$ 54.90
Regulatory charges (WMSR+RRRP)	$ 13.47	$ 5.40	$ 13.49	$ 5.42	$ 13.56	$ 5.48	$ 13.71	$ 5.51
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	0.11%	0.30%	0.09%	0.00%	0.00%	0.10%	0.06%	0.08%
Total bill (11/10)	2.40%	2.83%	3.14%	6.30%	6.85%	3.48%	3.75%	3.10%

2011

Applicant	**Enersource Hydro Mississauga Inc.**	**ENWIN Utilities Ltd.**	**ENWIN Utilities Ltd.**	**Erie Thames Powerlines Corporation**	**Erie Thames Powerlines Corporation**	**Espanola Regional Hydro Distribution Corporation**	**Espanola Regional Hydro Distribution Corporation**	**Essex Powerlines Corporation**
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	39.58	10.7	25.22	14.19	18.94	9.96	17.95	12.57
Volumetric Charge	0.0115	0.02	0.0162	0.0126	0.009	0.012	0.0147	0.0148
RTSR_Network	0.0061	0.0067	0.0061	0.0088	0.0081	0.0058	0.0054	0.0065
RTSR_Connection	0.005	0.0044	0.0041	0.0057	0.0052	0.0041	0.0037	0.0049
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.036	1.0377	1.0377	1.0427	1.0427	1.0543	1.0543	1.0602
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1295	208	1297	209	1303	211	1318	212
DX_Base	$ 62.58	$ 26.70	$ 57.62	$ 24.27	$ 36.94	$ 19.56	$ 47.35	$ 24.41
Retail TX Service Charges	$ 23.00	$ 9.21	$ 21.17	$ 12.10	$ 27.74	$ 8.35	$ 19.19	$ 9.67
Commodity Charge	$ 153.31	$ 57.20	$ 153.47	$ 57.27	$ 153.97	$ 57.46	$ 155.11	$ 57.55
Regulatory charges (WMSR+RRRP)	$ 13.47	$ 5.40	$ 13.49	$ 5.42	$ 13.56	$ 5.48	$ 13.71	$ 5.51
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	Essex Powerlines Corporation	Festival Hydro Inc.	Festival Hydro Inc.	Festival Hydro Inc. - Hensall	Fort Frances Power Corporation	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Greater Sudbury Hydro Inc.	Grimsby Power Inc.	Grimsby Power Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	20.59	14.75	29.05	11.21	11.85	28.55	16	21.72	15.17	25.66
Volumetric Charge	0.007	0.0163	0.0145	0.012	0.0087	0.0065	0.0123	0.0187	0.0086	0.01
RTSR_Network	0.0051	0.0057	0.005	0.0057	0.005	0.0046	0.0051	0.0037	0.0064	0.0058
RTSR_Connection	0.0048	0.0046	0.0041	0.0046	0.0016	0.0014	0.0038	0.0027	0.0055	0.0049
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0602	1.0307	1.0307	1.0307	1.0406	1.0406	1.0527	1.0527	1.0502	1.0502
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	800	2000	800	2000	800	2000
Consumption-Tier1	750	600	750	600	600	750	600	750	600	750
Consumption-Tier2	1325	206	1288	206	208	1301	211	1316	210	1313
DX_Base	$ 34.59	$ 27.79	$ 58.05	$ 20.81	$ 18.81	$ 41.55	$ 25.84	$ 59.12	$ 22.05	$ 45.66
Retail TX Service Charges	$ 20.99	$ 8.49	$ 18.76	$ 8.49	$ 5.49	$ 12.49	$ 7.50	$ 13.47	$ 10.00	$ 22.47
Commodity Charge	$ 148.14	$ 54.46	$ 145.38	$ 54.46	$ 54.61	$ 146.31	$ 54.79	$ 147.44	$ 54.75	$ 147.21
Regulatory charges (WMSR+RRRP)	$ 13.78	$ 5.36	$ 13.40	$ 5.36	$ 5.41	$ 13.53	$ 5.47	$ 13.69	$ 5.46	$ 13.65
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00
DX_Base (11/10)	25.73%	0.40%	-0.31%	11.53%	0.21%	0.22%	0.00%	-1.62%	-0.27%	-0.22%
Total bill (11/10)	7.56%	2.84%	2.97%	5.46%	4.07%	4.31%	2.74%	2.73%	1.69%	2.18%

2011

Applicant	Essex Powerlines Corporation	Festival Hydro Inc.	Festival Hydro Inc.	Festival Hydro Inc. - Hensall	Fort Frances Power Corporation	Fort Frances Power Corporation	Greater Sudbury Hydro Inc.	Greater Sudbury Hydro Inc.	Grimsby Power Inc.	Grimsby Power Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	25.89	14.78	28.87	12.49	11.89	28.64	16	21.36	15.11	25.56
Volumetric Charge	0.0088	0.0164	0.0145	0.0134	0.0087	0.0065	0.0123	0.0184	0.0086	0.01
RTSR_Network	0.0057	0.0058	0.005	0.0058	0.0061	0.0056	0.0054	0.0039	0.0059	0.0054
RTSR_Connection	0.0047	0.0047	0.0042	0.0047	0.0017	0.0015	0.0036	0.0026	0.0049	0.0043
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0602	1.0307	1.0307	1.0307	1.0406	1.0406	1.0527	1.0527	1.0502	1.0502
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	800	2000	800	2000	800	2000
Consumption-Tier1	750	600	750	600	600	750	600	750	600	750
Consumption-Tier2	1325	206	1288	206	208	1301	211	1316	210	1313
DX_Base	$ 43.49	$ 27.90	$ 57.87	$ 23.21	$ 18.85	$ 41.64	$ 25.84	$ 58.16	$ 21.99	$ 45.56
Retail TX Service Charges	$ 22.05	$ 8.66	$ 18.96	$ 8.66	$ 6.49	$ 14.78	$ 7.58	$ 13.69	$ 9.07	$ 20.37
Commodity Charge	$ 155.69	$ 57.09	$ 152.78	$ 57.09	$ 57.24	$ 153.76	$ 57.43	$ 154.95	$ 57.39	$ 154.71
Regulatory charges (WMSR+RRRP)	$ 13.78	$ 5.36	$ 13.40	$ 5.36	$ 5.41	$ 13.53	$ 5.47	$ 13.69	$ 5.46	$ 13.65
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00

2010

Applicant	Guelph Hydro Electric Systems Inc.	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Hearst Power Distribution Company Limited
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	13.39	12.24	12.23	28.6	12.92	28.23	9	19.5
Volumetric Charge	0.0164	0.0156	0.0334	0.0202	0.0121	0.0089	0.0156	0.0066
RTSR_Network	0.0059	0.0054	0.0052	0.0047	0.0049	0.0044	0.0052	0.0047
RTSR_Connection	0.0052	0.0046	0.0046	0.0042	0.004	0.0037	0.0044	0.004
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0404	1.0404	1.068	1.068	1.0499	1.0499	1.046	1.046
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000
Consumption-Tier1	600	750	600	750	600	750	600	750
Consumption-Tier2	208	1301	214	1335	210	1312	209	1308
DX_Base	$ 26.51	$ 43.44	$ 38.95	$ 69.00	$ 22.60	$ 46.03	$ 21.48	$ 32.70
Retail TX Service Charges	$ 9.24	$ 20.81	$ 8.37	$ 19.01	$ 7.48	$ 17.01	$ 8.03	$ 18.20
Commodity Charge	$ 54.61	$ 146.29	$ 55.02	$ 148.88	$ 54.75	$ 147.18	$ 54.69	$ 146.81
Regulatory charges (WMSR+RRRP)	$ 5.41	$ 13.53	$ 5.55	$ 13.88	$ 5.46	$ 13.65	$ 5.44	$ 13.60
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00
DX_Base (11/10)	0.08%	0.05%	0.08%	0.07%	0.09%	0.11%	0.00%	0.00%
Total bill (11/10)	2.86%	3.40%	3.56%	4.09%	3.55%	3.88%	2.76%	3.32%

2011

Applicant	Guelph Hydro Electric Systems Inc.	Guelph Hydro Electric Systems Inc.	Haldimand County Hydro Inc.	Haldimand County Hydro Inc.	Halton Hills Hydro Inc.	Halton Hills Hydro Inc.	Hearst Power Distribution Company Limited	Hearst Power Distribution Company Limited
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	13.41	12.26	14.1	28.65	12.94	28.28	9	19.5
Volumetric Charge	0.0164	0.0156	0.0311	0.0202	0.0121	0.0089	0.0156	0.0066
RTSR_Network	0.0062	0.0057	0.0063	0.0057	0.0055	0.0049	0.0052	0.0047
RTSR_Connection	0.0052	0.0046	0.0051	0.0047	0.0043	0.004	0.0044	0.004
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0404	1.0404	1.068	1.068	1.0499	1.0499	1.046	1.046
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000
Consumption-Tier1	600	750	600	750	600	750	600	750
Consumption-Tier2	208	1301	214	1335	210	1312	209	1308
DX_Base	$ 26.53	$ 43.46	$ 38.98	$ 69.05	$ 22.62	$ 46.08	$ 21.48	$ 32.70
Retail TX Service Charges	$ 9.49	$ 21.43	$ 9.74	$ 22.21	$ 8.23	$ 18.69	$ 8.03	$ 18.20
Commodity Charge	$ 57.24	$ 153.74	$ 57.67	$ 156.47	$ 57.39	$ 154.68	$ 57.33	$ 154.29
Regulatory charges (WMSR+RRRP)	$ 5.41	$ 13.53	$ 5.55	$ 13.88	$ 5.46	$ 13.65	$ 5.44	$ 13.60
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00

2010

Applicant	Horizon Utilities Corporation	Horizon Utilities Corporation	Hydro 2000 Inc.	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro One Networks Inc.
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential Urban**	**Residential Medium Density**
Service Charge	12.68	27.45	8.5	24.52	5.87	13.55	10.48	20.15	13.71	18.62
Volumetric Charge	0.0127	0.0073	0.006	0.0081	0.0079	0.0054	0.0154	0.0178	0.0276	0.0313
RTSR_Network	0.0059	0.0052	0.006	0.0055	0.0056	0.0051	0.0061	0.0055	0.00575	0.00585
RTSR_Connection	0.0049	0.0045	0.0047	0.0047	0.0031	0.0028	0.0051	0.0044	0.00456	0.00464
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0421	1.0421	1.066	1.066	1.0446	1.0446	1.0356	1.0356	1.078	1.085
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000	800	800
Consumption-Tier1	600	750	600	750	600	750	600	750	600	600
Consumption-Tier2	208	1303	213	1333	209	1306	207	1295	216	217
DX_Base	$ 22.84	$ 42.05	$ 13.30	$ 40.72	$ 12.19	$ 24.35	$ 22.80	$ 55.75	$ 35.79	$ 43.66
Retail TX Service Charges	$ 9.00	$ 20.22	$ 9.12	$ 21.75	$ 7.27	$ 16.50	$ 9.28	$ 20.50	$ 8.89	$ 9.11
Commodity Charge	$ 54.63	$ 146.45	$ 54.99	$ 148.69	$ 54.67	$ 146.68	$ 54.53	$ 145.84	$ 55.17	$ 55.28
Regulatory charges (WMSR+RRRP)	$ 5.42	$ 13.55	$ 5.54	$ 13.86	$ 5.43	$ 13.58	$ 5.39	$ 13.46	$ 5.61	$ 5.64
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 5.60
DX_Base (11/10)	13.00%	16.43%	0.23%	0.22%	0.16%	0.21%	-7.41%	-12.81%	5.79%	5.95%
Total bill (11/10)	7.39%	7.49%	2.54%	2.76%	3.99%	4.17%	1.19%	0.24%	4.26%	4.40%

2011

Applicant	Horizon Utilities Corporation	Horizon Utilities Corporation	Hydro 2000 Inc.	Hydro 2000 Inc.	Hydro Hawkesbury Inc.	Hydro Hawkesbury Inc.	Hydro One Brampton Networks Inc.	Hydro One Brampton Networks Inc.	Hydro One Networks Inc.	Hydro One Networks Inc.
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential Urban**	**Residential Medium Density**
Service Charge	14.45	32.16	8.53	24.61	5.89	13.6	9.75	17.61	14.52	19.72
Volumetric Charge	0.0142	0.0084	0.006	0.0081	0.0079	0.0054	0.0142	0.0155	0.02918	0.03317
RTSR_Network	0.0071	0.0062	0.0057	0.0052	0.0063	0.0057	0.0065	0.0058	0.00575	0.00585
RTSR_Connection	0.0057	0.0052	0.0045	0.0045	0.0033	0.0029	0.005	0.0043	0.00456	0.00464
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0407	1.0407	1.066	1.066	1.0446	1.0446	1.0349	1.0349	1.078	1.085
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000	800	800
Consumption-Tier1	600	750	600	750	600	750	600	750	600	600
Consumption-Tier2	208	1301	213	1333	209	1306	207	1294	216	217
DX_Base	$ 25.81	$ 48.96	$ 13.33	$ 40.81	$ 12.21	$ 24.40	$ 21.11	$ 48.61	$ 37.86	$ 46.26
Retail TX Service Charges	$ 10.66	$ 23.73	$ 8.70	$ 20.68	$ 8.02	$ 17.97	$ 9.52	$ 20.90	$ 8.89	$ 9.11
Commodity Charge	$ 57.24	$ 153.77	$ 57.64	$ 156.27	$ 57.30	$ 154.15	$ 57.15	$ 153.20	$ 57.83	$ 57.94
Regulatory charges (WMSR+RRRP)	$ 5.41	$ 13.53	$ 5.54	$ 13.86	$ 5.43	$ 13.58	$ 5.38	$ 13.45	$ 5.61	$ 5.64
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 5.60

2010

Applicant	**Hydro One Networks Inc.**	**Hydro One Networks Inc.**	**Hydro One Networks Inc.**	**Hydro Ottawa Limited**	**Hydro Ottawa Limited**	**Innisfil Hydro Distribution Systems Limited**	**Innisfil Hydro Distribution Systems Limited**	**Kenora Hydro Electric Corporation Ltd.**	**Kenora Hydro Electric Corporation Ltd.**
Service_Territory	**Residential Low Density**	**GSe**	**UGe**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	24.09	33.19	13.3	8.52	14.73	19.02	30.88	13.53	25.77
Volumetric Charge	0.034	0.0372	0.022	0.0207	0.0185	0.0186	0.0092	0.0099	0.004
RTSR_Network	0.00574	0.00431	0.00445	0.0065	0.0059	0.0055	0.005	0.0059	0.0052
RTSR_Connection	0.0044	0.00329	0.00335	0.0044	0.0041	0.0047	0.0043	0.0016	0.0014
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.092	1.092	1.092	1.0344	1.0344	1.0746	1.0746	1.043	1.043
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	800	2000	2000	800	2000	800	2000	800	2000
Consumption-Tier1	600	750	750	600	750	600	750	600	750
Consumption-Tier2	218	1365	1365	207	1293	215	1343	209	1304
DX_Base	$ 51.29	$ 107.59	$ 57.30	$ 25.08	$ 51.73	$ 33.90	$ 49.28	$ 21.45	$ 33.77
Retail TX Service Charges	$ 8.86	$ 16.60	$ 17.04	$ 9.02	$ 20.69	$ 8.77	$ 19.99	$ 6.26	$ 13.77
Commodity Charge	$ 55.38	$ 151.13	$ 151.13	$ 54.52	$ 145.73	$ 55.12	$ 149.49	$ 54.65	$ 146.53
Regulatory charges (WMSR+RRRP)	$ 5.68	$ 14.20	$ 14.20	$ 5.38	$ 13.45	$ 5.59	$ 13.97	$ 5.42	$ 13.56
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00
DX_Base (11/10)	9.16%	6.19%	5.72%	0.08%	0.06%	0.09%	-7.47%	38.60%	42.91%
Total bill (11/10)	5.80%	4.73%	4.33%	2.57%	2.95%	3.09%	2.21%	11.66%	9.90%

2011

Applicant	**Hydro One Networks Inc.**	**Hydro One Networks Inc.**	**Hydro One Networks Inc.**	**Hydro Ottawa Limited**	**Hydro Ottawa Limited**	**Innisfil Hydro Distribution Systems Limited**	**Innisfil Hydro Distribution Systems Limited**	**Kenora Hydro Electric Corporation Ltd.**	**Kenora Hydro Electric Corporation Ltd.**
Service_Territory	**Residential Low Density**	**GSe**	**UGe**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	27.19	35.49	14.08	8.54	14.76	19.05	28.6	18.77	36.86
Volumetric Charge	0.036	0.03938	0.02325	0.0207	0.0185	0.0186	0.0085	0.0137	0.0057
RTSR_Network	0.00574	0.00431	0.00445	0.0066	0.006	0.0061	0.0055	0.0059	0.0052
RTSR_Connection	0.0044	0.00329	0.00335	0.0042	0.0039	0.0049	0.0045	0.0016	0.0014
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.092	1.092	1.092	1.0344	1.0344	1.0746	1.0746	1.043	1.043
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	800	2000	2000	800	2000	800	2000	800	2000
Consumption-Tier1	600	750	750	600	750	600	750	600	750
Consumption-Tier2	218	1365	1365	207	1293	215	1343	209	1304
DX_Base	$ 55.99	$ 114.25	$ 60.58	$ 25.10	$ 51.76	$ 33.93	$ 45.60	$ 29.73	$ 48.26
Retail TX Service Charges	$ 8.86	$ 16.60	$ 17.04	$ 8.94	$ 20.48	$ 9.46	$ 21.49	$ 6.26	$ 13.77
Commodity Charge	$ 58.05	$ 158.84	$ 158.84	$ 57.14	$ 153.15	$ 57.78	$ 157.12	$ 57.28	$ 154.00
Regulatory charges (WMSR+RRRP)	$ 5.68	$ 14.20	$ 14.20	$ 5.38	$ 13.45	$ 5.59	$ 13.97	$ 5.42	$ 13.56
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00

2010

Applicant	Kingston Hydro Corporation	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	Lakeland Power Distribution Ltd.	London Hydro Inc.
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	10.12	23.39	9.55	25.17	9.25	23.14	15.19	36.26	12.59
Volumetric Charge	0.0124	0.0097	0.0169	0.0122	0.0133	0.0085	0.0137	0.0083	0.0142
RTSR_Network	0.0055	0.005	0.0048	0.0042	0.0052	0.0047	0.0051	0.0047	0.0061
RTSR_Connection	0.0046	0.0042	0.0015	0.0014	0.0042	0.0038	0.0041	0.0038	0.0051
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0375	1.0375	1.032	1.032	1.0541	1.0541	1.0585	1.0585	1.0409
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	600	750	600	750	600	750	600	750	600
Consumption-Tier2	208	1297	206	1290	211	1318	212	1323	208
DX_Base	$ 20.04	$ 42.79	$ 23.07	$ 49.57	$ 19.89	$ 40.14	$ 26.15	$ 52.86	$ 23.95
Retail TX Service Charges	$ 8.38	$ 19.09	$ 5.20	$ 11.56	$ 7.93	$ 17.92	$ 7.79	$ 17.99	$ 9.33
Commodity Charge	$ 54.56	$ 146.02	$ 54.48	$ 145.50	$ 54.81	$ 147.57	$ 54.88	$ 147.98	$ 54.61
Regulatory charges (WMSR+RRRP)	$ 5.40	$ 13.49	$ 5.37	$ 13.42	$ 5.48	$ 13.70	$ 5.50	$ 13.76	$ 5.41
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	19.26%	6.17%	0.52%	0.20%	0.60%	-4.33%	0.11%	0.13%	0.08%
Total bill (11/10)	7.32%	4.63%	3.19%	3.38%	3.21%	2.75%	2.42%	2.83%	2.68%

2011

Applicant	Kingston Hydro Corporation	Kingston Hydro Corporation	Kitchener-Wilmot Hydro Inc.	Kitchener-Wilmot Hydro Inc.	Lakefront Utilities Inc.	Lakefront Utilities Inc.	Lakeland Power Distribution Ltd.	Lakeland Power Distribution Ltd.	London Hydro Inc.
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	12.06	24.83	9.59	25.27	9.29	22.2	15.22	36.33	12.61
Volumetric Charge	0.0148	0.0103	0.017	0.0122	0.0134	0.0081	0.0137	0.0083	0.0142
RTSR_Network	0.0057	0.0052	0.0053	0.0046	0.0054	0.0049	0.005	0.0046	0.0062
RTSR_Connection	0.005	0.0046	0.0013	0.0012	0.0043	0.0039	0.0039	0.0036	0.005
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0344	1.0344	1.032	1.032	1.0541	1.0541	1.0585	1.0585	1.0409
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	600	750	600	750	600	750	600	750	600
Consumption-Tier2	207	1293	206	1290	211	1318	212	1323	208
DX_Base	$ 23.90	$ 45.43	$ 23.19	$ 49.67	$ 20.01	$ 38.40	$ 26.18	$ 52.93	$ 23.97
Retail TX Service Charges	$ 8.85	$ 20.27	$ 5.45	$ 11.97	$ 8.18	$ 18.55	$ 7.54	$ 17.36	$ 9.33
Commodity Charge	$ 57.14	$ 153.15	$ 57.11	$ 152.91	$ 57.45	$ 155.09	$ 57.52	$ 155.53	$ 57.25
Regulatory charges (WMSR+RRRP)	$ 5.38	$ 13.45	$ 5.37	$ 13.42	$ 5.48	$ 13.70	$ 5.50	$ 13.76	$ 5.41
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	**London Hydro Inc.**	**Middlesex Power Distribution Corporation**	**Middlesex Power Distribution Corporation**	**Middlesex Power Distribution Corporation - Dutton**	**Middlesex Power Distribution Corporation - Dutton**	**Middlesex Power Distribution Corporation - Newbury**
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	29.27	13.73	18.14	12.78	26.11	11.9
Volumetric Charge	0.0091	0.0139	0.0048	0.0121	0.0058	0.012
RTSR_Network	0.0057	0.0058	0.0053	0.0057	0.0052	0.006
RTSR_Connection	0.0045	0.0047	0.0042	0.005	0.0045	0.0054
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0409	1.0608	1.0608	1.0662	1.0662	1.058
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600
Consumption-Tier2	1301	212	1326	213	1333	212
DX_Base	$ 47.47	$ 24.85	$ 27.74	$ 22.46	$ 37.71	$ 21.50
Retail TX Service Charges	$ 21.23	$ 8.91	$ 20.16	$ 9.13	$ 20.68	$ 9.65
Commodity Charge	$ 146.33	$ 54.91	$ 148.20	$ 54.99	$ 148.71	$ 54.87
Regulatory charges (WMSR+RRRP)	$ 13.53	$ 5.52	$ 13.79	$ 5.54	$ 13.86	$ 5.50
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	0.11%	0.12%	0.14%	0.18%	0.21%	0.19%
Total bill (11/10)	3.09%	3.53%	4.24%	2.84%	3.35%	0.67%

2011

Applicant	**London Hydro Inc.**	**Middlesex Power Distribution Corporation**	**Middlesex Power Distribution Corporation**	**Middlesex Power Distribution Corporation - Dutton**	**Middlesex Power Distribution Corporation - Dutton**	**Middlesex Power Distribution Corporation - Newbury**
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	29.32	13.76	18.18	12.82	26.19	11.94
Volumetric Charge	0.0091	0.0139	0.0048	0.0121	0.0058	0.012
RTSR_Network	0.0058	0.0064	0.0059	0.006	0.0055	0.0057
RTSR_Connection	0.0044	0.0051	0.0045	0.0048	0.0043	0.0033
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0409	1.0608	1.0608	1.0662	1.0662	1.058
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600
Consumption-Tier2	1301	212	1326	213	1333	212
DX_Base	$ 47.52	$ 24.88	$ 27.78	$ 22.50	$ 37.79	$ 21.54
Retail TX Service Charges	$ 21.23	$ 9.76	$ 22.06	$ 9.21	$ 20.90	$ 7.62
Commodity Charge	$ 153.79	$ 57.56	$ 155.75	$ 57.65	$ 156.29	$ 57.52
Regulatory charges (WMSR+RRRP)	$ 13.53	$ 5.52	$ 13.79	$ 5.54	$ 13.86	$ 5.50
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	Middlesex Power Distribution Corporation - Newbury	Midland Power Utility Corporation	Midland Power Utility Corporation	Milton Hydro Distribution inc.	Milton Hydro Distribution inc.	Newmarket - Tay Power Distribution Ltd.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	21.78	11.66	14.7	13.71	14.7	14.06	25.82	15.96
Volumetric Charge	0.0108	0.0194	0.0154	0.0128	0.0156	0.0136	0.0159	0.0136
RTSR_Network	0.0055	0.0054	0.0049	0.0059	0.0054	0.0054	0.0049	0.0053
RTSR_Connection	0.0047	0.0046	0.0042	0.0047	0.0042	0.0048	0.0043	0.0046
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.058	1.0651	1.0651	1.0351	1.0351	1.0365	1.0365	1.0572
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1323	213	1331	207	1294	207	1296	211
DX_Base	$ 43.38	$ 27.18	$ 45.50	$ 23.95	$ 45.90	$ 24.94	$ 57.62	$ 26.84
Retail TX Service Charges	$ 21.58	$ 8.52	$ 19.38	$ 8.78	$ 19.87	$ 8.46	$ 19.07	$ 8.37
Commodity Charge	$ 147.94	$ 54.98	$ 148.60	$ 54.53	$ 145.79	$ 54.55	$ 145.92	$ 54.86
Regulatory charges (WMSR+RRRP)	$ 13.75	$ 5.54	$ 13.85	$ 5.38	$ 13.46	$ 5.39	$ 13.47	$ 5.50
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	0.16%	0.07%	0.07%	7.89%	7.60%	4.85%	17.11%	4.99%
Total bill (11/10)	1.31%	2.70%	3.24%	4.20%	4.19%	5.85%	8.74%	4.40%

2011

Applicant	Middlesex Power Distribution Corporation - Newbury	Midland Power Utility Corporation	Midland Power Utility Corporation	Milton Hydro Distribution inc.	Milton Hydro Distribution inc.	Newmarket - Tay Power Distribution Ltd.	Newmarket - Tay Power Distribution Ltd.	Niagara Peninsula Energy Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	21.85	11.68	14.73	14.8	15.79	14.71	29.28	15.62
Volumetric Charge	0.0108	0.0194	0.0154	0.0138	0.0168	0.0143	0.0191	0.0157
RTSR_Network	0.0052	0.0056	0.0051	0.0055	0.005	0.0069	0.0063	0.006
RTSR_Connection	0.0029	0.0045	0.0041	0.0046	0.0041	0.0056	0.0050	0.0045
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.058	1.0651	1.0651	1.0362	1.0362	1.0383	1.0383	1.056
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1323	213	1331	207	1295	208	1298	211
DX_Base	$ 43.45	$ 27.20	$ 45.53	$ 25.84	$ 49.39	$ 26.15	$ 67.48	$ 28.18
Retail TX Service Charges	$ 17.14	$ 8.61	$ 19.60	$ 8.37	$ 18.86	$ 10.38	$ 23.47	$ 8.87
Commodity Charge	$ 155.48	$ 57.63	$ 156.18	$ 57.17	$ 153.32	$ 57.21	$ 153.53	$ 57.48
Regulatory charges (WMSR+RRRP)	$ 13.75	$ 5.54	$ 13.85	$ 5.39	$ 13.47	$ 5.40	$ 13.50	$ 5.49
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Niagara-on-the-Lake Hydro Inc.	Norfolk Power Distribution Inc.	Norfolk Power Distribution Inc.	North Bay Hydro Distribution Limited	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	47.27	18.03	45.27	20.73	49.65	14.16	21.7	17.57
Volumetric Charge	0.01	0.0127	0.0136	0.019	0.0139	0.0127	0.0168	0.0133
RTSR_Network	0.0049	0.0062	0.0057	0.0057	0.0052	0.0053	0.0049	0.0054
RTSR_Connection	0.0041	0.0015	0.0014	0.0052	0.0045	0.0048	0.0043	0.0044
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0572	1.0463	1.0463	1.056	1.056	1.048	1.048	1.0448
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1322	209	1308	211	1320	210	1310	209
DX_Base	$ 67.27	$ 28.19	$ 72.47	$ 35.93	$ 77.45	$ 24.32	$ 55.30	$ 28.21
Retail TX Service Charges	$ 19.03	$ 6.45	$ 14.86	$ 9.21	$ 20.49	$ 8.47	$ 19.28	$ 8.19
Commodity Charge	$ 147.86	$ 54.69	$ 146.84	$ 54.84	$ 147.75	$ 54.72	$ 147.00	$ 54.67
Regulatory charges (WMSR+RRRP)	$ 13.74	$ 5.44	$ 13.60	$ 5.49	$ 13.73	$ 5.45	$ 13.62	$ 5.43
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	-5.50%	0.11%	0.11%	0.11%	0.12%	0.21%	0.51%	0.53%
Total bill (11/10)	1.81%	2.40%	2.65%	2.26%	2.71%	3.91%	4.29%	1.58%

2011

Applicant	Niagara Peninsula Energy Inc.	Niagara-on-the-Lake Hydro Inc.	Niagara-on-the-Lake Hydro Inc.	Norfolk Power Distribution Inc.	Norfolk Power Distribution Inc.	North Bay Hydro Distribution Limited	North Bay Hydro Distribution Limited	Northern Ontario Wires Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	36.77	18.06	45.35	20.77	49.74	14.21	21.78	17.64
Volumetric Charge	0.0134	0.0127	0.0136	0.019	0.0139	0.0127	0.0169	0.0134
RTSR_Network	0.0055	0.0061	0.0056	0.0066	0.006	0.0063	0.0059	0.0057
RTSR_Connection	0.004	0.0013	0.0012	0.0041	0.0036	0.0052	0.0047	0.0027
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.056	1.0463	1.0463	1.056	1.056	1.048	1.048	1.0448
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1320	209	1308	211	1320	210	1310	209
DX_Base	$ 63.57	$ 28.22	$ 72.55	$ 35.97	$ 77.54	$ 24.37	$ 55.58	$ 28.36
Retail TX Service Charges	$ 20.06	$ 6.19	$ 14.23	$ 9.04	$ 20.28	$ 9.64	$ 22.22	$ 7.02
Commodity Charge	$ 155.28	$ 57.33	$ 154.32	$ 57.48	$ 155.28	$ 57.36	$ 154.49	$ 57.31
Regulatory charges (WMSR+RRRP)	$ 13.73	$ 5.44	$ 13.60	$ 5.49	$ 13.73	$ 5.45	$ 13.62	$ 5.43
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Orillia Power Distribution Corporation	Oshawa PUC Networks Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	23.55	13.25	32.54	16.18	32.76	13.47	35.32	8.43
Volumetric Charge	0.0132	0.0145	0.0143	0.014	0.01	0.0162	0.0157	0.0123
RTSR_Network	0.005	0.0055	0.0051	0.0052	0.0048	0.0038	0.0033	0.0061
RTSR_Connection	0.004	0.0046	0.0042	0.003	0.0027	0.0035	0.0032	0.0047
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0448	1.0377	1.0377	1.0468	1.0468	1.0561	1.0561	1.0487
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1306	208	1297	209	1309	211	1320	210
DX_Base	$ 49.95	$ 24.85	$ 61.14	$ 27.38	$ 52.76	$ 26.43	$ 66.72	$ 18.27
Retail TX Service Charges	$ 18.81	$ 8.38	$ 19.30	$ 6.87	$ 15.70	$ 6.17	$ 13.73	$ 9.06
Commodity Charge	$ 146.70	$ 54.57	$ 146.03	$ 54.70	$ 146.89	$ 54.84	$ 147.76	$ 54.73
Regulatory charges (WMSR+RRRP)	$ 13.58	$ 5.40	$ 13.49	$ 5.44	$ 13.61	$ 5.49	$ 13.73	$ 5.45
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	0.58%	-1.25%	-1.21%	-0.44%	0.11%	0.08%	0.09%	0.11%
Total bill (11/10)	2.16%	3.18%	3.37%	2.76%	3.36%	3.04%	3.21%	4.11%

2011

Applicant	Northern Ontario Wires Inc.	Oakville Hydro Electricity Distribution Inc.	Oakville Hydro Electricity Distribution Inc.	Orangeville Hydro Limited	Orangeville Hydro Limited	Orillia Power Distribution Corporation	Orillia Power Distribution Corporation	Oshawa PUC Networks Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	23.64	13.1	32.2	16.14	32.82	13.49	35.38	8.45
Volumetric Charge	0.0133	0.0143	0.0141	0.0139	0.01	0.0162	0.0157	0.0123
RTSR_Network	0.0053	0.0065	0.006	0.0054	0.005	0.0043	0.0037	0.0066
RTSR_Connection	0.0025	0.0046	0.0042	0.0031	0.0028	0.0034	0.0031	0.0056
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0448	1.0377	1.0377	1.0468	1.0468	1.0561	1.0561	1.0487
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1306	208	1297	209	1309	211	1320	210
DX_Base	$ 50.24	$ 24.54	$ 60.40	$ 27.26	$ 52.82	$ 26.45	$ 66.78	$ 18.29
Retail TX Service Charges	$ 16.30	$ 9.21	$ 21.17	$ 7.12	$ 16.33	$ 6.51	$ 14.36	$ 10.24
Commodity Charge	$ 154.17	$ 57.20	$ 153.47	$ 57.34	$ 154.37	$ 57.49	$ 155.29	$ 57.37
Regulatory charges (WMSR+RRRP)	$ 13.58	$ 5.40	$ 13.49	$ 5.44	$ 13.61	$ 5.49	$ 13.73	$ 5.45
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	**Oshawa PUC Networks Inc.**	**Ottawa River Power Corporation**	**Ottawa River Power Corporation**	**Parry Sound Power Corporation**	**Parry Sound Power Corporation**	**Peterborough Distribution Incorporated**	**Peterborough Distribution Incorporated**	**PowerStream Inc. - Barrie**
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	8.37	10.95	22.41	16.79	25.29	11.79	29.59	15.34
Volumetric Charge	0.0172	0.0149	0.0103	0.0134	0.0104	0.0115	0.0089	0.0137
RTSR_Network	0.0055	0.0048	0.0044	0.0054	0.0049	0.0065	0.0059	0.0061
RTSR_Connection	0.0043	0.0023	0.0021	0.0047	0.0043	0.0035	0.0032	0.0053
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0487	1.039	1.039	1.0586	1.0586	1.0487	1.0487	1.0565
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1311	208	1299	212	1323	210	1311	211
DX_Base	$ 42.77	$ 22.87	$ 43.01	$ 27.51	$ 46.09	$ 20.99	$ 47.39	$ 26.30
Retail TX Service Charges	$ 20.55	$ 5.90	$ 13.51	$ 8.55	$ 19.48	$ 8.39	$ 19.09	$ 9.64
Commodity Charge	$ 147.07	$ 54.59	$ 146.16	$ 54.88	$ 147.99	$ 54.73	$ 147.07	$ 54.85
Regulatory charges (WMSR+RRRP)	$ 13.63	$ 5.40	$ 13.51	$ 5.50	$ 13.76	$ 5.45	$ 13.63	$ 5.49
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	0.05%	0.00%	0.00%	28.35%	27.12%	0.10%	0.11%	-0.80%
Total bill (11/10)	4.30%	2.78%	3.23%	10.85%	9.50%	3.31%	3.56%	2.88%

2011

Applicant	**Oshawa PUC Networks Inc.**	**Ottawa River Power Corporation**	**Ottawa River Power Corporation**	**Parry Sound Power Corporation**	**Parry Sound Power Corporation**	**Peterborough Distribution Incorporated**	**Peterborough Distribution Incorporated**	**PowerStream Inc. - Barrie**
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**
Service Charge	8.39	10.95	22.41	21.55	32.19	11.81	29.64	15.21
Volumetric Charge	0.0172	0.0149	0.0103	0.0172	0.0132	0.0115	0.0089	0.0136
RTSR_Network	0.006	0.0048	0.0044	0.0054	0.0049	0.0062	0.0056	0.0065
RTSR_Connection	0.0051	0.0023	0.0021	0.0047	0.0043	0.0044	0.004	0.0055
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0487	1.039	1.039	1.0809	1.0809	1.0487	1.0487	1.0565
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800
Consumption-Tier1	750	600	750	600	750	600	750	600
Consumption-Tier2	1311	208	1299	216	1351	210	1311	211
DX_Base	$ 42.79	$ 22.87	$ 43.01	$ 35.31	$ 58.59	$ 21.01	$ 47.44	$ 26.09
Retail TX Service Charges	$ 23.28	$ 5.90	$ 13.51	$ 8.73	$ 19.89	$ 8.89	$ 20.14	$ 10.14
Commodity Charge	$ 154.56	$ 57.22	$ 153.60	$ 57.88	$ 157.74	$ 57.37	$ 154.56	$ 57.49
Regulatory charges (WMSR+RRRP)	$ 13.63	$ 5.40	$ 13.51	$ 5.62	$ 14.05	$ 5.45	$ 13.63	$ 5.49
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	**PowerStream Inc. - Barrie**	**PowerStream Inc. - South**	**PowerStream Inc. - South**	**PUC Distribution Inc.**	**PUC Distribution Inc.**	**Renfrew Hydro Inc.**	**Renfrew Hydro Inc.**	**Rideau St. Lawrence Distribution Inc.**	**Rideau St. Lawrence Distribution Inc.**
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	15.94	11.87	28.34	8.71	14.84	14.49	29.96	10.26	24.3
Volumetric Charge	0.0163	0.0134	0.0115	0.0151	0.0178	0.0149	0.0132	0.0117	0.0074
RTSR_Network	0.0057	0.0059	0.0053	0.0055	0.005	0.0048	0.0044	0.0061	0.0055
RTSR_Connection	0.0047	0.0025	0.0023	0	0	0.0028	0.0026	0.0049	0.0045
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0565	1.0299	1.0299	1.0454	1.0454	1.081	1.081	1.0764	1.0764
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800	2000
Consumption-Tier1	750	600	750	600	750	600	750	600	750
Consumption-Tier2	1321	206	1287	209	1307	216	1351	215	1346
DX_Base	$ 48.54	$ 22.59	$ 51.34	$ 20.79	$ 50.44	$ 26.41	$ 56.36	$ 19.62	$ 39.10
Retail TX Service Charges	$ 21.98	$ 6.92	$ 15.65	$ 4.60	$ 10.45	$ 6.57	$ 15.13	$ 9.47	$ 21.53
Commodity Charge	$ 147.80	$ 54.45	$ 145.30	$ 54.68	$ 146.76	$ 55.22	$ 150.09	$ 55.15	$ 149.66
Regulatory charges (WMSR+RRRP)	$ 13.73	$ 5.36	$ 13.39	$ 5.44	$ 13.59	$ 5.62	$ 14.05	$ 5.60	$ 13.99
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00
DX_Base (11/10)	0.06%	0.09%	0.10%	0.10%	0.06%	-2.35%	0.55%	0.10%	0.10%
Total bill (11/10)	3.50%	3.30%	3.53%	3.46%	3.72%	2.40%	3.53%	1.90%	2.49%

2011

Applicant	**PowerStream Inc. - Barrie**	**PowerStream Inc. - South**	**PowerStream Inc. - South**	**PUC Distribution Inc.**	**PUC Distribution Inc.**	**Renfrew Hydro Inc.**	**Renfrew Hydro Inc.**	**Rideau St. Lawrence Distribution Inc.**	**Rideau St. Lawrence Distribution Inc.**
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	15.97	11.89	28.39	8.73	14.87	14.11	30.07	10.28	24.34
Volumetric Charge	0.0163	0.0134	0.0115	0.0151	0.0178	0.0146	0.0133	0.0117	0.0074
RTSR_Network	0.006	0.0064	0.0058	0.0061	0.0056	0.0051	0.0047	0.0056	0.0051
RTSR_Connection	0.0049	0.0026	0.0023	0	0	0.0029	0.0027	0.0044	0.0041
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0565	1.0299	1.0299	1.0454	1.0454	1.081	1.081	1.0764	1.0764
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800	2000
Consumption-Tier1	750	600	750	600	750	600	750	600	750
Consumption-Tier2	1321	206	1287	209	1307	216	1351	215	1346
DX_Base	$ 48.57	$ 22.61	$ 51.39	$ 20.81	$ 50.47	$ 25.79	$ 56.67	$ 19.64	$ 39.14
Retail TX Service Charges	$ 23.03	$ 7.42	$ 16.68	$ 5.10	$ 11.71	$ 6.92	$ 16.00	$ 8.61	$ 19.81
Commodity Charge	$ 155.33	$ 57.07	$ 152.70	$ 57.32	$ 154.23	$ 57.88	$ 157.75	$ 57.81	$ 157.29
Regulatory charges (WMSR+RRRP)	$ 13.73	$ 5.36	$ 13.39	$ 5.44	$ 13.59	$ 5.62	$ 14.05	$ 5.60	$ 13.99
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00

2010

Applicant	Sioux Lookout Hydro Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Tillsonburg Hydro Inc.
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	24.01	42.65	10.93	15.5	10.17	17.86	10.53	24.81
Volumetric Charge	0.0103	0.0081	0.0156	0.0142	0.0128	0.0131	0.018	0.0151
RTSR_Network	0.0054	0.0049	0.006	0.0059	0.0053	0.005	0.0058	0.0053
RTSR_Connection	0.002	0.0018	0.0052	0.0049	0.0039	0.0036	0.0047	0.0043
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0642	1.0642	1.0339	1.0339	1.0448	1.0448	1.042	1.042
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000
Consumption-Tier1	600	750	600	750	600	750	600	750
Consumption-Tier2	213	1330	207	1292	209	1306	208	1303
DX_Base	$ 32.25	$ 58.85	$ 23.41	$ 43.90	$ 20.41	$ 44.06	$ 24.93	$ 55.01
Retail TX Service Charges	$ 6.30	$ 14.26	$ 9.26	$ 22.33	$ 7.69	$ 17.97	$ 8.75	$ 20.01
Commodity Charge	$ 54.96	$ 148.52	$ 54.51	$ 145.68	$ 54.67	$ 146.70	$ 54.63	$ 146.44
Regulatory charges (WMSR+RRRP)	$ 5.53	$ 13.83	$ 5.38	$ 13.44	$ 5.43	$ 13.58	$ 5.42	$ 13.55
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00
DX_Base (11/10)	0.12%	0.14%	3.80%	5.69%	-2.99%	0.07%	-6.70%	0.07%
Total bill (11/10)	1.92%	2.47%	3.61%	4.20%	3.31%	4.32%	1.47%	3.34%

2011

Applicant	Sioux Lookout Hydro Inc.	Sioux Lookout Hydro Inc.	St. Thomas Energy Inc.	St. Thomas Energy Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Thunder Bay Hydro Electricity Distribution Inc.	Tillsonburg Hydro Inc.	Tillsonburg Hydro Inc.
Service_Territory	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	24.05	42.73	11.5	17	9.88	17.89	9.82	24.85
Volumetric Charge	0.0103	0.0081	0.016	0.0147	0.0124	0.0131	0.0168	0.0151
RTSR_Network	0.0054	0.0049	0.006	0.0059	0.0058	0.0055	0.006	0.0054
RTSR_Connection	0.0012	0.0011	0.0052	0.0049	0.0047	0.0044	0.0051	0.0046
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0642	1.0642	1.035	1.035	1.0448	1.0448	1.042	1.042
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	800	2000	800	2000	800	2000	800	2000
Consumption-Tier1	600	750	600	750	600	750	600	750
Consumption-Tier2	213	1330	207	1294	209	1306	208	1303
DX_Base	$ 32.29	$ 58.93	$ 24.30	$ 46.40	$ 19.80	$ 44.09	$ 23.26	$ 55.05
Retail TX Service Charges	$ 5.62	$ 12.77	$ 9.27	$ 22.36	$ 8.78	$ 20.69	$ 9.25	$ 20.84
Commodity Charge	$ 57.61	$ 156.09	$ 57.15	$ 153.21	$ 57.31	$ 154.17	$ 57.26	$ 153.90
Regulatory charges (WMSR+RRRP)	$ 5.53	$ 13.83	$ 5.38	$ 13.46	$ 5.43	$ 13.58	$ 5.42	$ 13.55
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00

2010

Applicant	Toronto Hydro-Electric System Limited	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Veridian Connections Inc.	Veridian Connections Inc. - Gravenhurst	Veridian Connections Inc. - Gravenhurst	Veridian Connections Inc. - Gravenhurst	Wasaga Distribution Inc.
Service_Territory	**Residential Regular**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential Suburban Year-Round**	**Residential Urban Year-Round**	**General Service Less Than 50 kW**	**Residential**
Service Charge	18.25	24.3	11.06	13.69	14.56	9.95	11.49	11.81
Volumetric Charge	0.01572	0.0227	0.0156	0.0169	0.0201	0.0192	0.0195	0.0147
RTSR_Network	0.00663	0.00664	0.0047	0.0043	0.0052	0.0052	0.0048	0.006
RTSR_Connection	0.00535	0.00546	0.0033	0.003	0.0051	0.0051	0.0045	0.0054
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0376	1.0376	1.0442	1.0442	1.1013	1.1013	1.1013	1.0739
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	800	2000	800	2000	800	800	2000	800
Consumption-Tier1	600	750	600	750	600	600	750	600
Consumption-Tier2	208	1297	209	1305	220	220	1377	215
DX_Base	$ 30.83	$ 69.70	$ 23.54	$ 47.49	$ 30.64	$ 25.31	$ 50.49	$ 23.57
Retail TX Service Charges	$ 9.94	$ 25.11	$ 6.68	$ 15.25	$ 9.07	$ 9.07	$ 20.48	$ 9.79
Commodity Charge	$ 54.56	$ 146.03	$ 54.66	$ 146.64	$ 55.52	$ 55.52	$ 152.00	$ 55.11
Regulatory charges (WMSR+RRRP)	$ 5.40	$ 13.49	$ 5.43	$ 13.57	$ 5.73	$ 5.73	$ 14.32	$ 5.58
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 5.60	$ 14.00	$ 5.60
DX_Base (11/10)	-1.35%	-0.66%	0.08%	0.00%	12.60%	0.08%	-5.61%	0.04%
Total bill (11/10)	2.22%	2.08%	3.46%	3.77%	4.72%	1.19%	0.65%	2.93%

2011

Applicant	Toronto Hydro-Electric System Limited	Toronto Hydro-Electric System Limited	Veridian Connections Inc.	Veridian Connections Inc.	Veridian Connections Inc. - Gravenhurst	Veridian Connections Inc. - Gravenhurst	Veridian Connections Inc. - Gravenhurst	Wasaga Distribution Inc.
Service_Territory	**Residential Regular**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential Suburban Year-Round**	**Residential Urban Year-Round**	**General Service Less Than 50 kW**	**Residential**
Service Charge	18.25	24.3	11.08	13.69	16.42	9.97	10.86	11.82
Volumetric Charge	0.0152	0.02247	0.0156	0.0169	0.0226	0.0192	0.0184	0.0147
RTSR_Network	0.00703	0.0068	0.0059	0.0054	0.007	0.007	0.0064	0.0073
RTSR_Connection	0.00513	0.00463	0.0029	0.0026	0.0016	0.0016	0.0014	0.0044
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0376	1.0376	1.0442	1.0442	1.1013	1.1013	1.1013	1.0739
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	800	2000	800	2000	800	800	2000	800
Consumption-Tier1	600	750	600	750	600	600	750	600
Consumption-Tier2	208	1297	209	1305	220	220	1377	215
DX_Base	$ 30.41	$ 69.24	$ 23.56	$ 47.49	$ 34.50	$ 25.33	$ 47.66	$ 23.58
Retail TX Service Charges	$ 10.09	$ 23.72	$ 7.35	$ 16.71	$ 7.58	$ 7.58	$ 17.18	$ 10.05
Commodity Charge	$ 57.19	$ 153.46	$ 57.30	$ 154.11	$ 58.20	$ 58.20	$ 159.75	$ 57.77
Regulatory charges (WMSR+RRRP)	$ 5.40	$ 13.49	$ 5.43	$ 13.57	$ 5.73	$ 5.73	$ 14.32	$ 5.58
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 5.60	$ 14.00	$ 5.60

2010

Applicant	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.	Wellington North Power Inc.	West Coast Huron Energy Inc.	West Coast Huron Energy Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	13.64	14.56	30.63	14.21	24.54	13.86	27.83	14.08	33.44
Volumetric Charge	0.0138	0.0131	0.0104	0.0143	0.0086	0.0139	0.012	0.0182	0.0115
RTSR_Network	0.0055	0.0058	0.0053	0.0072	0.0064	0.005	0.0046	0.0049	0.0045
RTSR_Connection	0.0047	0.002	0.0018	0.0053	0.0047	0.0058	0.0048	0.0048	0.0043
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0739	1.0505	1.0505	1.0532	1.0532	1.0699	1.0699	1.0467	1.0467
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800	2000
Consumption-Tier1	750	600	750	600	750	600	750	600	750
Consumption-Tier2	1342	210	1313	211	1317	214	1337	209	1308
DX_Base	$ 41.24	$ 25.04	$ 51.43	$ 25.65	$ 41.74	$ 24.98	$ 51.83	$ 28.64	$ 56.44
Retail TX Service Charges	$ 21.91	$ 6.56	$ 14.92	$ 10.53	$ 23.38	$ 9.24	$ 20.11	$ 8.12	$ 18.42
Commodity Charge	$ 149.43	$ 54.76	$ 147.23	$ 54.80	$ 147.49	$ 55.05	$ 149.05	$ 54.70	$ 146.88
Regulatory charges (WMSR+RRRP)	$ 13.96	$ 5.46	$ 13.66	$ 5.48	$ 13.69	$ 5.56	$ 13.91	$ 5.44	$ 13.61
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00
DX_Base (11/10)	0.02%	16.93%	12.83%	0.12%	0.10%	0.08%	0.10%	0.00%	-0.02%
Total bill (11/10)	3.44%	7.70%	6.17%	1.87%	2.44%	1.13%	1.87%	2.40%	2.83%

2011

Applicant	Wasaga Distribution Inc.	Waterloo North Hydro Inc.	Waterloo North Hydro Inc.	Welland Hydro-Electric System Corp.	Welland Hydro-Electric System Corp.	Wellington North Power Inc.	Wellington North Power Inc.	West Coast Huron Energy Inc.	West Coast Huron Energy Inc.
Service_Territory	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**	**Residential**	**General Service Less Than 50 kW**
Service Charge	13.65	14.56	30.63	14.24	24.58	13.88	27.88	14.08	33.43
Volumetric Charge	0.0138	0.0184	0.0137	0.0143	0.0086	0.0139	0.012	0.0182	0.0115
RTSR_Network	0.0067	0.0067	0.0061	0.0066	0.0059	0.0053	0.0049	0.005	0.0046
RTSR_Connection	0.0038	0.0022	0.002	0.005	0.0044	0.0037	0.0031	0.0045	0.004
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0739	1.0404	1.0404	1.0532	1.0532	1.0699	1.0699	1.0467	1.0467
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	2000	800	2000	800	2000	800	2000	800	2000
Consumption-Tier1	750	600	750	600	750	600	750	600	750
Consumption-Tier2	1342	208	1301	211	1317	214	1337	209	1308
DX_Base	$ 41.25	$ 29.28	$ 58.03	$ 25.68	$ 41.78	$ 25.00	$ 51.88	$ 28.64	$ 56.43
Retail TX Service Charges	$ 22.55	$ 7.41	$ 16.85	$ 9.77	$ 21.70	$ 7.70	$ 17.12	$ 7.95	$ 18.00
Commodity Charge	$ 157.05	$ 57.24	$ 153.74	$ 57.44	$ 155.00	$ 57.70	$ 156.65	$ 57.34	$ 154.36
Regulatory charges (WMSR+RRRP)	$ 13.96	$ 5.41	$ 13.53	$ 5.48	$ 13.69	$ 5.56	$ 13.91	$ 5.44	$ 13.61
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00

2010

Applicant	Westario Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.	Woodstock Hydro Services Inc.
Service_Territory	Residential	General Service Less Than 50 kW	Residential	General Service Less Than 50 kW	Residential	General Service Less Than 50 kW
Service Charge	11.22	20.55	17.71	19.51	11.1	21.45
Volumetric Charge	0.0141	0.0091	0.0137	0.0181	0.019	0.0123
RTSR_Network	0.0055	0.0051	0.0052	0.0048	0.0061	0.0055
RTSR_Connection	0.0041	0.0037	0.0053	0.0048	0.0047	0.0043
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0788	1.0788	1.0601	1.0601	1.044	1.044
Commodity-Tier1	0.065	0.065	0.065	0.065	0.065	0.065
Commodity-Tier1	0.075	0.075	0.075	0.075	0.075	0.075
Total Monthly Consumption	800	2000	800	2000	800	2000
Consumption-Tier1	600	750	600	750	600	750
Consumption-Tier2	216	1349	212	1325	209	1305
DX_Base	$ 22.50	$ 38.75	$ 28.67	$ 55.71	$ 26.30	$ 46.05
Retail TX Service Charges	$ 8.29	$ 18.99	$ 8.90	$ 20.35	$ 9.02	$ 20.46
Commodity Charge	$ 55.18	$ 149.89	$ 54.90	$ 148.13	$ 54.66	$ 146.63
Regulatory charges (WMSR+RRRP)	$ 5.61	$ 14.02	$ 5.51	$ 13.78	$ 5.43	$ 13.57
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00
DX_Base (11/10)	0.09%	0.10%	-0.52%	5.19%	14.68%	14.61%
Total bill (11/10)	-0.26%	0.42%	3.28%	4.54%	5.73%	5.32%

2011

Applicant	Westario Power Inc.	Westario Power Inc.	Whitby Hydro Electric Corporation	Whitby Hydro Electric Corporation	Woodstock Hydro Services Inc.	Woodstock Hydro Services Inc.
Service_Territory	Residential	General Service Less Than 50 kW	Residential	General Service Less Than 50 kW	Residential	General Service Less Than 50 kW
Service Charge	11.24	20.59	17.24	19.8	12.72	24.58
Volumetric Charge	0.0141	0.0091	0.0141	0.0194	0.0218	0.0141
RTSR_Network	0.0051	0.0047	0.0066	0.006	0.0055	0.005
RTSR_Connection	0.0011	0.001	0.0055	0.005	0.0045	0.0042
WMSR	0.0052	0.0052	0.0052	0.0052	0.0052	0.0052
RRRP	0.0013	0.0013	0.0013	0.0013	0.0013	0.0013
SSSC	0.25	0.25	0.25	0.25	0.25	0.25
DRC	0.007	0.007	0.007	0.007	0.007	0.007
TLF	1.0788	1.0788	1.0454	1.0454	1.0431	1.0431
Commodity-Tier1	0.068	0.068	0.068	0.068	0.068	0.068
Commodity-Tier1	0.079	0.079	0.079	0.079	0.079	0.079
Total Monthly Consumption	800	2000	800	2000	800	2000
Consumption-Tier1	600	750	600	750	600	750
Consumption-Tier2	216	1349	209	1307	209	1304
DX_Base	$ 22.52	$ 38.79	$ 28.52	$ 58.60	$ 30.16	$ 52.78
Retail TX Service Charges	$ 5.35	$ 12.30	$ 10.12	$ 23.00	$ 8.34	$ 19.19
Commodity Charge	$ 57.85	$ 157.53	$ 57.32	$ 154.23	$ 57.28	$ 154.01
Regulatory charges (WMSR+RRRP)	$ 5.61	$ 14.02	$ 5.44	$ 13.59	$ 5.42	$ 13.56
Standard Supply Service Charge	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25	$ 0.25
Debt Retirement Charge	$ 5.60	$ 14.00	$ 5.60	$ 14.00	$ 5.60	$ 14.00

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

Forecast Consumption per Customer

Reference: Attachment 9A

Interrogatory

Remotes has projected annual consumption per year-round residential customer in 2013 at 13,485 kWh, in the existing communities covered in this evidence. The consumption is approximately 925 kWh per year more than the most recent actual data (2011), but slightly lower than the corresponding consumption in 2009.

a) If 2012 actual consumption data are now available, please provide an update of Attachment 9A.

b) Please provide an explanation for the actual consumption observed in 2011, as that year may be an anomaly in the time-series.

c) Even disregarding the results in 2011, it appears that Remotes is projecting a reversal in the trend toward lower consumption per year-round residential customer. Please confirm that this is Remotes' assumption for this customer class, and provide any information that Remotes is relying on in coming to this assumption.

Response

a) The 13,485 kWh average per residential customer quoted for 2013 represents the original forecasted average consumption per residential customer for the previous year. 2012 actual data is available and updated in Exhibit I, Tab 1, Schedule 32, Attachment 1. As a result of rounding differences, 2013 kWh are 110,000kWh higher, or 0.2% of the total consumption. Except to show 2012 actuals, the data remains the same as originally submitted. Based on the 2012 actuals, this actual average kWh per customer in 2012 was 13,374.

b) The average consumption in 2011 was 13,022.9. Average consumption in 2010 was 12,559.6, lower than both the previous and following years. Remotes notes that actual kWh consumption for the class increased annually year over year. Remotes attributes the differences in average consumption per customer to differences in the effective number of customers which is based on the timing of new connections/disconnections and is influenced when a larger number of customers connect close to the end of the year or alternatively disconnect closer to the beginning of the year.

c) Remotes bases its forecast on historical kWh usage and historical customer numbers. This data is adjusted for increases in customer numbers and in usage. Remotes notes that, as shown in the chart below, its forecasted growth in total kWh for the class is less than 1 per cent.

SUMMARY	**2009**	**2010**	**2011**	**2012**	**2013**
	ACTUAL	**ACTUAL**	**ACTUAL**	**ACTUAL**	
	Total	**Total**	**Total**	**Total**	**Total**
Residential - Year Round - Non Std. 'A'					
Number of Customers - Beginning of Period	2440	2562	2578	2604	2585
Customer Additions/Deletions	122	16	26	-5	21
Number of Customers - End of Period	2562.0	2578.0	2604.0	2599.0	2605.2
Effective # of Customers During Period	2501.0	2570.0	2591.0	2601.5	2594.9
Average kWh's/Customer Previous Year	13,538	13,264	12,560	13,023	13,485
kWh's/Customer Increases/Decreases	(274)	(704)	463	351	51
Average kWh's/Customer During Period	13,264	12,560	13,023	13,374	13,536
Total kWh's for Period	33,173,200	32,278,300	33,742,400	34,792,800	35,125,612
% increase inTotal kWh		-2.70%	4.54%	3.11%	0.96%

Attachment 9A
Load Forecast by Month

SUMMARY	2009	2010	2011	2012	2013
	ACTUAL	ACTUAL	ACTUAL	ACTUAL	
	Total	Total	Total	Total	Total
Residential - Year Round - Non Std. 'A'					
Number of Customers - Beginning of Period	2440	2562	2578	2604	2585
Customer Additions/Deletions	122	16	26	-5	21
Number of Customers - End of Period	2562.0	2578.0	2604.0	2599.0	2605.2
Effective # of Customers During Period	2501.0	2570.0	2591.0	2601.5	2594.9
Average kWh's/Customer Previous Year	13537.9	13264.0	12559.6	13022.9	13485.2
kWh's/Customer Increases/Decreases	-273.9	-704.3	463.3	351.2	51.3
Average kWh's/Customer During Period	13264.0	12559.6	13022.9	13374.1	13536.5
Total kWh's for Period	33,173,200.05	32,278,300.00	33,742,400.00	34,792,800.00	35125612
Residential - Seasonal					
Number of Customers - Beginning of Period	139	144	160	161	164
Customer Additions/Deletions	5	16	1	-7	0
Number of Customers - End of Period	144	160	161	154.0	164
Effective # of Customers During Period	141.5	152.0	160.5	157.5	164
Average kWh's/Customer Previous Year	1534.5	1578.1	1927.0	1973.2	2145.7
kWh's/Customer Increases/Decreases	43.6	348.9	46.2	179.2	7.2
Average kWh's/Customer During Period	1578.1	1927.0	1973.2	2152.4	2152.9
Total kWh's for Period	223300	292900	316701	339000	353073
General Service 1-Phase - Non Std. 'A'					
Number of Customers - Beginning of Period	286	281	272	283	279
Customer Additions/Deletions	-5	-9	11	6	1
Number of Customers - End of Period	281	272	283	289.0	280
Effective # of Customers During Period	283.5	276.5	277.5	286.0	279.4
Average kWh's/Customer Previous Year	18998.6	18163.7	18023.9	19538.7	20058.7
kWh's/Customer Increases/Decreases	-834.9	-139.8	1514.9	67.2	153.2
Average kWh's/Customer During Period	18163.7	18023.9	19538.7	19605.9	20211.9
Total kWh's for Period	5149400	4983600	5422001	5607300	5648114
General Service 3-Phase - Non Std. 'A'					
Number of Customers - Beginning of Period	26	26	27	28	27
Customer Additions/Deletions	0	1	1	19	0
Number of Customers - End of Period	26	27	28	47.0	27
Effective # of Customers During Period	26.0	26.5	27.5	37.5	27.0
Average kWh's/Customer Previous Year	135992.2	149650.0	137301.9	129225.5	133280.1
kWh's/Customer Increases/Decreases	13657.8	-12348.1	-8076.4	-21793.5	620.4
Average kWh's/Customer During Period	149650.0	137301.9	129225.5	107432.0	133900.5
Total kWh's for Period	3890900	3638500	3553701	4028700	3615314
Street Lighting					
Number of Customers - Beginning of Period	5	5	6	6	6
Customer Additions/Deletions	0	1	0	0	0
Number of Customers - End of Period	5	6	6	6.0	6
Effective # of Customers During Period	5.0	5.5	6.0	6.0	6.0
Average kWh's/Customer Previous Year	39880.0	36880.0	39581.8	34350.0	26916.7
kWh's/Customer Increases/Decreases	-3000.0	2701.8	-5231.8	3066.7	19.0
Average kWh's/Customer During Period	36880.0	39581.8	34350.0	37416.7	37336.5
Total kWh's for Period	184400	217700	206100	224500	224019
Residential - Road Access - Std. 'A'					
Number of Customers - Beginning of Period	18	11	11	11	12
Customer Additions/Deletions	-7	0	0	-2	1
Number of Customers - End of Period	11	11	11	9.3	13
Effective # of Customers During Period	14.5	11.0	11.0	10.2	12.2
Average kWh's/Customer Previous Year	3913.5	4482.8	4072.7	4772.7	5295.3
kWh's/Customer Increases/Decreases	569.2	-410.0	700.0	-425.2	69.4

Average kWh's/Customer During Period	4482.8	4072.7	4772.7	4347.5	5364.7
Total kWh's for Period	65000	44800	52500	44200	65568
Residential - Air Access - Std. 'A"					
Number of Customers - Beginning of Period	107	116	111	110	113
Customer Additions/Deletions	9	-5	-1	-4	2
Number of Customers - End of Period	116	111	110	106.0	115
Effective # of Customers During Period	111.5	113.5	110.5	108.0	113.7
Average kWh's/Customer Previous Year	11974.8	11261.9	10423.8	11026.2	11274.7
kWh's/Customer Increases/Decreases	-712.9	-838.1	602.5	1304.3	71.2
Average kWh's/Customer During Period	11261.9	10423.8	11026.2	12330.6	11345.8
Total kWh's for Period	1255700	1183100	1218400	1331700	1289644
General Service - Road Access - Std. 'A'					
Number of Customers - Beginning of Period	25	27	27	27	27
Customer Additions/Deletions	2	0	0	1	0
Number of Customers - End of Period	27	27	27	28.0	27
Effective # of Customers During Period	26.0	27.0	27.0	27.5	27.0
Average kWh's/Customer Previous Year	24074.5	24080.8	21651.9	22981.5	23914.3
kWh's/Customer Increases/Decreases	6.3	-2428.9	1329.6	-243.3	108.3
Average kWh's/Customer During Period	24080.8	21651.9	22981.5	22738.2	24022.6
Total kWh's for Period	626100	584600	620500	625300	648610
General Service - Air Access - Std. 'A'					
Number of Customers - Beginning of Period	285	297	298	303	304
Customer Additions/Deletions	12	1	5	-11	2
Number of Customers - End of Period	297	298	303	292.0	306
Effective # of Customers During Period	291.0	297.5	300.5	297.5	305.3
Average kWh's/Customer Previous Year	30930.4	30725.4	30105.2	31158.4	30939.8
kWh's/Customer Increases/Decreases	-205.0	-620.2	1053.2	-467.0	50.4
Average kWh's/Customer During Period	30725.4	30105.2	31158.4	30691.4	30990.3
Total kWh's for Period	8941100	8956300	9363100	9130700	9460635
TOTAL SUMMARY					
Number of Customers - Beginning of Period	3331	3469	3490	3533	3516
Customer Additions/Deletions	138	21	43	-3	27
Number of Customers - End of Period	3469	3490	3533	3530	3543
Effective # of Customers During Period	3400.0	3479.5	3511.5	3532	3530
Average kWh's/Customer Previous Year	15940.9	15738.0	14996.4	15519.1	15933.1
kWh's/Customer Increases/Decreases	-203.0	-741.6	522.8	372.2	55.2
Average kWh's/Customer During Period	15738.0	14996.4	15519.1	15891.3	15988.3
Total kWh's for Period	53509100	52179800	54495402	56124200	56430591

Customer numbers and kWh have been updated for actuals in 2012 to June 2012 and projected to the end of the year. The 2013 forecast based on a projection for 2012.

was

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

Revenue Forecast

References:

- Attachment 8
- Attachment 9A
- Exhibit G2 / 1 / 1

Interrogatory

Attachment 8 'Revenue Reconciliation' provides a calculation of revenue from the customers in the existing communities, for an unspecified year. However, the number of customers and the energy consumption do not match those in Attachment 9A, and the rates are not those requested in Exhibit G2.

a) Please explain why the inputs to Attachment 8 do not match the 2013 data in the other evidence.

b) If the inputs to Attachment 8 are preliminary forecasts that have been superseded, please provide an update.

Response

a) As indicated in Exhibit G1, Tab 1, Schedule 3 lines 8 and 9, Remotes pro-rated the proposed rates to account for the May 1 implementation date. Attachment 8 showed the pro-rated rates to derive the annual revenue, assuming that the 2012 rates would be in place for four months from January 1 to April 30, 2013 and the proposed rates would be in effect for eight months from May 1, 2013 to the end of the year. The pro-rating assumed consistent revenues each month.

Energy Consumption differences between the two attachments were 110,000 kWh or 0.2% of the total consumption and were the result of rounding differences between Remotes' Load Forecast and Revenue Forecast models. The Revenue Forecast Model was used to reconcile the revenue as it breaks down the load data into block consumption by month, whereas the Load Forecast model only shows this information in summary form.

Attachment 8 inadvertently omitted the effective number of Residential Year Round Non Standard A customers for Marten Falls and the effective number of General Service Air Access, Standard A customers for Bearskin Lake. The numbers of customers on the attachments match when those omissions are added in. Please see the tables below for further clarity. A corrected version of Attachment 8 is provided in Exhibit I, Tab 1, Schedule 33, Attachment 1

Residential Year Round Non Standard 'A'	
Effective Number of Customers - Per Attachment 8	2,531.6667
Effective Number of Customers - Per Attachment 9A	2,594.9000
Difference - Add Marten Falls to Schedule 9A	63.2333

MARTEN FALLS	**2013 YEAR Projected**
Residential - Year Round - Non Std. 'A'	
Number of Customers - Beginning of Period	63
Customer Additions/Deletions	1
Number of Customers - End of Period	64
Effective # of Customers During Period	63.2
Average kWh's/Customer Previous Year	12131.8
kWh's/Customer Increases/Decreases	0
Block 1 AVG kWh's/Customer During Period	11943
Block 2 AVG kWh's/Customer During Period	176
Block 3 AVG kWh's/Customer During Period	3
Average kWh's/Customer During Period	12131.8
Block 1 Total kWh's for Period	755057.9
Block 2 Total kWh's for Period	11101.0
Block 3 Total kWh's for Period	162.1
Total kWh's for Period	767002

General Service - Air Access - Std. 'A'	
Effective Number of Customers - Per Attachment 8	278.0556
Effective Number of Customers - Per Attachment 9A	305.2778
Difference - Add Bearskin Lake to Schedule 9A	27.22

BEARSKIN LAKE	**2013 YEAR Projected**
General Service - Air Access - Std. 'A'	
Number of Customers - Beginning of Period	27
Customer Additions/Deletions	1
Number of Customers - End of Period	28
Effective # of Customers During Period	27.22
Average kWh's/Customer Previous Year	23140.1
kWh's/Customer Increases/Decreases	102
Average kWh's/Customer During Period	23242.4
Total kWh's for Period	632711

b) An update to the business plan was approved; however, the outlook continues to be consistent with the load and revenue in the pre-filed evidence, with a difference of about 1%. Given the nature of Remotes' business and the RRRP variance account, updating the forecast for this small amount was not deemed to be efficient.

Attachment 8
Revenue Reconciliation

Total Revenue - Res Y-R Non Std. 'A'	Eff. # Cust	Est. kWh	Rate	Revenue
Monthly Service Charge	2595		$17.50	$531,650
Monthly Energy Charge - 1st Block (1000)		22599868	0.0824	$1,862,229
Monthly Energy Charge - 2nd Block (1000-2500)		10820036	0.1098	$1,188,040
Monthly Energy Charge - 3rd Block (Over 2500)		1699632	0.1655	$281,289
Total		**35119536**		**$3,863,208**
Total Revenue - Res. Seas. Non Std. 'A'	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	164		$29.56	$58,174
Monthly Energy Charge - 1st Block (750)		248312	0.0824	$20,461
Monthly Energy Charge - 2nd Block (750-1250)		810	0.1098	$89
Monthly Energy Charge - 3rd Block (Over 1250)		330	0.1655	$55
Total		**249452**		**$78,779**
Total Revenue - Gen. Ser. 1-phase	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	279		$29.72	$99,661
Monthly Energy Charge - 1st Block (5000)		5203171.957	0.0922	$479,732
Monthly Energy Charge - 2nd Block (5000-10000)		386774.5634	0.1224	$47,341
Monthly Energy Charge - 3rd Block (Over 10000)		76071.78354	0.1655	$12,590
Total		**5666018.304**		**$639,325**
Total Revenue - Gen. Ser. 3-phase	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	27		$37.22	$12,059
Monthly Energy Charge - 1st Block (25000)		3371199.944	0.0922	$310,825
Monthly Energy Charge - 2nd Block (25000-40000)		210231.1421	0.1224	$25,732
Monthly Energy Charge - 3rd Block (Over 40000)		14833.67322	0.1655	$2,455
Total		**3596264.759**		**$351,071**
Total Revenue - Street Lighting	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	6	0	0	$0
Monthly Energy Charge		224018.7934	0.0914	$20,941
Total		**224018.7934**		**$20,941**
Total Revenue Res. Rd. Access - Std. 'A'	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
First 250 kWh	12	36666.66667	0.5418	$19,866
Balance kWh		28901.73761	0.619	$17,890
Total		**65568.40428**		**$37,756**
Total Revenue Gen. Serv. Rd. Acc Std. 'A'	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
First 250 kWh	27		$0.00	$0
Balance kWh		648610.4495	$0.619	$401,490
Total		**648610.4495**		**$401,490**
Total Revenue Res. Air Access - Std. 'A'	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
First 250 kWh	114	341000	$0.818	$278,870
Balance kWh		948644.4003	$0.895	$849,132
Total		**1289644**		**$1,128,001**
Total Revenue Gen. Serv. Air Access - Std. 'A'	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	305		$0.00	$0
Monthly Energy Charge		9460635	$0.895	$8,468,214
Total		**9460635**		**$8,468,214**
Summary	**Eff. # Cust**	**Est. kWh**		**Revenue**
Summary	**3530**	**56319747**		**$14,988,785**

Attachment 8
Revenue Reconciliation

Total Revenue - Res Y-R Non Std. 'A'	Eff. # Cust	Est. kWh	Rate	Revenue
Monthly Service Charge	2595		$17.90	$543,783
Monthly Energy Charge - 1st Block (1000)		22599868	0.0843	$1,904,491
Monthly Energy Charge - 2nd Block (1000-2500)		10820036	0.1123	$1,215,090
Monthly Energy Charge - 3rd Block (Over 2500)		1699632	0.1693	$287,697
Total		**35119536**		**$3,951,061**
Total Revenue - Res. Seas. Non Std. 'A'	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	164		$30.24	$59,510
Monthly Energy Charge - 1st Block (750)		248312	0.08427	$20,925
Monthly Energy Charge - 2nd Block (750-1250)		810	0.1123	$91
Monthly Energy Charge - 3rd Block (Over 1250)		330	0.16927	$56
Total		**249452**		**$80,582**
Total Revenue - Gen. Ser. 1-phase	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	279		$30.40	$101,939
Monthly Energy Charge - 1st Block (5000)		5203171.957	0.09431	$490,711
Monthly Energy Charge - 2nd Block (5000-10000)		386774.5634	0.12522	$48,432
Monthly Energy Charge - 3rd Block (Over 10000)		76071.78354	0.16927	$12,877
Total		**5666018.304**		**$653,958**
Total Revenue - Gen. Ser. 3-phase	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	27		$38.07	$12,336
Monthly Energy Charge - 1st Block (25000)		3371199.944	0.094131	$317,334
Monthly Energy Charge - 2nd Block (25000-40000)		210231.1421	0.12522	$26,325
Monthly Energy Charge - 3rd Block (Over 40000)		14833.67322	0.16927	$2,511
Total		**3596264.759**		**$358,506**
Total Revenue - Street Lighting	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	6	0	0	$0
Monthly Energy Charge		224018.7934	0.09348	$20,941
Total		**224018.7934**		**$20,941**
Total Revenue Res. Rd. Access - Std. 'A'	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
First 250 kWh	12	36666.66667	0.55425	$20,323
Balance kWh		28901.73761	0.63325	$18,302
Total		**65568.40428**		**$38,625**

Total Revenue Gen. Serv. Rd. Acc Std. 'A'	Eff. # Cust	Est. kWh	Rate	Revenue
First 250 kWh	27		$0.00	$0
Balance kWh		648610.4495	$0.6333	$410,733
Total		**648610.4495**		**$410,733**
Total Revenue Res. Air Access - Std. 'A'	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
First 250 kWh	114	341000	$0.8367	$285,298
Balance kWh		948644.4003	$0.9157	$868,626
Total		**1289644**		**$1,153,924**
Total Revenue Gen. Serv. Air Access - Std. 'A'	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	305		$0.00	$0
Monthly Energy Charge		9460635	$0.9157	$8,662,630
Total		**9460635**		**$8,662,630**
Summary	**Eff. # Cust**	**Est. kWh**		**Revenue**
Summary	**3530**	**56319747**		**$15,330,959**

Ontario Energy Board (Board Staff) INTERROGATORY #34 List 1

Request for Annual RRRP

References:
- Exhibit: E1 / 1 / 1 / p. 3
- Exhibit: G1 / 1 / 3 / p. 8

Interrogatory

Remotes has identified incremental costs in Exhibit E1, with three items totaling approximately $3.9 million. It has provided a forecast of revenue from the customers in the Grid-connected communities of $1.9 million.

a) Please confirm that these two facts taken together imply that Remotes is proposing to increase the revenue required from the RRRP by approximately $2 million annually, beyond what would be requested for the existing service area.

b) Please provide documentation of any regulation or authorization that Remotes has received that the Board may rely on in considering Remotes' request for annual RRRP, including this component.

Response

a) Remotes is proposing to increase the revenue required from the RRRP by $1,148 thousand in order to serve these two communities. Please see Exhibit I, Tab 3, Schedule 11 for an outline of the costs and revenues associated with Pikangikum and Cat Lake and also setting out the RRRP requirement for both Grid-Connected and Off-Grid communities.

b) As indicated in Exhibit A, Tab 3, Schedule 1, Page 2, lines 13-17, the Ontario Government amended the *Electricity Act, 1998* ("the Act") to permit the inclusion of grid connected communities into Remotes' service territory. Section 48.1 of the Act now states that

> *Hydro One Inc. shall, through one or more subsidiaries, operate generation facilities and distribution systems in, and shall distribute electricity within, such communities as may be prescribed by regulation, whether or not the community is connected to the IESO-controlled grid, and shall do so in accordance with such conditions and restrictions as may be prescribed by regulation. 2010, c. 8, s. 37 (6).*

At Exhibit A, Tab 7, is a letter from the Honourable Chris Bentley, former Minister of Energy, wrote Pikangikum Chief Jonah Strang requesting that the Chief and Remotes "engage Aboriginal Affairs and Northern Development Canada (AANDC) to enter into an agreement on roles and responsibilities regarding the operation of the Pikangikum distribution system." The Minister also noted that "resolution of these matters is a prerequisite to the Provincial regulatory changes that the government may initiate to enable RemoteCo to assume operation of the Pikangikum distribution system."

On October 16, the former Minister sent a similar letter to Chief Keewaykapow of Cat Lake in response to the Chief's request (Exhibit A, Tab 7) that a permanent servicing arrangement for the communities transmission and distribution assets, which has been operated under interim licences issued under Section 59 of the *Ontario Energy Board Act, 1998* since 2006. A copy of the Minister's letter to Cat Lake is attached to this interrogatory as Exhibit I, Tab I, Schedule 29, Attachment 1.

As indicated in Remotes' response in Exhibit I, Tab 1, Schedule 1, Remotes believes that Ontario Energy Board review and approval of the costs and rates associated with any new community entering its service territory is required in order to come to an agreement with the First Nation and AANDC on service to the community.

Ministry of Energy
Office of the Minister
4th Floor, Hearst Block
900 Bay Street
Toronto ON M7A 2E1
Tel.: 416-327-6758
Fax: 416-327-6754

Ministère de l'Énergie
Bureau du ministre
4e étage, édifice Hearst
900, rue Bay
Toronto ON M7A 2E1
Tél. : 416 327-6758
Téléc. : 416 327-6754

Ontario

OCT 16 2012

MC-2012-1822

Chief Matthew Keewaykapow
Cat Lake First Nation
Gordon Oombash Memorial Building
2 Back Road West
Cat Lake ON P0V 1J0

Dear Chief Keewaykapow:

Thank you for your letter regarding Cat Lake First Nation's interest in having Hydro One Remote Communities Inc. (RemoteCo) take over operation of the transmission and distribution assets that service Cat Lake.

As a first step in transferring operational responsibilities for these assets, RemoteCo, Hydro One Networks Inc. (Hydro One) and Cat Lake First Nation would be required to work together to address outstanding issues relating to the transmission and distribution facilities that are currently operated by Hydro One, including arrears related to the connection of Cat Lake First Nation and the provision of electricity service.

These parties would also be required to engage Aboriginal Affairs and Northern Development Canada to enter into an agreement on roles and responsibilities regarding the ownership and operation of the transmission and distribution systems servicing Cat Lake. These include environmental remediation, transfer of assets, land and access rights and a commitment to support Standard "A" rates through federal electrical energy cost subsidies, which ended after Cat Lake Power assumed operation of these systems. Resolution of these matters is a prerequisite to any provincial regulatory changes that the government may initiate to enable a permanent arrangement for operating these assets.

I encourage you to continue discussions with RemoteCo on transferring operational responsibilities. My staff will contact Mr. Myles D'Arcey, President and Chief Executive Officer of RemoteCo, to encourage continued negotiation, and I am providing Mr. D'Arcey with a copy of our correspondence.

If you need further information, please contact Mr. Michael Reid, the ministry's Acting Assistant Deputy Minister of Regulatory Affairs and Strategic Policy, at 416-325-6544.

Thank you again for writing.

Sincerely,

Chris Bentley
Minister

c: Mr. Myles D'Arcey, Hydro One Remote Communities
Ms Sarah Campbell, MPP, Kenora–Rainy River

Ontario Energy Board (Board Staff) INTERROGATORY #35 List 1

Bill Impacts for Consumers in Cat Lake and Pikangikum

Reference: Exhibit G1 / 1 / 3

Interrogatory

a) Please provide a detailed calculation of the forecast revenue that Remotes will receive annually from non-Standard A consumers in Cat Lake and Pikangikum, distinguishing between the Monthly Service Charge component versus the variable component

b) Please provide a schedule showing the bill impact, in the format of Appendix 2-W in the Board's Filing Requirements, for a representative customer in each non- Standard A class in Cat Lake, and in Pikangikum if different from Cat Lake.

Response

a) The detailed calculation of the forecast revenue that Remotes will receive in 2013 from non-Standard A customers in Cat Lake and Pikangikum is attached as Exhibit I, Tab 1, Schedule 35, Attachment 1.

b) The format of Appendix 2-W does not easily support Remotes' rate structures. The bill impacts for customers in Cat Lake and Pikangikum are shown below.

CAT LAKE BILL IMPACTS[1]

Residential - Year Round - Non Std. 'A'					
Scenario kWh	**Current Bill**	**Current Bill with OCEB**	**Proposed Bill**	**Proposed Bill with OCEB**	**Percentage Change**
-	$ 8.00	$ 7.20	$ 18.10	$ 16.29	126.25%
100	$ 17.00	$ 15.30	$ 26.62	$ 23.96	56.59%
250	$ 30.50	$ 27.45	$ 39.40	$ 35.46	29.18%
500	$ 53.00	$ 47.70	$ 60.70	$ 54.63	14.53%
800	$ 80.00	$ 72.00	$ 86.26	$ 77.63	7.82%
1,000	$ 98.00	$ 88.20	$ 103.30	$ 92.97	5.41%
2,000	$ 188.00	$ 169.20	$ 216.90	$ 195.21	15.37%

[1] Comparisons based on existing rate classes in Cat Lake.

General Service 1-Phase - Non Std. 'A'					
Scenario kWh	Current Bill	Current Bill with OCEB	Proposed Bill	Proposed Bill with OCEB	Percentage Change
0	$ 27.95		$ 30.75		10.02%
1,000	$ 114.45	$ 103.01	$ 126.15	$ 113.54	10.22%
1,500	$ 157.70	$ 141.93	$ 173.85	$ 156.47	10.24%
2,000	$ 200.95	$ 180.86	$ 221.55	$ 199.40	10.25%
3,000	$ 287.45	$ 258.71	$ 316.95	$ 285.26	10.26%
5,000[2]	$ 460.45	$ 431.71	$ 507.75	$ 476.06	10.27%

General Service 3-Phase - Non Std. 'A'					
Scenario kWh	Current Bill	Current Bill with OCEB	Proposed Bill	Proposed Bill with OCEB	Percentage Change
	$ 27.95	$ 25.16	$ 38.50	$ 34.65	37.75%
1000	$ 124.45	$ 112.01	$ 133.90	$ 120.51	7.59%
2,000	$ 220.95	$ 198.86	$ 229.30	$ 206.37	3.78%
3,000	$ 317.45	$ 285.71	$ 324.70	$ 292.23	2.28%
5,000[3]	$ 510.45	$ 478.71	$ 515.50	$ 483.03	0.99%

Streetlights

Streetlights					
Scenario kWh	Current Bill	Current Bill with OCEB	Proposed Bill	Proposed Bill with OCEB	Percentage Change
100	36.00	32.40	9.46	$ 8.51	-73.72%
200	72.00	64.80	18.92	$ 17.03	-73.72%
300	108.00	97.20	28.38	$ 25.54	-73.72%
400	144.00	129.60	37.84	$ 34.06	-73.72%
500	180.00	162.00	47.30	$ 42.57	-73.72%

[2] As of September, 2012, the 10% OCEB applies to only the first 3,000 kWh of usage per month.

[3] As of September, 2012, the 10% OCEB applies to only the first 3,000 kWh of usage per month.

PIKANGIKUM BILL IMPACTS[4]

Residential Year Round				
Scenario kWh	Current Bill	Proposed Bill	Proposed Bill with OCEB	Percentage Change
-	$ 16.45	$ 18.10	$ 16.29	10.03%
100	$ 27.03	$ 26.62	$ 23.96	-1.52%
250	$ 42.90	$ 39.40	$ 35.46	-8.16%
500	$ 69.35	$ 60.70	$ 54.63	-12.47%
800	$ 101.09	$ 86.26	$ 77.63	-14.67%
1,000	$ 122.25	$ 103.30	$ 92.97	-15.50%
1,500	$ 175.15	$ 160.10	$ 144.09	-8.59%
2,000	$ 228.05	$ 216.90	$ 195.21	-4.89%

Residential Old Age				
Scenario kWh	Current Bill	Proposed Bill	Proposed Bill with OCEB	Percentage Change
-	$ 8.23	$ 18.10	$ 16.29	119.93%
100	$ 13.52	$ 26.62	$ 23.96	96.89%
250	$ 21.46	$ 39.40	$ 35.46	83.64%
500	$ 34.68	$ 60.70	$ 54.63	75.03%
800	$ 50.55	$ 86.26	$ 77.63	70.64%
1,000	$ 61.13	$ 103.30	$ 92.97	68.98%
1,500	$ 87.58	$ 160.10	$ 144.09	82.80%
2,000	$ 114.03	$ 216.90	$ 195.21	90.21%

Commercial - Native				
Scenario kWh	Current Bill	Proposed Bill	Proposed Bill with OCEB	Percentage Change
0	$ 27.95	$ 30.75	$ 27.68	10.02%
1,000	$ 142.05	$ 126.15	$ 113.54	-11.19%
1,500	$ 199.10	$ 173.85	$ 156.47	-12.68%
2,000	$ 256.15	$ 221.55	$ 199.40	-13.51%
3,000	$ 370.25	$ 316.95	$ 285.26	-14.40%
5,000[5]	$ 598.45	$ 507.75	$ 476.06	-15.16%

[4] Comparisons based on existing rate classes in Pikangikum as provided to Remotes on February 13, 2011. Pikangikum does not currently participate in the OCEB program.

[5] As of September, 2012, the 10% OCEB applies to only the first 3,000 kWh of usage per month.

Commercial Non-Native				
Scenario kWh	Current Bill	Proposed Bill	Proposed Bill with OCEB	Percentage Change
0	$ 37.22	$ 30.75	$ 27.68	-17.38%
1000	$ 244.82	$ 126.15	$ 113.54	-48.47%
1500	$ 348.62	$ 173.85	$ 156.47	-50.13%
2,000	$ 452.42	$ 221.55	$ 199.40	-51.03%
3,000	$ 660.02	$ 316.95	$ 285.26	-51.98%
5,000[6]	$ 1,075.22	$ 507.75	$ 476.06	-52.78%

Arena				
Scenario kWh	Current Bill	Proposed Bill	Proposed Bill with OCEB	Percentage Change
0	$ 27.95	$ 30.75	$ 27.68	10.02%
1,000	$ 578.95	$ 126.15	$ 113.54	-78.21%
1,500	$ 854.45	$ 173.85	$ 156.47	-79.65%
2,000	$ 1,129.95	$ 221.55	$ 199.40	-80.39%
3,000	$ 1,680.95	$ 316.95	$ 285.26	-81.14%
5,000	$ 2,782.95	$ 507.75	$ 476.06	-81.75%

[6] As of September, 2012, the 10% OCEB applies to only the first 3,000 kWh of usage per month

Attachment G - Staff - 35 - Appendix
Pikangikum - Non Standard 'A' Revenues

RESIDENTIAL - YEAR ROUND - NON STD 'A'	2013			
Pikangikum	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	414.5		$17.90	$89,032
Monthly Energy Charge - 1st Block (1000)		4,101,706	$0.08	$345,651
Monthly Energy Charge - 2nd Block (1000-2500)		2,570,742	$0.11	$288,694
Monthly Energy Charge - 3rd Block (Over 2500)		555,320	$0.17	$93,999
Total Revenue				**$817,376**

GENERAL SERVICE 1-PHASE - NON STD 'A'	Year 2			
Pikangikum	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	27.0		$30.40	$9,849
Monthly Energy Charge - 1st Block (5000)		575,700	$0.09	$54,294
Monthly Energy Charge - 2nd Block (5000-10000)		17,282	$0.13	$2,164
Monthly Energy Charge - 3rd Block (Over 10000)		3,414	$0.17	$578
Total Revenue				**$66,885**

GENERAL SERVICE 3-PHASE - NON STD 'A'	Year 2			
Pikangikum	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	1.0		$38.07	$457
Monthly Energy Charge - 1st Block (25000)		500,273	$0.09	$47,091
Monthly Energy Charge - 2nd Block (25000-40000)		157,578	$0.13	$19,732
Monthly Energy Charge - 3rd Block (Over 40000)		14,667	$0.17	$2,483
Total Revenue				**$69,763**

Total Revenue - Non Standard 'A'		**$954,024**
	($000's)	**$954**

Attachment G - Staff - 35 - Appendix
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		$17.90	$12,780
Monthly Energy Charge - 1st Block (1000)		999,600	$0.08	$84,236
Monthly Energy Charge - 2nd Block (1000-2500)		-	$0.11	$0
Monthly Energy Charge - 3rd Block (Over 2500)		-	$0.17	$0
Total Revenue				**$97,016**

GENERAL SERVICE 1-PHASE - NON STD 'A'	Year 2 - 2013			
Cat Lake	**Eff. # Cust**	**Est. kWh**	**Rate**	**Revenue**
Monthly Service Charge	16.2		$30.40	$5,903
Monthly Energy Charge - 1st Block (5000)		291,273	$0.09	$27,470
Monthly Energy Charge - 2nd Block (5000-10000)		-	$0.13	$0
Monthly Energy Charge - 3rd Block (Over 10000)		-	$0.17	$0
Total Revenue				**$33,373**

Total Revenue - Non Standard 'A'		**$130,389**
	($000's)	**$130**

<u>Energy Probe Research Foundation (Energy Probe) INTERROGATORY #1 List 1</u>

Exhibit A – Administrative

Ref: Exhibit A, Tab 4, Schedule 1

<u>Interrogatory</u>

Page 4 describes the funding limitations for generation upgrades imposed by AANDC resulting in increased "capital and maintenance work programs" for Remotes.

a) According to lines 14-21 on page 3, it appears that Remotes has contractual agreements in place with the Federal Government that require AANDC to provide funding for generation upgrades and expansions. Please explain what actions Remotes has taken to enforce the provisions of those agreements in the face of generation funding constraints imposed by AANDC.

b) Please describe the increased capital program required to compensate for the AANDC generation funding constraints.

c) Has Remotes attempted to recover its increased capital costs caused by the funding constraints from AANDC? If yes, please describe the outcome. If not, please explain why recovery from AANDC would not be feasible.

<u>Response</u>

a) The Agreements do not provide a mechanism to recover funds directly from AANDC for capital costs unless AANDC agrees to pay the costs. If AANDC does not agree to pay, the only recourse is to impose connection restrictions in communities where generation resources are at or very near their limits. Remotes continues to work with AANDC and the respective First Nations despite the challenging funding climate. Remotes meets annually with AANDC to discuss funding and project needs and offers on-going professional and technical support to the First Nations throughout the capital funding process.

b) Both OMA and Capital are impacted by AANDC funding constraints as assets continue to age. The increased costs are required mainly to extend the life of older assets or replace end of life assets. Please see Exhibit I, Tab 4, Schedule, Part f) for further information.

c) No. Please see the answer to question a) above.

Energy Probe Research Foundation (Energy Probe) INTERROGATORY #2 List 1

Exhibit C – Cost of Service

Ref: Exhibit C, Tab 2, Schedule 2

Interrogatory

Line 19 on page 5 refers to a cost of $300 k for "road maintenance to the Shoulderblade Falls site at Deer Lake". Please explain what this project involved and why it was needed.

Response

As part of the Agreement to defer the ownership transfer to Deer Lake First Nation for three years, Remotes agreed to make a financial contribution to the Deer Lake First Nation to improve the service access road to the Shoulderblade Hydroelectric generating Station. The road was marginal when first constructed almost 15 years ago, and has been long identified as requiring improvement. The completed work reduces the risk of accident, improving road safety and site access for many years to come. Additionally, access to the distribution line was improved as some forestry and brushing was done roadside which should result in lower trouble related costs.

Energy Probe Research Foundation (Energy Probe) INTERROGATORY #3 List 1

Exhibit C – Cost of Service

Ref: Exhibit C1, Tab 2, Schedule 2

Interrogatory

Lines 2-3 on page 6 refer to "a battery survey initiated to investigate batteries and chargers after a battery failure at Sandy Lake" at a cost of $166 k. Please describe the survey and its results.

Response

This project was a health and safety initiative resulting from a high risk battery explosion in Sandy Lake that occurred when an employee was in proximity. A comprehensive site survey of all stations, including an assessment of the chargers, starting batteries, UPS, PLC back-up and emergency lighting in service was completed. The survey generated modifications that are required in the field to ensure staff and operator safety, system reliability and consistent standards in all stations. As a result of the survey and study, all acid filled starting batteries have been replaced with maintenance free gel batteries. Other battery related improvements have also been made.

<u>Energy Probe Research Foundation (Energy Probe) INTERROGATORY #4 List 1</u>

Exhibit C – Cost of Service

Ref: Exhibit C1, Tab 2, Schedule 2

<u>Interrogatory</u>

Page 6 describe on site operator agents as being "responsible for responding to emergencies such as power outages, house fires and spills".

a) Please describe the role of agents in house fires.

b) Page 7 states that Remotes has increased the number of agents in most communities.
   1. How many agents are normally employed in a community?
   2. Are they Remotes employees or are they contract employees?
   3. What is the average annual cost per agent?

<u>Response</u>

a) The primary role of operators responding to a house fire is to "make safe" so that the public is not exposed to an unsafe electrical situation or condition as a result of the fire.

b)
   1. Remotes has a primary operator in each of the 19 stations. Additionally, back-up or secondary operators have been added in most communities to offer relief for vacation/sick days etc. As of March 2013, Remotes has 34 trained and competent operators with one primary and one back up operator in most communities.

   2. The operators are independent contractors who are contracted either through the respective First Nation community or directly by Remotes.

   3. The average annual contracted cost per community not including overtime is currently $49,306.51 (Mar 2013). Monthly amounts paid to specific operators are based on actual working hours. Included in the above annual amount is an overhead percentage for vacation, sickness, accident insurance, liability insurance, and administration.

Energy Probe Research Foundation (Energy Probe) INTERROGATORY #5 List 1

Exhibit C – Cost of Service

Ref: Exhibit C1, Tab 2, Schedule 4, Page 1

Interrogatory

Table 1 shows Customer Care costs increased from $1,143 k in 2009 to $1,930 in 2011, an increase of $787 k. About $333 k of the increase in 2011 is attributed to Remotes share of the cost of a new billing system.

a) Please explain the balance of $454 k ($787k - $333k).

b) Bridge year spending is shown as $1,689 k and the reduction from 2011 is attributed to the new billing system project costs winding down. How much of the $1689 k in 2012 is attributable to the billing system project?

c) Test year spending is shown as $1,855 k and the increase is attributed to the cost of including Cat Lake and Pikangikum in the Remotes customer care system. How much of the $1,855 k is attributable to each of these new communities?

d) Please compare the expected Customer Care costs in Cat Lake and Pikangikum to the average Customer Care costs for the rest of Remotes service territory and explain any variances.

Response

a) The most significant factors associated with the balance of $454 K over a two year period are as follows:

   1) Meter-related services ($133K) including the 2011 meter project in which over 400 meters where changed out.
   2) Increased general customer service related costs including new customers acquired when Marten Falls was added to Remotes service territory and costs related to internal assessment, planning and preliminary discovery work for the billing system. ($342K).

b) Approximately $64K was budgeted for the billing system project.

c) In the test year, Customer Care costs of approximately $33K and $113K are attributed to the cost of including Cat Lake and Pikangikum respectively. This includes all customer care relates costs, specifically, meter-related costs, general customer service costs and collections activities costs.

d) The forecast for expected customer care costs in Cat Lake and Pikangikum are based on approximations derived from existing similar-sized serviced communities. This was based on known, and estimated, customer levels for Cat Lake and Pikangikum respectively.

Energy Probe Research Foundation (Energy Probe) INTERROGATORY #6 List 1

Exhibit C – Cost of Service

Ref: Exhibit C1, Tab 2, Schedule 4, Page 2

Interrogatory

According to the evidence on this page, outstanding account receivables have been reduced from $9,532 k to $4,685 k by the end of 2012 as a result of negotiated payment plans with most First Nations Band Councils leaving a balance of $4,847 k.

a) Please describe the circumstances leading to this large amount of receivables.

b) How is Remotes treating the outstanding balance? I.e. is another payment plan contemplated to reduce it or is it to be written off to bad debt expense?

c) Bad debt expense is forecast to rise again in 2012 and 2013. Please describe the actions taken by Remotes to prevent another large accumulation of receivables from First Nation Band Councils.

Response

a) Arrears related to First Nation Band accounts accumulated over a long period of time. Prior to 2005, Remotes did not disconnect Standard A accounts in arrears, did not write-off outstanding balances and did not have an adequate provision for bad debts since it had been assumed that the accounts were "guaranteed" by AANDC. In 2005, AANDC officials indicated that AANDC would no longer backstop amounts due from First Nations. Following that discussion, Remotes established a provision for bad debts related to these accounts and also set targets to reduce outstanding arrears by 15% each year by negotiating payment arrangements with communities. There are limited options available to address non payment of First Nation Band accounts since these accounts relate primarily to essential services such as nursing stations, water and sewage facilities and schools.

b) About 70% of the balance is related to a single First Nation and a payment arrangement is now in place with that community. The payment arrangement requires that monthly bills are kept current and also requires quarterly payments against the outstanding arrears. Payment plans with four other communities were also in place in 2012. Please also see the response to Exhibit I, Tab 4, Schedule 9, part g) for the relationship between payment plans and bad debt expense.

c) Remotes continues to work with Band Councils to ensure that accounts are kept up-to-date. Remotes meets regularly with First Nations to discuss service issues, which may also include discussions of receivables. Every month, Remotes reviews First Nation arrears and follows up with Band Councils that have missed payments. Remotes also faxes updated account balance summaries for specific accounts as requested and works with communities to ensure that accounts are properly classified.

Energy Probe Research Foundation (Energy Probe) INTERROGATORY #7 List 1

Exhibit C – Cost of Service

Ref: Exhibit C1, Tab 2, Schedule 5, Page 1

Interrogatory

Table 1 shows Community Relations costs have increased from $394 k in 2009 to $444 k in 2011. Some or all of this $50 k increase appears to be related to the program to offer rebates for the purchase of Energy Star appliances.

a) Please describe the rebate program offered. How does it compare with past or present OPA programs offered in non-Remotes service territories?

b) Increased conservation spending is proposed for 2012 ($344 k) and 2013 ($361 k) according to lines 24-25 on page 2. Please describe in more detail the actions planned "to conserve electricity used in band operated assets such as Band Offices, arenas and water and sewage plants" referred to in lines 26-27.

c) How much energy is expected to be saved by this increased effort and how much will it reduce costs?

Response

a) The current OPA (saveonenergy.ca) rebate programs have not been made available in Remotes' service territory. It is not clear from the OPA's March 25, 2013 Aboriginal Conservation Program launch materials whether rebate programs will be available in Remotes service territory. Remotes staff have requested a meeting with the OPA program provider to find out how and whether the overall program will be offered in Remotes' service territory. The comparison below is to the OPA's current residential program, which offers free pick-up of old appliances provided certain criteria are met. It does not offer a financial incentive at this time.

   The Hydro One Remotes program is an enhanced customer program that offers free pick-up by the Northwest Company Stores and financial rebates at source. Since energy efficient appliances are usually a little more expensive, Remotes offers rebate amounts to off-set the extra cost. The rebate amounts to Energy Star appliances available through Northwest Company Stores are as follows:

   - Refrigerators – Rebate Amount $200
   - Freezers – Rebate Amount $125
   - Washing Machine – Rebate Amount $120 + free sample full size sample of HE cold

- Dryer– Rebate Amount $100
- Combo washer and Dryer – Rebate Amount $220
- Dishwasher – Rebate Amount $100
- Range – Rebate Amount $175

b) Band offices, arenas and water and sewage plants are typically the largest power users in our communities. Remotes is proactively and specifically targeting these facilities for conservation opportunities as they offer more payback opportunities. Conservation initiatives will be identified through joint energy audits in cooperation with the community. Communities are encouraged to perform commercial lighting retrofits or other initiatives to reduce their overall consumption.

c) The success or failure of this program will largely be determined by the uptake and support by the individual communities, so the program results are unknown at this time. Since the program is designed to target the heavy users vs. residential accounts the program should result in more cost effective results.

Energy Probe Research Foundation (Energy Probe) INTERROGATORY #8 List 1

Exhibit C – Cost of Service

Ref: Exhibit C1, Tab 2, Schedule 5

Interrogatory

In the previous proceeding EB-2008-0232, Remotes responded to Board Staff IR#22 that the OPA was compiling research results from a test CDM project for remote communities and planned to launch a program in 2009. Was the program ever introduced? Please provide an update.

Response

The OPA introduced an Aboriginal Conservation Program on March 25, 2013. The program announcement states that, for the first year of the program in 2013, 2 "First Nation without year-round road access to a service centre that is serviced by Hydro One Remote Communities Incorporated or by a remote independent power authority" are eligible to apply for participation. According to the OPA website the program will provide customized conservations services and will also create clean energy employment opportunities, potentially providing up to 30 jobs in selected Aboriginal communities.

<u>Energy Probe Research Foundation (Energy Probe) INTERROGATORY #9 List 1</u>

Exhibit D – Rate Base

Ref: Exhibit D1, Tab 2, Schedule 1, Pages 10-11

<u>Interrogatory</u>

Distribution system improvement costs are projected to increase in 2012-2013 and this is attributed to the acquisition of the Cat Lake and Pikangikum systems.

1. Has Remotes conducted a condition assessment of these systems? If yes, please provide a summary of the work necessary to bring the systems up to acceptable standards.

2. If Remotes has not conducted a condition assessment of the systems, please describe what the increased costs in 2012-2013 are based on.

<u>Response</u>

1. The Electrical Safety Authority conducted an audit of the asset condition in Pikangikum. The ESA audit of the system compares the condition of the assets to the standard to which the assets were built, mid 1970s. The cost to bring the assets up to the ESA audit standard is expected to be borne by AANDC through a minor capital project. At the time of the ESA audit, Remotes staff also undertook an asset condition assessment to compare the asset condition to today's standards and identified work required to replace conductors. The distribution system capital improvement spending referenced is for improvements to the community distribution system required as poles, conductors and other equipment wear out and need to be replaced. Remotes has budgeted $40,000 for this work.

   Remotes also undertook an asset condition assessment of the distribution system in Cat Lake. No specific improvements are required in this community. Remotes has budgeted $20,000 for distribution system improvements required as poles, conductors and other equipment wear out and need to be replaced.

2. Please see the answer to 1. above.

<u>Energy Probe Research Foundation (Energy Probe) INTERROGATORY #10 List 1</u>

Exhibit D – Rate Base

Ref: Exhibit D2, Tab 2, Schedule 2

Interrogatory

In the previous proceeding EB-2008-0232, Board Staff IR#3 asked about Remotes "plans to test catalytic reactor technology at its Armstrong station at a cost of $358,368". Please provide an update on that project including results, cost and effect on Remotes operating strategy for its generating plant.

Response

This project is now complete and the final project costs were approximately $250,000. Please see the attached letter to the Ontario Ministry of Environment outlining the findings as Attachment 1.

Hydro One
Remote Communities Inc.
680 Beaverhall Place
Thunder Bay ON P7E 6G9
Tel: (807) 474-2800
Billing: Toll Free 1-800-465-5085
Operations Toll Free 1-888-825-8707
Fax: (807) 475-8123

hydro one

2011 August 03

Director
Ontario Ministry of the Environment
Environmental Assessment and Approvals Branch
2 St. Clair Avenue West, Floor 12A
Toronto, ON M4V 1L5

Dear Sir or Madam:

New Certificate of Approval (Air) for Remotes' Diesel Generating Stations

Hydro One Remote Communities Inc. is in the process of updating the Certificates of Approval (Air) for several of our remote diesel generating sites.

Our research work on engine emissions has identified that the actual measurements for an installed engine are moderately higher than what is documented in our original Certificate of Approval applications. The reasons for this discrepancy are that the numbers provided by the engine manufacturers are test cell measurements operating under ideal conditions without parasitic loads, in a controlled environment, and burning laboratory fuel.

In 2010 Hydro One Remotes installed a Pro-Cal emissions measuring system at our Armstrong Diesel Generating Station. Although our facilities are below the ministry threshold for constant emissions monitoring, Remotes is being proactive in conducting tests to better understand the emissions of different fuels, the impacts of auxiliary equipment, etc. Once our emissions measurements are complete, we will compare them to the original C of A applications data. This percentage difference will then be applied to future C of A submissions.

This research will also address our longstanding request for MOE approval in 2001 to operate a crankcase ventilation (CCV) blower system. The test equipment will measure the impact of a crankcase ventilation blower system upon station emission levels.

Emissions reduction continues to be one of Hydro One Remotes' significant priorities which has led us to the use of bio-diesel, and the replacement of old engines with new engines utilizing current technology to lower emissions and fuel consumption.

If you have any questions regarding this strategy, do not hesitate to contact us.

Regards

Dan Santerre

Dan Santerre
Director
☎ 807.474.2837

<u>Energy Probe Research Foundation (Energy Probe) INTERROGATORY #11 List 1</u>

Exhibit D – Rate Base

Ref: Exhibit D2, Tab 2, Schedule 3, Attachment 3

<u>Interrogatory</u>

This attachment describes distribution system improvement projects. Page 1 refers to expected system expansion into the communities of "Pikangikum and Peawanuk (2013 and 2014)".

a) Please describe the expansion projects planned for these two communities including an analysis of need.

b) Will Cat Lake also require some expansion work?

<u>Response</u>

a) Pikangikum First Nation is paying for the construction of a line to connect the community to the grid in order to reduce their reliance on diesel fuel. Remotes expects to take over service to the community of Pikangikum through a service agreement. The existing distribution system would be added to Remotes' service territory. None of the capital associated with Pikangikum's line construction will be included in Remotes' rate base. The distribution system capital improvement spending referenced ($40 thousand for Pikangikum) is for improvements to the community distribution system required as poles, conductors and other equipment wears out and needs to be replaced.

   Similarly, Remotes expects to take over service to Peawanuk (Weenusk) through a service agreement. Distribution system capital improvement spending is also related to the need to replace system components as they wear out.

b) No expansion is required to serve Cat Lake. A requirement for distribution system capital improvement funding of $20 thousand was identified for this work in Cat Lake and was included in this submission.

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

Exhibit A - Administration

Reference: Exhibit A, Tab 9, Schedule 3, page 3 and pages 5 and 6 (Tables)

Interrogatory

a) Please provide a table showing the revenue received by Remotes from Networks in respect of metering and lines services provided by Remotes in 2012 and forecasted for 2013.

Response

a) The revenue received by Remotes from Networks in respect of metering and lines services provided in 2012 and forecast for 2013 are shown in the table below. Remotes does not generally budget for these activities specifically, since the services are generally demand or emergency related.

Fees Payable by Networks to Remotes

Services	**Actual 2012**	**Forecasted 2013**
Metering	$0	$0
Lines Services	$75,423	$0
Total	$75,423	$0

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

Exhibit A - Administration

Reference: Exhibit A, Tab 15, Schedule 1, page 2, Table 1

Interrogatory

a) Are actual 2012 Customer Service Indicators now available? If so, please provide 2012 actuals.

Response

a) Please see the Table below.

Customer Service Indicators

Performance Measure	*OEB* Target	2009 Actual	2010 Actual	2011 Actual	2012 Actual
Connection of New Services (% completed in ≤ 5 days)	**≥ 90**	**100**	**100**	**100**	**100**
Emergency Response (% responded to in ≤ 120 min)	**≥ 80**	**92.3**	**97.8**	**96.6**	**98.0**
Written Response to Inquiries (% responded to in ≤ 10 days)	**≥ 80**	**100**	**100**	**100**	**100**

*Emergency Response results including the impact of Force Majeure.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #3 List 1

Exhibit A - Administration

Reference: Exhibit A, Tab 15, Schedule 1, page 5, Table 2

Interrogatory

a) Are actual 2012 Service Reliability Indicators now available? If so, please provide 2012 actuals.

b) Does Remotes track momentary outages?

Response

a) Please see the table below.

Service Reliability Indicators

Performance Measure	2009 Target	2009 Act	2010 Target	2010 Act	2011 Target	2011 Act	2012 Target	2012 Act
SAIFI ***Frequency of Interruptions*** (#of interruptions per customer)	**≤ 15.6**	**11.5**	**≤ 12.0**	**8.1**	**≤ 12.0**	**7.8**	**≤ 11.7**	**16.9**
SAIDI ***Duration of Interruptions*** (hrs of interruption per customer)	**≤12.7**	**9.4**	**≤ 10.5**	**10.9**	**≤10.5**	**8.3**	**≤8.3**	**11.2**
CAIDI ***Average Interruption Time*** (#of hrs per interruption)	**≤ 0.8**	**0.8**	**≤ 0.9**	**1.3**	**≤ 0.8**	**1.1**	**≤0.9**	**1.4**

Reliability was worse than plan in 2012 primarily as a result of a series of generation outages related to poor quality bio-diesel fuel and unexpected engine failures.

b) Remotes' SCADA system records outages less than two minutes that affect an entire community distribution system. Some of the outages recorded on the SCADA system can be temporary voltage reductions (brown outs) or dimming of lights. These outages can be generation or distribution related. The number of outages that lasted less than two minutes and were recorded by the SCADA system are shown for the relevant years in the table below. Momentary outages are largely due to unexpected engine failures, automatic pickup and load switching between units.

Generation Outages less than 2 minutes	**2009**	**2010**	**2011**	**2012**
Total Number of Outages	**65**	**49**	**89**	**115**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #4 List 1

Exhibit C – Cost of Service

Reference: Exhibit C1, Tab 2, Schedule 4, page 1, Table 1, and page 2

Preamble: On lines 6-10 of page 2, Remotes states that "*Customer Care spending in 2011 was higher mainly due to participation on the corporate project to replace Hydro One's billing system ($333 thousand). Bridge year spending is expected to be lower as the billing system project is implemented and required involvement in the project designwinds down. Increases in 2013 relate to the inclusion of Cat Lake and Pikangikum in Remotes' service territory*."

Interrogatory

a) Focussing on the line item "Customer Care" in Table 1, the increase in 2010 Customer Care spending over 2009 was $337 thousand. Please provide the main drivers of this increase.

b) Similarly, the increase in 2011 Customer Care spending over 2010 was $450 thousand, $333 thousand of which Remotes attributes to Remotes' participation in the corporate billing system project. Please provide the main driver(s) of the residual 2011 increase of $117 thousand in Customer Care spending.

c) Please indicate how the cost of Remotes' participation in the project was determined and provide the allocation of the project's costs to all other parties.

Response

a) The main drivers of the 2010 increase over 2009 of $337K are summarized as follows:

   1) Increased customer care costs related to metering-related services ($39).
   2) Increased general customer service related costs including new customers acquired when Marten Falls was added to Remotes service territory at the end of December 2009 ($240).
   3) Increased collections costs in 2010 resulting from increased collections ($58K).

b) The main drivers of the residual increase of $117K in customer care spending of 2011 over 2010 are summarized as follows:

   1) Increased incremental customer care costs relating to the 2011 metering project; over 400 meters were changed in 2011 ($94K).

2) Increased costs associated with general account services and internal assessment, planning and preliminary discovery work for the billing system project ($102K).
3) Reduced year over year collections-related costs (-$79K).

c) Remotes' staff participated on the CIS project to ensure that the new billing system will meet Remotes' requirements. The costs reflect the actual cost of Remotes' staff participation in the discovery process, the review and editing of business process documentation and participation in system testing, data cleansing and report design. Also included are travel costs for staff located in Thunder Bay to travel to the Greater Toronto Area where the project team is undertaking the work. None of these costs reflect any allocation from the project or Hydro One Networks and were for the sole benefit of Remotes. When completed, the CIS will be owned and, hence, capitalized by Hydro One Networks. Remotes will not capitalize any part of the asset. The transfer pricing associated with Remotes' use of Hydro One Networks IT infrastructure, including CIS, can be found at Appendix A, Tab 9, Schedule 3 page 5 ($180K). These costs were allocated to Remotes using the cost allocation methodology developed by Black and Veatch and described in Exhibit C1, Tab 2, Schedule 6.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #5 List 1

Exhibit C – Cost of Service

Reference: Exhibit C1, Tab 2, Schedule 4, page 1, Table 1, and page 2

Interrogatory

a) Please reconcile the reduction in accounts receivable of $4,847 thousand (from $9,532 thousand in January 2009 to $4,685 thousand in January 2011) with the corresponding line items shown for "Bad Debt" in Table 1.

b) Are the entries in Table 1 for the 2012 Bridge Year actual or forecasted?

Response

a) The bad debt figures in Table 1 are for all bad debts of Remotes for the noted years; this includes both Energy and Non-Energy related bad debts, First Nation and Non-First Nation bad debts. As a result, the following summary reconciliation is provided on a fiscal year basis, which shows how changes in the accounts receivable provision impact the bad debt figures of each year:

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

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

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

b) The entries in Table 1 for the 2012 Bridge year are forecasted.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #6 List 1

Exhibit C – Cost of Service

Reference: Exhibit C1, Tab 6, Schedule 1, page 3, 2013 Forecasted Labour Rate

Interrogatory

a) Please provide a table similar to the one at the top of page 3, that shows comparable "Billable $ per Hr." by component for the years 2009-2012 inclusive.

Response

a) The table indicated in Exhibit C1, Tab 6, Schedule 1, page 3 has been reproduced with comparable "Billing $ per Hr" per component for the years 2009 – 2012 is as follows:

Remote Communities Technician and Maintainer - Regular Staff Labour Rate	Billable $ per Hr. 2009	Billable $ per Hr. 2010	Billable $ per Hr. 2011	Billable $ per Hr. 2012
Composition Of Standard Labour Rate	**$205**	**$181**	**$182**	**$187**
Includes the following components:				
Meal Surcharge		$5	$5	$6
Payroll Obligations	$68	$68	$70	$72
Non-Labour Administration Costs	$29	$22	$20	$22
Non-Project, Administration, Management and Support Services Labour	$108	$86	$87	$87

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #7 List 1

Exhibit G – Cost Allocation and Rate Design

Reference: G-Staff-31, Exhibit G1, Tab 1, Schedule 1

Interrogatory

a) With respect to page 1 (lines 18-20), please indicate precisely where in its EB-2008-0232 Decision the Board "prescribed the methodology for calculating the average rate increase for other Local Distribution Companies ("LDC") to apply in a cost-of-service proceeding".

b) With respect to page 2 (lines 2-3), if the information is available, please provide a calculation of the average increase approved by the Board in 2012.

Response

a) The Prefiled evidence should have referred to the methodology detailed in Appendix B of the Board's Decision and Order in Algoma Power Inc's application EB-2009-0278, not Remotes' application EB-2008-0232. On page 7 of the Board's Decision in EB-2009-0278 the Board adopted the recommended changes as detailed in the report titled "Board Staff Report on: Rural and Remote Rate Protection and Adjustment Mechanism", dated October 1, 2010 with the time period to be used for calculating the average rate changes based on the two most recent years for which rate changes are available.

b) As of this date, the Board has not yet provided the 2012 Electricity Distribution Rates Databases and so the average increase for all LDCs from 2011 to 2012 is not available.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #8 List 1

Exhibit G – Cost Allocation and Rate Design

Reference: G-Staff-3, Exhibit G1, Tab 1, Schedule 2, page 1 (line 28) to page 2 (line 2)

Interrogatory

a) Please provide a schedule that sets out, for 2013, the total forecast costs (i.e. revenue requirement) associated with service to Off Grid communities, the total forecast kWh sales to these communities and the resulting average 2013 cost per kWh.

b) Please provide a schedule that sets out the forecast 2013 average revenue per kWh for
- Standard A Road/Rail Access customers
- Standard A Air Access customers, and
- All Standard A customers.

Response

a) A schedule that sets out the forecast 2013 total costs, total revenue and resulting average 2013 cost/ kWh for "off-grid" communities is as follows:

	2013 Forecast Cost	2013 Forecast kWh sales	Forecast 2013 Cost per kWh
Off Grid Communities - Total	$49,180,000	56,319,747	$0.873

b) A schedule that sets out the forecast 2013 average revenue per kWh for the noted customer types is as follows; this information is derived from Attachment 8 (Attachment 8 has been superseded and included as Exhibit I, Tab 1, Schedule 33, Attachment 1):

Customer Type	Revenue	Est. kWh	Forecast 2013 Average Revenue per kWh
Std A Road Rail (Res/GS)	$449,357	714,179	$0.629
Std A Air Access (Res/GS)	$9,816,554	10,750,279	$0.913
All Std A Customers	$10,265,911	11,464,458	$0.895

<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #9 List 1</u>

Exhibit G – Cost Allocation and Rate Design

Reference: Exhibit G1, Tab 1, Schedule 2

Preamble: The Schedule calculates proposed 2013 Grid-connected Standard A rates but in doing so uses: i) Generation Costs excluding Fuel for 2012 (Table 1); ii) Fuel Costs for 2009-2011 (Table 3); iii) Commodity Charges for 2011; iv) Current (2012?) Wholesale Market and RRRP charges; v) HON's proposed 2013 RTSRs and vi) the 2012 Standard A General Service Air Access Rate.

<u>Interrogatory</u>

a) Given the starting point for the this rate is the 2012 Standard A General Service Air Access Rate, why wasn't the result of calculation as set out in Table 5 escalated by 3.45% in order to produce the proposed rate for 2013?

b) Please re-do the calculation set out in Table 5 using the following:
   - Generation Costs excluding Fuel for 2012 (per Table 1)
   - Average Fuel Costs based on 2009-2012 average
   - Commodity Costs for 2012
   - 2012 Wholesale Market and RRRP charges
   - 2012 RTSRs and
   - 2012 Standard A General Service Air Access Rates
   - A 3.45% escalation factor to derive 2013 rates.

c) Please also re-do the calculation using 2013 costs/rates for all components. (Note – For commodity costs a forecast of HOEP and Global Adjustment is available in the Board's most recent Regulated Price Plan – Price Report)

<u>Response</u>

a) Remotes used the 2012 rates to initiate discussions with the First Nations. We did not apply the 3.45% escalation because the 3.45% was not part of the discussions with the communities.

b) Table A below updates Exhibit G, Tab 1, Schedule 2, Table 5 using
   - Generation Costs excluding Fuel for 2012 (per Table 1)
   - Average Fuel Costs based on 2009-2012 average (Table B)
   - Commodity Costs for 2012 (Table C)

- 2012 Wholesale Market and RRRP charges (Table C)
- 2012 RTSRs and (Table C)
- 2012 Standard A General Service Air Access Rates (Table A)
- A 3.45% escalation factor to derive 2013 rates. (Table A)

Table A Proposed Grid Connected Standard A Rates (Updating Table 5)	
2012 Standard A General Service Air Access Rates	0.8951
Remotes' Generation Costs Excluding Fuel (No Change from Exhibit G1-1-2 Tables 1 & 2)	(0.2917)
Air Access Fuel 4 Year Average (as per Table B)	(0.4142)
Cost of Grid Power (Updated per Table C)	0.0885
Grid-connected Standard A Rate (Total of Above)	**0.2777**
Grid-connected Standard A Rate (Escalation 3.45%)	**0.2873**

Tables B & C are shown to provide the supporting calculations

Table B below, shows the supporting calculation for the requested four year fuel cost calculation (based on the four year average for 2009-2012).

Table B Four Year Air Access kWh Fuel Costs				
	2009	2010	2011	2012
kWh Sold	47,293,000	46,093,800	48,128,800	49, 493,300
Annual Fuel Costs (Air Access)	$17,057,404	$19,404,895	$20,373,560	$22,284,962
Four Year Average kWh Sold				191,008,900
Four Year Average Fuel Costs				$79,120,821
Four Year Average $/kWh				**$0.4142**

Table C, below, shows the supporting calculation for the updated "cost of Grid power" calculation showing

- Commodity Costs for 2012
- 2012 Wholesale Market and RRRP charges
- 2012 RTSRs

Table C Estimated Cost of Grid Power Updated for 2012	
2012 Commodity	0.0733
2012 Wholesale Market Retail Service Charge	0.0052
2012 RRRP Charge	0.0011
2012 RTSR - Network	0.0043
2012 RTSR - Line	0.0033
Cost of Power (Grid)	**0.0872**
Line Losses @ 1.5%	0.0013
Cost of Grid Power	**0.0885**

c) Table D below updates the original Table 5 using 2013 for all components. The supporting calculations for the values used in Table D are shown in Tables E, F and G. As requested, 2013 costs are used for all components. Remotes notes that fuel costs are inherently volatile, such that Remotes chose to use a three-year average in the pre-filed evidence. Table D and F use a single, forecasted value for fuel as requested.

Table D - Proposed Grid Connected Standard A Rates	
2013 Proposed Standard A General Service Air Access Rates (Exhibit G-1-1)	0.9260
2013 Generation Costs Excluding Fuel (Table E)	(0.2532)
2013 Air Access Fuel Average (Table F)	(0.4442)
Cost of Grid Power (Table G)	0.0951
Grid-connected Standard A Rate	**0.3237**

Table E - 2013 Generation Costs (G1-1-2 Updated for 2013 Values)	($000's)
Operations & Maintenance (excluding fuel)	8,722
Environmental OM&A[1]	343
Generation Depreciation	1,976
Land Assessment and Remediation (Amortization)	2,713
Administrative	509
Total Generation Costs Excluding Fuel	**14,263**
kWh sold (000's projected)	56,320
Cost per kWh off-grid generation ($/kWh)	**0.2532**

Table F 2013 - Average per kWh Air Access Fuel Costs	
	2013
kWh Sold (Air Access)	49,760,584
Annual Fuel Costs (Air Access)	$22,101,706
2013 Average $/kWh	**$0.4442**

Table G - Estimated Cost of Grid Power Updated for 2013	
2013 Commodity	0.0793
2013 Wholesale Market Retail Service Charge	0.0044
2013 RRRP Charge	0.0012
2013 RTSR- Network	0.0052
2013 RTSR - Line	0.0036
Cost of Power (Grid)	**0.0937**
Line Losses @ 1.5%	0.0014
Cost of Grid Power including Line Losses	**0.0951**

[1] Environmental costs are comprised only of generation-related costs and include 50% of the legislative monitory costs and environmental costs related to fuel spills.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #10 List 1

Exhibit G – Cost Allocation and Rate Design

Reference: Exhibit G1, Tab 1, Schedule 2, page 1, Exhibit A, Tab 2, Schedule 1, page 2

Interrogatory

a) Please provide a copy or reference for any Regulation that has been issued with respect to Hydro One Remotes serving Grid-connected communities.

b) What is the current status of the discussions with Cat Lake and Pikangikum communities and AANDC (per G1/1/2)?

c) What is the best estimate of when Hydro One Remotes will assume service for these communities?

d) Please outline what the service arrangements generally will be in each case, i.e. what assets, if any, is Hydro One Remotes assuming, what responsibilities is it assuming, etc.?

Response

a) Please see the answer to Exhibit I, Tab 1, Schedule 34, Part b.

b) Both Cat Lake and Pikangikum have issued Band Council Resolutions affirming their interest in getting service from Remotes and meetings have been held with each community to discuss the terms of the Agreements. Agreements cannot be finalized with either community before the rates that would be charged to community members are known. Completion of updated environmental assessments is required in both communities. This work is expected to be completed in Cat Lake this summer and is also underway in Pikangikum. The environmental assessments are required to delineate the allocation of costs and responsibilities to remediate lands in each of the Agreements.

c) The community of Pikangikum has not yet secured funding for its grid connection. The completion of this project is required before Remotes can take over the provision of service to that community. Service to Cat Lake could begin in the fall of 2013, providing that all of the approvals outlined in Exhibit I, Tab 1, Schedule 1 are secured, including provincial government changes to the Remote Rate Protection and Service Territory Regulations.

d) Please see Exhibit I, Tab 1, Schedule 3, Part b for an overview of the assets Remotes would assume in the transaction. Remotes would assume the obligation to serve the customers in Pikangikum and Cat Lake under its existing Conditions of Service (Exhibit G1, Tab 3, Schedule 1, Appendix A).

<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #11 List 1</u>

Exhibit G – Cost Allocation and Rate Design

Reference: Exhibit G1, Tab 1, Schedule 2, page 1, A-Staff-3, G-Staff-35

Interrogatory

a) What is the effective date that Hydro One Remotes is proposing for its 2013 rates?

b) Please provide a schedule sets out the portions of the requested $35,329,000 RRRP that are required to make up the differences between revenues at proposed 2013 rates and 2013 revenue requirement for the Off Gird and the Grid-connected communities respectively.

Response

a) The effective date that Hydro One Remotes is proposing for its 2013 rates is May 1, 2013.

b) Please see Tables below.

Grid Connected RRRP	
Total Grid-Connected Costs (Please see I-01-3)	3,111
Total Grid-Connected Revenues (Exhibit G-01-03)	(1,929)
Other Revenues	(34)
Total Annual RRRP Grid Connected Customers	**1,148**

Off-Grid RRRP	
Total Off-Grid Costs[1]	49,173
Total Off-Grid Customer Revenues at Proposed 2013 Rates (G-1-3 Table 4)	(15,331)
Other Revenues	(480)
Total Annual RRRP Off-Grid Customers	**33,362**
Recovery of Balance of RRRP Variance Account and other Regulatory Accounts	**819**
Total RRRP Off-Grid Customers	**34,362**
Total RRRP Grid Customers	**1,148**
Total RRRP all Customers	**35,329**

[1] Off Grid Costs are Total Revenue Requirement (Exhibit E-1-1) Less Total Grid-Connected Costs (Exhibit I-1-3) (52,284 - 3,111 = 49,173).

<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #12 List 1</u>

Exhibit G – Cost Allocation and Rate Design

Reference: Exhibit G1, Tab 1, Schedule 3, page 4, Exhibit G1, Tab 2, Schedule 1, pages 2-4

<u>Interrogatory</u>

a) Using the average use values from G1/1/3, page 4, please provide a schedule that sets out the 2013 monthly bill for each 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 Hydro One Networks' Distribution.

<u>Response</u>

a) Please see the schedule below. Note that current rates (as of April 1, 2013) are used in the calculations for both Networks and 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	Total Monthly Bill After OCEB
Residential-Networks- R1	13,537	**1,128**	**$160.38**
Residential-Remotes	13,537	**1,128**	**$102.56**
Seasonal-Networks	2,153	**179**	**$50.79**
Seasonal-Remotes	2,153	**179**	**$39.88**
GS 1 GSE- Networks	20,212	**1,684**	**$256.81**
GS 1 Phase -Remotes	20,212	**1,684**	**$166.48**
GS 3 GSE-Networks	133,901	**11,158**	**$1,548.25**
GS 3 Phase-Remotes	133,901	**11,158**	**$959.39**
Streetlight-Networks	37,337	**3,111**	**$502.46**
Streetlight-Remotes	37,337	**3,111**	**$230.32**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #13 List 1

Exhibit G – Cost Allocation and Rate Design

Reference: Exhibit G1, Tab 1, Schedule 3, pages 7-8, G-Staff-25

Interrogatory

a) If not provided in response to Staff 25, please provide schedules that set out the current rates for Cat Lake and Pikangikum and also provide definitions for the customer classes used by each community.

b) Please provide the projected 2013 use per customer for each customer class for each of Cat Lake and Pikangikum.

c) Using the average use values from part (b), please provide a schedule for each of Cat Lake and Pikangikum which sets out the 2013 monthly bill for each non-Standard A customer class and compares it with the monthly bill that a similar customer would receive for 2013 if served by Hydro One Networks' Distribution.

Response

a) Please see Exhibit I, Tab 3, Schedule 13, Attachments 1 and 2 for the rates charged in Cat Lake and Pikangikum. Please note that the rates are not regulated by the Ontario Energy Board and that no detailed definitions for the rate classes are available.

b) & c)
Please see the schedules below. The bills do not include HST or DRC since most customers in Cat Lake and Pikangikum are exempt from these charges. Customers in Pikangikum are not currently participating in the OCEB program. Note that Remotes assumes that Standard A customers can generally be compared to Networks GS1 Phase Gse rate.

Bill Comparison, Average Usage by Class, Cat Lake to Hydro One Networks

Customer Class	Annual Avg kWh/Cust	Monthly Avg kWh	Total Monthly Bill After OCEB
Networks Residential R1	16,800	**1,400**	**196.64**
Cat Lake Residential	16,800	**1,400**	**$120.60**
Networks GS 1 Phase Gse	18,000	**1,500**	**231.73**
Cat Lake GS 1 Phase	18,000	**1,500**	**$165.29**
Cat Lake Standard A	30,000	**2,500**	**$1,432.08**

Bill Comparison, Average Usage by Class Pikangikum to Hydro One Networks

Customer Class	Annual Avg kWh/Cust	Monthly Avg kWh	Total Monthly Bill After OCEB
Networks Residential R1	17,437	**1,453**	**203.7**
Pikangikum Residential	17,437	**1,453**	**$170.18**
Pikangikum Residential Old Age	17,437	**1,453**	**$85.09**
Networks GS 1 Phase Gse	22,089	**1,841**	**278.21**
Pikangikum Commercial Native	22,089	**1,841**	**$238.01**
Pikangikum Arena	22,089	**1,841**	**$1,042.34**
Pikangikum Commercial Non-Native	672,517	**56,043**	**$11,671.75**
Networks GS 3 Phase Gse	672,517	**56,043**	**$7,666.68**
Pikangikum Standard A	44,604	**3,717**	**$4,062.75**

Hydro One Networks Inc.
www.HydroOne.com

483 Bay Street
South Tower, 8th Floor
Toronto, ON, M5G 2P5
Oded.Hubert@hydroone.com

Tel: (416) 345-5240
Fax: (416) 345-5870
Cell: (416) 903-5240

Oded Hubert
Director, Regulatory Compliance

hydro one

October 19, 2006

Mr. Neil McKay
Manager, Facilities Applications
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Mr. Mckay; Dear Neil;

Review of Hydro One's Operations at Cat Lake

In a Decision and Order dated July 21, 2006 (EB-2006-0180), the OEB issued to Hydro One an interim distribution licence (ED-2006-0181) authorizing Hydro One to take possession and control of the deemed distribution assets owned by Cat Lake Power and the distribution assets in the Cat Lake community that are owned by the Ontario Electricity Financial Corporation. Hydro One Networks assumed possession and control of the assets covered by this order at 12:01 am on August 14, 2006. Hydro One's interim distribution licence expires on October 21, 2006.

We have been requested to provide the following information to the OEB as a summary of our operations to date in the Cat Lake community.

1. *Assessment of the condition of the distribution assets since taking possession and control (take over date). There are two sets of assets, those who were listed under the transmission licence which Cat Lake Power was the owner and the licensee, and the distribution assets owned by OEFC and is inside the community;*

   Answer: Hydro One's initial focus was to familiarize ourselves with the Cat Lake system, including obtaining and updating drawings.

   Cat Lake had apparently operated the system using a "corrective maintenance" philosophy. As such, there is little evidence that any preventative maintenance was performed; instead, maintenance was performed when equipment failed.

   Customer meters in the community had not been re-calibrated and re-sealed for the last 7 years, and were therefore non-compliant with Measurement Canada requirements. Many were not working. To ensure compliance and accurate billing, Hydro One has replaced all the meters in the community. Street lights, in particular were found in bad condition.

We have not conducted a comprehensive asset condition assessment at Cat Lake.

2. *Tracking the costs since the take over date, delineated by the two sets of distribution assets;*

   Answer: In its Order, the Board deemed the transmission assets owned by Cat Lake Power to be distribution assets. As instructed, Hydro One is recording the revenues from the customers in the Cat Lake community and the "costs of operation and maintenance of the system". OM&A and Capital Costs are recorded separately. The Order did not require separation of costs by asset owner. Accordingly, Hydro One has not incurred the additional costs to perform such cost tracking.

   Costs incurred, to the end of September, are about $145,000. This comprises payments to the IESO for 1.5 months of energy charges, capital expenses (new connections), and OM&A (for field work, billing system input and modifications, and administration). To date, Hydro One received and responded to 3 requests for new connections. A significant portion of the OM&A expenses is for transportation of personnel and materials (helicopters cost is approximately $ 8,250 per day).

3. *Tracking the revenues since the take over date from the rates charged to end-use customers (if available– revenues by class would be helpful). Please also attach the rates charged by class and the number of customers in each class;*

   No revenues have been booked to date, as the first bills have not yet been issued. Revenues for Cat Lake are recognized on a cash basis.

   The rates by class and the number of customers in each are as follows:

Rate Class	**# of Customers**	**Volumetric Charge**	**Service Charge**
Residential	106	$.09/kWh	$8.00/month
General Service	12	$.0865/kWh	$27.95/month
General Service 3 Phase	2	$.0965/kWh	$27.95/month
General Service Standard A	17	$.6253/kWh	$27.95/month
Streetlight	1	$.36/kWh	n/a

4. *Report on any issues or challenges facing Hydro One in carrying out the requirements set out in the Interim Licence; and*
5. *Other items that Hydro One Networks believes are relevant to the Cat Lake situation.*

The answers to Questions 4 and 5 are summarized below:

<u>**Work Program Highlights and Operational Issues**</u>

Real Time Operating: Hydro One has incorporated the Cat Lake facilities into our Network Management System (Ontario Grid Control Centre), enabling Control Room operators to monitor and control the Cat Lake system. The IESO recently approached Hydro One regarding the Operations agreement that Cat Lake, as a transmitter, has with the IESO. The IESO would like to establish a MOU with Hydro One stating that all rights and obligations of Cat Lake with respect to that agreement now reside with Hydro One as per the OEB Order. We will meet with the IESO to explore this request further.

Field Operations: Maintenance and repairs are done by Hydro One staff based in Dryden TS.

Hydro One had met with Sioux Lookout Hydro, Thunder Bay Hydro, Windigo First Nations and Cat Lake staff to arrange the details of the transfer and to obtain necessary information. At that time, Hydro One also discussed with these parties the possibility of having local personnel perform some of the 'back office' functions (eg billing, meter reading and collections), while Hydro One takes on the field operations. However, in most areas, this did not materialize.

Customer Communications: Hydro One printed 100 flyers informing customers of the change in operations, and sent these to the Band Office, Chief Elsie Gray and Sioux Lookout Hydro staff. Customers were informed that they can place service requests as follows:

- During Business hours (7:30am to 4:30pm EST, or 6:30 AM to 3:30 PM Central): Hydro One Thunder Bay Field Business Center: 1-800-208-9412
- After hours trouble calls 1-800-434-1235 (Markham Call Center).

Incorporation of Customers in Customer Information System: Cat Lake's customer information was incorporated into Hydro One's CSS databases. This enables the Call Centre to receive calls from customers reporting troubles or inquiring about service, and ensures accurate billing through our regular billing process. Plans are in place for quarterly meter readings and monthly bills.

Meters: As noted above, customers meters in Cat Lake had not been re-calibrated and re-sealed in seven years, and were therefore non-compliant with Measurement Canada requirements. Many were not operational. Additionally, Hydro One did not have accurate data on the meters that were in existence in Cat Lake. To ensure that the billing is accurate and compliant with Measurement Canada, to allow Hydro One to set up the meters in CSS, and to better protect the meters in this environment, Hydro One installed new meters on or about October 2, 2006.

Meter Reading: Hydro One had arranged for a final meter reading to be done by Cat Lake staff on August 14th. Around August 31, we received the final meter readings which were performed on August 16th (instead of August 14th) and we commenced input of the data into the billing process. The next meter reading was performed on or about October 2nd together with the meters replacement. The first bills corresponding to the period between the above dates will be issued on October 20th.

Billing: Hydro One has collected the necessary information on the rate structures, customer lists (including streetlights), account details, GST and DRC exemptions; commodity pricing (RPP, spot, and retailer enrolled customers, generators); meter reading; billing and settlements. We have obtained from Cat Lake an electronic copy of all the bills since March, 2006 of this year. Until Hydro One can secure a resource on site in Cat Lake to read the meters on a monthly basis, all customers have been established in our systems as "read quarterly/bill monthly". The first bills corresponding to the period between August 16 and October 2 will be issued on October 20, 2006.

Accounts Payable and Accounts Receivable: All bills and invoices for services before August 14th are the responsibility of the Cat Lake utility, and Hydro One will not collect bill payments or pay any invoices for services or supplies to the utility before that date.

Collections: Collections activities have not begun yet, as the first bill will be issued shortly. Hydro One is in discussions with the Cat Lake Band to arrange for bill payment reception at the Band Office instead (or in addition to) mailing a cheque.

Customer Service System (CSS) Licencing Issue: Hydro One's "Customer/1" system license restricts the use of the application for Hydro One customers only. We resolved this issue by obtaining a 6-month exemption from Accenture to place these customers into CSS. The exemption will lapse on April 20, 2007.

GST: Hydro One is seeking direction on GST collection as it seems that Cat Lake was not registered with CCRA to collect it. In the short term, Hydro One will collect and report GST from Cat Lake customers using its own registration with CCRA.

Hydro One continues to operate the Cat Lake system and to manage issues associated with these operations. We will inform Board staff of any significant issues and solicit their advice or guidance as needed.

Sincerely,

Oded Hubert
Director, Regulatory Compliance
Hydro One Networks

Cc. Mr. Nabih Mikhail, OEB

March 1, 2006

ESHKOTAY WAYAB CORPORATION

Increase in Hydro Rates to Customers

		Existing	Proposed	Change %
Residential	Basic Charge	$16.45 month	$16.45 month	0%
	KWhrs	8.82 ¢/kWhrs	10.58 ¢/kWhrs	20%
Resid.Old Age	Basic Charge	$ 8.23 month	$ 8.23 month	0%
	KWhrs	4.41 ¢/kWhrs	5.29 ¢/kWhrs	20%
Commercial				
Native				
	Basic Charge	$27.95 month	$27.95 month	0%
	KWhrs	9.51 ¢/kWhrs	11.41 ¢/kWhrs	20%
Non Native				
	Basic Charge	$27.95 month	$27.95 month	0%
	KWhrs			
	1 to 12500	17.30 ¢/kWhrs	20.76 ¢/kWhrs	20%
	12500 +	17.30 ¢/kWhrs	20.76 ¢/kWhrs	20%
Arena	Basic Charge	$27.95 month	$27.95 month	0%
	KWhrs	45.92 ¢/kWhrs	55.10 ¢/kWhrs	20%
Standard A	Basic Charge	$27.95 month	$27.95 month	0%
	KWhrs	108.55 ¢/kWhrs	130.26 ¢/kWhrs	20%

Eshkotay Wayab Corporation is responsible for generating and distributing power to all customers in the community of Pikangikum. The power is produced by the diesel generators located near the airport.

Diesel Fuel is brought into the community by winter road for approximately 2 months. The remaining fuel deliveries are by air transport (Wasaya Airways). Cost of fuel for the diesel generators represents almost 73% of the overall costs of operating the power utility. During the period 2000 operating year to 2006 fuel costs have increased from approximately $800,000 to $1,600,000. This 100% increase in actual cost includes an increase in usage of 12.5%.

The Board of Directors and Staff of Eshkotay Wayab Corporation encourage all customers to pay their power bills every month. The Power Authority has not increased the rates charged to our customers since October 2000.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #14 List 1

Exhibit G – Cost Allocation and Rate Design

Reference: Exhibit G1, Tab 1, Schedule 3, page 8

Interrogatory

a) Assuming Hydro One Remotes applies for 2014 rates based on IRM what will be the annual RRRP level for 2014 - $34,510,000 or $35,329,000?

b) If it's the latter, please explain why?

Response

a) $34,510,000.

b) N/A

Nishnawbe Aski Nation (NAN) INTERROGATORY #1 List 1

Exhibit A - Administrative
Ref: Exhibit A, Tab 3, Schedule 1

On page 3, Remotes indicates that it is "proposing to increase rates to the average customer in its service territory by 3.45%, the average increase for grid-connected customers approved by the Board in 2011."

Interrogatory

a) To what extent has Remotes arrived at the proposed 3.45% increase by performing a deductive analysis based on its estimated budgetary needs, looking at the available sources of funding other than rate increases for the customers it serves, and then calculating the percentage rate increase from its customers that would be required for Remotes had to meet the budget that Remotes has put together? NAN cannot see any indication in Remotes' Application and filed evidence to suggest that any such (deductive) methodology has been used to arrive at the percentage rate increase that should be imposed on Remotes' customers.

b) Stated in a different manner, to what extent has Remotes simply adopted the 3.45% average increase for grid-connected customers approved by the Board in 2011 and then built its financial and budgetary analysis around the increased rate contribution it intends obtain from its customers? Based on NAN's review of the Application and filed evidence, it appears that this is the methodology which Remotes has used.

c) How much additional revenue (in total dollar terms) will Remotes obtain by increasing its customer rates by the proposed $3.45%.

Response

a) As indicated in Exhibit A, Tab 6, Schedule 1, page 2, Remotes customers do not pay rates based on the cost of service. Remotes did not base the proposed rate increases on its revenue requirement.

b) Remotes has not built its budget around the proposed 3.45% increase to its customer rates. As indicated in Exhibit A, Tab 14, Schedule 1, Remotes has built its financial plan based on the required levels of investment to meet its strategic goals and to mitigate risk associated with financial, operational, environmental, safety, regulatory and legal considerations.

c) In 2013, the proposed increase to customer rates will increase Remotes' revenues from its existing customers by $343 thousand. Over a full year, the proposed rate increase would increase revenues from existing customers by approximately $517 thousand.

Nishnawbe Aski Nation (NAN) INTERROGATORY #2 List 1

Exhibit A - Administrative

Summary of Remotes Business
Ref: Exhibit A, Tab 4, Schedule 1

On pp. 3-4, Remotes discusses the Electrification Agreements (NAN assumes those are the Agreements being referred to by Remotes in this Exhibit) between the federal and Ontario governments under which Remotes is ostensibly responsible for funding ongoing operations and maintenance of the generation/distribution system in the communities which it serves. According to Remotes, the same agreements specify that AANDC (formerly INAC) is responsible for funding capital related to system expansions and capital upgrades in First Nation communities.

Remotes notes that AANDC has devolved much of its financial responsibility for infrastructure to First Nation communities which now administer approximately 85 per cent of the funding that AANDC previously administered. Remotes suggests that this devolution of funding control has complicated the process for "capital upgrades" and ensured that it is not completely within Remotes control.

Finally, Remotes states that AANDC has advised that, owing to federal funding constraints, funding for "generation upgrades" or "generation capital" will not be included in AANDC's capital plan from 2012 to 2017. Remotes states that upgrades will likely be needed in seven communities during the next five years. Remotes also advises that it will not be able to "connect new customers in communities where generation has reached its limits-- but that Remotes' capital and maintenance programs must still be increased to meet safety, environmental, and reliability standards.

Interrogatory

a) What is the difference between Remotes' funding of "ongoing operations and maintenance of the generation/distribution system" and AANDC's funding of capital related to system expansions and capital upgrades in the same communities? How has this worked previously in terms of the sharing of funding between Remotes and AANDC for capital equipment in the generation/distribution system?

b) Please describe the process involved between Remotes and AANDC for the sharing or allocation of a capital expenditure, as follows:

   i. Who identifies the need for a capital expenditure as it relates to generation equipment?

   ii. Who identifies the need for a capital expenditure as it relates to distribution equipment?

iii. Who identifies which party to an Electrification Agreement should be paying for the capital cost of generation equipment which needs to be repaired, replaced, or upgraded (i.e. upgraded is understood by NAN as the need to replace generation equipment in order to increase the capacity/output of electrical supply)?

iv. Who identifies which party to an Electrification Agreements should be paying for the capital cost of distribution equipment which needs to be repaired, replaced, or upgraded?

v. If capital costs are to be apportioned between Remotes on the one hand, and AANDC on the other hand, who determines the percentage apportionment between these parties?

vi. What mechanisms exist to resolve any disputes between Remotes and AANDC concerning the apportionment of capital costs for certain equipment as between the two parties?

vii. What happens if AANDC objects to and then refuses to contribute to capital costs for certain equipment when called upon to do so? Does Remotes make the necessary capital investment to ensure that the equipment in question is either repaired, replaced, or upgraded?

c) Explain how the devolution of funding from AANDC to First Nation Communities (e.g. Band Councils) since the 1990s has affected any responsibility which AANDC has under the Electrification Agreements to contribute to the capital costs of certain equipment for the generation/distribution system. Remotes has suggested that funding devolution has had certain impacts on the allocation of responsibility between Remotes and AANDC under the Electrification Agreements and NAN would appreciate knowing what Remotes believes those impacts are.

d) Remotes suggests that devolution of funding from AANDC to First Nation communities has complicated the process for "capital upgrades" and ensured that it is not completely within Remotes control. How has devolution of funding had that impact? Is Remotes suggesting that devolution of funding to First Nation communities has involved AANDC delegating financial responsibility to those communities for the capital costs which AANDC was previously bearing under the Electrification Agreements? Please explain what Remotes means by its comments on the devolution of funding and, if possible, compare the current situation to the situation that existed for Remotes before devolution was implemented.

e) What conununications have been ex hanged between Remotes and AANDC on the funding constraints relating to AANDC s capital plan for 2012 to 2017? Please produce any and all relevant documentation between Remotes and AANDC concerning this issue, which is of considerable significance to NAN.

f) How does Remotes intend to deal with the issue of repairing, replacing, and/or upgrading any equipment during the years 2013 to 2017 inclusive to which AANDC would have otherwise contributed if AANDC will not be contributing to the capital costs of such equipment during that period? Does Remotes intend to provide the capital funding for the activities that it would ordinarily provide and not compensate for any shortfall caused by a lack of contribution on the part of AANDC? If so, how will the existing and future electrical needs of First Nation communities be met?

g) After noting the funding constraints of AANDC during the period 2012 to 2017, Remotes states that its own capital and maintenance programs must still increase to meet safety, environmental, and reliability standards. Please explain how AANDC funding constraints (i.e. reduced capital funding for certain generation/distribution equipment is linked to an increase in Remotes' capital and maintenance work programs designed to meet safety, environmental and reliability standards. Does Remotes not have to fund those programs in any event?

Response

a) AANDC is responsible for actual construction of new assets that will expand system capacity. Remotes is responsible for on-going maintenance and operations. This is both the current and the historical funding relationship. To add clarity, a household example is provided. AANDC is responsible for buying a vehicle suitable for the family (community) needs, whereas Remotes is responsible for the necessary oil changes, tires, brakes, and fuel etc to keep the vehicle running.

b) Note that when the term “Customer” is used below, the term is based on the definition in the Electrification Agreements. The Electrification Agreements define “Customers” to mean “a user of power supplied through systems constructed or acquired pursuant to this Agreement.”

   i. Remotes identifies the need for capital expenditures related to generation equipment.

   ii. Remotes identifies the need for capital expenditures related to distribution equipment replacement and repair. The need for capital expenditures related to distribution expansion are normally identified by the community.

   iii. Under the Electrification Agreements, Remotes is responsible for repairing and replacing assets and is also responsible for making rates and charges associated with providing electrical service. When changes are required to the electrical system as a result of increased electrical load, Remotes is responsible for determining which portion is to be paid by AANDC and which portion by Customers.

iv. The Electrification Agreements specify that when capital charges are related to increases in electrical load, Remotes is responsible for determining which portion is to be paid by AANDC and which portion by Customers.

v. Remotes determines the portion of capital costs associated with load growth to be paid for by AANDC and by other Customers.

vi. There is no dispute resolution mechanism to resolve disputes over the apportionment of capital under the Electrification Agreements. Remotes notes that there have been no disputes relating to the distinction between operations and maintenance funding, capital replacements and capital expansions.

vii. Remotes continues to repair and replace equipment as required. As part of the upgrade and capital process, AANDC and the community hire an independent consultant to review Remotes' identified capital needs and to present alternative solutions. AANDC's decision to fund capital costs is solely their decision. If generation upgrades and funding is delayed, connection restrictions are put in place. Remotes does not currently upgrade the electrical systems unless AANDC or the local First Nation agrees to pay for the cost of the upgrade.

c) Remotes does not believe that AANDC's devolution of funding to First Nation Band Councils has changed AANDC's responsibilities to fund the capital costs associated with load growth under the Electrification Agreements.

d) Prior to AANDC's devolution of funding, Ontario Hydro was itself responsible for building capital upgrades. Ontario Hydro would give an estimate to AANDC and AANDC would fund the approved cost of upgrades. The funding process is now more complex as many parties are involved and many separate approvals are required. First Nation Band Councils must develop Terms of Reference to apply for funding to review Remotes' identified need for an upgrade, to study alternatives and to present alternative solutions if they exist. If funding is approved, a tender to complete the study is put to competition. Once the study is complete, the First Nation must apply for funding for a project. If a project is approved for funding, a competitive tender is required to hire a project management/engineering/consulting firm. Remotes, AANDC, and the First Nations collaborate on drafting the tender proposal and all three parties review and rate the responses. Once the project management/engineering/consulting firm wins the tender, then construction proceeds in accordance with Remotes' standards. In order to commission and accept the station, Remotes must inspect it and ensure that it meets its standards. If there are deficiencies, all four parties must come to an agreement about resolving those deficiencies. The process is more complex as more approvals are required and more parties are involved.

e) Please below for the relevant exerpts from the minutes of the annual planning meeting held with AANDC (then INAC) on April 12, 2011.

INAC Budget & Processes

Leigh Jessen explained that INAC's budget is constrained, and that needs far out weigh available resources. The Economic Action Plan provided some additional funding for schools, housing and water but that program has now ended. INAC has a 5 year capital plan that must provide for all infra structure.
Project costs have recently increased, so fewer projects can be completed. Priorities are based on health and safety, focus is on water and the strategic partnership initiatives (remote energy, ring of fire).

Total Ontario Budget is $1.2B, to cover salaries and transfers to First Nations. Capital and O&M budget is $200-210M. This pot covers transfers including minor capital and O&M funding agreements and core capital.

Sectoral agreements require INAC to fund specific activities such as education. Budget is targeted to education.
The "discretionary" capital budget is $100M for Ontario Region. Budget has been cut by 16-20%. Emergencies and health and safety items impact planning for this budget amount. New schools are now planned nationwide, with projects competing for funds. Targeted funding for infrastructure is increasing, reducing flexibility.

Leigh Jessen noted that First Nations do have other sources of funding, including the private sector, provincial governments and other federal departments such as Health Canada. Janet Kendall advised that communities also have access to application based funding, for economic development initiatives as an example.

Kasabonika Lake Upgrade

Hydro One advised that Kasabonika Lake has needed an upgrade for 2 years, and that the community has been on connection restrictions since 2008. Hydro One and the community signed an MOU for an upgrade and the community has borrowed funds to purchase a new generator.

Leigh Jessen stated that the Kasabonika Upgrade is not on INAC's five year capital plan. She noted that First Nations do get some funding from sources other than INAC, so can borrow money for capital projects. She noted that INAC would not be providing the community with a letter, at this time, to confirm that it will fund a future upgrade.

Upgrade Requirements

Ralph Falcioni presented the peak load report and noted that (excluding the Webequie project) upgrade projects are forecast to need to start 6 communities, Kasabonika, Kingfisher, Wapekeka, Big Trout Lake, Deer Lake and Gull Bay, by 2014.

Leigh Jessen explained that due to budget constraints, there are no upgrades currently built into INAC's 5 year plan.

A meeting was also held August 20, 2012 where AANDC explained that, due to ongoing funding constraints, funding for generation upgrades would not be available in its most recent 5 year plan. Minutes were not taken for that meeting. Please also see Attachments 1 and 2 of this Exhibit, which show the forecast for required upgrades that Remotes shared with AANDC at the two meetings. Attachment 3 is a letter provided to AANDC to advocate for upgrade funding for the community of Kasabonika Lake.

f) As indicated in the application, particularly in Exhibit C, Tab 2, Schedule 2 and in Exhibit D1, Tab 2, Schedule 1, Remotes is requesting an increase to its revenue requirement to fund the increased maintenance costs associated with repairing and replacing assets that were expected to be replaced through generation upgrade projects. These investments are required to maintain generation reliability and to maintain the current levels of generation available. Remotes does not currently plan to compensate for the shortfall in federal government funding for increasing the available generation in the communities.

g) When generation assets are replaced through upgrades, smaller generation assets are replaced by new, larger units. AANDC is responsible for paying for these larger units. If upgrades are delayed, then the cost to replace and repair these smaller assets is borne by rate payers, and by increases to RRRP. Similarly, when generating stations are upgraded, a new station is built to accommodate the increased size of the generating units. When these upgrades are delayed, older stations must be maintained to meet reliability, safety and environmental standards.

STATION UPGRADE PROCESS STARTS 2012 July 16

Based upon recent community peak loads within past five years.
Any major housing starts or infrastructure projects will advance timing.
Connection restrictions levied on community when load reaches 85% of station Prime Rating.
Station Prime Rating determined by sum of all gensets except largest single unit.
Typical community growth is 3% to 5% annually.

YEAR UPGRADE IDENTIFIED	Estimated Restriction 85%	LOCATION	STATION PRIME RATING	RECENT 2011-2012		HISTORICAL FIVE YEAR	
2006	now	KASABONIKA	1000	874	87%	900	90%
		DEER LAKE (Diesel Only)	**1200**	**1156**	**96%**	**1156**	**96%**
	now	**DEER LAKE with 160 kW from one hydraulic**	**1360**	**1156**	**85%**	**1156**	**85%**
	now	**KINGFISHER**	**705**	**598**	**85%**	**598**	**85%**
2012	2015	**WAPEKEKA**	**705**	**555**	**79%**	**555**	**79%**
	2015	BIG TROUT LAKE	1600	1223	76%	1249	78%
2004	2016	FORT SEVERN	650	497	76%	524	81%
2002		WEAGAMOW					
		Remotes 3-gen plant	650	936	144%	967	149%
		4-unit plant	1250	936	75%	967	77%
	now	3 largest units only	1000	936	94%	967	97%
		GULL BAY	**430**	**317**	**74%**	**317**	**74%**
		SANDY LAKE	**3250**	**2316**	**71%**	**2316**	**71%**
		LANSDOWNE	**650**	**446**	**69%**	**446**	**69%**
		ARMSTRONG/WHITESAND	**1425**	**890**	**62%**	**890**	**62%**
		SACHIGO	1055	630	60%	670	64%
		WEBEQUIE	1000	565	57%	614	61%
		BEARSKIN	1000	567	57%	639	64%
		MARTEN FALLS	650	350	54%	383	59%

BOLD INDICATES NEW PEAK SET THIS PAST WINTER SEASON

STATION UPGRADE PROCESS STARTS

2011 March 02

Based upon recent community peak loads within past five years.
Any major housing starts or infrastructure projects will advance timing.
Connection restrictions levied on community when load reaches 85% of station Prime Rating.
Station Prime Rating determined by sum of all gensets except largest single unit.
Typical community growth is 3% to 5% annually.

YEAR UPGRADE IDENTIFIED	Estimated Restriction 85%	LOCATION	STATION PRIME RATING	RECENT 2010-2011		HISTORICAL FIVE YEAR	
2002		**WEAGAMOW**					
		Remotes 3-gen plant	**650**	**967**	**149%**	**967**	**149%**
		4-unit plant	**1250**	**967**	**77%**	**967**	**77%**
	now	**3 largest units only**	**1050**	**967**	**92%**	**967**	**92%**
2004	now	WEBEQUIE	650	602	93%	614	94%
2006	2008	**KASABONIKA**	**1000**	**900**	**90%**	**900**	**90%**
2004	2011	FORT SEVERN	650	478	74%	546	84%
	2012	KINGFISHER	650	531	82%	532	82%
	2013	WAPEKEKA	705	540	77%	546	77%
	2013	**BIG TROUT LAKE**	**1600**	**1249**	**78%**	**1249**	**78%**
		DEER LAKE (Diesel Only)	**1035**	**934**	**90%**	**934**	**90%**
	2013	**DEER LAKE with 160 kW from one hydraulic**	**1195**	**934**	**78%**	**934**	**78%**
		GULL BAY	**430**	**315**	**73%**	**315**	**73%**
		SANDY LAKE	3200	2253	70%	2257	71%
		SACHIGO	1000	626	63%	670	67%
		ARMSTRONG / WHITESAND	1450	745	51%	898	62%
		BEARSKIN	1000	564	56%	639	64%
		LANSDOWNE	650	368	57%	460	71%
		MARTEN FALLS	650			383	59%

BOLD INDICATES NEW PEAK SET THIS PAST WINTER SEASON

Nishnawbe Aski Nation (NAN) INTERROGATORY #3 List 1

Exhibit A - Administrative

Compliance with Licence and OEB Filing Requirements for Electricity Distributors
Ref: Exhibit A, Tab 6, Schedule 1

On page 5, Remotes notes that its cost of capital is based on a "100% debt financing structure", consistent with a previous decision of the OEB. Further, as "Remotes operates as a break-even company, it does not plan to seek a return on capital."

Interrogatory

a) What does Remotes mean by "100% debt financing structure"? This is not clear.

b) Does Remotes actually borrow funds to make whatever ongoing capital investments it must make to maintain and operate its generation and distribution facilities? Or are most of Remotes' capital needs met through the RRRP subsidy which it receives each year?

c) What does Remotes mean by the term "break-even company"? Please elaborate. Remotes uses this term frequently in Hs filed evidence. NAN assumes that Remotes does not mean that its capital expenditure and operating and maintenance costs are equivalent to its revenue sources because Remotes entire perations ar heavily subsidized by other ratepayers in the Province through the RRRP.

Response

a) The financing of Rate Base for most electrical utilities uses a combination of debt and most utilities earn a return on their equity investment. Remotes is financed only through debt and therefore does not earn an equity return.

b) Remotes maintains $23 million of publicly-issued, long term debt having a maturity date of May 19, 2036. Remotes also borrow funds as required through an inter-company demand facility, as indicated on page 5 of Exhibit A, Tab 11, Schedule 1.

c) Remotes means that its expenditures equal its revenues, with any difference being recorded in the RRRP variance account. Revenues include revenues from its own customers and revenues from RRRP.

Nishnawbe Aski Nation (NAN) INTERROGATORY #4 List 1

Exhibit A - Administrative

Green Energy Plan
Ref: Exhibit A, Tab 16, Schedule 1

Remote claims that it is working with local First Nations and with private sector developers to assist in developing renewable energy resources. Remotes also states that "the development of renewable energy is limited by very small community loads and the lack of water and wind resources close to the communities."

Interrogatory

a) What precisely is Remotes doing in the area of developing renewable energy resources? Please identify the specific First Nation communities which Remotes is working with, outline what Remotes has done during the past five years to assist in the development of renewable energy resources, identify the private sector developers being referred to, and disclose the capital investment Remotes has made in this area during the past five years.

b) Please provide any investigations or studies which Remotes has conducted or commissioned which confirm that the potential to develop renewable energy resources close to First Nation communities is limited, having regard to Remotes' statements about the lack of water and wind resources.

Response

a) Hydro One Remotes is actively encouraging the development of renewable technologies in its communities through the introduction of the REINDEER program. The REINDEER program is a renewable program designed to encourage diesel reduction through the introduction of renewable technology within our service territory by purchasing power at the avoided cost of diesel. Please refer to Attachment 1.

   Over the last five years, Remotes has had various community and supplier discussions and meetings about renewables. Additionally, we have added on-going technical support and provided critical data in the investigation of these technologies. Communities that have been more active in the investigation of renewable technologies include Bearskin Lake, Fort Severn, Deer Lake, Kasabonika, Kingfisher, North Caribou and Sandy Lake. Suppliers have included various wind, solar, hydro-electric and organic rankine cycle suppliers. As stated in the noted section, Remotes believes that First Nations must be involved in renewable energy projects in their communities. Over the last 5 years, Remotes has continued to maintain and operate two hydels and small demonstration windmills as its commitment to renewables.

b) Remotes has not conducted or commissioned its own studies regarding water or wind power. Remotes knowledge of water and wind resources within the communities we serve is largely supported by studies external to Remotes. Some of these studies or reports are publically available from group such as Ontario Hydro, OPA, Ontario Water Association, MNR, Ontario Sustainable Energy Association and others. Additionally, Remotes discusses renewable options with communities regularly including wind and water resources. Although wind and water resources do exist, close proximity to communities is essential in making these projects cost effective.

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay ON P7E 6G9
Toll Free: 1-888-825-8707
Telephone: 1-807-474-2800
Fax: 1-807-577-1318

www.HydroOne.com

Remote Communities Inc.

Hydro One Remote Communities Inc.
Renewable Energy INovation DiEsel Emission Reduction (REINDEER) Standard and Load Displacement Guideline

Hydro One Remote Communities Inc. (Remotes) is a subsidiary of Hydro One Inc. From its service centre in Thunder Bay, Ontario, provides energy services primarily through diesel generation to approximately 3500 customers in 21 remote northern communities that are not connected to the provincial electricity grid.

The Ontario Power Authorities (OPA) FIT or MicroFIT program does not currently extend to Remotes' service territory. Potential REINDEER providers are encouraged to review both OPA programs at www.powerauthority.on.ca as they may be better suited to participant needs.

Remotes is interested in enabling the connection of renewable energy projects to reduce the impact of diesel fuel on the environment within its service territory. The guidelines surrounding projects of this nature are provided below.

Renewable Energy INovation DiEsel Emission Reduction (REINDEER) Standard Guideline

The standard REINDEER guideline is as follows:

- REINDEER provider builds, owns, operates and maintains all assets up to and including point of connection to Remotes' distribution system.
- Hydro One Remotes provides connection access to the distribution system or generation station as applicable provided that the REINDEER project meets technical and metering specifications.
- Remotes' service reliability, customer power quality and existing assets must not be negatively impacted by the connection of the generation facility.
- REINDEER projects must be sized according to the electricity needs of the community and according to the kW size of the existing generation in the community.
- Hydro One Remotes reserves the right to determine the connection point and configuration to its distribution system.
- Hydro One Remotes offers to pay the 3 year historical average cost of fuel per KWH produced/avoided cost of fuel specific to that community.
- Escalation of the offer rate will be increased annually based on the Consumer Price Index for "all items" as established by Statistics Canada.
- 10 year term, renewable thereafter in 5 year contracts.
- Amounts to be paid to the REINDEER provider quarterly.
- Consultation with First Nation communities may be required as directed by Hydro One Remotes.
- All projects must meet the technical requirements set out in Sections 6.2.25, 6.2.26 and 6.2.27 of the Distribution System Code.

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- REINDEER projects must be sized according to generation in each community. All projects are subject to a technical review. The proponent is responsible for paying for the cost of this technical review. Generally, larger projects will require a more comprehensive engineering review.
- REINDEER project providers must enter into a connection agreement with Remotes.
- All contracts are subject to legal review and must be approved by President & C.E.O. of Hydro One Remotes

REINDEER Proposed Rates

The proposed rates as of January, 2012 (based on 2009-2011 annual data) are as follows:

ARMSTRONG	0.226
BEARSKIN	0.448
BIG TROUT (KI)	0.440
BISCO	0.316
DEER LAKE	0.372
FORT SEVERN	0.682
GULL BAY	0.254
HILLSPORT	0.328
KASABONIKA	0.382
KINGFISHER	0.395
LANDSDOWNE	0.394
MARTEN FALLS	0.521
OBA	0.382
SACHIGO	0.410
SANDY LAKE	0.364
SULTAN	N/A[1]
WAPEKEKA	0.498
WEAGAMOW	0.340
WEBEQUIE	0.428

[1] Reindeer Projects not required in Sultan

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Alternatives and Conditions to the REINDEER Standard Guideline

Hydro One Remotes recognizes that its operating environment is unlike any other and the above guideline may not match the unique circumstances of each situation.

As such:

- Hydro One Remotes is willing to commit labour and equipment resources, to install, operate and maintain any REINDEER project, provided that the offered rate is reduced accordingly.
- Hydro One Remotes will not provide up-front financing or capital contribution at this time.
- Hydro One Remotes will also consider asset purchase clauses, during or at expiry of the contract term.
- Preference is given to proven technology. Remotes may consider research or innovation projects provided the contract terms are adjusted accordingly. Hydro One Remotes reserves the right to assess each project on its own merit and may consider variations of standard terms, provided regulatory and business requirements are met.
- Hydro One Remotes reserves the right to withdraw this guideline at any time.

Load Displacement Guideline

Hydro One Remotes encourages proponents to consider working with First Nations to develop Load Displacement Projects as an alternative to stand alone generating projects.

Load Displacement Projects are permitted within Hydro One Remotes' service territory. Load Displacement permits customers to generate their own electricity to reduce or eliminate the per kWh cost of electricity paid to Hydro One Remotes.

Electricity must be generated primarily for use within the metered facility and must be generated from a renewable source. Projects must be sized according to the facility's load. An engineering review of the connection is required in order to qualify for connection to Hydro One Remotes' distribution system and for the purchase of stand-by power from Hydro One Remotes.

From time to time, Load Displacement Projects may send excess generation into Hydro One Remotes' distribution system. Hydro One Remotes will credit the customer's bill for this excess electricity based on the REINDEER rates. The bill credits for electricity beyond the customer's own needs will expire after 12 months.

Additional REINDEER Standard Guideline Information

Potential REINDEER providers looking for additional information are to contact Kevin Mann, Manager of Generation, Hydro One Remote Communities Inc. at 807-474-2802 or kevin.mann@HydroOne.com.

Nishnawbe Aski Nation (NAN) INTERROGATORY #5 List 1

Exhibit B1 – Cost of Capital

Cost of Capital
Ref: Exhibit B1, Tab 1, Schedule 1

In this Exhibit, Remotes identifies the amount of its deemed short-term debt, third party debt, long-term debt, and deemed long-term debt.

Interrogatory

a) What is the source of Remotes' original $23 million worth of third party long-term debt that was matched by a note issued by Hydro One Inc. on 1 April 1999 in consideration of the assets transferred? What assets are being referred to?

b) What is Remotes' deemed long-term debt of $16,446,000 for the year 2013 comprised of? Please explain what Remotes means by stated that the long-term debt "reflects the remaining amount of debt required to balance the total financing with the rate base." This is not clear to NAN.

Response

a) As discussed on lines 8 to 12, page 2 of Exhibit B1, Tab 1, Schedule 1, Remotes' original $23 million of third party long-term debt matured in November 2005 and was refinanced in 2005 with new debt having a maturity date of May 19, 2036. The original $23 million debt was issued in 1999 in consideration of the assets transferred from Ontario Hydro to Hydro One Remotes.

b) Remotes' deemed long-term debt of $16,446,000 reflects the remaining amount of debt required to finance the rate base. This is calculated as Remotes 2013 rate base of $41,090,000 less third party long term debt of $23,000,000 less deemed short term debt of $1,644,000.

<u>Nishnawbe Aski Nation (NAN) INTERROGATORY #6 List 1</u>

Exhibit C – Cost of Service

Summary of OM&A Expenditures
Ref: Exhibit C1, Tab 2, Schedule 1

Remotes notes that its total OM&A expenditures will increase by approximately 10% during the 2012 to 2013 period, in part because of the increase in transmission and distribution costs associated with serving two new grid-connected communities-Pikangikum and Cat Lake First Nation in 2013.

<u>Interrogatory</u>

a) Does Remotes see any conflict between its role as a grid-connected transmitter and distributor of electricity to certain communities which it serves, and its role as a generator and distributor in other communities using diesel generation? Has Remotes considered filing separate applications to the OEB in respect of the capital, operating, and maintenance costs as a transmitter/distributor as opposed to its role as a generator/distributor using diesel generation?

b) Leaving the contribution of the RRRP aside, to what extent are the additional capital and operating & maintenance costs of transmitted electricity to Pikangikum and Cat Lake First Nation being spread among other communities served by Remotes?

<u>Response</u>

a) No. Remotes does not believe that a conflict exists. Furthermore, Remotes does not intend to separate its business into separate components in order to serve grid connected communities and has therefore not contemplated filing a separate application.

b) The cost to serve Pikangikum and Cat Lake are not being spread among the communities Remotes currently serves. Please also see Exhibit I, Tab 3, Schedule 11 for a schedule setting out the portions of the requested RRRP that are required to make up the differences between revenues at proposed 2013 rates and 2013 revenues for the Off Grid and Grid-connected communities

Nishnawbe Aski Nation (NAN) INTERROGATORY #7 List 1

Exhibit C – Cost of Service

Generation OM&A
Ref: Exhibit Cl, Tab 2, Schedule 2

Remotes states that the single most costly aspect of Remotes' operation is fuel. In this Exhibit at p. 10, Table 5, Remotes indicates that average delivery cost per litre is $1.53, a figure which NAN has assumed was based on prices in the Fall of 2012. Based on NAN's own research, the "at the pump" prices for diesel in Ontario, as of March 26, 2013, were as low as $1.04/litre and as high as $1.50/litre, with the price in Kapuskasing being $1.47/litre.

Remotes observes that the cost of delivery of fuel is approximately 45% of the cost of the fuel itself, with air delivery comprising 70% of the fuel delivered to communities served by Remotes. Remotes also states that winter roads are becoming less and less reliable for the delivery of full fuel loads.

In addressing fuel usage as a means to reduce the costs of fuel overall, including delivery costs, Remotes advises that it has instituted CDM programs for communities and residential customers; Renewable Energy Technologies generation facilities; it has improved fuel generation efficiency through SCADA technology; it has a proactive scheduled maintenance program; and there is an active generation asset replacement program combined with more efficient technology. With respect to SCADA, Remotes indicates in Exhibit C1, Tab 2, Schedule 2, that it has improved fuel generating efficiency through such technology and by instituting a proactive scheduled maintenance program.

Interrogatory

a) What will be the estimated high and low and average cost of fuel/litre delivered by various means to Remote communities in 2013?

b) Given the problems with the reliability of winter road delivery, and the high cost of delivering fuel to communities by air transport, is Remotes working on a strategy to mitigate the costs of fuel delivery in the future (e.g. by increasing storage capacity in various communities, or by other means). If so, what kinds of alternative measures has Remotes identified thus far?

c) Who bore the cost of the SCADA program, hardware and communications infrastructure? Who will bear the on-going costs of that program?

d) Can Remotes provide confirmation of the savings achieved to date by using SCADA?

e) Have SCADA and other technologies been made available to the First Nations for other infrastructures such as water and sewage treatment?

f) Is the SCADA program considered part of the costs of *upgrading* generation, such that they should be borne by AANDC?

g) Is the SCADA system being used to monitor the distribution systems in communities served by Remotes?

h) Is the SCADA software, and its supporting telecommunications technology, capable of supporting smart metering in communities served by Remotes?

i) What effect has the SCADA program/technology had on the frequency and nature of community visits by Remotes' officials to perform ongoing maintenance and/or disconnection or reconnections of electrical service?

Response

a) The high and low average cost of fuel delivery into Remote communities is a factor of the distance of a community as well as the means of transportation. As a result, the following estimates were made for the 2013 year:

		Estimate Per Unit Cost		
Community Location	**Means of Delivery**	**Low**	**High**	**Average (weighted)**
Road/Rail Access	All Weather Road	$0.989	$1.029	$1.002
Air Access	Air	$1.468	$2.625	$1.729
Air Access	Winter Road	$0.838	$1.804	$1.030
Air Access	External Source (i.e. First Nation)	$1.466	$2.363	$1.660

b) Yes, Remotes has in place a strategy to mitigate the costs of fuel delivery as well as to ensure secure and reliable supply given the challenges associated with winter road delivery and high cost of air transportation. Remotes has taken many different steps to reduce risks associated with fuel delivery. Please see Exhibit I, Tab 1, Schedule 12 for further details.

c) Remotes paid for the initial installation of the SCADA system (between 1999 and 2004). SCADA systems are now part of the station standard so that when stations are upgraded, AANDC pays for the installation of the new system. Remotes pays for the ongoing operation and maintenance of the SCADA systems.

d) Please see Exhibit I, Tab 1, Schedule 10.

e) No they have not. The SCADA technology Remotes uses is specific to generation and would not provide benefit with respect to the other services mentioned.

f) See answer to part c) above. Remotes expects this arrangement to continue.

g) Remotes does not use the SCADA system specifically to monitor the distribution system. However, the station SCADA technology is used to help trouble shoot and identify causes of distribution outages, to monitor outages that affect the entire community and to assist in balancing distribution load.

h) No. Significant improvements in both telecommunications and software would be necessary to support smart meters.

i) SCADA technology provides instant (real time) and valuable information that helps to better manage work. SCADA technology has improved the visibility of the station operations to both the operator and to staff in Thunder Bay, which improves trouble shooting, planning and normal maintenance. The most obvious benefit is a reduction in the frequency of crews flying in to communities to perform trouble-related work. Many issues can be resolved by the on-site operator and a contact in the Thunder Bay Service Centre discussing and working together to investigate the SCADA alarm files. Disconnections and reconnections are not impacted by SCADA operation. General maintenance and reliability is also improved as the SCADA helps to identify and analyse areas of operating concern.

Nishnawbe Aski Nation (NAN) INTERROGATORY #8 List 1

Exhibit C – Cost of Service

Distribution OM&A
Ref: Exhibit Cl, Tab 2, Schedule 3

Interrogatory

a) Please clarify the meaning of sentence beginning on page 2, line 27: Lower distribution operations in 2010 compared to 2009 primarily reflect lower data collection activities as part of Remotes' program to assess the condition of its distribution assets.

b) On page 3, Remotes projects that increases between 2012 and 2013 reflect increased trouble response ($180,000), higher planned maintenance ($111,000) and higher forestry services ($1,200,000) mainly associated with clearing the transmission line right of way to Cat Lake and costs associated with service to Pikangikum ($380,000). What is the basis for the $180,000 trouble response estimate? Also, how do the forestry costs of $1,200,000 relate to a request for a rate increase for *generation and distribution* in the communities served by Remotes?

Response

a) Due to the small isolated distribution systems, Remotes asset condition assessment program is cyclical in nature to maximize efficiencies in data collection and provide an outlook of maintenance and capital defect correction that will be required over a five year planning period. The majority of Remotes' assets were assessed in 2009 and will be reevaluated in 2015.

b) Most of the increased trouble call response is related to Cat Lake and Pikangikum. The estimate for these communities was derived from experience with similar sized communities. The forestry costs associated with the Cat Lake "transmission" line do not relate in a linear fashion to the request for a rate increase. The requested rate increase is based on the average increase for grid-connected customers approved by the board in 2011.

Nishnawbe Aski Nation (NAN) INTERROGATORY #9 List 1

Exhibit C – Cost of Service

Customer Care OM&A
Ref: Exhibit Cl, Tab 2, Schedule 4

Remotes indicates that it applied credits to bad debt expense in 2009, 2010 and 2011 because of Remotes' "success in neg tiating paym nt arrangements with First Nation Band Councils." Further, and despite statements that Remotes bad r duced the overall amount of bad debt from 2009 onward, Remotes asserts that "bad debt expense is expected to increase to reflect the conclusion of most of these payment plans in the bridge and test years."

Interrogatory

a) What payment arrangements is Remotes referring to in its evidence? Please identify the Band Councils in question and the month and year of the alleged payment arrangements.

b) If possible, please provide written evidence of such payment arrangements.

c) Were the payment arrangements made by Band Councils on behalf of residential customers in their communities? In other words, were the payment arrangements in relation to residential accounts?

d) Or were the payment arrangements made in respect of Standard A accounts which had fallen into arrears?

e) What is the percentage breakdown between bad debt attributable to residential customers and bad debt attributable to Standard A customers for the years 2009, 2010, 2011, and 2012?

f) Please provide a copy of any standard form payment agreement used by Remotes in the negotiations it says it conducted in 2009,2010, and 2011.

g) Please indicate if bad debt expense actually increased in 2012, and provide further details on why Remotes believes that bad debt will increase in 2013.

h) Why would bad debt be expected to increase in the coming years because of the conclusion of payment plans previously arranged between Band Councils and Remotes? Does Remotes not have arrears payment programs or bad debt recovery arrangements in place on an ongoing basis?

Response

a) For customer confidentiality reasons, non-identifying information is provided in the table below.

Band Council	Duration of Plan
A	Sept/05 – Aug/10 Completed
B	Oct/07 – Nov/11 – Completed
C	Apr/07 – Jan/08 - Completed June/08 – Oct/11 – Completed
D	Aug/08 – Sept/11 - Completed
E	June/08 – Aug/11 - Completed
F	Dec/11 – Sept/12 - Completed Jan/12 – Feb/19 – In progress

b) Remotes cannot provide written evidence of such payments; this information is confidential.

c) No. The payment arrangements were not made by Band Councils on behalf of residential customers in their communities.

d) Yes. The payment arrangements were for accounts under the Band's control and were Standard 'A' accounts and non-residential accounts.

e) Bad debt is not broken down among rate classes in the manner requested.

f) A copy of Remotes Standard Form Payment Arrangement used and in use by Remotes is included as Exhibit I, Tab 4, Schedule 9, Attachment 1. Note that this standard form and the covering letter are templates only and the contents of the related plan may change with each use.

g) No. Bad debt expense was lower than forecast as a result of payments resuming under a payment plan for a group of accounts with particularly high, aged arrears.. Because the allowance is based on aging, bad debt expense will increase once all or most of the significantly aged arrears are paid.

h) The conclusion of the previous payment plans resulted in the reduction of substantial and significantly aged arrears and, therefore, the reduction of the bad debt allowance and a credit to bad debt expense. Once all or most of these significantly aged arrears are paid, bad debt expense will be based on normal accounts receivable activity. Remotes continues to negotiate and enter into payment plans for these more recent arrears.

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

[Insert Date]

Chief & Council
[Insert Band Council Address]

Re; **[Insert Band Council] Energy Arrears Payment Plan**

Dear Chief & Council

We have carefully reviewed the "**[Insert Band Council]**" accounts with Hydro One Remote Communities Inc. ("Hydro One") and the arrears (balances) as at **[Insert Date].** With this and further to recent correspondence between myself and representative of **[Insert Band Council]** we wish to propose a payment plan that would serve to reduce these historical balances to nil. We propose that this payment plan addresses only the balances as of the said date and that all current and future Hydro One billings to **[Insert Band Council]** remain "current" and outside of this payment plan.

Please review the attached plan, and if acceptable, sign and return to me.

Thank you.
Sincerely,

[Insert Name]
Customer Service Manager
Ph. **[Insert Phone Number]**

cc. **[Insert Any Relevant Partie(s) as Agreed]**

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hydro one

Letter of Understanding on First Nation Energy Arrears Payment Plan

This letter will document Hydro One Remote Communities Inc.'s ("Hydro One") and **[Insert Band Council]** agreement on a payment plan (the "Plan") to assist the **[Insert Band Council]** in managing their energy arrears owing to Hydro One as of **[Insert Date]**. This Letter of Understanding applies to accounts listed in Attachment 1. The Plan is as follows:

- **[Insert Band Council]** currently owes Hydro One the sum of **[Insert Amount]** for outstanding First Nation energy arrears. A summary of the accounts is listed in Attachment "1" (the "Outstanding Arrears").
- **[Insert Band Council]** will pay Hydro One over the course of this agreement, **[Insert Amount]** (the "Arrears Payment") broken down on a **[Insert Payment Frequency]** basis as indicated in Attachment "2" starting with the **[Insert Date]** billing and until such time as the outstanding arrears described in Attachment "1" (the "Outstanding Arrears") have been reduced to zero.
- **[Insert Band Council]** will also pay their regular monthly energy accounts identified in Attachment 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.
- **[Insert Band Council]** payments must be received by the Hydro One Remotes Office in Thunder Bay by the date identified on the monthly bills.
- In recognition of **[Insert Band Council]** efforts in paying the Outstanding Arrears, Remotes will waive future monthly interest charges on the Outstanding Arrears provided that the **[Insert Band Council]** makes all Arrears Payments and pays its regular monthly bill;
- Failure to pay Hydro One any Arrears Payments or the **[Insert Band Council]** regular monthly bill will result in the application of current and future interest on the Outstanding Arrears to the **[Insert Band Council]** 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 **[Insert Band Council]** 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 First Nation's control (i.e. Program funding deposits from Indian and Northern Affairs Canada or gaming commission revenues are delayed) and for extreme financial hardship. A mutually agreeable timeframe for continuance of payments will be determined.
- This agreement will be subject to a review in **[Insert Review Years]** years by Hydro One and **[Insert Band Council]** in **[Insert Review 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.

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The parties agree that this letter accurately reflects the understanding reached by Hydro One Remote Communities Inc. and **[Insert Band Council]**. 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.
[Insert Name]
Director, Hydro One Remote Communities Inc.

[Insert Band Council]. by the Chief of the **[Insert Band Council]** and a majority of the Council of the **[Insert Band Council]** at the **[Insert Band Location]** Indian Reserve on this ___ day of ________, **[Insert Year].**

Witness	Chief
Witness	Councilor
Witness	Councilor
Witness	Councilor
Witness	Councilor

Attachment # 1 – Outstanding Arrears

Hydro One Remote Communities Inc.
Summary of Arrears
Customer: [Insert Band Council]

TOWNSHIP	REVENUE CLASS	STR #	METER #1	Premise Identifier	CUST LEGAL NAME	BILL ACCNT	0 - 21 DAYS	22 - 59 DAYS	60 - 119 DAYS	120 - 239DAYS	240 - 1YEAR	1 - 2YEARS	A/R
[First Nation Name]	Commercial	500	J1xxxx4	"The Bowling Alley"	[Insert Band Council]	35xxxxxx2	200.00	200.00	500.00	1,000.00	1,700.00	1,700.00	**5,300.00**
[First Nation Name]	Commercial	501	J1xxxx5	"The Store/Commercial Complex"	[Insert Band Council]	35xxxxxx3	2,000.00	2,100.00	4,200.00	8,400.00	9,100.00	8,100.00	**33,900.00**
[First Nation Name]	Commercial	502	J1xxxx6	"The Hotel"	[Insert Band Council]	35xxxxxx4	600.00	500.00	-	-	-	-	**1,100.00**
[First Nation Name]	Commercial	503	J1xxxx7	"The Store 2"	[Insert Band Council]	35xxxxxx5	500.00	1,000.00	-	-	-	-	**1,500.00**
[First Nation Name]	Commercial	504	J1xxxx8	"The Garage"	[Insert Band Council]	35xxxxxx6	10,000.00	15,000.00	15,000.00	100,000.00	100,000.00	200,000.00	**440,000.00**
[First Nation Name]	Commercial	505	J1xxxx9	"The Water Plant	[Insert Band Council]	35xxxxxx7	9,000.00	18,000.00	36,000.00	36,000.00	144,000.00	144,000.00	**387,000.00**
[First Nation Name]	Commercial	506	J1xxx10	"The Industrial Building"	[Insert Band Council]	35xxxxxx8	9,000.00	11,000.00	5,000.00	50,000.00	56,200.00	-	**131,200.00**
												Total	**1,000,000.00**

Attachment # 2 – Payment Plan Schedule

Sample Payment Schedule

Month	Year	Outstanding Amount*	Payment*	Total*	Current Bill EXTRA**
January	20xx	1,000,000	(40,000)	960,000	TBD
February	20xx	960,000	(40,000)	920,000	TBD
March	20xx	920,000	(40,000)	880,000	TBD
April	20xx	880,000	(40,000)	840,000	TBD
May	20xx	840,000	(40,000)	800,000	TBD
June	20xx	800,000	(40,000)	760,000	TBD
July	20xx	760,000	(40,000)	720,000	TBD
August	20xx	720,000	(40,000)	680,000	TBD
September	20xx	680,000	(40,000)	640,000	TBD
October	20xx	640,000	(40,000)	600,000	TBD
November	20xx	600,000	(40,000)	560,000	TBD
December	20xx	560,000	(40,000)	520,000	TBD
January	20xx	520,000	(40,000)	480,000	TBD
February	20xx	480,000	(40,000)	440,000	TBD
March	20xx	440,000	(40,000)	400,000	TBD
April	20xx	400,000	(40,000)	360,000	TBD
May	20xx	360,000	(40,000)	320,000	TBD
June	20xx	320,000	(40,000)	280,000	TBD
July	20xx	280,000	(40,000)	240,000	TBD
August	20xx	240,000	(40,000)	200,000	TBD
September	20xx	200,000	(40,000)	160,000	TBD
October	20xx	160,000	(40,000)	120,000	TBD
November	20xx	120,000	(40,000)	80,000	TBD
December	20xx	80,000	(40,000)	40,000	TBD
January	20xx	40,000	(40,000)	0	TBD

*** Note: All amounts are fictitious and for display purposes only**
**** Note: Current monthly charges must be kept current**

Nishnawbe Aski Nation (NAN) INTERROGATORY #10 List 1

Exhibit C – Cost of Service

Community Relations Operations, Maintenance and Administration
Ref: Exhibit Cl, Tab 2, Schedule 5:

Remotes notes in Exhibit C1, Tab 2, Schedule 5, page 2 at line 3 that Remotes includes three communities per year in the CDM program, and that eventually all communities will have participated in the program.

Also in Exhibit Cl, Tab 2, Schedule 5, page 2 at line 13, Remotes states that customer conservation programs resulted in 245,600 kWH of yearly savings and life cycle savings of 1,891,878 kWH.

Interrogatory

a) Why is the CDM program staggered and limited to three communities per year?

b) Why is the CDM program not on-going and available to all communities simultaneously if it has had such a positive effect on the reduction of energy use, the consumption of fuel, and operational costs in communities served by Remotes?

c) How were these alleged savings in electricity use determined by Remotes?

d) On page 2, line 16, it is noted that the OPA Conservation Program for the Remotes service territory is not yet available. Is this Program projected to be available this calendar year? If so, what effect is predicted to result from the co-ordinated conservation programs?

Response

a) Including more than two or three communities per year in Remotes' Pilot Program would require significantly more resources than what is available within Remotes' current funding levels.

b) Please see a) above. Remotes also notes that there are three components to the program, a "pilot" program, which focuses on up to three communities per year; a rebate program, which is available to all fly-in communities; and a commercial program, which is also available to all fly-in communities.

c) The savings are calculated using the OPA's Prescriptive Measures and Assumptions Lists based on the products, materials and appliances Remotes has distributed and installed or that customers have purchased through the rebate program.

d) The OPA announced an Aboriginal Conservation Program on March 25, 2013. One community in Remotes' service territory is expected to be included in this program in 2013. Remotes does not know the predicted savings from the OPA program.

Nishnawbe Aski Nation (NAN) INTERROGATORY #11 List 1

Exhibit C – Cost of Service

Shared Services and Other Administrative Costs
Ref: Exhibit Cl, Tab 2, Schedule 6, p. 3, Table 2

Table 2 notes that the Low Income Energy Assistance Program (LEAP) cost for each of the years 2011 , 2012, and 2013 will be $52,000.

Interrogatory

a) In November 2010, Hydro One wrote to the OEB and indicated that it wanted an *exemption* from LEAP requirements as it related to Cat Lake First Nation. NAN is not aware of Hydro One having commenced any application for an exemption from LEAP requirements, as outlined under the Distribution System Code. What is the status of LEAP for Cat Lake First Nation? Has LEAP been made available to residents of Cat Lake? If so, what is the source of funding for the LEAP in Cat Lake First Nation? Has Hydro One or Remotes identified a social agency partner to administer LEAP in Cat Lake First Nation?

b) What is the status of arrears payment programs for regular customers and low-income customers in Cat Lake First Nation? Has Remotes being complying with the requirements of the Distribution System Code in offering arrears payment programs to residents in Cat Lake First Nation?

c) Were all of the funds made available for LEAP in 2011 and 2012 used by the low-income applicants for such assistance? Did demand for financial assistance from LEAP outstrip the funds available for applicants in the years 2011 and 2012? If so, by what aggregate amount?

d) Has Remotes identified a social agency partner to administer LEAP in every First Nation community it serves?

e) What is the source of financing for LEAP in First Nation communities served by Remotes? Is the funding for LEAP derived from additional charges applied to the electricity bills of Remotes' customers? Or is a funding source *external* to Remotes' customers being used to fund LEAP in each community?

Response

a) Hydro One Networks currently offers LEAP to Cat Lake. The lead agency for Hydro One Networks is 'United Way of Greater Simcoe Country' and they are responsible for the overall LEAP program – including Cat Lake. The local Social Service rep for the Cat Lake Band office is the intake agency.

b) Hydro One Networks currently offers arrears payment programs in accordance with the Distribution System Code to all its customers, including those in Cat Lake. Remotes does not yet serve the community of Cat Lake. Remotes expects to serve customers in Cat Lake under the same Conditions of Service as all of the rest of its customers.

c) No. The funds were not fully spent in either year.

d) Remotes has contracted with the Ontario Native Welfare Administrators Association (ONWAA) to act as its social agency partner in all of the communities Remotes serves.

e) Remotes has requested funding for LEAP as part of its overall revenue requirement, to be funded by its customers and by RRRP in the same proportion as all of its costs.

Nishnawbe Aski Nation (NAN) INTERROGATORY #12 List 1

Exhibit C – Cost of Service

Depreciation and Amortization Expenses
Ref: Exhibit C1, Tab 4, Schedule 1

Remotes discusses liabilities relating to the remediation of past environmental contamination, specifically the assessment and remediation of contaminated lands based on th net present value of these estimated future expenditures. Remotes also notes that such expenditures are expected to be recoverable in future rates. Based on the figures in Table (Remotes Amortization Expense), the environmental expenditures appear to be significant and they will increase substantially in 2012 and 2013.

Interrogatory

a) Remotes notes that most of the contamination at Remote sites is associated with historic spills of diesel fuel. Have all of the sites for which remediation is planned been identified in this Schedule (i .e. Sandy Lake, Pikangikum Attawapiskat, and Webequie) ? If not, what are the other sites that are or will be the subject of environmental assessment and remediation?

b) Who was in possession, charge, or control of the diesel fuel when the historic spills of diesel fuel occurred at the sites being referred to in this Schedule?

c) If Remotes (or its predecessor, Ontario Hydro) was responsible for the historic/previous spills of diesel fuel at a site, what basis does Remote believe it has to pass onto its customers (many of whom are low-income customers) the costs of environmental assessment and remediation?

d) On page 4, in Table 2, the 2013 Environmental Assets Amoritization expense is estimated at $2,713,000. The narrative also indicates that the 2013 expense includes the remediation of an old tank farm site at Attawapiskat at a cost f $350,000. Why has the existing or proposed expenditure on this environmental clean-up work been included in the costs identified in this Application because Attawapiskat is not listed as one of the communities to which Remotes provides electricity.

Response

a) Sites for which remediation and/or monitoring are planned include the following generating sites that were once served by Ontario Hydro:

- Attawapiskat (tank only)
- Bearskin Lake

- Big Trout Lake
- Biscotasing
- Cat Lake
- Deer Lake
- Fort Severn
- Gull Bay
- Hillsport
- Kasabonika Lake
- Kingfisher Lake
- Lansdowne House
- Oba
- Pikangikum
- Sachigo
- Sandy Lake
- Sultan
- Wapekeka
- Weagamow
- Webequie

b) Ontario Hydro

c) Approval to remediate historic spills and to monitor sites under this program was originally approved by the OEB in RP-1998-0001.

d) The LAR program relates to the remediation of contamination associated with historic spills by Ontario Hydro.

Nishnawbe Aski Nation (NAN) INTERROGATORY #13 List 1

Exhibit C – Cost of Service

2009 Board Approved vs. 2009 Actual OM&A Variance Explanations
Ref: Exhibit C2, Tab 6, Schedule 1

Remotes notes that its actual OM&A costs were almost $6 million lower than Remotes had estimated in the OEB proceeding which was EB-2008-0232. Approximately half of that amount was due to lower than expected diesel fuel prices, with the remainder accounted for by lower generation maintenance, lower customer care, distribution and community relations costs. Also, bad debt expenses were lower than expected because of the "successful negotiation of arrears payment plans with First Nation communities."

Interrogatory

a) Given that the OEB approved a rate increase in EB-2008-0232 based on estimated OM&A costs of $36,020,000 when the actual costs were only $30,125,000 (a difference of $5,895,000), has any *rebate* been given to Remotes' customers since they were compelled to pay a rate increase based on significantly higher costs which never materialized? If not, why not?

b) With respect to the within Application, does Remotes propose to offer a rebate to its customers to the extent that the projected overall costs on which the 3.45% rate increase is being requested for OEB approval do not materialize? If not, why not?

Response

a) No. Remotes notes that the increase to its customers in 2009 was 4.4%, and was based on the Ontario LDC average. RRRP increased by a greater amount. Remotes is of the view that basing its customer increases on the Ontario LDC average is equitable. Fuel and transportation costs in Remotes service territory are inherently volatile. Remotes would not want to set a precedent whereby 100% of the volatility of its costs is borne by its customers.

b) No. Please see the answer to a) above.

Nishnawbe Aski Nation (NAN) INTERROGATORY #14 List 1

Exhibit D1 – Rate Base

Capital Programs
Ref: Exhibit D1, Tab 2, Schedule 1

Remotes refers in Exhibit D1, Tab 2, Schedule 1 to the Electrification Agreements with INAC (now AANDC), under which the latter funds new generation and distribution capital within First Nation communities served by Remotes. NAN understands that most of those Agreements were entered into during the 1980s and 1990s between what used to be Ontario Hydro on the one hand, and the Department oflndian and Northern Affairs Canada (INAC) on the other.

In making reference to the Electrification Agreements, Remotes also notes that the assets purchased using federal funds become the property of Remotes, although they are not included in the rate base or revenue requirement as they have a nominal carrying value because they are provided as contributed capital. Remotes states that in non-First Nation communities, a similar arrangement exists, except that the provincial government funds the original costs of the plants.

NAN makes the following requests as they relate to the issue of the said Electrification Agreements or such other electrification agreements as may have been executed after the termination of any Electrification Agreements:

Interrogatory

a) Provide copies of all of the Electrification Agreements and any amendments thereto for the First Nation communities served by Remotes;

b) Provide copies of any other electrification agreements which have replaced the Electrification Agreements if the latter have been terminated by either party thereto.

c) Are there any electrification agreements which have been entered into by Remotes or any of its corporate predecessors where a First Nation community or Band is actually a signatory to the agreement? If so, please produce copies of any such agreements.

d) When Remotes states that AANDC funds new generation and distribution capital within First Nation communities served by Remotes, does Remotes mean that AANDC funds such costs *at first instance*, that is, when electrification is being introduced into a First Nation community where it did not previously exist? Or does Remotes mean that such funding is provided by AANDC on an ongoing basis to fund the costs of replacement generation and/or distribution equipment as older equipment wears out? In other words, please clearly identify the capital costs which are ordinarily paid for by AANDC under Electrification Agreements as well as the capital costs which are paid for by Remotes-- whether at first instance when a generation or distribution system is initially being constructed in a First Nation community or, alternatively, where an existing system is being maintained on an ongoing basis, replaced as equipment wears out, or upgraded to expand its capacity.

e) On page 2, Remotes indicates that it capitalizes costs that are directly attributable to the acquisition and construction of capital projects, as well as certain overhead and indirect costs. Are the capital costs incurred by Remotes for the construction and/or replacement of generating or distribution facilities in First Nation communities passed onto or imposed on any of these entities by way of electricity rates or special charges?

   i. a First Nations business enterprise entirely owned by one or more First Nation persons;

   ii. a First Nation community enterprise, including a business undertaking by a First Nations Band;

   iii. a residence consisting of one or more units in which every occupant is a First Nations person or, alternatively, where there are non-First Nation boarders or lodgers who are paying compensation to a First Nations person for such service;

   iv. a school or other educational facility operated by the Federal Government; or

   v. any premises which have been specifically designated by the Minister of AANDC (or his predecessor, a former Minister ofiNAC)

f) In the First Nations communities served by Remotes, are the costs to make service connections to any one of the following entities passed onto or imposed on these entities by way of electricity rates or special charges?

   i. a First Nations business enterprise entirely owned by one or more First Nation persons;

   ii. a First Nation community enterprise, including a business undertaking by a First Nations Band;

   iii. a residence consisting of one or more units in which every occupant is a First Nations person or, alternatively, where there are non-First Nation boarders or lodgers who are paying compensation to a First Nations person for such service;

   iv. a school or other educational facility operated by the Federal Government; or

v. any premises which have been specifically designated by the Minister of AANDC (or his predecessor, a former Minister ofiNAC)

g) On page 6, Remotes states that "because of the inherent uncertainty of costs and budgeting associated with catastrophic failures, emergency system breakdowns are no longer included in Remotes' business plan."

i. What was the practice of Remotes in the past in providing for reserves or contingency funds for emergency system breakdowns? If such figures were estimated and included in previous business plans, how can Remotes advise that such matters now involve inherent uncertainty of costs and budgeting and therefore they should be excluded from the business plan? What circumstances have changed since 2011 (See Table 4 on p. 6) to warrant such a conclusion?

ii. Remotes also states that minor breakdowns would be addressed in the engine replacement program. Catastrophic failures would be treated as unforeseen expenditures." Can Remotes provide examples of "catastrophic failures"? What is meant by this term as it relates to the breakdown or viability of equipment? Do catastrophic failures include leaks or ruptures from diesel fuel tanks and/or associated piping? Please provide clarification.

h) Given that AANDC has been funding certain capital upgrades in First Nation communities, which therefore reduces the capital costs associated with Remotes' activities in those communities, why have electrical rate increases in such communities been set at the same level as non-First Nation communities served by Remotes?

i) Why has Remotes not created and calculated a two-tiered rate increase structure for non-First Nation communities (which do not receive federal funding for capital expenditures) and the First Nation communities (which do receive federal funding and thereby reduce the capital costs payable by Remotes in such communities)?

j) By not differentiating between non-First Nation communities (which do not receive federal funding) and First Nation communities (which do receive federal funding) as far as rate increases are concerned, does Remotes not agree that First Nation communities end up bearing the burden of certain capital costs in non-First Nation communities which they should not be bearing?

Response

a) Please find attached a representative Electrification Agreement attached as Exhibit I, Tab 4, Schedule 14, Attachment 1. All of the Electrification Agreements in place between Remotes and its communities have effectively the same terms.

b) Remotes does not have any Electrification Agreements that have replaced a terminated agreement.

c) Please find attached as Attachment 2, a signed copy of an agreement for service with the community of Marten Falls First Nation. .

d) Under the Electrification Agreements, the federal government, through AANDC, is responsible to pay the ongoing cost for capital associated with increased load in the communities. Please also see Exhibit I, Tab 4, Schedule 1, b).

e) Yes, pursuant to the terms of the Electrification Agreements.

f) Yes, pursuant to the terms of the Electrification Agreements.

g)

i. The previous practice was to include an arbitrary amount for unexpected failures. Given the unknown nature, timing and amount of expenditures related to unexpected failures, it was decided that this arbitrary amount should no longer be included in revenue requirement. Remotes does not feel that it is in the best interest of its rate payers to include in rates an amount for capital expenditures that has a limited certainty of being spent and that is largely beyond our control.

ii. Catastrophic failures are unexpected, unforeseen major breakdowns where the existing generating unit can not be repaired in a cost effective manner. This is normally when the engine block or significant components are permanently compromised and beyond safe repair. Although catastrophic, tank leaks or ruptures are not considered failures, and if they were to happen would be handled under the normal unplanned tank maintenance program.

h) Remotes is proposing an increase to its customer rates based on the average increase to customers of LDCs across Ontario. The proposed rate increases do not cover the entire cost to provide electricity to any of the communities that Remotes serves.

i) The federal government and the provincial government (through Ontario Hydro) agreed to share the costs to serve First Nation communities in Remotes service territory. In no community that Remotes serves do the local rate payers cover the full cost to generate and distribute electricity. In that context, Remotes does not believe that it is necessary to create different rates for non First Nation and First Nation off-grid communities.

j) No. Please see Exhibit I, Tab 3, Schedule 11, b) for details on the total amounts contributed by Remotes' rate payers toward the actual costs.

AGREEMENT FOR ELECTRICAL SERVICE

KINGFISHER COMMUNITY ELECTRIFICATION

THIS AGREEMENT made in triplicate this 23rd day of March 1989.

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.

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
Supt. Of Finance and Administration

Date

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

THIS OPERATING AGREEMENT made this 11th day of ~~April~~ May, 2009

AMONG:

MARTEN FALLS, a Band of Indians or any successor to the Band within the meaning of the *Indian Act* represented by the Marten Falls Band Council (the "**First Nation**")

OF THE FIRST PART

- and -

HYDRO ONE REMOTE COMMUNITIES INC., a body corporate incorporated pursuant to the *Ontario Business Corporations Act*, ("**Remotes**")

OF THE SECOND PART

- and -

HER MAJESTY THE QUEEN in RIGHT of CANADA, as represented by the Minister of Indian Affairs and Northern Development ("**INAC**" or "**DIAND**" or the "**Minister**")

OF THE THIRD PART

WHEREAS Remotes is agreeable to operating the Marten Falls Assets on the terms and conditions herein during the Term.

NOW THEREFORE, for and in consideration of the mutual promises and of the agreements set forth herein and for good and valuable consideration the receipt and sufficiency of which is irrevocably acknowledged, the parties hereto mutually agree as follows:

1. In this Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Applicable Laws" means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any government or government department, commission board, court authority or agency and includes codes and terms of licences issued by the OEB.

"Capital Funding Process" means INAC's defined processes for capital projects, as they may be amended or replaced from time to time.

"Conditions of Service" means Remotes' Conditions of Service document as developed by Remotes in accordance with subsection 2.4 of the Distribution System Code that describes Remotes' operating practices and connection rules, as it may be amended or re-issued from time to time.

"Distribution Services" is as defined in the Distribution System Code.

"Distribution System Code" means the code of standards and requirements issued by the OEB on July 14, 2000, as it may be amended from time to time.

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"**DGS**" means the diesel generating station located on the Marten Falls Reserve.

"Electricity Act, 1998" being Schedule "A" to the *Energy Competition Act,* S.O. 1998, c. 15, and regulations made thereunder, all as amended or replaced, from time to time.

"Electrical Distribution System" means the system for distributing electricity, and includes any structures, equipment or other things used for that purpose. The Electrical Distribution System is comprised of the main system capable of distributing electricity to many customers and the connection assets used to connect an individual customer to the main systems. The demarcation point between the Electrical Distribution System and the assets owned by individual customers in the community is the top of a customer's service entrance stack for overhead connections.

"Environmental Site Assessment Report" means the Phase II Environmental Site Assessment & Remedial Investigations and Options Analysis – Marten Falls Diesel Generating Station Final Report performed by Anebeaaki Environmental Inc. dated October 2008.

"Excluded Assets" means those assets identified in Schedule "B" that are located on the Marten Falls Reserve or on properties adjacent to the Marten Falls Reserve .

"Force Majeure Event" means, in relation to any party to this Agreement, any event or circumstance, or combination of events or circumstances,

(i) that is beyond the reasonable control of the affected party;
(ii) that adversely affects the performance by the affected party of its obligations under this Agreement; and
(iii) the adverse effects of which could not have been foreseen or prevented, overcome, remedied or mitigated in whole or in part by the person through the exercise of diligence and reasonable care and includes, but is not limited to, acts of war (whether declared or undeclared), invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, civil disobedience or disturbances, vandalism or acts of terrorism, strikes lockouts, restrictive work practices or other labour disturbances, unlawful arrests or restraints by government or governmental, administrative or regulatory agencies or authorities unless the result of a violation by the person of a permit, licence or other authorization or of any applicable law, and acts of God including lightning, earthquake, fire, flood, landslide, unusually heavy or prolonged rain or accumulation of snow or ice or lack of water arising from weather or environmental problems;

provided however, for greater certainty, that the lack, insufficiency or non-availability of funds shall not constitute a Force Majeure Event.

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America.

"**Indian Act**" means *Indian Act*, R.S.C. 1985, c. I-5, and regulations made thereunder, all as amended or replaced, from time to time;

"Initial 5 Year Operating Term" means the period of time commencing on the Takeover Day and terminating on the 5th anniversary of the Takeover Day.

"**Marten Falls Assets**" means all fixtures, chattels and equipment located on the Marten Falls Reserve or on properties adjacent to the Marten Falls Reserve that now or in the future comprises or relates to:

(i) the Electrical Distribution System;
(ii) the DGS including, but not limited to those assets that are identified in Schedule "A"; and
(iii) the Meter Installations,

with the exception of the Excluded Assets.

"**Marten Falls Reserve**" means Marten Falls Indian Reserve No. 186, in the Province of Ontario.

"**Meter Installation**" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment. For greater certainty, the meter base does not form part of the Meter Installation.

"**OEB**" means the Ontario Energy Board.

"**Ontario Energy Board Act, 1998**" means the *Ontario Energy Board Act, 1998* being Schedule "B" to the *Energy Competition Act,* S.O. 1998, c. 15, and regulations made thereunder, all as amended or replaced, from time to time.

"**Pre-existing Environmental Condition**" means the presence of any contamination, whether on the Marten Falls Reserve or on properties adjacent to the Marten Falls Reserve, that has (i) been identified in the Environmental Site Assessment Report; or (ii) existed prior to Remotes commencing its performance of the obligations set out in Section 7 of this Agreement, whether or not such contamination is identified in the Environmental Site Assessment Report. In the event of any dispute between the parties as to whether contamination constitutes a Pre-Existing Environmental Condition, the First Nation shall bear the burden of proving that the contamination resulted from the activities of Remotes on the Marten Falls Reserve and is not a Pre-existing Environmental Condition.

"**Standards for Hydrocarbons in Soil**" means the Canadian Council of Ministers of Environment's Canada Wide Standards for Hydrocarbons in Soil.

"**Takeover Day**" means the day that the First Nation and Remotes mutually agree that Remotes will begin to generate and distribute electricity in the community of Marten Falls using the Marten Falls Assets, which day shall not be later than 100 days following the later of the date that:

(i) the conditions precedent described in Section 4 below have been satisfied; and
(ii) the date that all obligations set out in this Agreement to be performed prior to Takeover Day have been performed.

"**Term**" has the meaning ascribed thereto in Section 6 of this Agreement.

<u>Representations and Warranties</u>

2. The First Nation represents and warrants to Remotes that:

(a) the First Nation has all necessary power, authority and capacity to enter into this Agreement and to perform its obligations hereunder;
(b) the execution of this Agreement and compliance with and performance of the terms, conditions and covenants contemplated herein have been duly authorized by all necessary

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action on the part of the First Nation, including the passing of Band Council Resolutions, certified copies of which have been delivered to Remotes simultaneously with the execution and delivery of this Agreement;

(c) no consent, authorization or approval of, or exemption by, any governmental or public body or authority, or by any person, pursuant to statute, contract or otherwise, is required by the First Nation in connection with the execution and performance of this Agreement, or any of the covenants or transactions contemplated herein referred to, or the taking of any action contemplated herein;

(d) the First Nation owns the Marten Falls Assets; and

(e) the First Nation has received competent and independent legal advice with respect to all the terms and conditions of this Agreement and its implementation.

3. Remotes represents and warrants to the First Nation that:

(a) Remotes is a corporation duly incorporated and validly subsisting in all respects under the laws of its jurisdiction of incorporation;

(b) Remotes has all necessary corporate power, authority and capacity to enter into this Agreement and to perform its obligations hereunder;

(c) the execution of this Agreement and compliance with and performance of the terms, conditions and covenants contemplated herein have been duly authorized by all necessary corporate action on the part of Remotes;

(d) no proceedings have been instituted by or against Remotes with respect to bankruptcy, insolvency, liquidation or dissolution; and

(e) except for the approval of the conditions outlined in 4(a), (b), (c) below, no consent, authorization or approval of, or exemption by, any governmental or public body or authority, or by any person, pursuant to statute, contract or otherwise, is required by Remotes in connection with the execution and performance of this Agreement, or any of the covenants or transactions contemplated herein referred to, or the taking of any action contemplated herein.

Conditions Precedent and Term

4. The parties acknowledge and agree that this Agreement and the fulfillment of all terms and conditions hereunder are conditional upon:

(a) Remotes obtaining an amendment to its distribution and generation licences issued by the OEB in accordance with section 57 of the *Ontario Energy Board Act, 1998* or obtaining such other required documentation or approval from the OEB that will permit Remotes to generate electricity and distribute electricity within the Marten Falls Reserve;

(b) Ontario Reg. 442/01 "Rural or Remote Electricity Rate Protection" being amended such that consumers who occupy premises, other than government premises, in the Marten Falls Reserve are eligible for rate protection under section 79 of the *Ontario Energy Board Act, 1998*; and

(c) Ontario Reg. 199/02 being amended to add the Marten Falls Reserve to the list of communities prescribed for the purposes of subsection 48.1(1) of the *Electricity Act, 1998*.

5. If any of the conditions precedent set out in Section 4 above are not satisfied by July 1, 2009 and a time extension cannot be agreed upon, the parties agree that there shall be no legal obligation or any liability of any nature whatsoever with respect to the matters described herein by virtue of this Agreement, and no party shall be liable for any penalty or damages as a result thereof.

6. Subject to the termination rights set out in Subsections 12.1 and 12.2 of this Agreement, this Agreement shall have a term commencing as of the date first above written and upon the expiration of the

Initial 5 Year Operating Term, this Agreement shall be deemed to be renewed automatically for such further and consecutive one (1) year terms **(each one year term, a "Renewal Term")** unless either Remotes or the First Nation delivers written notice to the other Parties by no later than twelve (12) calendar months prior to the expiration of the Initial 5 Year Operating Term or a Renewal Term advising that the notifying Party does not wish to renew this Agreement, in which event this Agreement shall terminate. Notwithstanding the foregoing, if either Party gives notice of termination under this Section 6 during the Initial 5 Year Operating Term, this Agreement shall not terminate until the end of the Initial 5 Year Operating Term.

Terms and Conditions

7. Commencing on the Takeover Day and thereafter during the Term, Remotes shall:
   (a) maintain in force, at its sole cost and expense, any and all necessary licences, permits and approvals required under the *Ontario Energy Board Act* in order for Remotes to perform its obligations under this Agreement;
   (b) operate, maintain, repair and replace (including any repair or replacement arising out, related to or attributable to a Force Majeure Event) the Marten Falls Assets in accordance with Good Utility Practice, all Applicable Laws, and the *Distribution System Code*;
   (c) provide Distribution Services in accordance with its distribution licence issued by the OEB, the *Distribution System Code* and the Conditions of Service;
   (d) have the right to grant joint use to third parties (provided such third parties obtain their own permit pursuant to Section 28 of the *Indian Act*) in accordance with the Remotes practices in the other communities served by Remotes, including, but not limited to the right to refuse to permit joint use activities on all or any portion of the Electricity Distribution System save and except that Remotes will not be entitled to refuse to permit joint use activities associated with attachments already attached to poles as of the date of this Agreement where such attachments are not in compliance with Remotes practices in other communities until such time as the joint user is proposing to replace such attachments;
   (e) integrate the existing Marten Falls customer base, as well as future customers into Remote's customer billing system (CSS) and to bear those costs;
   (f) charge electricity rates and charges approved by the OEB;
   (g) subject to (ii), (iii) and (iv) below, assume the responsibilities for and the cost of the operation and maintenance of the Marten Falls Assets; and
   (h) assume responsibility for and the cost of the replacement of the Marten Falls Assets once the First Nation has complied with its obligations under Subsection 8(b) below.

   Notwithstanding the foregoing, the First Nation and Remotes agree as follows:

   (i) Remotes will not be required to operate any of the Marten Falls Assets that Remotes considers unsafe or an environmental hazard until such time as the First Nation has complied with its obligations under Subsection 8(d) below to remedy the deficiencies and make the operational improvements described therein;
   (ii) at no time will Remotes be financially responsible for the cost of remedying any of the deficiencies identified by the Technical Standards and Safety Authority and the Electrical Safety Authority or the deficiencies and operational improvements described in Schedules "C" and "D" attached hereto;
   (iii) at no time will Remotes be financially responsible for the cost of any capital improvements required to meet future load growth in Marten Falls;
   (iv) at no time will Remotes be financially responsible for the cost of connecting customers on the Marten Falls Reserve or on properties adjacent to the Marten Falls Reserve to the Marten Falls Assets as such costs are to be borne by those customers in accordance with the *Distribution System Code* and the Conditions of Service;

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(v) at no time will Remotes be financially responsible to pay the First Nation any amounts for the use of the Marten Falls Assets to provide the services described in this Agreement;

(vi) even though Remotes will be responsible for the operations and maintenance of the Assets and the cost of the replacement of the Marten Falls Assets once the First Nation has complied with its obligations under Subsections 8(d) and 8(e) below, Remotes will have no right, title or interest in the assets that replace the Marten Falls Assets;

(vii) Remotes will have no responsibility or liability with respect to any Pre-existing Environmental Condition(s); and

(viii) Remotes is entitled to all revenues derived from the provision of Distribution Services and other services performed by Remotes in order to supply electricity on the Marten Falls Reserve or on properties adjacent to the Marten Falls Reserve.

8. The First Nation agrees that the First Nation shall:

(a) obtain on behalf of Remotes, at the First Nation's expense, the Certificate of Approval for Air/Noise required for Remotes to operate the DGS during the Term;

(b) should water and/or sewage systems be installed for the DGS at any time during the Term, obtain on behalf of Remotes, at the First Nation's expense, the Certificate of Approval for Water/Sewer required for Remotes to operate the DGS;

(c) make reasonable efforts to have the Technical Standards and Safety Authority inspect the new tank farm prior to May 31, 2009;

(d) at its own expense prior to the Takeover Day, remedy the deficiencies and make the operational improvements:

i. listed in Schedule "C" ; and

ii. noted as required by the Technical Standards and Safety Authority arising out of the inspection performed under subsection 8(c) above; and

iii. noted as required by the Electrical Safety Authority arising out of the inspection performed by the Electrical Safety Authority in November 2008;

(e) at its own expense, remedy the deficiencies and make the operational improvements listed in Schedule "D" within the periods specified in Schedule "D";

(f) provide Remotes with access to reserve lands to provide electricity services, including, but not limited to requesting the Minister of DIAND to issue Remotes a permit pursuant to section 28 of the *Indian Act* for $1 and for such period of time as the permit is required for the purpose of providing electrical energy services;

(g) provide Remotes with customer information to facilitate the transfer of customer billing by no later than 100 days prior to the Takeover Day;

(h) work within the Capital Funding Process to address the deficiencies (and required operational improvements) described above in Subsections 8(d) and 8(e) above;

(i) build accommodation for the exclusive use of Remotes' staff (staff house) in accordance with Remotes' design guidelines, and identify accommodation available for Remotes' staff use until a staff house is built;

(j) follow the Capital Funding Process in respect of capital upgrades required to the DGS, the Electrical Distribution System forming part of the Marten Falls Assets and to build accommodation for Remotes' staff to use while in the community (staff house); and

(k) retain responsibility and liability for any Pre-existing Environmental Condition(s).

Furthermore, during the Initial 5 Year Operating Term and any Renewal Term, the First Nation hereby grants to Remotes and any of its employees or agents, a licence to operate, maintain, repair and replace the DGS and other Marten Falls Assets in accordance with the terms and conditions of this Agreement.

9. INAC agrees that:

(a) upon receipt of a proposal from the First Nation seeking funding support of INAC for a project to be undertaken by the First Nation to address identified deficiencies in the Marten Falls Assets in order that Remotes may assume operational responsibility of the Marten Falls Assets, INAC will, if approved through the Capital Funding Process, support the First Nation by identifying funds to allow the required work to be completed. Without limiting the scope of the anticipated proposal, it is contemplated that the First Nation's capital proposal will involve improvements required to remedy the deficiencies identified by the TSSA and the Electrical Safety Authority and to remedy the deficiencies and make the operational improvements listed in Schedules "C" and "D";

(b) to continue to provide financial support to the First Nation, consistent with the support provided to other First Nation communities which are serviced by Remotes. This support can and will reflect any subsidy program generally provided by DIAND to the other First Nation communities serviced by Remotes, including specifically any electrical energy cost subsidy, and further to provide to the First Nation access to support, within the framework of the Capital Funding Processes, for First Nation proposals relating to capital upgrades to the DGS;

(c) upon receipt of a proposal from the First Nation seeking funding support of INAC for building of accommodation (staff house) for Remotes staff for their use while in the community, INAC will, if approved through the Capital Funding Process, support the First Nation by identifying funds to allow the requisite accommodation to be built by the First Nation in accordance with Remotes' design guidelines;

(d) upon the request made and direction from the First Nation Council, the Minister of DIAND will issue to Remotes a permit under 28(2) of the Indian Act to allow Remotes to use and occupy those portions of the Marten Falls Reserve as set out therein, for such period of time as Remotes is required to operate the Marten Falls Assets and to perform any environmental remediation work following the termination of this Agreement; and by its employees to occupy the staff house; and

(e) INAC shall provide not less than thirteen (13) calendar months prior written notice to Remotes if:

(i) proposed changes to the Capital Funding Processes may or will result in a decrease in funds available for Capital Improvements generally; and/or

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(ii) proposed changes to the electrical energy cost subsidy presently provided to other First Nation communities which are serviced by Remotes may or will result in a decrease in such electrical energy cost subsidy.

10. Remotes shall be entitled to use agents and contractors to perform its obligations under this Agreement. The use of any such agent or contractor shall not relieve Remotes of any of its obligations hereunder.

11. The First Nation acknowledges and agrees that Remotes shall have the right to disconnect customers including, but not limited to the Band Council, residential and commercial customers, in accordance with any one or more of Remote's Conditions of Service, the *Distribution System Code* and Sections 31 and 31.1 of the *Electricity Act, 1998* and that during the Term, the First Nation shall not do anything to hinder or prevent Remotes from performing disconnections or other utility services such as making repairs to or inspecting the Marten Falls Assets and will permit Remotes to access the Marten Falls Reserve to perform same. For greater certainty, the actions of an individual member or a small group of members of the First Nation shall not be construed as the First Nation hindering or preventing Remotes from performing disconnections or other utility services such as making repairs to or inspecting the Marten Falls Assets.

12. Termination

12.1 Notwithstanding Section 6 hereof, Remotes shall have the right to terminate this Agreement:

(a) on twelve (12) months prior written notice if INAC ceases to provide financial support to the First Nation consistent with the support provided to other First Nation communities which are serviced by Remotes including specifically any electrical energy cost subsidy in the circumstance where INAC gave Remotes prior notice thereof under Subsection 9(e)(ii) above;

(b) on three (3) months prior written notice if INAC ceases to provide financial support to the First Nation consistent with the support provided to other First Nation communities which are serviced by Remotes including specifically any electrical energy cost subsidy in the circumstance where INAC failed to give the notice to Remotes under Subsection 9(e)(ii) above;

(c) on twelve (12) months prior written notice, if the First Nation is unable to obtain access to support, within the framework of the Capital Funding Process, for First Nation proposals relating to capital upgrades to the DGS in the circumstance where INAC gave Remotes prior notice thereof under Subsection 9(e)(i) above;

(d) on three (3) months prior written notice, if the First Nation is unable to obtain access to support, within the framework of the Capital Funding Process, for First Nation proposals relating to capital upgrades to the DGS in the circumstance where INAC failed to give the notice to Remotes under Subsection 9(e)(i) above; or

(e) on ninety (90) days prior written notice if the First Nation does not remedy a breach by the First Nation of any Material term, condition or covenant of the Agreement to Remotes satisfaction (acting reasonably), 30 calendar days from the date of receipt of a written notice from Remotes to rectify the Event of Default, at the First Nation's sole expense.

Subject to the terms of this Agreement, Remotes shall not be subject to penalties or damages as a result of exercising its rights to terminate this Agreement. Remotes agrees to provide a copy of any notice of termination delivered by Remotes under the terms of this Agreement (including, but not limited to Section 6 hereof) to INAC.

For greater certainty, it is acknowledged and agreed that Article 14 (Dispute Resolution) of this Agreement does not apply to the exercise by Remotes of its right to terminate this Agreement pursuant to subsections 12.1(a), 12.1(b), 12.1(c) or 12.1(d) above.

12.2 The First Nation shall have the right to terminate this Agreement on ninety (90) days prior written notice if Remotes does not remedy a breach by Remotes of any Material term, condition or covenant to the First Nation's satisfaction (acting reasonably), 30 calendar days from the date of receipt of a written notice from the First Nation to rectify the Event of Default, at Remote's sole expense. Subject to the terms of this Agreement, the First Nation shall not be subject to penalties or damages as a result of exercising its rights to terminate this Agreement. The First Nation agrees to provide a copy of any notice of termination delivered by the First Nation under the terms of this Agreement (including, but not limited to Section 6 hereof) to INAC.

12.3 Notwithstanding Section 7 and Subsections 12.1 and 12.2 above, the First Nation shall pay Remotes the net book value of the capital contributed by Remotes to replace or add to the Marten Falls Assets in existence on the date first written above. The net book value shall be determined using either generally accepted accounting principles (GAAP) or International Financial Reporting Standards (IFRS) whichever Remotes is required to follow at that time due to Remotes being a subsidiary of Hydro One Inc., a reporting issuer. This section 12.3 shall survive the termination of this Agreement under any circumstances.

12.4 The First Nation acknowledges and agrees that termination of this Agreement under any circumstances shall not release:

(a) the First Nation from having to pay all amounts owing to Remotes on First Nation (Band) accounts with Remotes; or
(b) individual members of the First Nation from having to pay all amounts owing on their individual accounts with Remotes;

in respect of electricity generated and delivered by Remotes or other Distribution Services provided by Remotes in accordance with its distribution licence issued by the OEB, the *Distribution System Code* and the Conditions of Service prior to termination of this Agreement.

12.5 Upon the termination of this Agreement for any reason, the First Nation shall have the right to be exercised with 60 days of the termination of this Agreement to have:

(a) the Electrical Safety Authority ("ESA") inspect the Electrical Distribution System; and
(b) the Technical Standards and Safety Authority ("TSSA") inspect the tank farm used by Remotes during the term of this Agreement;

with the cost of such inspection to be at the First Nation's sole expense. If there are any deficiencies identified by the ESA or the TSSA, Remotes shall be responsible for remedying same provided such deficiencies are as a result of Remotes failing to operate, maintain, repair and replace the Marten Falls Assets in accordance with Good Utility Practice, all Applicable Laws, and the *Distribution System Code*. Upon termination, the First Nation shall also have the right to request that Remotes

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provide the First Nation with the maintenance records for the DGS as well as all records relating to installations of Remotes for which Remotes is claiming compensation pursuant to Section 12.3 of this Agreement.

12.6 Upon the termination of this Agreement for any reason, Remotes shall retain an environmental consulting firm to perform an environmental investigation of the lands on the Marten Falls Reserve used by Remotes during the Term (including, but not limited to the tank farm(s) utilized by Remotes) and shall direct the consulting firm to prepare a report outlining the results of the environmental investigation ("**Closure Assessment**"). Remotes shall afford the opportunity for the First Nation, at its own expense, to complete a technical review of the Closure Assessment and to comment on the findings.

Remotes shall be responsible for remediating to meet the Standards for Hydrocarbons in Soil:

(i) contamination that is both identified in the Closure Assessment and that is caused entirely by or results completely from the activities of Remotes on the Marten Falls Reserve during the Term ("**Remotes Contamination**"); and
(ii) other than contamination that is identified in the Closure Assessment which but for the Pre-existing Environmental Condition, there would not be any remedial work required on the part of Remotes, contamination that is a combination of a Pre-Existing Environmental Condition and Remotes Contamination (the "**Joint Contamination**").

In the event of any dispute between the parties as to whether contamination identified in the Closure Assessment constitutes Remotes Contamination, the First Nation shall bear the burden of proving that the contamination constitutes Remotes Contamination.

Remotes shall remediate:

(a) Remotes Contamination at its sole cost and expense and shall make reasonable commercial efforts to perform any such remediation within 365 days of the termination of this Agreement; and

(b) Joint Contamination, with the cost and expense of such remediation to be shared by Remotes and the First Nation in proportion to their respective contamination as determined in the Closure Assessment. Remotes shall prepare and deliver to the First Nation an estimate of the First Nation's proportionate share of the cost and expense associated with the remediation of the Joint Contamination by Remotes. Provided that the First Nation pays Remotes the amount specified in the estimate (the "**First Nation Remediation Deposit**") within 60 days of Remotes delivering such estimate to the First Nation, Remotes shall make reasonable commercial efforts to perform the remediation of the Joint Contamination within 365 days of the date that Remotes receives the First Nation Remediation Deposit. In the event that the actual cost of remediation is higher than estimated, the First Nation shall be responsible for paying Remotes their proportionate share of the increase. In the event that the actual cost of remediation is lower than estimated, Remotes shall be responsible for reimbursing the First Nation, their proportionate share of the decrease. If the First Nation does not pay Remotes the First Nation Remediation Deposit within 60 days of Remotes delivering such estimate to the First Nation, Remotes shall only be responsible for remediating Remotes proportionate share of the Joint Contamination.

Furthermore, Remotes agrees to share the remediation plan with the First Nation and INAC. The First Nation and INAC shall have 30 days from delivery of the remediation plan by Remotes to review and provide Remotes with comments on the remediation plan at their respective own expense.

Remotes shall have a report prepared by an environmental consulting firm that verifies the remediation of any Remotes Contamination meets the Standards for Hydrocarbons in Soil (the "**Completion Report**"). Remotes shall give the First Nation and INAC the opportunity to review and provided comments on the Completion Report at their own respective expense. The First Nation shall have the option to retain, at its sole cost and expense, an environmental consultant to confirm its satisfaction with the remediation conducted by Remotes, but must do so and confirm its satisfaction within 365 days of receipt of the Completion Report, failing which the First Nation shall be deemed to be satisfied with the remediation conducted by Remotes.

12.6 Sections 12.3, 12.4, 12.5 and 12.6 shall survive the termination of this Agreement under any circumstances.

13. Environmental Remediation and Liability

13.1 Remotes shall be liable to the First Nation only for any damages that arise directly out of the willful misconduct or negligence of Remotes, its agents, employees or contractors in meeting its obligations under this Agreement. Remotes shall not be liable under any circumstances whatsoever for:

(i) any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential or incidental damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise; or

(ii) any actions, causes of action, proceedings, suits, claims, demands, losses, damages, penalties, fines, costs, expenses, obligations and liabilities in connection therewith arising out of, resulting from any Pre-existing Environmental Condition(s).

13.2 The First Nation shall:

(a) be responsible for remediating, at its sole cost and expense any Pre-existing Environmental Condition associated with the tank farm operated by the First Nation on the Marten Falls Reserve. The First Nation shall make reasonable efforts to perform such remediation within the first year of the Initial 5 Year Operating Term.

(b) indemnify and save harmless Remotes, its successors and assigns, directors, officers, employees, agents, contractors, subcontractors, representatives and servants, from and against all actions, causes of action, proceedings, suits, charges, claims, demands, losses, damages, penalties, fines, costs, expenses, obligations and liabilities in connection therewith arising out of, resulting from any Pre-existing Environmental Condition.

13.3 Subsections 13.1 and 13.2 shall survive the termination of this Agreement under any circumstances.

14. Dispute Resolution

Solely for the purposes of Sections 14.1, 14.2 and 14.3 below, the term "Parties" means the First Nation and Remotes and "Party" means either one of them.

14.1 Notice of Concern

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In the event any dispute, claim, difference or question arises among any of the Parties concerning the construction, meaning, effect or implementation of this Agreement that requires consideration (each a **"Concern"**), any Party may provide notice to another Party of same. The Party receiving such notice shall have a reasonable period of time to consider and, if it believes fit, address the Concern, such period not to exceed 45 days. If the Concern is addressed to the reasonable satisfaction of the Party giving the notice (as confirmed by such Party in writing), the dispute shall be deemed to be cured and may not be the basis for further remedies hereunder.

14.2 Good Faith Discussion

If the Concern is not addressed to the reasonable satisfaction of the Party who provided notice of same, the Parties to the notice shall consult in good faith to discuss the Concern and possible remedial action which could take place to address it. This step shall be completed within 90 days unless the Parties otherwise agree (in writing). If the Concern is addressed to the reasonable satisfaction of the Party who provided the notice (as confirmed by such Party in writing), the dispute shall be deemed to be cured and may not be the basis for further remedies hereunder.

14.3 Arbitration

(a) If, pursuant to Section 14.2, the Parties cannot come to a resolution on the Concern, then the Concern shall, at the election of either Party, be submitted to arbitration conducted pursuant to the *Arbitration Act, 1991* of Ontario, then in effect, to the extent not inconsistent with the provisions herein specified.

(b) Such arbitration shall be held in Thunder Bay, Ontario and the dispute shall be heard by one arbitrator who has not previously been employed by either Party, does not have a direct or indirect interest in either Party, and shall be disinterested in the subject matter. Such arbitrator shall either be mutually agreed by the Parties within ten (10) calendar days after agreeing to arbitration, or failing agreement, shall be selected under the rules of the *Arbitration Act, 1991* of Ontario.

(c) The judgment rendered by the arbitrator may be enforced in any court of competent jurisdiction. All costs of the arbitration shall be paid equally by the Parties, unless the award shall specify a different division of the costs. Each Party shall be responsible for its own expenses, including counsel's fees unless the award shall specify differently. Both Parties shall be afforded adequate opportunity to present information in support of its position on the matter being arbitrated. The arbitrator may also request additional information from the Parties.

(d) Should the Parties commence arbitration pursuant to this Section 14.2, then the following arbitration rules shall apply:

(i) The arbitrator shall be bound by the terms of the Agreement and may not detract from or add to its terms.

(ii) The Parties may by mutual agreement specify additional rules that are to govern the arbitration proceedings and limit the matters to be considered.

(iii) The arbitrator, any Party, any witness and any other participant in the arbitration proceeding shall not disclose, transmit or disseminate:

(a) anything said or done in the arbitration;
(b) any documents disclosed or provided during or in connection with the arbitration;

(c) any information disclosed during or in connection with the arbitration; and

(d) the existence or result of the arbitration, including without limitation arbitration settlement, and the arbitration award and any explanations or reasons for the award; however, the preceding shall not apply to the extent that it is legally necessary for the purposes of a court challenge of the arbitration or in respect of an action to enforce the arbitration award.

(iv) Each Party agrees that it will not bring a lawsuit concerning any Concern other than any legally necessary court challenge of the arbitration or in respect of an action to enforce the arbitration award.

14.4 For greater certainty, Sections 14.1, 14.2 and 14.3 do not apply to any dispute nor any concern pertaining to the supply of electricity to a particular customer's premises or the electricity account of a particular customer even if the affected customer is the First Nation. All such disputes will follow the dispute resolution processes set out in the Conditions of Service and the *Distribution System Code*.

15. Force Majeure

15.1 Neither Remotes nor the First Nation shall be considered to be in default in the performance of its obligations under this Agreement to the extent that performance of any such obligation is prevented or delayed by a Force Majeure Event, such party shall immediately provide notice to the other party of the circumstances preventing or delaying performance and the expected duration thereof. Such notice shall be confirmed in writing as soon as reasonably possible. The party so affected by the Force Majeure Event shall endeavour to remove the obstacles which prevent performance, including in the event of manufacturer's delays for equipment or materials, Remotes shall use reasonable efforts to obtain acceptable substitutes for such equipment or materials, and the party so affected by the Force Majeure Event, shall resume performance of its obligations as soon as reasonably practicable, except that there shall be no obligation on the party so affected by the Force Majeure where the event of Force Majeure is a strike, lockout or other labour disturbance.

General

16. Subject to Article 14, all rights and remedies of any Party provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to either Party respectively at law or in equity, and any one or more of a Party's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy either Party may have or may have exercised.

17. This Agreement constitutes the entire agreement between the parties with respect to the maintenance and operation of the Assets during the Term and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement.

17. Nothing in this Agreement creates the relationship of principal and agent, employer and employee, partnership or joint venture between the parties. The parties agree that they are and will at all times remain independent and are not and shall not represent themselves to be the agent, employee, partner or joint venturer of the other. No representations will be made or acts taken by any party which could establish any apparent relationship of agency, employment, joint venture or partnership and no party shall be bound in any manner whatsoever by any agreements, warranties or representations made by any other party to any other person nor with respect to any other action of any other party.

RPM

18. Any reference in this Agreement to any Act or statute or Section thereof or any regulation made pursuant thereto shall be deemed to be a reference to such Act or statute or Section or regulation as amended or re-enacted from time to time. Words importing the singular number include the plural and vice versa.

19. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein, and the Courts of Ontario shall have exclusive jurisdiction to adjudicate disputes concerning this Agreement.

20. Each party to this Agreement acknowledges and agrees that it has participated in the drafting of this Agreement and, accordingly this Agreement shall not be interpreted either more or less favourably in favour of any party to this Agreement by virtue of the fact that one party or its counsel has been principally responsible for drafting of all or a portion of this Agreement.

21. Any amendment to this Agreement shall not have any force and effect until it is reduced in writing and mutually agreed to and signed by all parties hereto.

22. The failure of any party hereto to enforce at any time any of the provisions of this Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of this Agreement or any part hereof or the right of any party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of this Agreement shall not be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly and impliedly waives a right or rights or an option or options under this Agreement.

23. Neither this Agreement nor any rights, remedies, liabilities or obligations arising under it or by reason of it shall be assignable by any party.

24. All notices must be given in writing and delivered in accordance with this clause. All notices shall be delivered to the other parties and no notice shall be effective until such delivery has been made. The addresses for delivery are:

(a) Remotes:

Hydro One Remote Communities Inc.
680 Beaverhall Place
Thunder Bay, ON P7E 6G9

Attention: Director
Fax: (807) 475-8123

With a copy to:

Hydro One Remote Communities Inc.
483 Bay Street
North Tower, 14th Floor
Toronto, ON M5G 2P5

Attention: President & C.E.O.

Fax: (416) 345-6402

(b) to the First Nation:

Marten Falls First Nation
General Delivery
Ogoki Post, ON P0T 2L0

Attention: Chief and Council
Fax: (807) 349-2511

(c) to INAC:

Indian and Northern Affairs Canada
25 St. Clair Avenue East, 8th Floor
Toronto, ON M4T 1M2

Attention: Regional Director General

(d) Notice shall be deemed to have been delivered:

(a) if delivered by hand, upon receipt;
(b) if delivered by electronic transmission, 48 hours after the time of transmission, excluding from the calculation weekends and public holidays; and
(c) if delivered by registered mail, fifteen (15) business days after the mailing thereof, provided that if there is a postal strike such notice shall be delivered by hand.

25. This Agreement 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.

[Intentionally Left Blank]

MM

26. INAC is a party to this Agreement for the purposes of Sections 4 and 9 and Sections 15 through 26 respectively and for no other purpose.

IN WITNESS WHEREOF, Hydro One Remote Communities Inc. has caused this Agreement to be executed by the signatures of its proper officer duly authorized in that behalf as of the day and year first above written.

HYDRO ONE REMOTE COMMUNITIES INC.

Myles D'Arcey
President & C.E.O.
I have authority to bind the corporation.

IN WITNESS WHEREOF THIS AGREEMENT HAS BEEN EXECUTED ON BEHALF OF THE MARTEN FALLS BAND OF INDIANS by the Chief of the Marten Falls Band of Indians and a majority of the Council of the Marten Falls Band of Indians at the Marten Falls Reserve as of the day and year first above written.

Witness	Chief Harry Baxter
Witness	Councillor
Witness	Councillor
Witness	Councillor
Witness	Councillor
Witness	Councillor

SIGNED, SEALED AND DELIVERED in the presence of:

WITNESS

HER MAJESTY THE QUEEN in RIGHT OF CANADA, as represented by the Minister of Indian Affairs and Northern Development

Joseph Young
Acting Associate Regional Director North
Ontario Region

Schedule "A": Marten Falls Assets that will be Operated by Remotes

Generator Set Assets: (Confirm data and finish populating closer to transfer date)

MAKE	MODEL	SERIAL #	RPM	RATED OUTPUT	ENGINE HOURS (as of December 18, 2008)
Caterpillar	3512	67Z01416	1200	600 kW	54,310
Caterpillar	3412	81Z20517	1800	400 kW	31,544
Cummins	275DFBF	J940559146/Generator Engine 30348294	1800	275 kW	12,758

Diesel Fuel Tank Farm Assets:

MAKE	MODEL	SERIAL #	Capacity (l)	Year of Manufacture	Year Installed
Westeel	FV-350	63062815	35,000	2006	2009
Westeel	FV-350	63062816	35,000	2006	2009
Westeel	FV-350	63062817	35,000	2006	2009
Westeel	FV-350	63062818	35,000	2006	2009
Westeel	FV-350	63062819	35,000	2006	2009

Schedule "B": Excluded Assets (Will <u>not</u> be Operated by Remotes)

All fuel storage tanks other than those listed in Schedule "A" under the heading "Diesel Fuel Tank Farm Assets".

Schedule "C": Deficiencies to be Remedied Before the Takeover Day

Fuel Tank and Fuel Offloading:

Comply with federal environmental laws including, any environmental screening requirements.

Replace Fuel Tanks, Fuel Offload and upgrade the interior fuel transfer system to bring the fuel system up to provincial/industry standards and in accordance with Remotes' design guideline. This includes, but is not limited to, remedying the following deficiencies identified within the 2007 Station Assessment Report prepared by Remotes:

- Fuel Kiosk with automated PLC system for fuel transfer system.
- Interior fuel system: a separate day tank is required for each generation unit.
- Interior fuel, a magnetic level gauge is required on day tanks.
- Supply and return fuel lines connected to day tanks by hoses running through a floor conduit. New fuel lines are to be run above grade as specified in guidelines.
- Fuel offload and associated pipe work must be replaced.
- Off load connection point must be brought up to standard, camlock fitting should be 2" for aircraft and 3" for tractor trailer units. The hose must be replaced and the area secured.
- Drip tray under offload point does not comply with Industry standard(s).
- Leaking connection valves weeping fuel into the dike.
- No fuel meter at the fuel offload delivery point.

The First Nation shall also be responsible for obtaining any approvals required under any Applicable Laws with respect to the new tank farm, including the requirement to register the new tank farm with the Technical Standards and Safety Authority.

Fire Suppression System:

The Fire Protection System is not functioning. It must be refurbished and/or replaced with a system using FM200 fire suppressant.

Planned Maintenance:

All engine manufacturer prescribed maintenance procedures must be up-to-date and all generating units must be in working order. In August/07, all units were currently overdue for major maintenance procedures, and the Cummins unit was out of service.

Clean up Site:

Scrap transformers, engines, boat and snow machines should be removed from the site. Clean up the workshop area in the original plant.

Note: All of the above shall be performed in accordance with Remotes' standards.

NPL

Schedule "D": Other Deficiencies

Part A: To be Remedied by no Later than 6 months after Takeover Day

Upgrade the existing Martin Falls Programmable Logic Control (PLC) system to current Remotes guidelines, to conform to their communication and SCADA systems. This includes hardware (PLC, computer), operating software, field wiring changes, and any communication devices. Integration with the genset controls and fuel system components, configuration of, and system testing, is also included after the installation is complete.

Part B: To be Remedied before the 1st Anniversary of the Takeover Day

- Install additional exhaust fan for A Unit;
- Install variable frequency drives (VFD) to control the Radiator fans;
- Install rubber Proco expansion joints at engines;
- Modify cooling system to provide access into expansion tanks for inspection/cleaning;
- Install insulating blankets on expansion joints and flanges (cooling system);
- Install new oil transfer system and coolant storage system;
- Change batteries in the starting system for unit A;
- Install expansion joints at radiator Unit B;
- Install wall fans to upgrade station ventilation;
- Install expansion tank in cooling system;
- Insulate C Unit exhaust pipe and modify interior support structure;
- Purchase operating and maintenance manuals and service and parts manuals for each unit and auxiliary equipment such as pumps and switchgear;
- Provide desk, chair, filing cabinet, fax machine;
- Provide air compressor, antifreeze pumps and welder; and
- Subject to the Certificate of Approval, silencers on building ventilation openings may be required.

Note: All of the above shall be performed in accordance with Remotes' standards.

<u>Nishnawbe Aski Nation (NAN) INTERROGATORY #15 List 1</u>

Exhibit G1 – Proposed Grid-Connected Customer Rates

Proposed Grid-connected Customer Rates
Ref: Exhibit G1, Tab 1, Schedule 2

Remotes states that "to ensure that residential customers whose communities connect to the grid do not experience significant rate increases Remotes plans to include non-Standard A grid-connected resident and general service customers in its existing non-Standard Residential and General Service rate classes. Remotes adds that doing so will reduce potential rate impacts if communities that Remotes serves connect to the grid."

<u>Interrogatory</u>

a) Does Remotes expect to maintain in the long term the rate structure which it is currently proposing for customers in Pikangikum and Cat Lake First Nation? Or does Remotes expect that the rate being charged to various customers in these communities will eventually be the same as the rate structure for other grid-supplied customers in Ontario?

<u>Response</u>

a) Remotes has no plans to implement the same rate structure as in other grid-supplied communities. Remotes is exempt from the competitive retail electricity market. Furthermore, given that Remotes does not earn a return on equity and because Remotes believes most of these customers will be eligible for RRRP, Remotes does not believe that introducing an unbundled grid-rate structure is required or beneficial for customers.