EXHIBIT 10 - INTERROGATORY RESPONSES

Exhibit 10, Tab 3, Schedule 1

Responses to Interrogatories from the School Energy Coalition (SEC)

INTERROGATORY 1

Reference: 1/1/12, p. 5 and numerous other references

Question:

Please provide all documents relating to the tax consequences of the corporate structure, including planning letters, memoranda, reports and opinions, and including any tax department rulings, letters of analysis or technical interpretations, and all other documents relating to the relationship of the specific corporate structure and the taxation of the entities within the structure. Please include in the documents provided all tax opinions, memoranda, and rulings, if any, relating to the reorganization transactions in 2008 and 2009. Please also include in the documents provided any tax opinion, memoranda, and rulings, if any, relating to the impact on Canadian taxes of the residence, management and control, or similar attributes of any of the related entities, including but not limited to Brookfield Infrastructure Partners L.P. Please also advise the jurisdiction of formation and the jurisdiction of residence of each of the entities listed on this corporate structure chart.

Response:

Please see GLPT's response to Board Staff Interrogatory #47(ii). As noted in that response, the partners of GLPT are taxable Canadian corporations. All tax is paid and accounted for at that level. All distributions made from the partners to related or parent entities are made on an after tax basis. Therefore, all inquiries related to non-regulated activities or entities, including Brookfield Infrastructure Partners LP, and the respective tax arrangements are irrelevant.

INTERROGATORY 2

Reference: 1/1/13, p. 2

Question:

Please provide all minutes or reports relating to the stakeholder meetings conducted under section 1.2 of the Settlement Agreement.

Response:

Please see the requested materials in Appendix 2 of Exhibit 10, Tab 3, Schedule 2.

INTERROGATORY 3

Reference: 1/1/13/App. A, p. 19

Question:

Please provide a description of all changes that have been made to the "Operating Budget Methodology" since the date of this Settlement Agreement.

Response:

GLPT's current budget methodology is outlined at Exh.1/Tab2/Sch.2. GLPT has not materially changed its budget methodology from the one used in preparing the future test year evidence in EB-2005-0241.

INTERROGATORY 4

Reference: 1/2/1

Questions:

With respect to the Summary of the Application:

(a) p. 2 [as well as 4/2/1, p. 36 and many other references]. Please provide the source documents, reports, and other materials on which the 630 MW figure is based. Please explain the difference between the figure of 630 MW here and elsewhere and the figure of 1500 MW at 4/2/1, p. 36.

(b) p. 6. Please provide any cost/benefit analysis or similar material prepared in or prior to 2006 justifying the change in the vegetation management program, including in particular any estimates of incremental costs and the rationale behind them.

(c) p. 6. Please provide specific references to the "regulatory changes" referred to, including the dates, sources, and document names.

(d) p. 7. Please provide any memoranda, reports, emails, letters, or other documents or presentations relating to the reduction in vegetation management expenditures in 2009, or with respect to any other cost-cutting activities in that year having a common cause with the vegetation management reduction.

(e) p. 13. [as well as 4/2/1, p. 36] Please provide the source documents, reports, and other materials on which the 40-60 MW figure is based. Please explain the difference between the figure of 40-60 MW here and elsewhere and the figure of 100 MW at 4/2/1, p. 36.

(f) p. 19. Please advise whether the Applicant is proposing to follow the Board's December 11, 2009 Report on the Cost of Capital, and the ROE and other provisions contained therein, or to use the 10.5% ROE proposed in the Application.

(g) p. 20. Please provide a full list of the actual balances in all deferral and variance accounts as of December 31, 2009. Please advise when audit confirmation of those figures is expected to be available.

(h) p. 24. Please provide the OM&A Agreement referred to. Please advise the date that agreement ceased to be applicable. If any part of that agreement is still applicable, please provide details.

Responses:

(a) Please see GLPT's response to Board Staff Interrogatory #5(ii) from the deferral account proceeding (EB-2009-0409). The actual number is 670 MW and is a part of the OPA IPSP. A link to the document is provided below.

http://www.powerauthority.on.ca/Storage/82/7763_B-1-1_updated_2008-09-04.pdf

The 1500 MW was taken from an earlier draft of the IPSP. However, it was revised to show 670 MW in the most recent revision of the plan.

(b) See GLPT's response to Board Staff Interrogatory #8(iv). In addition, as described in GLPT's response to Board Staff Interrogatory #71, while no formal studies were performed, GLPT undertook an internal assessment and concluded that the program improvements should be undertaken as a "non-discretionary" project in order to maintain compliance with NERC FAC-003.

(c) See pages 23 and 24 of Exh.4/Tab2/Sch.1, which discuss species protection and pesticides regulatory changes.

(d) Please see Appendix 4(d) of Exhibit 10, Tab 3, Schedule 2.

(e) The 40 – 60 MW numbers were calculated specifically for the FIT program, as requested directly by the OPA. The OPA provided GLPT with a set of guidelines that were input into a computer simulation model (PSS/E) on which the 40- 60 MW figure is based. Specifically, the 40 – 60 MW number refers to the maximum available capacity of transmission elements (transmission lines and transformers) within the system. Once calculated, these numbers were given to the OPA and posted on the FIT website for generator proponents to view. The guidelines are provided in Appendix 4(e) of Exhibit 10, Tab 3, Schedule 2, along with the available capacity tables that were submitted to the OPA.

The 100 MW figure was calculated a result of the East Lake Superior report. This report was filed pre-FIT and uses different numbers and assumptions in the model. The report link is as follows:

http://www.powerauthority.on.ca/Storage/49/4461_E-3-4_Att_1.pdf

(f) Please see GLPT's response to Board Staff Interrogatory #92(i).

(g) GLPT has provided below a supporting schedule for all regulatory assets and a separate supporting schedule for regulatory liabilities. Audit confirmation of these figures is expected no later than April 30, 2010.

Regulatory Asset
$ 000's of Canadian Dollars

	USofA Account	
Deferred IFRS Transition Costs	1508	$2.0
Deferred Green Energy & Planning	1508	14.6
Extraordinary Event Legal Costs	1572	1,041.5
Transfer Pricing Review	1508	16.5
Regulatory Assets		**$1,074.5**

Regulatory Liability
$ 000's of Canadian Dollars

	USofA Account	
Deferred Rate Impact Accrual	1574	$2,577.7
PILS Variances	1562/1592	1,249.7
Deferred Loss on Disposal of PP&E	1505	71.4
Wholesale Meter Rebates	1508	122.1
Total Regulatory Liability		**$4,020.9**

(h) Please see GLPT’s response to Board Staff Interrogatory #40(v). The OM&A Agreement ceased to be applicable as at July 1, 2009.

INTERROGATORY 5

Reference: 1/2/3

Question:

Please calculate the impact in the test year of using the average of the opening and closing balances rather than the average of monthly averages previously used to calculate rate base/fixed assets.

Response:

As stated in Exh.1/Tab2/Sch.3, GLPT has calculated its rate base in accordance with the filing requirements. Based upon GLPT's response to VECC Interrogatory #3, the impact of calculating rate base using in-service dates is a decrease in rate base of approximately $500k or 0.23% of rate base. It is important to note that GLPT considered coming into service on the basis of quarters rather than months. As a result, some approximation of timing was required.

INTERROGATORY 6

Reference: 1/3/1

Questions:

With respect to the financial statements:

(a) 2007, p. 3. Please confirm that the actual return on equity for accounting purposes was 18.14% in 2006 and 15.05% in 2007.

(b) 2007, p. 10. Please advise the market interest rate used in the valuations of the Series 1 Bonds for each year, and their sources.

(c) 2008, p. 6. Please provide any valuation or similar document prepared to arrive at the price of $92.5 million plus assumption of debt.

(d) 2008, p. 9. Please advise the market interest rate used in the valuation of the Trans Senior Bonds, and its source.

(e) 2008, p. 12. Please provide a copy of the Partnership Agreement of the Applicant.

(f) 2008, p. 12. Please confirm that, despite the removal of the future income tax liability of the partnership, the proposed regulatory treatment of tax obligations in the Application would assume that ratepayers will ultimately be responsible for all recapture or any other impact of the future income tax liability previously recorded.

(g) 2008, p. 13. Please explain why the contributed capital is listed as coming from Brookfield Infrastructure Partners L.P. when the org chart at 1/1/12, p. 5 shows a different entity as the limited partner of the Applicant. If the explanation is that there has been any subsequent corporate reorganization or other such transaction, please provide complete details.

Responses:

(a) Confirmed. In addition, the actual return on equity for accounting purposes in 2008 was also 10.83%. The return used in this calculation is based on the before-tax income earned between March 13 and December 31, 2008, as the taxes paid by the partners are not reflected in the statements of GLPT. As a result, although not demonstrated in the financial statements, the 2008 return on equity would have been reduced further by the effective tax rate.

(b) For 2007, the discount rate used was 5.8% which was made up of the following:

4.0% market rate (weighted average of 10 year and 30 year Canada Government Bonds).

1.8% spread which is a weighted average for comparable midterm and long term bonds – obtained from Scotia Capital.

(c) The amount of $92.5 million disclosed in the notes to the 2008 financial statements refers to the amount Brookfield Infrastructure Partners LP paid for the net assets of the transmission business. This issue was fully discussed in EB-2007-0647, where it was estimated that the amount would be $90.4 million. As a result of working capital adjustments, this ended up at $92.5 million. The purchase price paid by Brookfield Infrastructure Partners LP had no impact to the rate base of GLPT as the transmission assets were transferred from GLPL transmission division to GLPT at their Net Book Value.

The $92.5 million includes $87.5 in consideration for fixed assets and $5 for working capital. The purchase price was set equal to an estimated fair market value with a working capital adjustment to true up any variances in closing date working capital as compared to the December 31, 2006 working capital balance.

(d) For 2008, the discount rate used was 7.5% which was made up of the following:

3.0% (Average of 10 year and 15 year Canada Government Bonds for 12/31/08 obtained from Bloomberg).

4.5% spread which is a comparable rate for an Ontario bond offering between 10-15 years (obtained from Bloomberg).

(e) Please see Appendix 6(e) of Exhibit 10, Tab 3, Schedule 2 for a copy of the Partnership Agreement, as well as a subsequent Amendment to the Partnership Agreement.

(f) Confirmed. The ratepayers will not incur tax costs that are different from what the ratepayer would have incurred had the business continued to operate as a division of GLPL.

(g) Please see note 1 of the 2008 Financial Statements at Exh.1/Tab3/Sch.1. There have been no subsequent corporate reorganizations that directly affect the transmission company.

INTERROGATORY 7

Reference: 1/3/2

Questions:

With respect to the pro forma financials:

(a) Please advise whether the 2009 pro forma financials are based on unaudited actuals, forecasts, or some combination, and if so on what basis. If those financials are not based on unaudited actuals, please provide 2009 unaudited actuals.

(b) App. A, p. 6. Please confirm that the forecast return on equity for accounting purposes is 7.08% in 2009 and 12.86% in 2010.

Responses:

(a) To the extent that actual results were available at the time of preparing the 2009 pro forma financials, they were reflected in the 2009 pro forma financials. For the period covered where actual results were not known, GLPT forecasted results using the best information available at the time.

Please see Appendix 7(a) of Exhibit 10, Tab 3, Schedule 2 for the unaudited actual results for GLPT as at December 31, 2009.

(b) Per GLPT calculations the forecast return on equity for accounting purposes is 7.18% in 2009 and 12.66% in 2010. GLPT's calculation uses ending equity as the denominator, while SEC's calculation uses opening equity as the denominator. When calculating return on equity in SEC Interrogatory 6(a), SEC utilized ending equity. Therefore, in the interest of consistency, GLPT recalculated the forecast return on equity for accounting purposes for 2009 and 2010.

It should also be noted that the pro forma financial statements for GLPT for the years ending 2009 and 2010 are prepared on a partnership basis and do not reflect any income or capital tax expenses that will be incurred by GLPT's partners. Therefore the forecast return on equity for accounting purposes is calculated on a before tax basis, and will appear inflated in comparison to what the end result return on equity will be for regulated purposes.

INTERROGATORY 8

Reference: 1/3/3, p. 2

Question:

Please provide further information on the $400,000 over-accrual, including the prior period to which it related, the nature of the expenditure, and the reason for the over-accrual.

Response:

The accrual was made in 2006. In 2006, GLPT accrued costs related to environmental clean-up activities that took place at a transmission station. An estimate of the costs was accrued in the year the obligation became known to the transmission business, and was based on the best information available at the time. In 2007, the work was completed at a cost that was approximately $400,000 lower than the accrued amount, and as a result the outstanding accrual was reversed. The reversing entry was treated as a change in estimate, and as a result was included in the 2007 financial statements on a prospective basis, with no requirement to re-state prior year financial statements.

INTERROGATORY 9

<u>Reference:</u> 1/3/4, App. A

Questions:

With respect to the DBRS Report:

(a) Please explain the purpose of this Private Rating Report, and contrast it with normal ratings reports.

(b) p. 1. Please advise whether the sentence "After 2013…programs)." remains true. If it is not true, please provide details.

Responses:

(a) The Private Rating Report is prepared in support of GLPT's Series 1 First Mortgage Bonds. The rating confirms the DBRS rating for the bond holders and is a condition of various covenants within the Deed of Trust.

(b) The sentence referred to remains true for 2013; in 2013 GLPT's depreciation expense is projected to exceed assets put in service during 2013. Since the Private Rating Report was completed, GLPT has expanded its projections to include 2014. For 2014, GLPT projects that assets put in service will exceed annual depreciation. After 2014, GLPT anticipates that on average depreciation will exceed assets put in service.

INTERROGATORY 10

Reference: 1/3/5

Questions:

With respect to the Form 20-F:

(a) p. 20. Please advise whether the first two risk factors listed on the page("Our organizational… unitholders" and "Our arrangements…parties") are also true of the Applicant. If they are not, please explain why not.

(b) p. 32. Please provide a copy of any opinion or ruling with respect to whether the Applicant or its limited partner is a SIFT Partnership.

(c) p. 33. Please confirm that Brookfield did not acquire its interest in Great Lakes Power Transmission L.P. in 1982. Please reconcile the statement on this page with the information contained elsewhere in the Application.

(d) p. 50. Please reconcile the target return of 11-15% with the current returns allowed by the Ontario Energy Board. Please advise how this target return is applied, with or without variations, to the Applicant.

(e) p. 63. Please advise the current interest rate on the Senior Secured Credit Facility closed in June, 2008.

(f) p. 88. If the Relationship Agreement referred to affects the Applicant, directly or indirectly, please provide a copy.

Responses:

(a) The statements are not true of GLPT. The statements are made in the context of the referenced document. The Form 20-F is the annual report for Brookfield Infrastructure Partners and the risk factors are all the known risks that Brookfield Infrastructure Partners considers relevant for investors in its units. As indicated in the response to SEC IR #6(g), GLPTLP is wholly controlled by BIP LP. As a result, no potential conflict could arise between the partners of GLPTLP.

(b) Please see GLPT's response to Board Staff Interrogatory #47(i).

(c) Confirmed. Brookfield did not acquire 100% of GLPT LP in 1982.

(d) The commentary made on page 50 referring to a return of 11-15% is made in the context of all infrastructure assets that are managed or to be purchased by Brookfield Infrastructure Partners L.P. Brookfield Infrastructure Partners is a diversified investment vehicle both in terms of the lines of business in which it invests and the geographic locations of those businesses. BIP has investments in Canada, the United States, Chile, Great Britain, Australia and Brazil.

The target return is not applied to GLPT. GLPT performance is measured against the deemed OEB return on equity.

Further to this, the stated returns provided by SEC are not comparable to the form of returns from the OEB. The targeted returns referred to in the annual report are based on adjusted net operating income plus growth in asset values, not strictly on after tax net income.

(e) London Inter-Bank Offer Rate (LIBOR) + 300 bps.

(f) The Relationship Agreement is unrelated to GLPT.

INTERROGATORY 11

Reference: 2/1/1

Questions:

With respect to the Rate Base Overview:

(a) p. 8. Please provide a copy of the Wardrop Engineering Report referred to.

(b) p. 12. Please confirm that the $1,230,000 of capital spending on the Third Line TS project that is proposed to be closed to rate base in the test year is not required for the safe and efficient operation of the facility.

(c) p. 15. Please provide a full description of any deterioration in performance of the equipment in the Third Line TS to date.

(d) p. 16. Please advise the Applicant's intentions with respect to the existing 115 KV section of the TS, assuming that the new 115 KV section is completed as proposed.

(e) p. 18. Please advise how long the current configuration of the Temporary Cross Bus has been in place, and provide details on all performance and compliance issues that have arisen during that period. Please demonstrate the rationale behind the timing of the change in configuration in 2010.

(f) p. 29. Please provide a copy of the ABB Report referred to.

(g) p. 49 and elsewhere. Please provide a copy of the Asset Purchase Agreement between GLPL and GLPT, including any schedules, and a full listing of all assets transferred. Please reconcile the "net book value" figure for each asset category with the rate base value of that category at the time of the transfer.

Responses:

(a) Please see Appendix 63(i) of Exhibit 10, Tab 1, Schedule 2.

(b) The $1,230,000 capital spending will be required to allow for the safe and reliable operation of the facility. A new ground grid meeting ESA and IEEE requirements must be installed, along with enhancements to the existing grid, to ensure that employee and public safety is not compromised. In addition, a new fence needs to be installed in order to maintain the high level of station security required to protect against vandalism and help prevent injury to the public. In addition to the existing need, because of the increased traffic and activity at the site due to the Third Line Redevelopment project, this work represents a fundamental part of the

Third Line Redevelopment project.

(c) Project need is described at Exhibit 2, Tab 1, Schedule 1 at pp. 14-19. To date, through continuous monitoring, GLPT has identified the following performance issues:

- Bus Connection Overheating - Infrared scans identified thermal issues on a number of bus connections. Where possible, connections were replaced. However, due to the existing bus configuration limitations, access to certain connectors was not possible and the connections have not been replaced. GLPT continues to monitor this situation.
- Insulator Cracking - It has been identified that 63 station strain bus insulators were cracked. 30 of the 63 were replaced. The other 33 cannot be replaced due to the existing station configuration limitations. (See Exhibit 2, Tab 1, Schedule 1, p. 17).
- Breaker Heating - It was identified that a connection between a bushing and bus conductor on Circuit Breaker 492 was overheating. The breaker was taken out of service, repaired and placed back into service.

(d) It is GLPT's intention to decommission the existing portion of the 115 kV section of the station as the assets are taken out of service. Where possible, GLPT intends to redeploy assets that are removed from service.

(e) The temporary cross bus has been in place since March 2008. The cross bus was installed to eliminate the need for IESO operating constraints due to thermal rating issues with the existing cross bus, as explained in Exhibit 2, Tab 1, Schedule 1, pp. 16-19. Performance and compliance issues that have arisen are set out at Exhibit 2, Tab 1, Schedule 1, pp. 14-19. The rationale is explained in Exhibit 2, Tab 1, Schedule 1, p. 14, under the Need heading.

(f) Please see response to Board Staff Interrogatory 66(i).

(g) Please refer to GLPT's response to Board Staff Interrogatory 60(v). With the exception of the value of the disallowed rate base addition described at p. 9 of the EB-2005-0241 settlement agreement, the net book value of the assets approximated the rate base values.

INTERROGATORY 12

Reference: 3/1/2

Question:

Please provide the basis for the Bridge and Test Year forecasts of revenue and expenses from Merchandising, Jobbing, etc.

Response:

The bridge year forecast of revenue and expenses from Merchandising, Jobbing, etc. was determined based on the actual activity that had taken place as of the time the forecast was prepared, plus a forecast for the activity expected to occur between that date and the end of the year.

The test year forecast of revenue and expenses from Merchandising, Jobbing, etc. was estimated based on historical levels of these activities, with 2009 being considered as a year with a unique level of activity.

INTERROGATORY 13

Reference: 4/2/1

Questions:

With respect to the Summary of Operating Costs:

(a) p. 20. Please advise whether the "additional costs" in line 16 are now completed, or whether further costs are anticipated. Please provide a table showing the costs for this category of expense annually starting in 2007, and including actuals and/or forecasts until the process is complete.

(b) p. 23. Please confirm that the "integrated pesticide management plan" has been completed. Please advise the total cost of the plan, and the year or years in which the cost has been or will be incurred. If the plan is being prepared by consultants, please provide details on the consultants selected, the work they have or will do, and the cost.

(c) p. 25. Please provide a copy of the most recent "strategic plan" as referred to, and the most recent "annual budget and capital expenditure program" as referred to.

(d) p. 30. Please confirm that there is now excess capacity at the OSCC. Please advise what steps, if any, the Applicant has taken to make that excess capacity available to other persons to reduce costs to ratepayers.

(e) p. 30, 35. Please confirm that the approval by the Board on May 5, 2009 did not include approval for recovery in rates of any cost increases.

(f) p. 33. Please advise how many square feet of space (broken down by types, such as yard or office) was used by transmission prior to the separation, and how many (with the same breakdown) afterwards.

(g) p. 33. Please advise how much additional space (of each type) is being leased that is not currently needed, and the annual cost of that space. Please provide all reports or other analyses currently in existence showing the timing of the future need for that space.

(h) p. 33. Please provide a copy of the report or other analysis identifying and calculating the under-allocation of costs to the transmission business. Please provide a copy of any report or other analysis calculating the correct allocation of costs to the transmission business.

(i) p. 37. Please provide more details on the Applicant's intention to partner with HONI on transmission projects. Please confirm that such projects may not be part of, or connected to, the Applicant's existing system, and may not be in the same geographic area of the province. Please confirm that the Applicant would propose to include such projects, and the costs of their operation, in rate base. Please provide any business plans, memoranda, reports, or other analyses relating to this proposed initiative.

(j) p. 37. Please estimate the amount of the "consulting and travel expenses" referred to, for the Bridge Year, for the Test Year and for each subsequent year in which the Applicant currently has any forecast or estimate.

Responses:

(a) Identifying and defining of the size and location of buffer zones is an ongoing project for GLPT. Buffer zones can change from year to year as a result of a number of factors including: legislative changes, water level changes, property owner changes, as well as other factors. The annual costs of managing the buffer zones are provided in the table below.

	2007	2008	2009	2010
Buffer Zone Treatment	**$255,00**	**$420,000**	**$110,000**	**$475,000**

(b) Please refer to Board Staff Interrogatory 9 (vii & viii).

(c) For any given year, GLPT's strategic plan consists of a capital budget, an operating budget, key objectives, and a human resource plan. For each of these items, GLPT has included a reference for where in the evidence it can be found.

- Capital budget – Please see GLPT's response to VECC Interrogatory #4(b);
- Operating budget – Please see GLPT's response to VECC Interrogatory #15(e);
- Key objectives – Please see GLPT's response to Board Staff Interrogatory #23(iii);
- Human resources – Please see Exhibit 4, Tab 2, Schedule 3, and GLPT's response to Board Staff Interrogatory #21.

(d) No excess capacity exists at the OSCC. The staffing level of 9 employees is the complement required to meet operational, regulatory, compliance and reporting requirements as a licensed transmitter with an asset base which is a critical part of the bulk transmission system in northern Ontario.

Please refer to GLPT's response to Board Staff Interrogatory 3.

(e) GLPT acknowledges that the approvals provided in that proceeding did not include approval for recovery in rates of any cost increases.

(f) Prior to the separation, distribution and transmission shared employees and space. As such, for the time period prior to the separation, specific allocation of space at the facility at Sackville Rd is not available. GLPT is currently occupying all of the allocated space, with some allowance for future growth. Please see a floor plan for the facility in Appendix 13(f) of Exhibit 10, tab 3, Schedule 2.

(g) All of GLPT's allocated space at 2 Sackville Rd is needed by GLPT. GLPT does not have any reports or analyses showing the timing of future needs. GLPT has attached a floor plan (current as of the time of filing this response) indicating the use of office space within the complex. See response to (f) above.

(h) GLPT does not have any reports that identify and/or calculate the under-allocation of costs to the transmission business. However, GLPT has provided the following analysis which was used as the basis for the 12% allocation to the transmission division.

Historical Building Expenses Allocation at 2 Sackville Rd.

	Allocation to Gx	Allocation to Dx	Allocation to Tx	Total
Administrative		6.1%	1.9%	8.0%
Transmission			9.8%	9.8%
Distribution		31.8%		31.8%
Generation	50.4%			50.4%
Total	**50.4%**	**38.0%**	**11.7%**	**100.0%**

The current analysis using the correct allocation is as follows. The costs displayed in the table reflect the costs in effect for the first year of the agreement. The costs are adjusted to reflect inflation each year on July 1.

Total Complex Space and Costs

	Sq. Ft	Rate	Total Cost
Main Office	24,572	6.50	159,718
Basement	18,216	2.50	45,540
Industrial 1 (Garage)	8,020	7.00	56,140
Industrial 2 (Stores)	3,200	5.00	16,000
Vacant Land	1	30,200.00	30,200
			$307,598

Algoma Power Inc's Complex Space and Costs

	Sq. Ft	Rate	Total Cost	Portion of Total
Main Office	13,132	6.50	85,358	
Basement	6,566	2.50	16,415	
Industrial 1 (Garage)	4,010	7.00	28,070	
Industrial 2 (Stores)	1,600	5.00	8,000	
Vacant Land	-	30,200.00	-	
			$137,843	**44.8%**

GLPT's Complex Space and Costs

	Sq. Ft	Rate	Total Cost	Portion of Total
Main Office	11,440	6.50	74,360	
Basement	11,650	2.50	29,125	
Industrial 1 (Garage)	4,010	7.00	28,070	
Industrial 2 (Stores)	1,600	5.00	8,000	
Vacant Land	1	30,200.00	30,200	
			$169,755	**55.2%**

(i) Regarding the intention to partner with HONI, please see the Response to Board Staff Interrogatory #7 in the Deferral Account Application relating to Renewable Energy Projects (EB-2009-0409). Regarding the geographic areas of such projects, please see response to Board Staff Interrogatory #2 in EB-2009-0409. Subject to the parameters of any joint venturing arrangements, GLPT would plan to add any such project into its rate base. Regarding the inclusion of such projects in rate base, please see the response to Board Staff Interrogatory #4(vi) in the Deferral Account Application relating to Renewable Energy Projects (EB-2009-0409).

(j) GLPT did not include any estimate for these expenses in the Bridge Year forecast. In the Test Year, GLPT included an estimate of approximately $144,500 related to consulting and travel expenses related to the *Green Energy and Green Economy Act* and related green energy initiatives.

INTERROGATORY 14

Reference: 4/2/2

Questions:

With respect to the OM&A Variance Analysis:

(a) p. 25. Please advise why these costs are reduced in each year from 2006 through 2009, when the move to standalone did not take place until 2009.

(b) p. 40. Please provide a table breaking down the total annual legal fees costs for each year from 2006 to 2010 (actual and forecast as available) into the various categories listed in the text, and any other material categories that arose during the period.

(c) p. 41-2. Please provide a table breaking down the total annual consulting fees relating to regulatory for each year from 2006 to 2010 (actual and forecast as available) into the various categories listed in the text, and any other material categories that arose during the period.

(d) p. 46. Please provide a table showing all regulatory related costs, including those under Account 5655, and those in any other account (e.g. 5630), for each year from 2006 through 2010. Please provide a brief explanation of any large changes year over year.

(e) p. 47. Please advise the impact on the Applicant's interest rate on its debt of the move to separate the regulated transmission business, as referred to in the last bullet.

Responses:

(a) The annual costs in account 5605 decreased or remained steady in each year from 2006 through 2009 as a result of the elimination of the Ontario Operations division. This elimination required GLPT to add resources in other areas of the company, as described by the four bullet points on page 26 of Exhibit 4, Tab 2, Schedule 2.

(b) The following table breaks out the legal fees included in GLPT's revenue requirement for the 2010 test year. GLPT has provided total annual legal costs for 2006 to 2009 in its pre-filed evidence. GLPT does not believe that the requested break downs for these prior years are relevant to this proceeding.

Legal Cost Category	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
2010 and 2011 Rate Applications					$345.0
2010 Rate Application - Intervenors					60.0
Interpretation of Legislation					5.0
Other General Legal Counsel					40.0
Total	**$424.5**	**$90.6**	**$301.4**	**$520.0**	**$450.0**

(c) Please see the table below. Please also refer to GLPT's response to Board Staff Interrogatory 30, which is a copy of Appendix 2-I from the filing requirements providing a breakdown of regulatory costs incurred.

Regulatory Consulting Cost Category	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Rate Application	$0.0	$0.0	$9.3	$73.1	$40.0
Other Regulatory Proceedings	-	-	-	-	25.3
Total	**$0.0**	**$0.0**	**$9.3**	**$73.1**	**$65.3**

(d) Please refer to GLPT's response to Board Staff Interrogatory 30, which is a copy of Appendix 2-I providing a breakdown of regulatory costs incurred. The largest change that is notable in the table is the increase in legal costs for regulatory matters. This change is a result of the legal support required in preparing and filing of this rate application, and the costs associated with the proceeding.

(e) GLPT's stated interest rate on debt did not change from the rate of 6.60%.

INTERROGATORY 15

Reference: 4/2/3, p. 2

Question:

Please provide a table showing FTEs for each year from 2006 through 2010, broken down by function (e.g. General Admin, Executive/Management, Operations, etc.). Please provide a brief explanation of any substantial increase in the FTEs for a function from 2006 to the Test Year.

Response:

Please see the table below. Changes in FTE's and employee compensation are described in detail in GLPT's response to Board Staff Interrogatory 21.

	2006	2007	2008	2009 Bridge	2010 Test Year
General Admin	9.2	8.2	9.1	11.9	15.0
Executive/Management	1.0	1.0	1.3	2.9	5.0
Operations	16.3	14.2	14.8	25.1	34.7
Total	**26.5**	**23.4**	**25.2**	**39.9**	**54.7**

INTERROGATORY 16

Reference: 4/2/3, p. 4

Question:

Please provide a copy of the current Incentive Compensation Plan, together with the specific metrics in use in 2010 for corporate objectives, and the formula applied to determine the incentive paid. If the metrics for 2010 are not yet available, please provide 2009, and advise when the 2010 metrics will be known.

Response:

Please see GLPT's response to Board Staff Interrogatory #23(i)-(iii).

INTERROGATORY 17

Reference: 4/2/4

Questions:

With respect to Shared Services and Corporate Cost Allocation:

(a) Please provide a comprehensive table for each of the 2006 through 2010 years, showing, for each cost category in which there is a sharing by, or allocation to, the transmission business:

(i) The total cost incurred or forecast (with breakdown if material)

(ii) The entity that incurs the cost

(iii) The basis of allocation (cost driver, etc.)

(iv) The allocation of the cost to each related entity, including the transmission business (and showing the amount to each of the entities)

(v) The cost to the transmission business of alternative methods of executing the function

(b) p. 2. Please provide the consulting report referred to.

(c) p. 4. Please provide a copy of the SCADA licensing agreement. Please explain the rationale behind recovering from the transmission business only half of the depreciation cost. Please provide any memoranda, reports, business case analyses, or other documents relating to the amounts payable by the transmission business for the SCADA system.

(d) p. 5. Please provide details on all payments made or to be made to the Applicant as compensation for the use of its towers and other infrastructure for the fibre optic system.

(e) p. 11. Please complete Table 4-2-4 B by inserting, in the column “2010 Test Year”, the amounts for each of the functions listed that are currently included in the revenue requirement for the Test Year. By way of example, the entire cost of the OSCC is included in revenue requirement, although no longer a shared service.

(f) App. B. Please confirm that the Navigant Report is no longer applicable. If it is applicable, please advise the details.

(g) App. B, p. 3. Please provide the “written explanation” referred to.

Responses:

(a)

Shared Services - 2010 Cost Category	Total Cost Incurred ($000's)	Entity Incurring Cost	Cost Driver	GLPT Allocation ($000's)	Non-GLPT Allocation ($000's)	Incremental Cost of Alternatives ($000's)
Office Complex						
Rent	$310.7	GLPT	Sq. Footage	$171.5	$139.2	$280.0
O&M	$679.3	GLPT	Sq. Footage	$361.9	$317.4	n/a
SCADA Equipment licence	$588.0	GLPL	50% Depr.	$294.0	$294.0	$294.0
Fibre Optic System licence	$154.1	GLPL	41% Depr.	$63.2	$90.9	Millions in Capital Costs
Radio System costs	$13.0	GLPT	50% of Costs	$6.5	$6.5	Unknown, immaterial
Corporate Cost Allocation	n/a	BIP	Time Spent	$298.6	n/a	Unknown (High)

GLPT has made the following assumptions in populating the "Incremental Cost of Alternatives" column:

Office Complex Rent – GLPT assumed the incremental cost would be equal to the return on investment that the owner of the complex is foregoing. As noted on page 3 of Exhibit 4, Tab 2, Schedule 4, this is estimated at $280,000 per year.

SCADA Equipment Licence – GLPT assumed the incremental cost is equal to the depreciation expense that is being borne by GLPL instead of GLPT (50% of the total). The incremental cost would also include the foregone return on investment, which GLPT has not calculated in preparing the table.

Fibre Optic System Licence – GLPT assumed that the only alternative to sharing the existing fibre optic system would be to install a new system. To do this, it is expected that GLPT's capital costs would be in the millions of dollars.

Corporate Cost Allocation – GLPT has not calculated an estimate of the costs that it would incur as an alternative to utilizing its parent company for corporate services. However, these costs would include, but not be limited to, the hiring of accounting specialists, income tax specialists, finance specialists, and management consultants, all at relatively high hourly rates.

(b) Please refer to GLPT's response to Board Staff Interrogatory 35(ii).

(c) Please see GLPT's response to Board Staff Interrogatory 38(i) for the SCADA licensing agreement.

Please refer to GLPT's response to Board Staff Interrogatory 41(iv) for a description of the rationale behind the cost allocation. In summary, when forming the agreement, GLPT considered the impact to transmission ratepayers, and made an effort to mitigate the impact of the SCADA costs to the ratepayers.

(d) No payments have been made.

(e)

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Ontario Operations Allocation	*386.5*	*232.1*	*213.1*	*133.4*	-	**-**
Ontario System Control Centre	*1,314.3*	*1,116.6*	*1,201.2*	*1,112.8*	*492.2*	***2,037.7***
General Manager & Admin Support	*100.0*	*195.7*	*188.2*	*269.1*	*218.8*	***873.4***
Accounting & Finance						
Payroll & Benefits	64.7	**	**	**	**	**
Accounting and Procurement	382.0	390.5	389.3	448.5	237.1	**450.1**
Stores	97.0	10.5	10.6	11.2	4.6	**-**
Subtotal Accounting & Finance	*543.6*	*401.1*	*399.9*	*459.7*	*241.7*	***450.1***
Planning & Maintenance and Admin Support						
Planning & Maintenance	276.4	201.3	227.9	215.6	122.5	**36.0**
Health & Safety	39.9	21.7	19.2	31.4	28.3	**240.8**
Environmental	18.8	12.4	17.5	7.2	1.6	**42.5**
Subtotal P & M and Admin Support	*335.1*	*235.3*	*264.5*	*254.1*	*152.3*	**-**
Building	*n/a*	*56.0*	*54.9*	*57.3*	*154.4*	***533.3***
Information Technology Services	*127.3*	*165.4*	*195.8*	*175.8*	*104.3*	***547.8***
Total Shared Services	***$2,806.9***	***$2,402.2***	***$2,517.6***	***$2,462.1***	***$1,363.7***	***$4,442.3***

GLPT would like clarify that the costs reflected in the 2009 column are the costs related to the services that were shared at the time. For example, the OSCC costs are reflective only of the January 1 – June 30 costs, and do not reflect any of the costs that were borne by GLPT after the OSCC became a transmission-only control centre.

For each line, the 2010 column reflects the costs associated with similar activities that will take place in the test year, whether or not the service is still a shared service or not.

OSCC costs increase in 2010 as described on pages 6-9 of Exhibit 4, Tab 2, Schedule 2.

General Management and Admin support costs increase in 2010 for the reasons described on pages 25-30 of Exhibit 4, Tab 2, Schedule 2, and on pages 24-28 of Exhibit 4, Tab 2, Schedule 1.

Planning and Maintenance costs have decreased in 2010 as a result of GLPT finding efficiencies and eliminating the need for a separate department to manage these duties.

Health and Safety and Environmental costs and *Information Technology Services* costs increase in 2010 for the reasons described on page 34 of Exhibit 4, Tab 2, Schedule 2, and on pages 31-33 of Exhibit 4, Tab 2, Schedule 1.

Building costs increase in 2010 for the reasons described on pages 13-14 of Exhibit 4, Tab 2, Schedule 2, and on pages 33-35 of Exhibit 4, Tab 2, Schedule 1.

(f) Confirmed. Please refer to GLPT’s response to Board Staff Interrogatory 36.

(g) Please see the “written explanation” in Appendix 17(g) in Exhibit 10, Tab 3, Schedule 2.

INTERROGATORY 18

Reference: 4/3/2

Questions:

With respect to Income Tax:

(a) p. 3. Please provide the most recent Canadian tax return for BIH.

(b) p. 4. Please explain why the transaction was carried out on a fully taxable basis, rather than using available rollovers under the Income Tax Act. Please provide any tax planning memoranda, opinions, or other documents explaining the tax consequences or tax choices in the transaction.

(c) p. 6. Please confirm that this proposed treatment of CCA results in the transmission business continuing to be liable for future recapture and/or for an added annual tax cost associated with the difference between accounting depreciation and allowed CCA.

Responses:

(a) Please refer to GLPT's response to Board Staff Interrogatory 55 (d).

(b) The sale of the transmission assets was carried out on a taxable basis, as opposed to a tax-deferred one, for a variety of reasons. The business objectives were more easily and directly achieved through the taxable sale than a tax deferral transaction. It was important that the transaction take place on arm's length terms and in a manner that ensured that the transmission business was wholly owned by Brookfield Infrastructure Partners LP ("BIP LP"), in keeping with the intended business deal. Although Brookfield Asset Management Inc. ("BAM") has an equity interest in each of Great Lakes Power Limited ("GLPL") (the vendor of the transmission assets) and BIP LP (the indirect purchaser of the assets), BIP LP is not wholly owned by BAM. BIP LP is partly owned by the public through limited partnership units. The interests of these partners in BIP LP had to be taken into consideration when the transmission assets were acquired.

Generally, the tax-deferred rollovers under the *Income Tax Act* that would have been available to GLPL on the asset sale (e.g., subsections 85(1) or 97(2)) would have required the issuance of equity of the purchaser to GLPL. This would have diluted the expected equity interests of the public BIP LP partners.

For regulatory reasons, GLPL intended to fully divest of its transmission assets to be compliant with Section 71 of the *OEB Act*. The taxable sale facilitated the achievement of this goal. A tax-deferred rollover would have left GLPL with a residual, indirect interest in the transmission assets.

As the asset sale was relatively straightforward from a tax perspective, no tax planning memorandum was specifically prepared for this transaction.

(c) GLPT confirms the proposed treatment of CCA will have no tax implication to the ratepayer. The ratepayer will not incur tax costs that are different from what the ratepayer would have incurred had the business continued to operate as a division of GLPL.

INTERROGATORY 19

Reference: 4/3/5

Questions:

With respect to Interest Expense:

(a) Please confirm that the Series 1 Bonds are the same as the Trans Senior Bonds referred to in the financial statements.

(b) Please provide full details of the terms of the Series 1 Bonds, including date of issue, security, maturity, payment schedule, etc. If the Series 1 Bonds replaced a previous debt issue, please provide details of the replacement transaction.

(c) Please advise how much, if any, of the Series 1 Bonds are held by entities affiliated, with, related to, under common control with respect to, or otherwise not fully arms-length from, the Applicant or GLPT.

(d) Please provide a copy of the offering document (e.g. offering memorandum, prospectus, etc.) related to the Series 1 Bonds. If there is more than one (for example, Canadian and American versions) please provide all such documents.

(e) Please provide all information available to the Applicant on market interest rates for long term debt at the time of the issuance of the Series 1 Bonds.

Responses:

(a) Confirmed.

(b) Please see response to Board Staff Interrogatory 93(i), as well the First Supplemental Trust Indenture and Assumption Agreement, which are provided in Appendix 19(b) of Exhibit 10, Tab 3, Schedule 2.

(c) Currently, none of the Series 1 Bonds are held by entities affiliated with, related to, under common control with respect to, or otherwise not fully arms-length from, the Applicant or GLPT.

(d) There is no offering document in respect of the existing bonds. The bonds secured against the transmission assets were initially issued by Great Lakes Power Limited, prior to transferring the transmission assets to GLPTLP, and upon such transfer, were assumed by GLPTLP. Please refer to the response to (b) above for a copy of the supplemental indenture setting out the financial terms of those bonds.

(e) GLPT has no information on market interest rates for long term debt at the time of the issuance of the Series 1 Bonds. The Series 1 Bonds replaced existing GLPL bonds that where in place to finance transmission assets. The existing bonds contained a set maturity date and terms and conditions that would require the transmission division to pay a makewhole amount that would effectively eliminate any interest differential thus eliminating any benefit of repricing.

INTERROGATORY 20

Reference: 9/1/2, p. 3

Question:

Please provide a continuity table for Account 1505 showing the actual amount of the initial entry ($9.2971 million), and the actual amounts of each other subsequent entry until the date of your IR answer. Please confirm that the Applicant is currently continuing to collect these amounts in rates.

Response:

Year	Opening	Lost Revenue	Balance Correction	Amortization Recorded	Closing Balance
2005	$9,079,130	$0	$0	($1,815,826)	$7,263,304
2006	7,263,304	-	(833,408)	(1,482,462)	4,947,434
2007	4,947,434	-	-	(1,649,144)	3,298,290
2008	3,298,290	-	-	(1,649,144)	1,649,146
2009	1,649,146	498,037	-	(2,218,551)	(71,368)

Amortization recorded in 2009 is driven by the regular amortization, plus the following two additional factors:

- Correction of prior year amortization - $1,649.1k was recorded, $1,855.8k should have been recorded. This results in total incremental amortization of $1,033,375.

- Correction of 2005 amortization – A full year amount was recorded instead of 9/12's based on an April 1, 2005 effective date. This reduces 2009 amortization by $463,955.

As a result, the 2009 amortization is approximately equal to:

$1,649k regular amortization
$1,033k true-up of annual variances
($464k) true-up of 2005 amortization
$2,218k

INTERROGATORY 21

Reference: 9/1/6, p. 3

Question:

Please provide the deal book for the transaction described. Please provide this on disk, and not in hard copy.

Response:

The Board fully reviewed the transaction in question in EB-2007-0647 and approved the transaction. As a result, it is not clear as to the relevance of the request made.

INTERROGATORY 22

Reference: 9/2/1, p. 2

Question:

Please provide the most recent actuarial report from Mercer.

Response:

Please see the most recent actuarial report in Appendix 22 of Exhibit 10, Tab 3, Schedule 2.

APPENDICES

2	2007 Stakeholder Presentation 2008 Stakeholder Presentation 2009 Stakeholder Presentation 2007 Stakeholder Meeting Transcripts 2008 Stakeholder Meeting Transcripts
4(d)	Materials re Vegetation Management Expenditures in 2009
4(e)	Criteria from the OPA
6(e)	GLPTLP Partnership Agreement Amendment to GLPTLP Partnership Agreement
7(a)	Unaudited Financial Statements
13(f)	Sackville Road Floor Plan
17(g)	Written Explanation of OSCC Provided to Navigant
19(b)	Assumption Agreement First Supplemental Trust Indenture
22	Actuarial Report from Mercer

Exhibit 10, Tab 3, Schedule 2

Appendices to the Responses to Interrogatories from SEC

EXHIBIT 10 - TAB 3 - SCHEDULE 2
APPENDICES

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22	Actuarial Report from Mercer

Great Lakes Power Transmission

2007 Stakeholder Session

Great Lakes Power

Agenda

- **Introduction**
- **Proposed 2007 Capital Plan**
  - GLPL Asset Management Strategy
  - Compliance
  - Refurbishment / Replacement
  - System Improvement
- **2007 Capital Summary**
- **Proposed 2007 Maintenance Plan**
  - Major Maintenance
- **Transfer Pricing Review**
  - Terms of Reference
  - Consultant
- **Questions**

Introduction

- **Great Lakes Power Limited**
  - Alex Lee – Manager, Transmission Engineering
  - Gary Gazankas – Transmission Engineer
  - Tim Lavoie – General Manager
- **Object of Stakeholder Session**
  - As part of GLPL's capital budgeting process, GLPL is conducting stakeholder meetings with stakeholders to consider its capital plan, together with its major maintenance plan. (section 1.2 of the settlement agreement)
  - GLPL has committed to retaining an independent third party consultant to review and report on the accuracy of its cost allocation and transfer pricing between its transmission and generation businesses, the results of which will be filed at GLPL's next transmission rate application. The stakeholder consultation group will provide input into setting the terms of reference of the review and choosing the third party consultant. (section 3.1.1 of the settlement agreement)

GLPL Asset Management Strategy – Plan Development

- **Visit Every Site and Perform an Assessment of all Assets**
- **Consider Direct Customer Concerns**
- **Determine When End of Life Assets Need to be Replaced**
- **Assess What Remedial Work was Required**
- **Examine System for Operational Improvements**
- **Identify Projects and Prioritize Annually**
- **Review Program for:**
  - Resource Adequacy
  - Reasonableness
  - Possible Synergies

Great Lakes Power

GLPL Asset Management Strategy - Prioritization

- **Prioritize All Projects Based on Criteria Basis:**
  - Addressing public and worker safety issues
  - Addressing significant environmental Issues
  - Replacing end of life equipment
  - Compliance with legislative and regulatory requirements
  - Improving system reliability, maintainability and operability
- **Project Timing considers:**
  - Priority as indicated above
  - Synergies based on outage and logistical requirements
- **Represents a Complete Approach to Evaluating All Proposed Projects**

GLPL Asset Management Strategy – Expected Outcome

- Best Allocation of Resources to Greatest Needs
- Risks are Managed in a Systematic Manner
- “Unexpected Expenditures” Are Significantly Reduced
- Plan Continues to Be Developed As Conditions Change, Regulatory Requirements Change, Asset Assessments and Stakeholder Concerns
- Proposed Capital Budget for 2007 is $11,254,893.

Great Lakes Power

GLP Proposed Capex Plan 2007

Category: Compliance

- **The following projects are required to meet current standards**

Goulais TS Oil Containment	$275,000
TS Grounding Study	$57,200
Category Total	**$332,200**

GLP Proposed Capex Plan 2007

Category: Refurbishment/Replacement

- **The following projects are required to meet end of life replacements**

New 230/115 kV Transformer- T1 Replacement -	$4,527,600
Mackay TS 115 kV Switchyard Refurbishment (1)	$1,798,500
Third Line TS 115 kV Switchyard Refurbishment (1)	$2,189,500
Magpie Transmission Line Structure Replacement	$473,000
Clergue LV (12kV) Bus and BF Protections	$148,500
Echo River TS Battery Replacement	$141,790
Minor Fixed Assets - 2007	$100,000
Transmission Line Emergency work	$80,003
Building Upgrades - 2007	$80,000
MacKay TS Breaker Failure Protections	$71,500
Magpie TS Battery Charger Replacement	$29,700
Category Total	**$9,640,093**

Great Lakes Power

GLP Proposed Capex Plan 2007

Category: System Improvement

- **The following projects are required to enhance system operation**

Upgrading 3 x 115kV Line Protections – Magpie TS	$407,550
Projects Pre- Engineering	$275,000
MacKay 115kV Line and Bus Protections	$170,500
Upgrade Clergue Bank MT1 and MT2 Protections	$165,550
Install 115kV Line PTs - Magpie TS	$137,500
Centralized Information Retreival	$71,500
Station Protection Automation - (1)	$55,000
Category Total	**$1,282,600**

Great Lakes Power

Proposed 2007 Maintenance Plan

- **Major Maintenance**
  - "major maintenance" indicates maintenance projects or programs that are of significant magnitude and that do not constitute a capital project. Typically major equipment repair/overhaul projects, vegetation management programs and soils remediation programs would fall under this category.
- **Completed on the basis of Budget Review, Stakeholder feedback, Outage Planning and Logistical Planning**

Proposed 2007 Maintenance Plan

Forestry / Vegetation Management	$800,000
Station Overhauls	$200,000
Soil Remediation	$35,000
Category Total	**$1,035,000**

Transfer Pricing

- **Identified through the 2005 Rate Application Settlement Process**
  - Independent 3rd Party Consultant will develop a Report that will assess the accuracy of GLPL cost allocation and transfer pricing between its transmission and generation businesses
    - This meeting will allow the stakeholders to provide input to the report terms of reference as well as to the available consultants to perform the review.

Great Lakes Power

Transfer Pricing con't

- **GLPL Share costs between it Transmission and Generation businesses on in the following areas:**
  - Ontario System Control Center
    - Dispatch Operations
    - Integrated Communication Network
    - Meter Service Provider
  - VP Ontario Operations Administration

Great Lakes Power

Terms of Reference for 3rd Party Review

- review and report in writing on the fairness of GLPL's cost allocation and transfer pricing methodology between its transmission and generation businesses.
- Suggest methodology changes (if required)

Consultant for 3rd Party Review

- Accounting Designation (CA, CMA, CGA or equivalent financial accreditation)
- Not affiliated with GLPL

Timing of the Report

- Seek consultant by the end of Q2 2007
- Final Report delivered by the end of Q3 2007

Questions ?

Great Lakes Power

Great Lakes Power Transmission

2008 Stakeholder Session

Great Lakes Power

Agenda

- **Introduction**
- **Direct Customer Presentations**
- **2007 Stakeholder Presentation Review**
- **GLPL Asset Management Strategy**
  - Plan Development
  - Prioritization
  - Expected Outcome
- **GLP Proposed Projects – 2008**
  - Compliance
  - Refurbishment / Replacement
  - System Improvement
  - Facilities tools & Equipment
- **Outlook**
  - Proposed Projects
- **Proposed 2008 Maintenance Plan**
  - Major Maintenance defined
  - Major Maintenance Program
- **Transfer Pricing update**
- **Questions**

Great Lakes Power

Introduction

- **Great Lakes Power Limited**
  - Alex Lee – Manager, Transmission Engineering
  - Gary Gazankas – Transmission System Planner
  - Tim Lavoie – General Manager
  - Peggy Lund – Customer Relations
- **Object of Stakeholder Session**
  - As part of GLPL's capital budgeting process, GLPL is conducting stakeholder meetings with stakeholders to consider its capital plan, together with its major maintenance plan. (section 1.2 of the settlement agreement)
  - GLPL has committed to retaining an independent third party consultant to review and report on the accuracy of its cost allocation and transfer pricing between its transmission and generation businesses, the results of which will be filed at GLPL's next transmission rate application.

Direct Customer Presentations

- Direct Customer Meeting Objectives
  - Considered Stakeholders
  - Develop effective lines of communication
  - Work with customers on an individual basis
    - Discuss individual needs
    - Customers Choice on attendance

2007 Stakeholder Presentation Review

- **2007 Stakeholder input**
  - **Plan Development**
  - **Prioritization**
  - **Future Outlook**

Great Lakes Power

GLPL Asset Management Strategy – Plan Development

- **Integrity of each asset and the transmission system performance are assessed on an ongoing basis.**
  - Assessment Based on
    - Field and Aerial Inspections
      - Infrared Inspections
      - Condition Assessments
    - Maintenance and operation reports
    - Remaining life estimates
    - System Planning activities
    - Direct Customer input
    - Customer Delivery Point Performance Standards (CDPPS)

GLPL Asset Management Strategy - Prioritization

- **Prioritize All Projects Based on set of Criteria:**
  - Addressing public and worker safety issues
  - Addressing significant environmental Issues
  - Consideration of equipment age
  - Compliance with legislative and regulatory requirements
  - Improving system reliability, maintainability and operability
- **Review Projects for (Logistics and Efficiency):**
  - Resource Adequacy
    - Material / Equipment Availability
    - Internal / External Manpower Resource
  - Possible Synergies
- **Projects are ranked based on:**
  - Criteria

    And
  - Logistics and Efficiency

Represents a Complete Approach to Evaluating All Proposed Projects

Great Lakes Power

GLPL Asset Management Strategy – Expected Outcome

- Best Allocation of Resources to Greatest Needs
- Risks are Managed in a Systematic Manner
- “Unexpected Expenditures” Are Significantly Reduced
- Outlook Continues to Be Developed As Conditions Change, Regulatory Requirements Change, Asset Assessments and Stakeholder Concerns
- Proposed Capital Budget for 2008 is $8,613,850.

GLP Proposed Projects - 2008

Category Explanation:

- Facilities Tools and Equipment
  - **Projects that Primarily involve procurement of maintenance and test equipment, major tools, spare parts, and other miscellaneous components. Examples include:**
    - **Spare Breaker**
    - **Various transformer and breaker parts**
    - **Test and maintenance equipment**
- Legislative Compliance
  - **This category consists of capital costs incurred to meet legislative and regulatory requirements prescribed by the OEB, IESO, NPCC, NERC, MOEE, ESA, etc.**
- Refurbishment / Replacement
  - **Major refurbishment and/or replacement of end-of-life equipment and facilities are listed in this category.**
    - **End of life equipment is replaced in accordance with good utility practices to avoid catastrophic failures and to maintain the integrity of the assets.**
    - **Equipment replacements are supplemented with configuration changes to improve reliability, maintainability and flexibility of the facilities requirements.**
- System Improvement
  - **System Improvements are comprised of upgrades and additions to the transmission system to improve efficiency of operations, quality of service, reliability, maintainability, flexibility, outage response and data gathering/analysis capabilities.**

GLP Proposed Projects - 2008

Category: Compliance

- **The following projects are required to meet current standards**

Steelton TS ground grid refurbishment	$292,600
Oil Containment Refurbishment	$247,500
Right of Way (ROW) management database	$148,000
SF6 gas storage facility	$96,250
Category Total	**$784,350**

GLP Proposed Projects - 2008

Category: Refurbishment/Replacement

- **The following projects are required to meet end of life replacements**

Third Line TS 115 kV Switchyard Refurbishment	$3,586,000
Mackay TS 115 kV Switchyard Refurbishment	$2,651,500
T2 Transformer Overhaul – Third Line TS	$225,000
Transformer Overhaul – Northern Avenue TS	$125,000
Minor Fixed Assets	$100,000
Transmission Line Emergency work	$80,000
Building Upgrades	$80,000
Category Total	**$6,847,500**

GLP Proposed Projects - 2008

Category: System Improvement

- **The following projects are required to enhance system operation**

Algoma Lines Engineering	$308,000
Projects Pre- Engineering	$250,000
Station Protection Replacement	$169,000
T2 On line Monitoring - Mackay	$100,000
Category Total	**$827,000**

Great Lakes Power

GLP Proposed Projects - 2008

Category: Facilities Tools & Equipment

- **The following projects are required to assist in the maintaining of the system**

Components	$100,000
115 kV circuit Lidar - database	$55,000
Category Total	**$155,000**

Outlook

Proposed Projects

ROW Management (IESO Standard)
115 kV Bus Replacement – Third Line TS
SVC Installation – Third Line TS
T1 - Bus and BF 34.5 kV protection Upgrades - Echo River TS
115 kV Switchyard Refurbishment - Third Line TS

Proposed 2008 Maintenance Plan

- **Major Maintenance Defined**
  - "major maintenance" indicates maintenance projects or programs that are of significant magnitude and that do not constitute a capital project. Major equipment repair/overhaul projects, vegetation management programs and soils remediation programs fall under this category.
- **Completed on the basis of Budget Review, Stakeholder feedback, Outage Planning and Logistical Planning**

Proposed 2008 Maintenance Plan

Major Maintenance Plan

Forestry / Vegetation Management	$1,500,000
Insulator Washing – Clergue / Algoma ccts	$125,000
Switchgear Inspection – Watson TS	$75,000
Transmission circuit infrared scan	$55,000
Soil Remediation Activities	$45,000
Category Total	**$2,150,000**

Great Lakes Power

Questions ?

Great Lakes Power

Great Lakes Power Transmission

2009 Stakeholder Session

Great Lakes Power

Agenda

- **Introduction**
- **Direct Customer Presentations**
- **GLPL Asset Management Strategy**
  - Plan Development
  - Prioritization
  - Expected Outcome
- **GLP Proposed Projects – 2009**
  - Compliance
  - Refurbishment / Replacement
  - System Improvement
  - Facilities tools & Equipment
- **Outlook**
  - Proposed Projects
- **Proposed 2009 Maintenance Plan**
  - Major Maintenance defined
  - Major Maintenance Program
- **Transfer Pricing update**
- **Questions**

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Introduction

- **Great Lakes Power Limited**
  - Gary Gazankas – Manager, Transmission and Distribution System Planning and Engineering
  - Tim Lavoie – General Manager
  - Peggy Lund – Customer Relations
- **Object of Stakeholder Session**
  - As part of GLPL's capital budgeting process, GLPL is conducting stakeholder meetings with stakeholders to consider its capital plan, together with its major maintenance plan. (section 1.2 of the settlement agreement)
  - GLPL has committed to retaining an independent third party consultant to review and report on the accuracy of its cost allocation and transfer pricing between its transmission and generation businesses, the results of which will be filed at GLPL's next transmission rate application.

Direct Customer Presentations

- Direct Customer Meeting Objectives
  - Considered Stakeholders
  - Develop effective lines of communication
  - Work with customers on an individual basis
    - Discuss individual needs
    - Customers Choice on attendance

2008 Stakeholder Presentation Review

- **2008 Stakeholder input**
  - Plan Development
  - Prioritization
  - Future Outlook

GLPL Asset Management Strategy – Plan Development

- **Integrity of each asset and the transmission system performance are assessed on an ongoing basis.**
  - Assessment Based on
    - Field and Aerial Inspections
      - Infrared Inspections
      - Condition Assessments
    - Maintenance and operation reports
    - Remaining life estimates
    - System Planning activities
    - Direct Customer input
    - Customer Delivery Point Performance Standards (CDPPS)

GLPL Asset Management Strategy - Prioritization

- **Prioritize All Projects Based on set of Criteria:**
  - Addressing public and worker safety issues
  - Addressing significant environmental Issues
  - Consideration of equipment age
  - Compliance with legislative and regulatory requirements
  - Improving system reliability, maintainability and operability
- **Review Projects for (Logistics and Efficiency):**
  - Resource Adequacy
    - Material / Equipment Availability
    - Internal / External Manpower Resource
  - Possible Synergies
- **Projects are ranked based on:**
  - Criteria

    And
  - Logistics and Efficiency

Represents a Complete Approach to Evaluating All Proposed Projects

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GLPL Asset Management Strategy – Expected Outcome

- Best Allocation of Resources to Greatest Needs
- Risks are Managed in a Systematic Manner
- “Unexpected Expenditures” Are Significantly Reduced
- Outlook Continues to Be Developed As Conditions Change, Regulatory Requirements Change, Asset Assessments and Stakeholder Concerns
- Proposed Capital Spending for 2009 is $12,188,000.

GLP Proposed Projects - 2009

Category Explanation:

- Legislative Compliance
  - **This category consists of capital costs incurred to meet legislative and regulatory requirements prescribed by the OEB, IESO, NPCC, NERC, MOEE, ESA, etc.**
- Refurbishment / Replacement
  - **Major refurbishment and/or replacement of end-of-life equipment and facilities are listed in this category.**
    - **End of life equipment is replaced in accordance with good utility practices to avoid catastrophic failures and to maintain the integrity of the assets.**
    - **Equipment replacements are supplemented with configuration changes to improve reliability, maintainability and flexibility of the facilities requirements.**
- System Improvement
  - **System Improvements are comprised of upgrades and additions to the transmission system to improve efficiency of operations, quality of service, reliability, maintainability, flexibility, outage response and data gathering/analysis capabilities.**
- Facilities Tools and Equipment
  - **Projects that Primarily involve procurement of maintenance and test equipment, major tools, spare parts, and other miscellaneous components. Examples include:**
    - **Spare Breaker**
    - **Various transformer and breaker parts**
    - **Test and maintenance equipment**

GLP Proposed Projects - 2009

Category: Compliance

- **The following projects are required to meet current standards**

	Estimated Costs
Cyber Security Requirements (System Wide)	$832,000
Category Total	**$832,000**

GLP Proposed Projects - 2009

Category: Refurbishment/Replacement

- **The following projects are required to meet end of life replacements**

	Estimated Costs
Third Line TS - Refurb / Rearrangement (Multi Year)	$3,064,000
Batchawana TS Gnd. Refurbishment	$991,000
Mackay 115kV Bus Upgrades / CVT replacement	$975,000
Steelton St TS Gnd. Refurbishment	$854,000
Components Storage Facility	$452,000
Building Upgrades – 2009	$249,000
Communications Upgrades - GLP System Control	$229,000
Magpie TS Battery Replacement	$206,000
Clergue Circuits - Components Replacement	$183,000
Transmission System Emergency work	$174,000
Minor Fixed Assets - 2009	$99,000
Category Total	**$7,476,000**

GLP Proposed Projects - 2009

Category: System Improvement

- **The following projects are required to enhance system operation**

	Estimated Costs
Echo River TS T1, Bus & BF 34.5 kV Prot. Upgrade	$977,000
Third Line Series Reactor Installation	$825,000
Algoma Lines Upgrade Engineering / Prelim Work	$286,000
Engineering	$248,000
Centralized Information Retrieval - Upgrades	$206,000
Category Total	**$2,542,000**

GLP Proposed Projects - 2009

Category: Facilities Tools & Equipment

- **The following projects are required to assist in the maintaining of the system**

	Estimated Costs
GIS Software Purchase / Installation	$506,000
Vegetation Management System	$424,000
Asset Management Software	$161,000
Installation of SF6 breaker access platforms	$98,000
Process Lidar data – (PLS Cadd)	$77,000
Purchase PLC Test Equipment	$53,000
Emergency Response Trailer purchase	$19,000
Category Total	**$1,338,000**

Outlook – 2010 and Beyond

Proposed Projects

- 115 kV Bus Replacement / Switchyard Refurbishment– Third Line TS
  - New Configuration
    - Breaker and a Half
  - Replacement of Bulk Oil Breakers
  - Replacement of Disconnect Switches
  - Replacement of Aging Components
- SVC Installation – Third Line TS
- Algoma 115kV Transmission circuits Refurbishment
- P12G Structure Replacements
- Clergue Metal Clad Switchgear Replacement

Proposed 2009 Maintenance Plan

- **Major Maintenance Defined**
  - "major maintenance" indicates maintenance projects or programs that are of significant magnitude and that do not constitute a capital project. Major equipment repair/overhaul projects, vegetation management programs and soils remediation programs fall under this category.
- **Completed on the basis of Budget Review, Stakeholder feedback, Outage Planning and Logistical Planning**

Proposed 2009 Maintenance Plan

Major Maintenance Plan

	Estimated Costs
Forestry / Vegetation Management	$1,500,000
Major Overhauls	$196,064
Right Of Way Access	$103,800
Transmission circuit infrared scan	$80,000
Soil Remediation Activities	$50,000
Process Lidar Data – Updates	$20,000
Category Total	**$1,949,864**

Questions ?

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GREAT LAKES POWER TRANSMISSION

2007 STAKEHOLDER SESSION

Tuesday, February 13, 2007

MR. LAVOIE: We'll get things started here. A couple of administrative items. This meeting is what we're calling the 2007 stakeholder session. We -- as a transmission company, we recognize through our last transmission re-application through input by intervening parties, that there is an interest in a stakeholdering session, an interactive involvement with the transmission company on at least an annual basis to get input on various items.

So this is the context of the meeting. I recognize that most of you around the room here are directly connected customers to the system, and this idea of meeting and talking and discussing with the transmission company isn't a new concept for you. I know we've done it on an individual basis on a regular basis.

So because of the process itself, we wanted to be able to establish that we definitely had the stakeholder session. We have a transcriber up at the front. The intention of it is, is that we had expressed -- sorry, some of the stakeholders had expressed an interest of understanding what the issues were and being able to refer to a minuted or documented meeting, and that's what the purpose is. The idea is not to have such a formal meeting that we're not relaxed about it. The idea is that this is a transcribed meeting and by all means you're welcome to the transcription, and we are -- will never use it without your permission. So the idea behind -- because it's a transcribed meeting, if you have any questions, if you would state your name for purposes of that before asking the question, that would be great. Is everyone comfortable with that concept?

In terms of an agenda today, a little bit of, obviously, an introduction. The topics that we would like to talk to you about are our proposed 2007 capital plan, talk a little bit about our strategy with respect to asset, managing our assets. Talk about the types of capital investments that we have planned and proposed for 2007. The context of addressing certain issues within our system, compliance issues, refurbishment or replacement activities, and system improvement activities.

We'll also talk to you about our major maintenance program and plan for -- proposed plan for 2007. And then there's another component that may be new to folks, and it is a direct relation to our grade application, where we are a company that it is -- exists as a transmission company, a distribution company and we have some generation activities that exist in our company.

The concept of transferring some costs between the organization became of interest, obviously, to interveners and stakeholders in the last grade application, and a commitment to -- from ourselves, an agreement in that process was to review this transfer pricing methodology and to review it in the context of a third party consultant.

So we're going to review and seek input from you on the terms of reference of this consultation, as well as what type of consultant that should be used in that.

The other topic that isn't on the board that, again, I wanted people just, I guess, to think about is as a direct connected customer, we do -- have had annual sessions in the past. This is a group setting. I guess there could be preferences either way on a go-forward basis on whether this group setting would be something that you'd be interested in on an annual basis or on an individual basis. So we don't want to, I guess, duplicate any efforts for everybody, but we do view the directly connected customers as a very big stakeholder in our system, and want to make sure that you're included in the stakeholder process from that standpoint. Your input, whether here at the meeting or after the meeting on what would be your preference on a go-forward basis to make it as efficient and effective for you folks as well.

Myself, I'm Tim Lavoie, general manager of Great Lakes Power Transmission and Distribution. With me today is Gary Gazankas our transmission engineer, and Alex Lee, who is our manager of transmission engineering. We'll be talking, taking turns in various parts of the session here today, and any questions that you may have at any time, please feel free to jump in. That's sort of the nature of the way we like to have this session conducted. So again, trying to be as informal as we can.

Again, the objective of this session is as part of our capital budgeting process, we're conducting stakeholder meetings with stakeholders to consider our capital plan, and also together with our major maintenance plan. The reference to this in terms of our commitment to the process was in our settlement agreement in our last grade application to do this. Also, the -- as I mentioned earlier about a consultant, GLP is committed to retaining an independent third party consultant review and report on the accuracy of its cost allocation, and transfer pricing between the transmission and generation businesses.

The results of which we filed in our next grade application and this group of all stakeholders will provide input into the setting of the terms of reference of the review, and choosing the third party consultant. Again, this is in our settlement agreement with our last grade application as referenced there.

I turn the floor over to Gary, who will take us through our asset management strategy and plan development.

MR. GAZANKAS: I think most of you know me. Of course, there's a couple in the room that don't. Basically I've been involved in the directly connected customer meetings in the past. You'll see a lot of this is fairly similar to what we've gone through in those directly connected customer meetings. I'll have a higher level -- this is more of a higher level discussion at this point, but, you know, if you've got questions, by all means throw them at me as we move along. Don't save them until the end.

Basically our asset management strategy, the first and foremost is the plan development. I think we brought this forward before with our 20 year capital plan and this sort of thing, where annually engineering goes out and does an assessment of each and every station. We've -- we look at the assets. We look at the condition of the yard, ground grid, that sort of thing. That's probably the start of it all. I mean, next we have our meetings every year and, you know, we look at outages and so forth.

Patrick Street is a good example of that, the aging equipment down there, and potential for reliability, you know, shortfall in that was probably a main driver in that project. So, you know, that's another thing that we're looking at, and feedback from the customers as we have our meetings. So determining when the end of life of the assets are. This is -- this is rather tricky. Obviously there's economic and actual end of life physical part of this.

Economic, we're looking more accounting measures. The actual quality, physical condition of the asset is -- you know, we go by best utility practice or good utility practice where we seek advice from people at hydro. We've got a couple gentlemen now from hydro that are in and they're giving us advice on what experience they've had in the past and so forth, and this helps us in determining when we should replace this. We also address what remedial work is required as well.

The next is examining their system for operational improvements. A good example of this would be, of course, the Third Line tie breaker. It's not in yet. For whatever reason this summer we're looking at possibly ASI in our meetings, looking at when is a good time for us to do that, and we can discuss that in our own meetings, and GP as well. But there's a definite need there for an operational enhancement, so there's an example of that.

Obviously we have a capital program where through the first steps we identify the projects and really it's a place holder. We have a 20 year plan. Well, people say what 20 year plan? Well, it's kind of out there. Well, most of the time a lot of it is a place holder, and every year we review it, this place holder, for ideas. And we review it and we prioritize the list annually from that. Then annually as well, you know, we review the program. Resource adequacy, everyone knows at this point that resources are few and far between from tradesmen to project managers to engineering. So we have to have a look at that prior to going forward with anything and getting too aggressive, reasonableness. And then synergies, of course, I can get into some of the synergies of our 2007 program where, you know, we're having an outage on our major replacement or a structure replacement, we want to of course piggy back off that as to minimize disruption of customer and that sort of thing.

The next step, of course, after the plan has been developed is prioritization. Well, I guess it's included in that development, of course. We have a criteria basis where first and foremost, like any other industry, worker and public safety issues are paramount to anything, of course.

The next is addressing the significant environmental issues. This could include oil containment and so forth. Next we're in and around that, replacing end of life equipment, compliance with legislative and regulatory requirements, the IESO. You know, and NURK, they keep coming out with a lot of standards. You know, most recent is the vegetation management was last year. So this has hugely impacted on us, of course. And also the new one that just came out I'm reviewing is cyber security and fault recording -- fault monitoring requirements on our system as well. That's pretty much been covered with our CIRS project that's in service now, pro-active on that. We knew that was coming. There's a mandate for that, but that's -- we've got that implemented already.

Lastly, of course, IESO and so forth is improving system reliability, maintainability and operability, where reliability is -- everyone knows what -- we have to ensure reliability of our system, and that means addressing any concerns with the end of life equipment, that sort of thing. You know, maintainability, a good example is bulk oil breakers. We don't have oil panel capability, this sort of thing. So installing newer breakers, you know, we'll see a huge reduction in maintenance costs, that sort of thing, just an example.

Of course operability is the system the way it is now looking for operational enhancements, like I mentioned, Third Line tie breaker installation. And then project timing considers all the priorities as above, of course. And then the synergies, of course, based on outage and logistical requirements. So we believe this represents a complete approach to evaluating all of our products.

Then lastly our expected outcome. The best allocation of resources to the greatest needs as we prioritize them, of course. It's such a dynamic document, the rating is subject to -- it's subjective, but we feel it's very close and when we have an allotment of work, we know in and around there, that's the highest priority of work for any given year.

The risks are managed in a systematic manner as well. We go out and do the assessment so we see what's coming back. We review our maintenance records from our internal inspections, and in a systematic manner we're going to manage that accordingly, of course as we prioritize.

This one here, unexpected expenditures are significantly reduced. We still have an aging system. We still have unexpected expenditures. As we move forward, of course, that's going to improve. Patrick Steelton is a good example of the SF-6 breakers. As we move forward with some of the projects I'll discuss, we've got Mackay breaker replacement and yard refurbishment, as well as Third Line. We're looking at outside of 2009, we should have our system up to a point where we'll have no bulk oil older breakers. We'll have all SF-6 breakers in our system.

The next point is extremely important because it is dynamic. This -- our capital plan is dynamic, the industry is dynamic. It continues to be developed as conditions change, of course. We have IESO requirements that are changing continuously that we need to adhere to. That's the regulatory requirements, change, that's the next one, of course, the asset assessments and, of course, stakeholder concerns.

This year for 2007, our proposed budget is 11 million, approximately, 11 and a quarter. Now, again, typically, you know, we're hovering around 11, 10 million, you know, for the past few years. If anything, this is a dynamic environment. These numbers can change, as you're well aware, because of unexpected issues that arise and that sort of thing. But for the most part if it changes it will go down.

Now, just I guess going in directly into the projects that we're proposing this year, this is higher level. We won't go into the details unless you ask specifically. Goulais, currently we have no oil containment at Goulais. We have three 115 to 12kV transformers there, so there's a considerable amount of oil. I think everyone's pretty much driven past the substation at one point or another and it's a public area. So it's part of Brookfield's environmental policy and they're approach to things. We're being pro-active and we're going to be installing the oil container this year on those transformers, and we'll be getting a C of A for that as well, so we're registered with the MOE.

BOB BURMASTER: Gary, Bob Burmaster here. So that's not a requirement, the oil containment? You're just doing it as a due diligence at this point of time?

MR. GAZANKAS: That's correct. Once

you have a C of A, once we do have the oil containment, then it is a requirement. And then there's --

BOB BURMASTER: Is the C of A just for the Goulais TS?

MR. GAZANKAS: That's correct. I mean, we have C of A's for allotted stations. Like, Third Line we have containment there of course. We have a C of A. Anywhere we have containment at this point we have a C of A for, and then there's requirements around that logbook, you know, annual visits, maintenance, and all that sort of thing that we track and maintain.

So for Goulais -- last year we did Batchawana, because it's right close to the lake, but we felt that if we ever had a failure, you know, environmentally it's just not good for everyone. Likewise, Goulais, because of priority, you can see it. Batchawana was on the list higher priority, because it was closer to water, you know, public area. Goulais isn't as close to the water, but of course there's some farm land in and around there. So this is part of that prioritized process, you can see it going.

TS grounding study, well, this is ESA requirement. We do have an inspector come through every year to do inspections on our stations. This really isn't a deficiency per se. Really it is our part in -- we've had enhancements to the system, you know, 230 additions through the TRP, plus the wind farm. So from a safety standpoint, we want to go through and do another assessment. Fault levels have decreased. We want to make sure the step-in-touch potentials are there. We know that some stations we may not be -- I guess we're on the fringe of the minimum depth for crushed stone, and that sort of thing.

So we just want to address these issues so we have no safety concerns, you know, for our workers and the public, of course, a lot of these sites, like Goulais and Batchawana. Want to ensure safety, public and employee. But it is a requirement by ESA that we are up to standards. So we just want to ensure that. This is what the study is. I don't think the stations this year are -- done performing the study are Batchawana and Goulais specifically.

MIKE ROSSO: Mike Rosso. With these projects, could you also just elaborate on what it would mean to the distribution system and the customers as far as outages, to what degree, as you go through just to give us an understanding.

MR. GAZANKAS: Sure. Maybe I'll go back to that slide. Okay, you're ahead of me. So for Goulais, we have to -- I think for Goulais is extremely tricky because of our limits of approach, and it's the configuration currently on the 12 kV side of things, the distribution side. For a contractor to get in and do -- we have -- we may have concerns, so there may be on the distribution side of things, there may be outages required just so that we ensure worker safety.

We have other projects on the distribution side. If you drive by on the highway you see the two breakers that are there with the red lights on all the time. They're aging. We tested them last year, so they do work, but they're at the end of life. So we have reposers that we're putting up, two

electronic reposers there. So, again, these are the synergies, and part of the plan, and plan with the distribution company, or distribution side of things, so that when we have the outage, if we have a customer outage, we'll actually address the breaker replacement at that time as well. But, yeah, it is impacted on the customers.

Length of time at this point, I don't know. It's part of the planning process and we on the distribution side, customer service department, we'll notify customers well in advance. There's some criteria around that that I'm not too aware of, but I know that we typically don't like taking outages in the winter, that sort of thing. But, yeah, definitely, for that it may impact the customers in summer.

There's a more refurb replacement type projects, and these are, I guess, more impactive to our directly connected customers like yourself for this one. For most of these, the first project, the new 230/115 kV transformer for Third Line. Basically we've never had a system spare, and we have four

autos in the system now, one in Mackay, two at

Third Line and one at Echo River. So if we have a failure on one, mind you Echo River configuration is that we could feed -- however, you know, Third Line or Mackay, we're looking at extended outages for long periods of time without having that system spared. That was the original driver behind this.

Well, in November we had an issue with our T1 transformer, the tertiary reactor blew the fault, the reactor blew on it. We picked it up through our maintenance process, through the sampling, and it was trending high, all the combustible gases were trending high, so we forced it out of service. We had a company come in and do an assessment. They found this at this point, or at that point. So it really further, I guess, reinforces the fact that we need the system spare because of the aging transformers and so forth. And due to the nature, being the network gases at Third Line, you know, having one transformer, I know we do have a parallel feed there, but having one transformer, say one is out for a given period really opens ourselves up to exposure

for complete city wide outage if there's any faults on the system that cause that to trip.

So what happens is it's really -- the reactor failing is -- has forced us to change gears, if you will, and this is where I go back to the dynamic environment. We were planning for the spare. Well, now what we're going to do is actually replace that transformer with the new one, and what we'll do is do a major maintenance, major overhaul on T1 provided there's still a few years left in it and that will become our system spare. So we're not outright abandoning that transformer. We still will utilize it as a spare coming forward.

BOB BURMASTER: What size is T1?

MR. GAZANKAS: 250 MVA. So that's the biggest one we have on the books next year. The next two are very similar in nature, Mackay TS, if everyone's familiar with the area I'm sure. Montreal River generation, Mackay TS. At this point on the 115 side we have a brand new 230 yard, because the TRP, but the 115 yard is -- we have vintage 1947 breakers there, 1952 bulk oil breakers. Maintenance is showing that they're -- you know, they're aging. I mean,

let's face it, they are over 40 years, and doing maintenance on them, we can't do full-blown maintenance. We don't have the capability and that sort of thing, so that's probably the biggest part of this project.

In and around that we have yard refurbishment. We're going to look at the ground grid again because of TRP and the changes, fault, current and so forth. We have limits of approach issues there with some of the older PT's that were installed very low. So we have to address our employee safety in that manner. And, of course, there's the Electrical Safety Authority, and I believe use of it has limit or -- I think it's use of the limits of approach. We're not there in some of them. They aren't fenced off. However, we have to address some of these issues in and around there.

Third Line TS is the same thing. We have breaker replacement going on there starting this year. We'll address the ground grid condition. We'll -- structure, reinforcement to extend the life of the structures there, so it's not a structure

replacement. We're looking at foundation work.

The substation needs some work inside. You know, we have asbestos issues there as well. So that's basically in and around those two projects.

Mackay, really there are some local customers, some local distribution customers. These people will be dealing more with our generators at that point, because it's on the 115 side. So the generators may be impacted, may be impacted at one point or another. Third Line TS is probably more of an interest to most of the people in the room, of course. As we do our breaker replacement, we'll more than likely require outages obviously on a given particular line, but I think the way we're configured on Third Line TS, I don't think we're going to require any major planned complete outages, forced outages. I mean we, again, would like to sit down outside of this and in our directly connected, and we can go into this in more detail. I'd like to know, obviously, your plan. What's your plans moving forward so we can plan together so that it's least impactive to you as well. That's the big point.

BOB BURMASTER: Is the tie breaker

part of that same --

MR. GAZANKAS: No, it's not. The tie breaker --

BOB BURMASTER: Is separate.

MR. GAZANKAS: It is separate, yes, and the transformer installation is separate. But the tie breaker has been on the books for awhile. I think resources is probably the biggest reason why it hasn't gone in, you know. It's just finding people to get to do the work. I mean, you can ask any contractor to do the work, but, you know, can they reasonably handle it is another question. Sure they'll take it on, but you've got to be cautious.

On the priority list of some of the things we've done, it's been pushed down. We're getting to the point of the refurbishment at Third Line that we need it in in order to facilitate the replacement of some of the breakers. It will assist us in that, that's for sure, taking outages on any one, in particular Algoma circuit. So really we should be minimized there with respect to outages on the Third Line project moving forward.

Magpie transmission line structure

replacement, this is, you know -- these structures were based on -- the replacement is based on our internal condition assessments. It's not a complete replacement. We've just hand picked a few that we deemed on our at end of life, whether that be woodpecker damage, which is actually a huge concern for us, and just a raw, internal raw and that sort of thing, so we've hand picked a select few.

This is more impactive to River Gold and our three generating customers up in the north. This may require outages, and again, we're planning on doing this project in the month of August. But, again, as part of our directly connected meetings, we want to discuss in detail, you know, how we can go about doing this and get feedback from the customer to ensure that we don't have too many issues moving forward.

I guess the next few here, I'll get Alex to speak to because they're really the P and C side of things and he can better talk to that.

MR. LEE: For the Clergue 112 kV Bus

and BF Protection, we don't have a backup protection on that. We only have a single protection. What we need to do is protection for it so we can down the road when we want to do maintenance on our relays and testing of protection, we can disable one part of the protection while the other part is still in service to make it easier for us to do maintenance and relay testing. At the present you have to take down an outage of the feed or the protection. Maybe we should go up to the next one, system improvement.

MR. LAVOIE: The balance of them, obviously they're getting smaller in value, and certainly if there's any questions on any one we can address them specifically, but I think they're more of minor in nature and I don't think any of them require any major outages. But certainly if they are impactive to the customers we will deal with them on a one-to-one basis. Are there any specific questions?

CLAUDIO STEFANO: Just going back -- Claudio Stefano from PUC, going back to the Third Line, what potential outages do you

envision based on the refurbishment project?

MR. GAZANKAS: Directly impactive to PUC, because of the configuration and your ability to parallel your bus, we shouldn't need them. We don't foresee specifically with the PUC that at this point that you will have any major outages. I think that your configuration will -- you know, you can adjust your configuration accordingly so that we can do our switch and breaker replacement.

CLAUDIO STEFANO: What time frame were you looking at?

MR. GAZANKAS: We were looking at, basically, I guess, in more detail to the project. Maybe I'll get up for a second and speak to that. The more detail to the project is because they're such -- such a critical project in magnitude, you're probably looking at the price there for 14 breakers and 20 some disconnects. You're probably thinking, well, how are you doing that for two million. But really it is in phases and this is the first part of a three-phase project, where because it's so critical, and to do it all at once, we just don't need anything to happen, you know,

outage wise or obviously first and foremost safety. So the first year really all it entails is a yard refurbishment, cleaning up the control billing, coming up with a really good plan with our customers to ensure that in 2008 we'll do the first seven breakers. So in 2008 is really the first set of the breaker replacement, breaker and switch replacement. And then in 2009, likewise we'll finish the remaining seven. So we just felt like because of the magnitude of this project and we're at a critical network asset, that we wanted to be as least impactive as possible, and we wanted to put a lot of thought into this project, just to ensure, as I'd aforementioned, the safety and the reliability of our employees and, of course, the customers.

So that's -- this year we don't see -- well, we won't. We'll be buying the breakers, we'll be buying the switches this year, just because they're longer lead items. But outside of that we won't be doing any installations this year. We'll be doing the prep work, install cable trench. Have to prep our building for the addition of that,

protection enhancements and that sort of thing.

I should have probably elaborated on that.

BOB BURMASTER: Gary, I would think the T1 replacement is more of a concern from a customer reliability point of view. Is that correct?

MR. GAZANKAS: At this point, yeah, I would have to agree with you.

BOB BURMASTER: So same question, when would that be planned and --

MR. GAZANKAS: That is planned for this September. That is coming. That is on order. I ordered the transformer and they are guaranteeing me a September 1st delivery. So I'm hoping that I have three weeks for installation and a week or two for testing at that point. What we're doing is -- leading up to that, we're doing some major maintenance on our -- not major maintenance, but we're really focusing -- not that we haven't in the past, but we're focusing on its sister transformer T2 just to ensure that we're up to speed with it. We are. There's no gas. I'm taking regular sampling. Everything seems fine there. Just want to make sure that the fans are running

properly for cooling. We want to make sure that the gas relay is working.

BOB BURMASTER: T1 at this point in time is operational. There's no immediate concerns.

MR. GAZANKAS: It's operational, but the concern is voltage support in the area. Because the tertiary winding is blown, we have no -- we've lost the use of our 120 -- so right now we have voltage issues, as you're well aware in the area. We already have both of our support issues, and this just further enhances that, the need to get the transformer back in. We've looked at the replacement of the reactor, and what that entails is actually sending the transformer away. So, again, we're probably looking at, I would assume, eight months to a year for it to be sent away, refurbished, sent back. We're looking at -- probably looking at over a million dollars for this to happen for an aging transformer, and we'll be exposed to one transformer for that period of time. So it just made sense to have our system install this transformer and alleviate that.

BOB BURMASTER: Algoma's load

requirements are going to be significantly reduced during the month of July, is our intent. It doesn't sound like we're really capitalizing on that at all.

MR. GAZANKAS: We will with the tie breaker, absolutely, because I've heard rumours that that's when that's going to happen. We'll try to do our best to do as much work as possible, prep work in and around that. Definitely the tie breaker has to go in at that point. That's what I've planned so far. The transformer, you know what, I mean, if I could have, Bob, we would have definitely done it. It's 52 weeks, that's a stretch. I got lucky, because we ordered it through Ariva and I just got it in time, because now if I was to order it today, the same transformer, it would be a two-year delivery time. It's changed that much. So unfortunately that won't work out. Again, I think the biggest issue is, you know, having the system, the entire city and -- well, of course, you're including in that, exposed to the one transformer. But we're doing everything possible leading up to that to ensure that we have no issues moving forward.

We did have T1 down in November for three weeks, I think, was the amount of time. T2 held, there was not a lot of issues there. So, you know, I appreciate the comment, and we do want to work with you moving forward for that type of opportunity. Go ahead.

CHARLIE LEISHMAN: Charlie Leishman from Algoma Steel. You had mentioned that you were looking at replacing the T1, but we have the voltage issues with capacity there. Are there any provisions in place to fix that issue, the caster bank?

MR. GAZANKAS: See, that really in essence will fix itself, because right now the tertiary winding has blown, so physically the lead's been taken, thirty-four-and-a-half kV leads have been taken off of our tertiary winding that actually feed the cap bank. So once we have the new transformer in, we'll -- yeah, we'll reconnect. The IESO at this point, they're looking at the voltage concerns in the area, specifically probably last night, because it probably was a huge concern with LSP's off, the PUC loading has probably increased dramatically because of heating, that sort of

thing. Algoma Steel's fairly -- you know, I wouldn't say flat, but constant, exactly. So the IESO is going to take that into consideration, whether that be putting the units at Wells on condensed for power support. They're looking into those issues.

Quick fix, no, we won't have -- we're not going to fix the -- there's no cost effective way for us to place those cap banks in service at this point. Outside of that, if they're still -- once that's back in and there's still a need for support at Third Line or Steelton, that's actually a place holder in our capital plan at this point. Mind you, it doesn't sit into the priority list this year so it's not identified, but eventually we've got to take a look at power quality issues as well, and that's feedback from the customers as we move forward.

MR. LEE: On the system improvement for the Magpie, three of the 115 kV transmission line, at the moment the transmission lines protection is near the end of life and we will replace it with a micro replacement relay, and the three lines that

we'll need to operate is the Magpie to Mission and Magpie to Harris and Magpie to Steelton. This is just to be in compliance with the IESO and our GFE line protection standards. In respect to (inaudible) -- what happened is that at the moment we have an A and B and one of them is still -- one of the life protection is electrical mechanical, so by replacing that so we can have a better interface with our source information retrieval system, that would help our operational staff to better understand that condition and identify the type and the location and to decide whether they should re-energize the line after.

The next one is the project pre-engineering. These pre-engineering projects are called the preliminary engineering design plan, and the cost for new connection and multiplication to the transmission system, and this would be -- the project would be for the whole year, year 2008.

Next one is the Mackay line, 115 kV line and Bus Protection. In this project we are doing line protection for the Mackay number one and Mackay number two line. At the moment

we don't have a duplicate line protection. So at the same time we will do the bus protection to have a duplicate for the north and south bus and the duplicate protection is to have a back-up line protection so that we can isolate one of the protections to do a maintenance on the relays on the protection scheme, and the new protective relay will have full feature for direct interface with our information retrieval system that will give us better understanding of the system, to help the operator to decide whether it should be re-energized before it has happened. In this case it increased the -- increase our reliability and maintenance and still stay in compliance with the IESO requirement, and also compliance with our GLF standard and line protection.

The next one is the upgrade Clergue Bank MT1 and MT2 transformer protection. At this moment the transformer protection is protected by only one scheme. It is a transformer, what we want to do is have it -- have a newer protection, and the present protective relay is at the end of life and is no longer -- so we have to replace it with a --

with a relay and that will also give us a chance to be able to interface with our information retrieval system, so that gives us a better understanding if there's a -- how are we going to retrieve the information, and that will give our operator a better understanding of the condition and identify -- and he will be able to decide whether they should re-energize the transformer after the condition.

The other one is the Magpie. Here we have to install the PT, because we have two transmission lines. They don't have a dedicated PT, which make it the line protection sometime when they try to decide whether it is on that line because we borrowed off from the bus on the 115 kV bus. Normally when you have a forth, the sensing of the direction might not be able to tell this is where the fork is. So by having a dedicated PT, three phase PT on that line will give us a better chance to look, okay, that fork is there, so we'll minimize the -- any missed, possible missed operation. It will give us a better alignment and operating and easy to maintain the line protection. That one -- that -- install PT,

line PT, project together with the line

protection at the same time. This year we'll start to install the line PT, and after the line PT is installed we'll operate the line protection together. The remaining smaller project, if you need me to elaborate more, I will.

MR. GAZANKAS: Just go back for a moment. As we said before we were looking for just an example of the synergies and how we plan. You can see a lot of Magpie TS flavour there, and that's going to go well with our structure replacement, and this is all part of that planning process again. I just wanted to make mention of that, just we are -- we are following, trying to follow a formalized plan and process. I think this is good evidence of that. Under major maintenance, I guess just its definition, indicates maintenance projects or programs that are of significant magnitude and do not constitute a capital project. Typically major equipment repair/overhaul projects, vegetation management programs and soils remediation programs fall under this category. Major equipment repair/overhaul

projects, we have a few scheduled this year for some of the TS's, Clergue TS being one of them. Mackay probably we won't do it, because we have obviously the breaker replacement, so we'll just do minor maintenance on that. We're also looking -- we look at that very closely. Unless there's a safety or a concern that we pick out, you know, we don't want to spend a lot of money maintaining new -- well, majorly maintaining equipment unless we absolutely have to if we're going to replace it, of course.

Forestry, vegetation management, this is quick in nature, of course. As we get to the end of our system, we obviously have to go back and start from scratch. This is an IESO requirement. As part of our transmission system, this ensures reliability. This is a very big one for us, for reliability. Overhauls, I just talked about that. Soils remediation, we're continuously sampling our soils, and from the sampling that determines whether the soils -- it determines whether we need to expand on the remediation there. Northern Avenue is an example of that, the work we did at Northern Avenue, the testing results

pushed us to in fact do a major remediation there. That's it on the major maintenance.

BOB BURMASTER: Gary, is all the PCB gone from the system now?

MR. GAZANKAS: From our system? Meaning, like, breakers and --

BOB BURMASTER: Breakers, transformers, anything that's regulatory.

MR. GAZANKAS: As part of the breaker replacement at Third Line, we can't go in and test the bushings. It's a destructive process, so we assume that there's under 50 parts per million in some of the bushings. That sort of thing, we tag -- the main tank oil, we do tag that under two parts per million or whatever, but the bushings we're not sure. So that's as part of that, as part of that diligence, that is a big driver for replacing the bulk oil in our system as well. Not only catastrophic failure, we have an environmental issue on our hands, outside of that it's the PCB.

BOB BURMASTER: The mandate by '09, you're not -- you've pretty well met that already for the higher levels of PCB to be all out of the system.

MR. GAZANKAS: Yes, I believe. Now,

I could get back to you on that. I don't know for sure, Bob. You know what, I'll make note of that and get back to you on it.

MIKE ROSSO: Before you get into the rate side of it, I still don't have an understanding of -- from the Flake Board perspective, how many scheduled outages we can anticipate in 2007 verses greater level of exposure because of lack of redundancy. You mentioned the Third Line breaker.

MR. GAZANKAS: Breaker, yeah. We have -- I don't foresee any scheduled outages. We should be able to run our system taking one subsequent transmission line out as we install the tie breaker. That's the plan. We can't -- and we could actually run on one Algoma circuit if the steel plant is down, if their load is greatly reduced. So we're trying to do the best possible to alleviate the -- you know what, we need an outage today, or plan for that outage as we did. There's no configuration changes like we had to do with the one Algoma circuit. We had the issue to take you down for the day.

MIKE ROSSO: That's what I was trying

to understand. We tried to work with yourself and Algoma, that makes sense, that's good.

MR. GAZANKAS: That's correct. Exposure to system faults and that sort of thing, we have a better chance if we've reduced our liability by taking the circuit out, but we have to in order to upgrade the system. There's some risk involved with that, of course. You're aware of that. We try to minimize it as much as possible. We let you know the conditions we're in. I think in the forefront --

BOB BURMASTER: I think we were kind of touching a little bit this year on the T minus one contingency. When you're talking taking a circuit, we'll be back into that situation with the IESO.

MR. GAZANKAS: But the tie loading will be down.

BOB BURMASTER: Assuming we coordinate with our down days, etc.

MR. GAZANKAS: That's correct. I mean, there are -- there is the load rejection. Like, the whole point of the load rejection at

Steelton is -- that's going to be implemented soon is so that we could take a line down for any given period of time, and if all it does is act for the loss of the second -- of the second circuit. It's not going to reject when we take one line down. So we have three Algoma circuits, we take one down and we have two remaining. LR is armed. If we lost the second line, depending on the load on the Third Line, which I'm assuming is going to be high, then we reject load. So there is still conditions in there and, of course, probabilities with added conditions. There's --

BOB BURMASTER: We recognize the risk there, but there was a little bit of noise being on two circuits to actually manage to one circuit loading, and I would anticipate that same noise when you do it again this year.

MR. GAZANKAS: I anticipate that as well, and that's why I want to piggy back off your extended outage in July. That's a big date for me, extremely big date.

BOB BURMASTER: So we need to have more discussions on that.

MR. GAZANKAS: Absolutely, and that's

the whole point outside this. I think the intent of our directly connected customer meetings this year, as we've done in the past. We went through a lot of this before with the Emanuel. You know, I think because it just started for the last few years. I think we want to change gears a bit and get a little bit of this and do more of this, just more discussions of our outage plan moving forward. You know, how was last year? What's the power quality? What issues -- what projects are you doing? You know, how can we help each other. That's the whole point.

BOB BURMASTER: Do those discussions mostly involve Flake Board and Algoma, PUC as well.

MR. GAZANKAS: So we have --

BOB BURMASTER: PUC as well.

MR. GAZANKAS: PUC, River Gold.

BOB BURMASTER: I'm talking about when you're planning on taking an Algoma line down, those specific for the Third Line tie breaker.

MR. GAZANKAS: GP Flake Board, St. Mary's Paper and ASI.

MIKE ROSSO: Flake Board, note that, Francine.

MR. GAZANKAS: Sorry. Mike, I answered your question?

MIKE ROSSO: Yes, thank you.

MR. LAVOIE: The last bit here in terms of transfer pricing, the idea behind this, obviously, is to -- and we're as interested in this as -- and I believe the interveners are, in terms of -- is establishing that whatever transfer pricing or transfer of activities and services that we have between ourselves and the transmission business, that we are doing it in an appropriate way. So in the assemble process, we specified that an independent third party consultant will develop a report, and will assess the accuracy of our cost allocation and transfer pricing between its transmission and distribution businesses. This meeting will allow for the group of stakeholders here an opportunity to input to what those terms of reference should be, as well as to provide input to the available consultants that will be able to perform this type of assessment.

Great Lakes Power Limited shares costs between its transmission and generation businesses in the following areas. Our Ontario system control centre which is the -- where we control and operate our transmission network from. It's our dispatch operations. We also have an integrated communication network that is tied in with the control centre's ability to operate. And for those that are on our transition -- on the transitional meeting arrangements, we provide -- our meter service provider is part of the Ontario system control centre and that's where the costs are collected for that particular service. Just to note that I believe 2008 will be the final year where our transmission will need to buy services from meter service provision, simply from the standpoint that some of you may be aware that as the transitions to -- of ownership to meters, to the actual market participants occur, then it will be the market participant's meter and transmission will have no need for the procurement of meter service provision on your behalf. Then the other cost centre that is shared between transmission and generation

is our vice-president of Ontario Operations and Administration. That really deals with the hierarchy of the corporation, and the head of the corporation administrative cost centre is divided between transmission and distribution.

The terms of reference that we are suggesting the group consider for -- and certainly look for any input that you might have to enhance this term of reference so that we get an outcome that I think we all would like to see in this, is that it review and report in writing on the fairness of GLPL's cost allocation and transfer pricing methodology between transmission and generation businesses. And in that analysis of that methodology, if there's anything that the consultant would see that would be a suggestion to change methodology to address the fairness question in terms of being more appropriate, then we would ask the consultant to report in writing on those suggested changes.

I think that's the essence of the question, and I think that's -- in terms of cost between that transmission is bearing in this -- that it is a fair allocation, so that

there is no advantage or disadvantage in that cost sharing arrangement. The idea behind cost sharing, just so that everyone is clear, we believe there is definitely a cost -- an economy of scale that we are achieving through this, and if sharing of that cost is more efficient in this basis rather than having a stand-alone control centre dealing strictly with transmission as a large item.

What type of consultant are we looking for? I believe someone who has an ability to look at transactions and the business, to understand the nature of the cost item, and the nature of the transactions that we have applied in the past. And we're suggesting that we use a certified accountant, certified management accountant or other accountant or equivalent in a financial background. I think another important piece, obviously, is that this consultant is not affiliated with Great Lakes Power Limited, so that we have a third party independent review this thing. Any comments on the terms of reference or the approach to the analysis?

MIKE ROSSO: Can you go back three

slides? Thank you. Okay, thanks.

MR. LAVOIE: The timing that we --

that we're going to provide in, develop -- finalize the terms of reference, find a consultant and go out for some sort of a tender or a bid process for this, is to seek the consultant to start the analysis by the end of 2007, and then have it deliverable for the consultant at Q3 2007 point. Our commitment also in this process is to share the report with the stakeholders prior to the filing of our next grade application. And 2008 is a date that we had indicated would be a filing of our application sometime during 2008. So I think it fits well timing wise, and I don't see any need for adjustment on the timing of the schedule, but I guess that's the said expectations for the group here what we're looking at.

That's the end of the formal part of the presentation. I know there was a lot of good questions during the session, and certainly open the floor up to any further questions the group might have on the topics discussed today.

DAVE JENNINGS: Dave Jennings from Dubreuil. I just wanted to -- the third party you're talking about, whether there's any requirement to have any expertise or knowledge in the distribution/generation field. You seem to focus in on familiarity. What about the business side?

MR. LAVOIE: In fact that was on my list when I thought about it. The issue that I -- and I didn't want to eliminate consultants, but I also put a potential problem with the standpoint of being a third party to Great Lakes Power Limited. I think our belief is that the arena is pretty tight on people that have expertise in the industry, and we use a lot of these people, and my fear would be that we specify that, I think, maybe as an optional. It would be -- we're going to make preference to somebody that has this, but to make an exclusive point on it, I'm just concerned that we might actually not be able to get somebody that is a third party to the process. But I certainly -- I think it may be a good idea if I'm understanding, that a reference would be given, or that it's a

recommendation that the consultant have its background. I agree that when I could see us leading a consultant through this, certainly someone who doesn't have the experience, someone would have to be brought up to speed on what's the business, what are we trying to achieve here, and then report on it. There's definitely a knowledge gap.

DAVE JENNINGS: Or maybe familiarity with market rules and electricity.

MR. LAVOIE: Okay, that's great. If there's no further questions, I guess --

MIKE ROSSO: I have one question with regards to the 11 million capital and then million plus in maintenance. This is all on the transmission side, protection.

MR. LAVOIE: Yes.

MIKE ROSSO: Whether it's 11 million or 21 million, what does that mean to us as the receivers of your service, the cost of transmission? When you get into this -- and I don't pretend to understand this whole --

MR. LAVOIE: I'll try to speak to it in general terms.

MR. ROSSI: You know where I'm going.

MR. LAVOIE: Very good point, and I was going to bring it up, but I'm glad you did, Mike. The design of the transmission rates, tariff system in the province is designed on a provincial benefit concept. And accordingly, what happens is that costs are pooled amongst all transmitters. So it's a cost of delivering transmission services across the entire province. So right now the contribution of cost to the entire transmission component of the bill assessed by the IESO in the province, our component of it is somewhere around two-and-a-half, two percent. It was certainly a detailed discussion when we put the transmission enforcement project in. Significant project from our perspective and it did have a slight impact of -- I think it was .01 percent of an increase on the provincial tariff. So that was the impact that that particular project of $80 million had on GP Flake Board, or anyone around the table from a transmission rate perspective. So all of our capital programs are pooled with Hydro One's capital program. So I guess when we look at this particular program that we have here, it

is no different from an impact perspective than 11 million dollars spent on Hydro One's system, or the other transmitters that were there. So it's shared amongst the entire profits. The only segregation of costs are depending on facility designations, network assets, line connection assets, or line connection transformation assets. So that really the only distinguishment there is that if you're on a line connecting asset, which a lot of folks are here, there's two components of the transmission right there, and it's really a rate discussion at that point. There's no change in designation as a result of any of these capital expenditures that we're talking about.

MIKE ROSSO: So is it just a flow through in essence? You know, if we have 11 million in cap X, that then 11 million dollar revenue is going to come from the fees from the folks?

MR. LAVOIE: Fees from -- or the structure --

MIKE ROSSO: Or is there a percentage?

MR. LAVOIE: If we think of it in simple terms, the local group here would pay approximately two-and-a-half percent of the impact of the 11 million dollar capital expenditure, because it's shared amongst the entire province. But I said, likewise, the capital program that Hydro One has, is also impacted to the local community, our group as well. So it's an equalization, I suppose, across the province on the impacts of this.

MIKE ROSSO: From your perspective, trying to maintain the integrity of the grid, when you're putting your cap X project together and it's 11 million, what's stopping you to go to 15? Is it just resources primarily, or you have -- do you know what I'm trying to --

MR. GAZANKAS: I know exactly. Basically there are rules that we have to abide by. The OEB, you know, things that are identified as prudent expenditures. I mean, that breaker replacement at Mackay. I have eight breakers there. I'm only replacing five. The other three are SF-6 breakers that we put in four years ago. Would it be prudent to replace all, no. So you're probably -- you

know, you're probably, I guess, right, what's stopping us. Well, there are bounds that we have to abide by. We have to ensure that this is a prudent expenditure, you know, end of life where reliability is affected. That's why we have, you know, a process in determining this, so that when we go to our rate filing, that this -- because they could turn us down. Nothing is etched in stone. I mean, so if we go down there and they don't deem that as a prudent expenditure, that's why there's a lot of time spent in planning and ensuring that, you know, we do -- we are prudent in what we're doing, definitely.

CLAUDIO STEFANO: All programs have to be justified and approved by the OAE.

MR. GAZANKAS: Exactly.

MR. LAVOIE: I think these types of sections, I think, is a way that we are certainly trying to hear concerns from the local perspective on reliability issues and our quality issues and build that in, as at the end of the day the goal being the transmitter that is providing all the required services, but at the same time addressing needs on a go-forward

basis.

MIKE ROSSO: I was just trying to

understand how it works, because it might be in our best interest to spend $20 million and have a greater reliability on the grid for the north, and what does that mean to us on the cost side relative to how it influences or how it's impacted on the rest of Ontario. That's what I was trying to --

MR. LAVOIE: I think there's certainly -- the needs that are expressed by folks around this table are certainly something to take seriously into consideration. We put it through our system modeling. We put it through the IESO market rule perspective, and if it's something that's a need, we can address it from the context of justifying this expenditure from good utility practice, then it's something we're going to strive to do. The only other limiting factor, I think, in terms of -- is addressing priorities and being -- just the shear ability to do X amount of capital work a year. There are certainly things -- if Gary had his way, I'm sure we would be able to move some things from next

year because, you know, in the grand priority of schemes, they are things that need to get done, but they can be done next year, but it's something that --

MR. GAZANKAS: There is a resource part to that.

MR. LAVOIE: It needs to be orchestrated from an outage perspective as well.

MIKE ROSSO: The other thing I'd like to understand, and I don't know if you have the data. But as far as capital activity on the transmission side, you know, has it been fairly consistent regardless of the change over to deregulation, or has it been a step up in percentage since then because of the way the structure works in Ontario? I'm just trying to understand as far as the investment back into the grid, you know, what's changed since deregulation through this whole process if anything.

MR. LAVOIE: I think if anything, Gary -- what has changed is the IESO's oversight of the system, and it has a reliability criteria that is certainly

different than what Great Lakes Power had traditionally done. It's a different methodology. The minus one reliability, and there's a lot of capital or maintenance specification that sort of falls out of that reliability criteria. I think that's the biggest thing that I certainly have seen since then. And we've tuned and addressed, or focused our maintenance and capital activities on the requirements of the market offered.

MR. GAZANKAS: I've only been here a few years, so I don't know what it was like pre market opening and the spending at GLP, but I think that it has increased, the spending has increased, and I think it's just -- I think it's the IESO requirements, ensuring reliability of the grid and that sort of thing. Since they're responsible for it that's really forced transmitters to put a little more focus on their system. I don't know -- if it was there in passing, I don't know. I can't comment on that but....

MR. LAVOIE: At the same time loads have increased. I don't think -- well, of course, Hydro One grade application is going on

right now. We'll see as a result of that what impact it has. There has not been a whole lot of change in the transmission rates since market opening. That's one area that hasn't moved that much, but I think there's been fair activity, certainly in our system. Any other questions? Comments? Again, I appreciate everyone's time. I think it was a pretty productive meeting here today and certainly I think we look forward to -- I think some individual meetings have been set up to deal with logistical issues, and if not, certainly Peggy Lund, I know, has been calling a few people to line up dates. And if that's your preference to certainly go down that path, it would be great. I hope everyone has a great day. Thank you.

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CERTIFIED CORRECT:

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Francine Wolfe, CSR

GREAT LAKES POWER TRANSMISSION

2007 STAKEHOLDER SESSION

TUESDAY, FEBRUARY 13, 2007

WATER TOWER INN

COURTYARD ROOM

SAULT STE. MARIE, ONTARIO

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VERBATIM REPORTING SERVICES, SAULT STE. MARIE, ONTARIO

MW/jb

GREAT LAKES POWER TRANSMISSION

2007 STAKEHOLDERS MEETING

PRESENT: Tim Lavoie - General Manager
Gary Gazankas - Transmission Engineer
Alex Lee - Manager, Transmission Engineer
Andrew A. Taylor
Bill Harper
Mike Buonaguro
Dave MacIntosh
Carl Burrel
Henry Andre
Bayu Kidane

HELD AT: Ogilvy Renault
Royal Bank Plaza, South Tower
Suite 3800
200 Bay Street
Toronto, Ontario

HELD ON: February 15, 2007

INDEX OF PROCEEDINGS

PAGE NUMBER

--- Upon convening at 2:00 p.m.

--- Upon commencing at 2:15 p.m.

MR. LAVOIE: I would like to welcome everybody here today. This is Great Lakes Power Transmission's 2007 stakeholders session and we appreciate everyone's return. Most of the stakeholders that are certainly in the area have acknowledged that this is something that is of interest to the group and I am glad to see everybody here today.

Just a little bit of agenda and some administrative items here. Timing-wise, this meeting, we are planning for an hour or so. Of course, it depends on questions and whatnot. If it runs past 3:30, I will excuse myself right now. I do have to run to a flight, but I would imagine we will get through most of the material by then. So, accept my apologies if that happens.

You will notice we have a reporter up at the front here. We are transcribing the meeting for purposes of recording the meeting, and so just to let everyone know that that is occurring, and I guess on with the agenda.

Really, we are going to address our Great

Lakes Power Transmission 2007 capital plan, in that our asset management strategy, the types of capital investments that we have, and we have grouped them into compliance-type capital expenditures, refurbishment and replacement and system improvement. We will then talk a little bit about our maintenance plan and the major maintenance program that we have proposed for 2007. And then the last component of the meeting is a discussion regarding a transfer pricing review. The context of that will be on the next slide where we will talk a little bit about why the components of this meeting are talking about those certain things.

Introduction. Myself, I am general manager of Great Lakes Power Transmission. At my right here is Gary Gazankas, our transmission engineer, and to his right is Alex Lee, the manager of transmission engineering, and they will be able to...certainly, Gary and Alex, talk a little bit more detailed about the technical aspects of the presentation.

As part of the objective of this stakeholder session, as part of GLPL's capital budgeting process, we are conducting stakeholder meetings to consider our capital plan, together with our major maintenance plan. This really stems out of a settlement agreement as a result of our last rate application made in 2005, and it was Section 1.2 of the agreement where we agreed with the intervenors at the settlement agreement to conduct these sessions.

A second part of the commitment to a stakeholdering group was our commitment to retaining an independent third party consultant to review and report on the accuracy of our cost allocation and transfer pricing between our transmission and generation businesses, the results of which we filed with our next rate application. The consultation group will also provide input in setting the terms of reference of the review and the choosing of a third party consultant. Again, that does stem directly from our settlement agreement, Section 3.1.1.

So, that is the context of the session here today and the balance of the session is to discuss those things. Again, jump in with questions as we go. I think that is probably the most efficient way to do it. Certainly, we will field questions at the end, as well.

I will turn it over now to Gary to talk a little bit about our asset management strategy.

MR. GAZANKAS: My name is Gary Gazankas. I am the transmission engineer for Great Lakes Power. Basically, this is part of or capital program every year annually. What we do is we visit every site, form an assessment of all the assets. We basically want to get out every year and take a look at the condition. We do this on an annual basis within our engineering group, as well as, obviously, as our maintenance group goes out, we get reports from them and that is reviewed, as well. So, we have a good indication of the condition of our assets.

Next, we meet with our directly connected customers on an annual basis in Sault Ste. Marie, and we get feedback from them with respect to such issues such as power quality and other things outside of that, possibly scheduling outages and that sort of thing and we present to them our proposed plan, as well.

From the assessment, from doing all the condition assessments and reviewing all the maintenance records and so forth, we determine when end-of-life assets need to be replaced, whether that be from those reports or a third party consultant coming in to review the assets to give us another outside view of their condition and that sort of thing, you know, good utility practice and that sort of thing. We kind of follow guidelines here. We also assess what remedial work is required, as well.

Next, this is not annually, this is more or less day to day. We are always examining our system for operational improvements, of course. That is my job. We put all this together and we identify projects and we prioritize them annually. We review the program every year for resource adequacy, which makes sense. If we don't have the resources out there to complete the work, we may not look at going into that, reasonableness and possible synergies where we do structure replacement, this sort of thing. If there are outages taken of that line, we look at other jobs in the control side of things that we can, basically, for lack of a better word, piggyback off of just so we know that we are least disruptive to our customers.

Next, basically, this is a prioritization, back to the last line, we have how we gather all the information, we prioritize the projects. Basically, first and foremost and paramount to any industry is the addressing of public and worker safety issues, grounding issues, that sort of thing, security issues with fencing. These are higher priority issues for us.

Environmentally, we look at environmental issues, bulk oil breakers, oil containment that sort of thing, that is on our priority list. Replacing end-of-life equipment, this moves into reliability. As our assets age, of course, there is a point where we may have reliability issues. Compliance with legislative and regulatory requirements. Here ESA, we can look at grounding, that sort of thing. We are always looking, obviously, into compliance.

Lastly is improving the system reliability, maintainability and operability. So, again, as our assets age, we may have reliability issues. As they age, there may be more need for maintainability to ensure the reliability. And, lastly, operability, we are always looking for possible ways to improve configurations in our system.

The project timing, of course, considers the priorities as indicated above, and synergies, as I mentioned before, based on outages and logistical requirements. So, we believe that this represents a complete approach to evaluating all of our proposed projects.

MR. ANDRE: Are those criteria all

weighed more of less the same or do you have a ranking for them?

MR. GAZANKAS: We do have a ranking for them. Off the top of my head...we do have a ranking system.

MR. ANDRE: But, you do have a ranking system?

MR. GAZANKAS: Yes, we do, absolutely, and it is basically the public/workers safety, next is environmental, then we have maintainability, reliability is in there. We would go even as far as public perception, probably lower down on that list, of course, for assets that may be close to Lake Superior or that sort of thing, within parks or close to parks and that sort of thing. It all plays a huge role in this ranking.

So, or expected outcome from this is best allocation of resources to the greatest needs. Our risks are managed in a systematic manner as we identify them and prioritize them. Unexpected expenditures are significantly reduced.

At this point, though, it is a dynamic environment. Our plan continues to be developed as obviously system conditions change. There is obviously ongoing regulatory requirements that are changing, the asset assessments, feedback from the asset assessments and the stakeholder concerns. This year, for 2007, our proposed capital budget is 11,254,000.

Now, basically, what I am going to get into is a little more detail and these are the actual projects that we are proposing for 2007. Basically, what I just discussed was the how, how we go about defining this program and now I am going to go into the need and why are we doing these in 2007. These fall under some type of compliance, that is the way we have categorized them here.

For Goulais TS oil containment, Goulais TS is located just outside of Sault Ste Marie. It is typically in farm-type land, so at this point we don't have containment on our transformers, so a failure there would definitely mean that the surrounding area and waterways would be compromised, of course. They are aging transformers and such, so to be proactive, GLP is looking at installing oil containment there.

The next one is our TS grounding study. Just through time and our asset assessments, we have identified that, through erosion and so forth, that some of our select TS's have lost some of their crushed stone, and ESA states...I can't remember which rule, but they state...it is in Section 36... that a minimum of six inches is required. So, basically what we want to do is go around and have a study done and determine what the step and touch potentials are at that time. We will get recommendations from this study to let us know what we require there.

MR. HARPER: I am not sure how many TS's you have. That one sounds like it is fairly critical in terms of geographic location. Are there other ones that sort of would have the same issue in terms of lack of containment? I mean, would be lower down on the priority level, but probably have to be addressed at some point in time going forward?

MR. LAVOIE: I guess this is a good example of one that was less a priority than one we did last year where we had that one TS which was situated almost literally across the highway from a public beach on Lake Sperior, so that was higher priority then. This was the next ranking one.

Are there a few more sites that we need to...we have addressed a number of the sites.

MR. GAZANKAS: There are a few more sites.

MR. LAVOIE: Again, they are a lower priority.

MR. HARPER: I was just trying to get a sense, you know...it is an ongoing process.

MR. GAZANKAS: I mean, without the containment, there is no regulatory requirement to have it. Once you have it, then there is a requirement, once you have your C of A to maintain and upkeep that. So, at this point, that is it for compliance.

This is a little more extensive. These are more refurbishment/replacement projects. The first one on the list is a new 230/115 kV auto-transformer. It is going to replace one of our existing auto-transformers at Third Line TS, which is situated right in Sault Ste. Marie. A typical configuration there. The basic overview is we have two transformers, the 230/115 auto, that are in parallel that feed the entire City of Sault Ste. Marie. This is one of them.

At this point or prior to this or prior to the transformer arriving, we have four auto-transformers in our DOP system and without a system spare. So, initially, this was a requirement for a system spare. However, in November, we had an issue with T1 at Third Line that has since been resolved. However, this just reinforces the need that we have a system spare. So, our intent here is to replace this transformer with the T1 existing with this new one, this new auto-transformer, same size, same make ...not same make, but same size. What we would like to do with the existing is take it out and refurbishment, so that will then become our system spare. So, we are utilizing still that older transformer.

The next project is the KTS 115 kV switch-yard refurbishment, and this is located in the Montreal River area, between basically geographically Wawa and Sault Ste. Marie. From our condition assessments and our maintenance records, it has been determined that we have five bulk oil breakers there of 1947 vintage that we would like to replace, as well as we have to address...at the same time, we are going to address grounding issues, possibly structural reinforcement to instal new switch gear and that sort of thing.

The switch gear currently there has a rating of 120 kV. Typically, the system voltages in the north rise slightly higher than that, so they have been subject to over voltages in the past.

The next project is located at Third Line TS, that is right in the City of Sault Ste. Marie, and this is very similar to the Mackay project. We have bulk oil breakers there, and basically, even with the Mackay project, with respect to maintainability, GLP has no bulk oil handling capabilities. We do or maintenance on the transformers. However, it is very costly when we do a major overhaul on them. So, not only do you reduce 38,000 gallons of oil by removing the breakers and installing newer SF6 breakers or like, we are also going to have a significant reduction in our maintenance costs.

The next is our transmission line structure replacement of Magpie, and again this is from assessments that our internal crews have done. The lines have seen substantial, believe it or not, woodpecker damage, amongst other problems. So, what we have done is...the whole line structures aren't being replaced. We have identified the select few that are, and that is what basically entails for this project.

I guess looking back to the how and the synergies, just one fact worth noting here. As you see Magpie transmission line structure replacement, if you look down the list, we also have a TS battery charger replacement, and then Alex will also get into a couple more smaller projects on the next slide with respect to Magpie. So, these are the synergies we were talking about so that we are least impactive to our customers and so forth.

Now I am going to pass it off to Alex who is going to go into some of the production control projects proposed.

MR. LEE: Good afternoon. My name is Alex Lee and I am here to talk about the upgrading of the three 115 kV line protection on the TS. Based on our condition assessment, we found that it is about time we have to do an upgrade on our line protection. At the same time, we have the line structure replacement. So, it seems to be the right time to do everything at the same time. That means we are...take less hours to do that line protection.

The current existing line protection is electromechanical relay, so I think it is about time we should remove it and put the modern microprocessor base relay so that we can have a direct interface with our new system or the information retriever system. So, that will give us a better understanding when there is a poor condition and the operator can decide if they should re-energizethe line or to dispense our line crew out.

The other one, the project, pre-engineering, this is the time when we do our engineering study and design for the next year's project. During that time we design and then we decide are we going to order some parts, equipment, because some of this equipment take a long time... need time to deliver.

The next one is Mackay 115 kV line and bus protections. The line protection at the moment, the protection relay no longer is supported by the manufacturer. Basically, we are trying to upgrade to the latest kind of modern relay so it can interface with our information retriever system.

Our information retriever system, it let us have all the connections to a remote station and we can interrogate the relay from a remote site whenever there is a falt or disturbance and, in the meantime, collect all the information that we can use for study our system performance, monitoring the system better. And then the other one, to upgrade the Clergue transformer MT1 and MT2 protections, it is also the same thing. The relays is...the protection relays are getting old and still there is not a lot of support by the manufacturer at the moment. And to interface these old relays with our information retriever is very difficult. We think it is about time we can replace it so that we have everything interface...easier interface with our information retriever system.

And then Magpie, the 115 kV, we have to add a line PT and this is the right time when we can put in...when we have the line structure out...have outage, we can add a line PT. The present condition setup is, we only have one line PT on the transmission line and our line protection, we need a three-phased input to the relay. At the moment, we just borrow a three-phased input from the bus PT, and sometimes it works very well when there is a poor...you know, the sensing of the direction is not really accurate at the moment. So, if we add the PT, dedicated line PT on that transmission line and with the line protection, the upgrade, that will give us a very good sense of direction when there is a fault on the line.

And the remaining small, little project, as we go, we still have to improve our central information retriever system and we are trying to make it more better. At this time, with the new technology coming in, we can still add on somewhat.

MR. ANDRE: So, that information retrieval is just some additional...

MR. LEE: Yes.

MR. ANDRE: ...additions to the existing system.

MR. LEE: So, that concludes mine...

MR. GAZANKAS: Okay. I am going to go a little bit into our major maintenance plan. I will define it first. Major maintenance indicates maintenance projects or programs that are of significant magnitude and that do not constitute a capital project. Typically, major equipment repair, overhaul projects, vegetation management programs and soils remediation programs would fall under this category, completed on the basis of budget review, stakeholder feedback, of course, and outage planning ...outage and logistical planning, just like capital.

This year, we have on schedule our forestry vegetation management program, that is ongoing. It is cyclic in nature. Once we get to the end, we start back and...

MR. HARPER: How often do you cut?

MR. LAVOIE: Every year.

MR. HARPER: Is it a six-year cycle, a seven-year cycle?

MR. LAVOIE: Exactly.

MR. HARPER: A six-year cycle?

MR. LAVOIE: It is a six-year cycle, and basically we take each right-of-way and say, "Okay. Well, we will start. This is this year and..."

MR. HARPER: That is what...

MR. LAVOIE: We try to plan it so the dollars are relatively equal, but, of course, we do have a little bit of variation, depending on the widths, the extent of cutting that is required in each right-of-way.

MR. GAZANKAS: And, of course, again, the Magpie structure replacement, when the line is down, it is an opportune time for them to get in and do the clearing at that point. It is the safest way to do it. So, there is obviously that co-ordination between major maintenance and capital.

Stations overhauls, these are the major overhauls, bulk oil breakers, that sort of thing. These are the six-year-type cycles of the bulk oil breakers, what we have maintaining or other. You know, our metal-clad switch gear, we have a few stations with metal clad that require the major overhauls. I don't think the bulk oil stations are going to be...I don't think they are scheduled this year. Soils remediation, of course, is ongoing. Bulk oil breakers and the transformers in the past, of course, we were always proactive in the approach of continuously sampling our soils. We get reports from Golder...I don't know if you have heard of that consulting firm before...and Wardrop. They go through and do risk assessments for us. And, at the time of those reports, we go in and further those studies and come up with the groundwork, if any, for any soils remediation.

MR. HARPER: On the capital side, I had gone back and I had looked at the application we had, and I guess the 11-odd million you had there was roughly equivalent to one year and a little bit less than the other. I couldn't find comparable numbers on the major maintenance, probably just because of the way the presentation was going in the previous application. So, I was just wondering how the little over a million dollars for 2007 would compare with...sort of in line with sort of...

MR. LAVOIE: We have tried to schedule all of these things in, maybe with the...well, even soil remediation now, because we have addressed a lot of the things in the past. Certainly, forestry is a number that is very similar to what you would have seen in the past, as well as station overhauls.

MR. GAZANKAS: That is it for the major maintenance plan. I will pass it back to Tim.

MR. ANDRE: There are no line overhauls that happen on a regular basis? It is covered in the line...

MR. GAZANKAS: You know what, it could. Not this year. Next year, we may wash insulators down at our industrial park, the ASI. That might be next year, it may be forthcoming. It all depends on if we have had any tracking incidents or more general power quality issues from our customers. We get feedback from them, as well, but that doesn't drive it, of course. We would obviously be on the forefront of that prior to that happening. So, I think we are looking at scheduling something possibly next year for insulator washing down in our more heavily polluted areas. But, yes, we do actually look at that, absolutely. There is some minor...obviously, minor maintenance ongoing every year, of course.

MR. LAVOIE: As I mentioned at the

beginning, identified in our 2005 rate application process, the commitment as a result of the settlement agreement was that an independent third party consultant will develop a report that will assess the accuracy of GLPL's cost allocation and transfer prices between the transmission and generation businesses. So, this meeting will allow a chance for the stakeholders to provide input to the report in terms of reference, as well as to the available consultants to perform the review.

So, just to get a little bit of a recap in terms of maybe a little bit of refresher for those that...in our last rate application, we described the areas of cost-sharing between our transmission and generation businesses, and it is in the following areas. We have a cost centre and a service centre called the Ontario System Control Centre. And, in that cost centre and service area is our dispatch operation. So, all of our operating SCADA system and control of our transmission system is dispatched through the Ontario System Control Centre.

We also have an integrated communication network to primarily deal with the SCADA operations and protection control systems that we have in our transmission network that we share with the generation business. A third piece is the meter service provider. Great Lakes Power Limited is a meter service provider in which it provides services.

This particular cost item, just out of interest, will not be a cost to transmission, I believe, beyond 2007, simply because of the transitional metering arrangements that transmitters were required to provide until such time that direct customers...until the meters were resealed and the direct customers then would assume ownership and meter service provision. So, that item will disappear. However, I think for purposes of continuity, that is still a cost in that area and will form part of that.

MR. HARPER: So, Great Lakes Power wasn't planning on being a licensed meter service provider on an ongoing basis for...

MR. LAVOIE: It has a number of meters in the generation business that it is currently servicing, and I would envision that it would probably continue to do that, but not for any other...

MR. HARPER: Not providing services to

third parties...

MR. LAVOIE: Exactly.

MR. HARPER: ...like Sault Ste. Marie or somebody else?

MR. LAVOIE: No. There are absolutely no third parties that we do provision for. I had done a few, I believe, in the early market opening, in the transition...

MR. HARPER: Right in the transition?

MR. LAVOIE: Exactly. The other main cost area is the vice-president of Ontario operations administrative area, and that really deals with the organizational structure. The single point of an oversight for the Great Lakes Power Limited corporation is under the VP of Ontario operations, and there is a cost-sharing mechanism to share costs between the businesses on that basis.

MR. ANDRE: Tim, forgive my ignorance on this, but do you not have distribution customers?

MR. LAVOIE: Yes, we have a distribution division, as well.

MR. ANDRE: And those costs are... because you only talk about identifying the transmission/generation split. I guess the distribution costs are clearly separate?

MR. LAVOIE: There is a cost-sharing that would be to distribution on the same basis. I guess that it was not part of the settlement agreement in terms of identifying the costs that would be part of distribution. It is obviously going to be something that would be discussed at a distribution setting, and it may be...

MR. MacINTOSH: It might be worthwhile to do it all at once.

MR. LAVOIE: Here we are at the terms of reference. So, I think this is...what we had suggested in terms of the terms of reference is to review and report in writing on the fairness of Great Lakes Power's cost allocation and transfer pricing methodology between its transmission and generation businesses dealing with appropriateness of cost-sharing between the divisions. And, as part of that study and review of the methodology, that we would ask the consultant to...if methodology changes would be something that would be recommended, we would ask the consultant to recommend changes if required in the study. Are there any other ideas, in terms of providing input into that terms of reference? I think I heard...one was the suggestion of inclusion of the distribution component of that allocation.

MR. HARPER: The other thing would be... you know, you maybe think about...I guess it is a matter of how far one wants to take it, you can ask. If someone comes up and suggests a methodology changes, it is easy to suggest it. I guess the other question is whether or not you would want them to...perhaps working with yourself, take a first cut at actually doing it and seeing whether it is actually practical to actually follow through and test.

It is fine for somebody to say, in principle, "Here is how you should do it", and then leave it up to you guys to go away and do it or to sort of perhaps...then, you know, if there are some suggestions...and that is maybe phase 1 of the report, to see whether or not you want to get them to work with you and at least take some accountability for the implementation of the suggestions. That might be...

MR. LAVOIE: Certainly, when we talked about how would we envision this study, that was certainly a topic that we talked about. That is an excellent suggestion. Because, at the end of it, I think certainly we...as a fairly small utility, these things can get quite complicated and it is a good...

MR. HARPER: "Exactly what did he mean?", sort of thing, as you are going away and trying to figure out what that report meant, at the end of the day, sort of thing.

MR. ANDRE: If they actually have to work out the numbers, then they may be able to answer that question.

MR. HARPER: Yes, that is right. Maybe to go back to David's comment, I know on the operating centre...I think if I remember...was that was primarily between, because the operating centre was dispatching generation, it was also co-ordinating with the transmission system. The VP of operations, I guess he would be involved in terms of...because I guess you have got...on the ground, staff were probably doing transmission or distribution work, but that is probably all tracked directly through work orders.

MR. LAVOIE: Exactly, correct.

MR. HARPER: I would suspect it is probably more of the...I don't like the word "overhead", but sort of the overhead costs of that in terms of if you have got a common human resource group that is providing support to both groups...

MR. LAVOIE: That is the idea. We don't have a human resources department, so to speak, but we do have a health and safety representative and a program that is common between, and that would be in that administrative area, an environmental-type program.

MR. HARPER: Right now, are those sorts of costs sort of worked in as a burden all in the direct labour costs? Is that...

MR. LAVOIE: We deal with it as an administrative line. So, it is a direct allocation rather than a burden.

MR. HARPER: So, that is how it is directed; it is alloted along the same direct basis.

MR. LAVOIE: Exactly. The type of consultant that we would at least envision to do this, because it has a financial/transactional basis upon which we are looking at it, as well as a business focus and functional focus, our recommendation and idea was to look at using a designated accountant, a certified accountant, CMA, CGA or some sort of equivalent financial accreditation background for the study. And the second component is that this consultant not be affiliated with Great Lakes Power Limited.

MR. ANDRE: But, Tim, as you know, Hydro One does quite extensive study on its common cost and allocating that. You are aware of who we use and maybe there are bigger outfits...or who we have talked to. R.J. Rudden actually did it, but I spoke to our finance people and they said they also send the RFP to Accenture and Deloitte would have been the other two that we sent the RFP to to get them to bid on it.

MR. LAVOIE: All right. Yes, I think some people who have done studies like this before, in particular Deloitte would be, I think, a focus for sending out an RFP-type document for that.

The timing of the report, we would like to aim for having a consultant selected by the end of Q2 of this year and have a deadline within the contract that a final report be delivered by the end of Q3, and that will allow us to fulfil the agreement that we would then upon that share the results of the study, as well as have it in advance of us, in terms of an application in our next transmission setting. So, I think the timing works well with what we need to accomplish, so we kind of set those as milestones for s, to report those.

MR. HARPER: If you haven't got this far in your thinking, that is fine, but I think when we did the last sort of review, we were looking at 2005 and 2006 and revenue requirements in those two areas. You know, the rates can go on from there, but do you have any thoughts yourself as to sort of what year you would be bringing forward your next transmission application for? I guess maybe before anyone answers that and how that dovetails, I guess. The Board is going through this process now of trying to slot everybody's distribution business in one of three years. Before coming back and doing a cost service review and whether there was any synergies in your mind in terms of doing both with the Board at the same point in time or whether that crossed your mind at all?

MR. LAVOIE: We really dealt with both of the businesses on a separate basis up to this point. In terms of timing for the next application, I believe the indication we have given in the settlement agreement was toward the end of 2008.

MR. HARPER: Within three years.

MR. LAVOIE: Or within three years, so I guess that works into that. So, that is our timing. So, I think soon after that Q3 target, we will be then applying those types of methodologies in terms of an application moving forward on that basis.

That brings us to the conclusion of the formal presentation. If there are any questions with respect to any of the material we have had here today, we will certainly open the floor to any of that.

MR. ANDRE: You said you had a session yesterday at the Sault with customers.

MR. LAVOIE: It was on Tuesday.

MR. ANDRE: On Tuesday, rather. What was the attendance like at that session?

MR. LAVOIE: Actually, it was very well attended. We had, I think, with the exception of one, we had all the local direct...well, I shouldn't say that. We had all of the local direct customers, except for one, and we had a few from the outlying areas, as well. So, from a direct customer/ stakeholder standpoint, it was sell attended.

MR. HARPER: I was thinking back on the settlement agreement. I think a lot of the major drive for this process, I think, was coming from sort of the parties we had in the 2005 hearing from a more local perspective in terms of trying to sort of...you know, because I guess they see where the rubber hits the road, in terms of how it impacts on them and having an understanding of that.

MR. LAVOIE: And we opened the invitation to our direct customers. Not all of them were party to the last rate application, but, you know, we have had very positive meetings on an individual basis with the direct customers throughout...basically, since market opening, approximately, and we just felt that they are definitely stakeholders in this process, and they were very appreciative to that and I think they got a fair bit out of the session. So, it was a very good meeting. At this point, we have captured the balance here with the exception, I think, of one or two parties, and we are going to have a follow-up session with the balance...a final session with the balance.

MR. MacINTOSH: Just to give you a heads up, the next time you come in, we would be looking at whether or not your transmission upgrades impacted new or existing generators in your area and whether any costs should be recovered from them as a result, like, the wind farms and whatever is out there.

MR. HARPER: Well, maybe that is an

interesting question, because, I guess, to some extent, I have been trying to remember back in terms of the OPA was doing some of their presentations in terms of where some of those circles of new wind or new hydraulic were in Northern Ontario, and I think some of them probably overlapped with the GLP service.

MR. LAVOIE: On the IPSP?

MR. HARPER: On the IPSP, yes. On the shore of Lake Superior and potential for wind generation around that. I guess none of your capital plans here really reflect any sort of potential impact of what they have been thinking about to date sort of thing?

MR. GAZANKAS: Yes. I mean, reviewing the IPSP, we would review it, but nothing here is at all directly or otherwise related.

MR. LAVOIE: Certainly, it is something that we are obviously paying close attention to. At this point, it would be very difficult for us to...

MR. HARPER: No, I was just trying to think, because contrast, you know, I guess Hydro One covers more of the province, so some of what their more capital plan spending is sort of talking about, making sure they are integrated with them, but you have got, obviously, a smaller area.

MR. ANDRE: Well, it is a smaller area and the timing. Presumably, there is nothing in the IPSP that forces you or requires you to do some stuff in 07, but if there are...if that included some wind in the future, presumably, you are building that in; right?

MR. LAVOIE: Absolutely.

MR. ANDRE: So, the IPSP will have some ...could potentially have some impact on rates.

MR. HARPER: I was just trying to clarify that there wasn't anything here that was tied to the IPSP. Okay.

MR. MacINTOSH: We have one other question that is really a matter of curiosity, but as a result of the last application you made, we never ever got any costs and we wondered what the hell happened there. I mean, it has only been since 2005, but...

MR. TAYLOR: Maybe I can speak to that. The way it works with the costs is, the Board will send out an order to...

MR. MacINTOSH: We have got that...

MR. TAYLOR: No, but it will actually send out a cost order for each intervenor to the applicant. What happened was there was a dispute over one of the party's costs in the proceeding. It was a coalition that included a distributor...and whether or not the distributor is entitled to costs, and special circumstances may or may not apply, so...

MR. MacINTOSH: Then that got resolved?

MR. TAYLOR: No, no. It was only recently resolved, so...

MR. MacINTOSH: Really?

MR. TAYLOR: ...I would imagine that the Board should be issuing something soon.

MR. HARPER: We are used to these things taking long...because of things like that, taking long periods of time.

MR. TAYLOR: I was actually surprised, too.

MR. HARPER: Some of the names you are mentioning, like the system reinforcement that was done which was a trigger for the 2005, but do I remember the Magpie being tied in somehow to that?

MR. GAZANKAS: That is Mackay.

MR. HARPER: Mackay? Okay, that is where the...I am sorry, my mind was trying to go back and I was trying to remember. That is right.

MR. GAZANKAS: That is right.

MR. HARPER: That is right, okay. Because I was wondering whether even that sort of major new development might have addressed some of Andre's questions about, you know, there doesn't seem to be a lot of system refurbishment... because a good chunk of that was put in new just a couple of years ago sort of thing.

MR. GAZANKAS: Well, that was more or less on the 230 side of things. The two refurbishment projects that we do have are on the 115 kV, and really they are end-of-life. We are looking at 1947 for the breakers and higher voltages in the area, bulk oil, that sort of thing. You know, they are not ten or 15 years old; for both Third Line and Mackay. It is really just an end-of-life replacement, and before we start having issues with reliability and/or, more important, safety and that sort of thing, environment.

MR. ANDRE: Yes, but the last time around, I think there was just one project related to a line in 2006 and this year you have the Magpie line that is getting replaced. I guess your lines are probably not that old that you see a lot of refurbishment?

MR. LAVOIE: The main network of our system was really addressed in the last application. So, in general, I think...I guess I can't speak to the age myself, I will defer to these guys, but there are some refurbishments coming up, I think, but nothing...

MR. ANDRE: Because P-21-G, I think, was the one that got refurbished that was in your plans back in 2005.

MR. GAZANKAS: That is right, structure replacement on it, just for limits, so that we could increase the rating of the line. The line was to be lower than P-22, its sister, if you will. So, obviously, in order to increase the rating per 90 degrees, we had to raise the elevation of the conductor.

MR. HARPER: Do you plan on doing anything in the capital or maintenance, major maintenance? You are talking about actually having to impose actual outages on customers or are you able to actually manage all that just through load, sort of?

MR. LAVOIE: It depends on the configuration.

MR. GAZANKAS: Yes, load, specifically.

Like, complete outages, I guess an example would be your Patrick Steel refurbishment, which was in 2006. It is done. It is right in the heart of Sault Ste. Marie and it feeds Algoma Steel. You know, Clerque lines are off it which feeds St. Mary's, in essence and as well our Flakeboard company. So, that was an extremely tricky project co-ordinating between Algoma Steel and/or Flakeboard/St. Mary's sort of thing. I think what we did there that typically worked the best was...you know, a lot of times we scheduled for their downtimes, not complete outages, of course, but they were down, you know, steel plants, we zap it down to 80 megs. So, we scheduled the breaker replacement. We could take down one transformer at a time and shuffle our breakers in there. I can't remember how many PCls were submitted and scheduled for that job, but it was extremely complicated.

But, at the end of it, it worked out really well, working with our customers. It was a very good, co-ordinated effort.

MR. HARPER: So, nothing sort of equivalent to that is required in what you are looking at?

MR. GAZANKAS: Well, Third Line will be

tricky, because it is the biggest station we have, and from Third Line, we have...well, we have everyone.

MR. HARPER: Everybody.

MR. GAZANKAS: Mind you, the configuration is different. We have four circuits emanating for PUC, we have the three Algoma circuits, we have Sault 3, we have two transformers. I mean, there is...plus three, four tie-breakers. So, it will be challenging, for sure. We think we have a fairly decent, high-level plan at this point and moving forward, we wouldn't see any...well, outages, you know, sometimes. You hate to say you are not going to have an outage. We never plan for that. It should go very well.

MR. LAVOIE: And there are some facilities that we have that in order to do specific maintenance or a replacement it would need...

MR. HARPER: No, I understand it is required at times. I was just curious.

MR. LAVOIE: We have had very good success working with customers and most, at least industrial customers, have downtimes when they do their own maintenance. So, it is really just...a lot of times, it is just co-ordination.

MR. ANDRE: Tim, we are into the...well, early into 2007, but these work programs for 2007 have been pretty much defined and committed. Is there some thought of having the discussion with stakeholders sort of towards the end of this year for the 2008? Is this your plan to sort of meet with stakeholders and talk about the program for the year or is there some notion of meeting with them and talking with them about what is coming up? Because let's say you got some feedback now that suggested that maybe there should be some re-prioritization of work. It would be a little late in the game to do the 2007.

MR. LAVOIE: Actually, a lot of the work has not been committed to yet. So, it is definitely a proposed...the transformer, I think, is the only exception. So, we are in a position...we do have a plan, though, I think, to move the sessions. It is a difficult time of the year for us, in particular, just because we would be gearing up now, very close to now to get things rolling. I think our plan this year is to try and move it up like you suggested.

MR. LAVOIE: Yes.

MR. HARPER: Well, thank you.

MR. LAVOIE: Thank you all for coming

today. It has been a very good discussion.

--- Upon adjourning at 3:10 p.m.

I hereby certify the foregoing to be a true and accurate transcription of the above noted proceedings held before me on the **15TH DAY OF FEBRUARY, 2007** and taken to the best of my skill, ability and understanding.

Certified Correct:

Matt Wojas
Verbatim Reporter

GREAT LAKES POWER TRANSMISSION

2007 STAKEHOLDER SESSION

Friday, April 13, 2007.

MR. LAVOIE: We'll get started. The presentation that you see here today is a presentation that we've used for all the stakeholdering that we've done, process that we've done for 2007. This is the same presentation that has been used for -- there's been three group sessions, this being the third one that we've done.

To kick it off, welcome. I certainly appreciate Chris coming down from Wawa and Rob and Paul for coming today. It's something that we found at least with the last two sessions, and I'm sure we'll find today, has been very positive and good dialogue with respect to our capital plans and the objectives that we want to achieve on the -- as an outcome of the settlement process from our last rate application, and I think we're all benefiting from it. So it's been very good.

Administrative item here. We have a transcriber at the back. This is a record of today, and we just -- I think what we've done in the past is we want to encourage open dialogue, and this is a means of recording it only. It's not meant to be a formality. The time frame we've allotted for the meeting today is about an hour-and-a-half. We do have a few commitments to take care of at the end of the day, so if -- just keep that in the back of our minds, that would be great.

Just a final administrative item. This is a transmission stakeholdering process. Many of you are familiar in the local community that Great Lakes Power does operate a distribution division, and it does have direct connected residential and commercial customers. This stakeholdering process is for transmission business only, so it does reflect all transmission only things, and of course, anything that is reflected in the transmission costs that are spread throughout the whole province.

Having said that, agenda for today, I've been through a little bit of introduction myself. Tim Lavoie, I'm the general manager of Great Lakes Power Transmission, and Distribution Divisions. To my left, immediate left is Gary Gazankas, he's our transmission engineer, and to his left is Alex Lee, who is our manager of transmission engineering. We'll all take turns here today on various parts of the session.

The -- so we'll go through the capital plan. We'll talk -- have a discussion around the plan itself, look at our proposed 2007 major maintenance, and we'll also talk about another topic that was -- as part of the stakeholdering session, which is the transfer pricing review, is what I called it on the agenda, but it's to deal with consultant to study the cost, transfers between distribution, sorry, transmission and generation.

So objective of today's session in more detail. As part of the capital budgeting process, GLP's conducting stakeholdering meetings with stakeholders to consider its capital plan together with major maintenance. That's taken directly from Section 1.2 of the Settlement Agreement from the last outcome of the last transmission rate application that Great Lakes Power made in 2005.

The second objective is GLP is

committed to retaining an independent third party consultant to review and report on the accuracy of the cost allocation and transfer of pricing between its transmission and generation businesses, the result of which will be filed at the next rate application. And the stakeholder consultation group will provide input into setting the terms of reference, review and choosing of the third party consultant. And that's taken directly from Section 3.1.1 of the Settlement Agreement as well. I'll turn the floor over now to Gary who will start talking about our capital plan.

MR. GAZANKAS: Basically every year we have -- we roll out our 2007 plan, 2006, every year. This is done on annual basis. It's a bottom-up approach. So it's a clean slate. Every year we visit the sites, we visit each asset. You know, we perform condition assessments and so forth, review maintenance records, that sort of thing on all the assets, just so we have a good indication of where they're at with respect to end of life. We look at health and safety concerns, potential safety hazards, and this sort of thing, and this is all compiled on an annual basis and reviewed when we do determine this -- the annual capital plan. In and around that, we also consider direct customer concerns where we do meet with our directly connected industrial customers every year. We meet with Weyerhaeuser, River Gold. We meet with Flakeboard, ASI, and St. Mary's paper, and we've already done that this year. And in that process, we, again, discuss power quality issues and amongst other things in those meetings, i.e. concerns they have. We not necessarily add that specifically to the program, however it's considered at that time.

Again, I mention when, you know, determining when end of life assets need to be replaced. Once again based on maintenance records, test reports from our maintenance group, as well the condition assessments. We assess what remedial work is required. We also examine the system for operational improvements. An example of that is installation Third Line tie breaker, which is currently under way, was previously approved in the last rate order. That was an example of an

operational enhancement. So just giving a brief example of that.

We identify these projects on an annual basis. As I've mentioned before, it's a bottom-up approach, and we prioritize it annually taking in all the considerations as I've mentioned. Health and safety, public safety, environmental, maintainability, reliability, operability, even as far as aesthetics is all a part of our ranking system that we utilize annually to develop this plan. We review it as well for resource adequacy. Right now provincially, you know, resources are stretched. It's an extremely busy time. Reasonableness, we also look at our own internal resources to see if we can handle these projects as well. Obviously there's synergies. As I'll explain, when I get into detail, the projects that are forthcoming this year are proposed projects. You'll see some synergies there with respect to we have a structure replacement. Well, we jump on that and we do a lot of protection and control upgrades, at the same time utilizing outages and so forth so customer outages are --

customers aren't impacted as severely.

Again, prioritization. As I mentioned, addressing public and safety -- and worker safety issues. Obviously that's paramount. That's with -- or should be with every utility or company. Addressing significant environmental issues, the placing end of life equipment. Obviously, here we're looking at reliability of the system, maintainability, costs, that sort of thing, operability. There's compliance with legislative and regulatory requirements, IESO and NPCC requirements and standards that we're obligated as a transmitter to obviously abide by, or even ESA, Electrical Safety Authority. Lastly, obviously looking at improving system reliability, maintainability and operability.

Project timing considers the priority obviously as indicated above, and synergy is based on outage requirements logistical requirements. So basically we lay everything on the table once we've gathered all our information and look at what synergies there are between projects. In that list we look at the ranking where we rank them with respect to

health and safety, and then at the end of the day we compile that list and obviously take a look at the resource requirements at that time as well, and if everything looks reasonable, that's what we look at putting out for our capital program for that upcoming year. We believe that that represents a complete approach to evaluating our projects.

The expected outcome, of course, best allocation of resources is the greatest needs. So the priorities being health and safety and that sort of thing. Obviously we want to allocate our resources to the projects we see, you know, that we rank the highest. Health and safety is in there, of course. Risks are managed in a systematic manner, we believe, as we identify the risks and we rank them, and we believe that this significantly reduces our unexpected expenditures.

This is a dynamic plan, however. It continues to be developed as conditions change.

There's regulatory requirements that change annually, you know. Asset assessments and there's stakeholder concerns as well that impact the development of our plan. This year

for 2007, our proposed budget is 11,254,000. Any questions so far?

MR. CASSAN: Do you want us to ask questions as you go or --

MR. LAVOIE: I thought I said that up front, to certainly jump in at any point in time. I was going to add to the capital budget here, just trying to weave in some of the questions that we had -- you posed before. The comparison 2006 plan was about 17 million, and 2005 was 90 million.

MR. GAZANKAS: Basically this is how we structure this every year.

MR. CASSAN: How long have you been using this process?

MR. GAZANKAS: I've been here for three years now, and since I've been here we've been using it. Probably since at least market opened, I'm assuming. I don't know prior. Prior I'm not too sure. All right.

MR. WRAY: Just a qualified statement or the term market opened, when it was re-regulated.

MR. GAZANKAS: Yeah, market deregulation.

MR. CASSAN: Deregulated we call it, Chris. It's not re-regulated.

MR. WRAY: I call it re-regulated.

MR. LAVOIE: Something happened in 2002.

MR. WRAY: Exactly. Okay, thanks.

MR. GAZANKAS: Now it's the -- this is what was developed for 2007. Nothing at that point is -- we have this program. We rolled it out. We've done the pre-engineering. We haven't awarded anything yet. Nothing is etched in stone at this point, so I mean not that -- we feel that this is a legitimate capital program for 2007 and we would obviously continue moving forward with that. To let you know that nothing is committed at this point.

MR. CASSAN: So you figure that this is all going to get done in 2007, or this is a question for later on?

MR. GAZANKAS: Absolutely. No, absolutely. Yeah, I'll go through this. This is what we believe is going to be done in 2007, absolutely. First part here is compliance. We have this categorized, and these projects are required to meet current standards. We're

looking at installing oil containment at Goulais subdivision. If you go down the highway from here to Wawa, first substation you see on the right just outside of Goulais is TS, that's Goulais TS. There's no oil containment on those transformers. There's farm land. There's public in the area. This isn't a legislated requirement. It's a Brookfield Power policy, but we obviously want to be proactive in environment and this is a project that because of, you know, its nature, situation geographically, we feel this year came up that we deem it important enough to obviously get it done. Last year we did a same oil containment at Batchawana. We did that one first, because as you go past Goulais up towards Pancake Bay you go passed the Batchawana site. You'll notice right across the highway is Lake Superior. This is an example of our prioritization. It's not Lake Superior, of course, at Goulais, but there's public in the area. So these are things that we are definitely looking at, and that's an example of that prioritization. The next one is the TS grounding study. This, I believe, is

at least an I-EEE standard, and it goes with respect to step and touch potentials, worker safety and so forth. Generally speaking, stations, you know, not so much change, but the ground is eroded over the years, possibility of loss of the crushed stone on top. So what we want to do is to ensure the worker safety and even public safety if they're on the outside. We want to make sure these grids are up to these current standards, and no one is going to get hurt. So that's really why we're doing this.

MR. REID: So is that generally across all stations or is that --

MR. GAZANKAS: No, no, that's a particular station, and we're looking at Goulais and Batchawana, and we're also looking at MacKay and Third Line as well.

MR. CASSAN: Once you have Goulais done, are they all -- do they all have the oil containment? Is that the last one or are there more?

MR. GAZANKAS: You know, very close. I think on the transmission side -- I can't speak for distribution, but transmission side

of things, I believe we will have most of them done. I've got to take a look again. I'd have to say I'm not sure, but you know what, if you'd like me to get back to you on that.

MR. CASSAN: I'd be interested to know, I guess, if there's others that aren't done, just so we can, I guess, look at if it's downtown Wawa or something like that, if you've got more public close by.

MR. GAZANKAS: Little different because it is the distribution system.

MR. CASSAN: Fair enough, not a good example.

MR. GAZANKAS: But that's okay, I mean, it's a legitimate question.

MR. LEE: It will be addressed on the

distribution side.

MR. GAZANKAS: Right. It could be a question that someone asks on the distribution side, but I can definitely find that out for you. Moving to the next one, refurbishment replacement, starting with the first one, Third Line TS, which is just located in the city here. We have two transformers that feed Sault Ste. Marie, the entire city. Last year we had

an issue with a component on one of the transformers. They're aging. And we felt it necessary, because we have four of these type of transformers in our system now, we needed a spare. This further reinforces the fact that we do need a spare. So what we're going to do here is we've purchased the transformer, and it's actually being manufactured right now. Its installation date is looking at September. That is one project that has been committed to because of the complexity in nature. We did not want to be running Sault Ste. Marie on one transformer. There's issues surrounding that. Technically I don't know if this is the right forum, but at this point, what's going to happen here is we purchased this transformer. It's going to get installed in September. The transformer that is there, what we're going to do is we're actually putting a pad down at the station and we're going to refurbish that transformer to become our system spare. So we're not throwing it out. We're utilizing that transformer, because we feel that there is still life in it. Any questions on that?

MR. REID: More interest, I guess.

The failure was what?

MR. GAZANKAS: Tertiary reactor, catastrophic basically. Right now that has been fixed internally and we are running on two transformers, however we've lost some of our voltage support in the area because we don't have the capacitor bank hooked up right now. So there's issues surrounding that right now as well, operationally speaking.

The next project is MacKay TS up at Montreal River area. This is not -- the 230 was the TRP project, and that's completely brand new yard. This is the 115, and this was not a part of that transmission project.

However, we have breakers there that are 60 years old and with tests, maintenance tests showing that some of them may be prone to failure. If we have failure up there, we could have catastrophic failure, of course. These actually are bulk oil breakers, so we have really no means of in-house maintaining them properly, because we have no oil containment facility. So to maintain them, do a major overhaul at this point would cost us a lot of money. Quantifying that, I don't know, I'm

assuming probably -- you know, I don't really know if I could quantify it. It's a lot of money to actually maintain those breakers. And end of life, they are reaching end of life, so we obviously have reliability issues there and safety issues if they now operate and we have personnel in station. So that is the focal point of that project is the breaker replacement, because of the age of the maintenance reports and obviously the environmental aspect, having all that bulk oil in there.

MR. WRAY: You said they're 60 years

old. How long have they been in the condition that they should have been replaced?

MR. GAZANKAS: Pardon me, sorry.

MR. WRAY: If they're 60 years old, how long have they been in a condition where they should be replaced.

MR. GAZANKAS: I don't think I could answer that question. I'm not sure.

MR. CASSAN: Do you know what life is?

MR. GAZANKAS: The life expectancy of a breaker, I'm assuming 40 years is a good

utility practice really. 40 years you should be looking at -- Rob could probably, even Alex, that's a good utility practice.

MR. LEE: Good utility practice, 40 years, 40, 45.

MR. WRAY: So the supplementary question to that would be then, if they're 60 years old, 40 years, let's just say is a generally accepted practice, what would lead it to not be replaced 20 years ago verses today?

MR. GAZANKAS: I don't know. I really can't -- all I know is when we went to market opening, this is -- I don't know. Possibly when we started the bottom-up approach there was other projects that were prioritized in front of this and this is where this has landed at this point. I can't speak to me prior being here or even 20 years ago. I apologize for that.

MR. WRAY: That's fine. That's fair.

MR. LAVOIE: I think the important point is to note here as well that, you know, as much as you can use life spans like 40 years. There's really no hard and fast rule that says, oh, something's up at 40 years. I

think what has continued to occur is that, you know, we look at the condition and operability of them. And, yes, it's time to replace them now. Are they still operating, absolutely. So we've shown that you have assets that are 60 years old that do function. So, you know, we -- you wouldn't necessarily look at 40 years as being something. A guideline, yes, and condition and other criteria at that point.

MR. LEE: The other criteria, you've got to see after 60 years of service you might not have the same spare part. If a major things breaks, you probably have to get somebody custom make it or you can't get it anymore.

MR. GAZANKAS: Basically the justification for that project, next at Third Line, switch yard replacement is similar to that of MacKay. The breakers aren't as old. They are at 40 years now, but again, this goes -- well, I guess your question, Chris, we're being proactive here. We're not replacing them at 30 years, we're not replacing 20, but at the 40-year mark we're looking at replacement of the ones at Third Line so we

don't have this question again. In another 20 years someone will come back to us and say, well, why wasn't this replaced 20 years ago. So there's the intent on this. Not only that, is that a reason, basically these breakers are rated for 121 kv, and we have voltages in the area subject -- Third Line TS subject to voltage much higher than that. And we're talking to manufacture representatives, and, you know, they feel that it's not a great way to operate your equipment. So what we're going to do is install equipment that is rated for the area. There's an actual specification for that through the IESO. Any questions on that?

Next is Magpie transmission line, the structure replacement, and that's up in the Wawa area. This was driven from reports, maintenance reports, and we have a lot of Woodpecker damage up there, believe it or not, severe. So what we've done is not all the structures are getting replaced. We've gone through and picked the most severely damaged structures, and those are the ones we're going to replace this year. Again, it's a matter of us reviewing the records. It's all a part of

our process where we review the records coming in and hand pick the ones that we think at this point require replacement so that we don't have catastrophic failure.

MR. WRAY: Replacement structures.

MR. GAZANKAS: No, composite. We did composite on BP1G structure replacement for TRP that worked out very well. So we want to alleviate at least the Woodpecker damage. When you introduce something like composite, I suppose, you don't know what -- you know, how impactive that's going to be. Not environmentally, it's a good product, but what other animal or --

MR. CASSAN: The next parasite that's going to be bugging it.

MR. GAZANKAS: Exactly. At least at this point Woodpecker damage will be greatly reduced, and it is a problem. It's a severe problem.

MR. CASSAN: Have you looked into any prevention programs or --

MR. GAZANKAS: We have, and Hydro One has done studies on it. As a matter of fact, they've -- you know, they focused on all kinds

of sound devices and this sort of thing, but nothing seems to work. Even the new transmission 230 circuit, prince wind farm when they installed the new 230 circuit. A week after, I've got pictures, and there's holes in the new wood structures that are massive. It is a real issue. Eventually -- they're not ready to topple, but I think if there's -- you want to minimize in design and this sort of thing. You want to minimize catastrophic failure, and that's what you design for. When you have this sort of stuff going on, you can't account for that type of damage. We have hand picked those, and that's typically, I think, going to happen in August, that structure replacement.

MR. WRAY: What's the composite material that you use, the composite?

MR. GAZANKAS: It's a fibre glass type material. The next project, Clergue low voltage 12 kv buses and breaker failure protection. Alex, did you want to talk about this?

MR. LEE: Okay. We had an incident happen a couple of months ago. We had the

breaker -- the bus protection operate because of one of the 12 kv cables was -- had a short, a leak. Good thing our protection operate, so actually that's bus and breaker failure has been there. It's been there with the whole system and then we think it would be better to upgrade it. It's an old method station, so it's come to a time that we decide that this is a good time to upgrade the protection and to bring it up to the industry standard now. And the breaker failure, I believe it wasn't there in the early days, so the industry standard would prefer you to have a breaker failure on this, on the breaker, on all this old method breaker. Actually, it's one of the requirement for all the breakers in the system. That we'll be trying to do it this year, once we have the schedule, the planning. The engineering is done, it's just ready to go for it.

MR. GAZANKAS: I'll talk about the TS battery replacement. It is part of our 230 kv system it is a requirement to have A and B battery protection, or A, B battery supply on the D, C, and we only have A. So this is just an upgrade to not only get rid of what is an

ICAD. It was an ICAD battery and there was environmental concerns with that. The disposable site in North America is Texas or something, so there's environmental issues with that. But it is nearing end of life as well. Obviously it is scheduled for refurbishment anyways, however, we are going to add the A and B protections as to meet IESO requirements.

Next we have a few smaller projects. I don't know, did you still want to go through the whole list of the smaller ones, or did you want to keep -- they're fairly minor. Obviously we have, you know, breaker failure, protections, battery charge and replacement at MacKay. But these are fairly minor projects on the scale, and I don't know if you want to discuss that.

MR. WRAY: I'd like to hear about every individual one.

MR. GAZANKAS: You would like to?

MR. WRAY: I'm just kidding.

MR. LAVOIE: If there's anything at any point, if something comes to mind, come back to it, not a problem.

MR. REID: Sorry, one question. The

transmission line emergency work, how does that number fit with some of the projections from the TRP?

MR. GAZANKAS: I don't know what you mean by TRP projections.

MR. REID: Some of the justification in the original need to construct was that there would be reduced maintenance costs and that sort of thing because of the new lines and new equipment at the TS, that kind of --

MR. GAZANKAS: Yeah. This has no relation to that. Every year obviously we're improving, but we have aging infrastructure and we have issues with our transmission circuits, specifically our Algoma circuits within the city limits. We've had last year a couple of issues with the aging structures, and we've had some minor problems where these are surprises to us. As we move forward with the structure replacements and maintenance records, I mean, you know, this is more of an unexpected expenditure, but it still is a capital expenditure, because we actually, you know, installing a new structure, cross arm, and that work is capitalized. But what we've done in

the past to get a number that is there, is we've looked at typically what we've spent in terms of these types of, you know, unexpected expenditures as I've mentioned before. We've gaged this. So that's the number that we came up with. This may drop in future years. This may go up. I would suspect it's going to drop because of all of the enhancements we're doing on our systems and the upgrades. But unfortunately lightening and storms, you can't expect for -- you can't plan for that type of stuff. So you want to have something in the transmission line emergency work just to accommodate that.

MR. LAVOIE: We can certainly say that our short history with the transmission reports from the project has been little, if any, emergency type work on it, and it's been predominantly with the older structures has Gary has mentioned. So I think it fits well with exactly what we had predicted with TRP at this point.

MR. REID: What about just generally? Do you have a sense of is there any of this work that was sort of carried over from

previous years, or sort of was originally planned previously and didn't get done and has now sort of moved forward in the plan?

MR. GAZANKAS: I would have to say maybe some of the smaller ones. I think anything that's -- anything that's here that's big, I would say no. I mean, the -- actually that's wrong, because the transformer at the top, we knew we had a requirement for a system spare. I think that was scheduled for, I think, next year, because we do have four auto transformer, Echo River, MacKay, and the two at Third Line, we do need a system spare. If we lost any one of those it could be down indefinitely. But because we had the failure, we didn't want to run with the risk of one transformer and expose ourselves to obviously system wide blackout and that sort of thing. So that was brought forward, and that's an example of -- as I mentioned before, this is dynamic in nature. The smaller ones, at times there are resource adequacy issues, specifically P and C, and there have been probably few smaller projects that were carried forward. But outside of that, I think the big

ones have generally stayed where we've planned them, give or take -- I shouldn't say give or take. I think they've pretty much stayed where we've at least originally kind of projected, and built it up again and proved itself out.

MR. REID: I'm not sure how to ask this really, but one of the issues that the Algoma Coalition raised previously was the idea of because you're both the distributor and transmitter, how do they know that the distribution system is being sort of properly looked at from this perspective? Like, not the asset base that is distribution. But if you think of distribution as a customer in the transmission system, how do you know that that's being looked after properly or whatever?

MR. GAZANKAS: Again, it comes into synergies and in meeting with directly connected customers. I mean, it just so happens they are distributor and transmitter. So an asset management engineering, our engineers both in distribution and transmission, when they roll out the plan tentatively, it's laid over top, and we actually look and see where we can synergize,

if you will. I don't know if that's a word, and, you know, plan to minimize disruption to the customer. Example, that would be Goulais this year, because we have the transformer, the oil containment going in. We have some other yard works there, grounding with grid and that sort of thing. We also have the replacement of those two breakers that you see with the lights on as you drive by. We're putting electronic enclosures there. Well, we've done that for a reason. We've planned that. So that any outages the customer is going to see, we can time that so that if we have any issues with the containment, you know, it's done in one fell swoop and it's -- we're minimizing that in time to the customer. So in that regard, that's how we look at that. I don't know, does that answer your question?

MR. REID: Yeah, I think so.

MR. GAZANKAS: We do plan according, not just on the transmission side of things. We do plan, you know, synergize on both sides of the house. We look for synergies on both sides. Not only am I looking at projects at MacKay or Magpie with the structure replacement. You'll see also I got battery charger replacement. The next page I'll have -- I have P and C work done for Magpie, so that's transmission planning as well at Goulais I mentioned, we planned that for Goulais as well so that, you know, we're not impacting those customers.

MR. REID: Yeah, and I don't have a specific concern, I guess. But the perspective is that when I look at the list, there's several things that are more generation connection asset work. Not necessarily distribution connection asset work. Like I say, I have no basis of saying that's good or bad, so that's not what I'm trying to say. But if that's the perspective we're looking at this from, right, is to say, okay, these are the priorities and --

MR. GAZANKAS: I guess my answer would be, in no way are we, you know, developing this plan to benefit the generators, obviously. I mean, this is -- we look -- this is -- there's no input from the generation side of the house, and that just can't happen. This is a bottom-up approach that we take on. We do our own condition assessments, and at the end of the day these are the projects that we come up with outside of any other group. Distribution, we work with them solely, as I've mentioned before, because we -- you know, it makes sense. Generation's a different story. It's a different business unit. It's something that, you know, we just can't be involved with that.

MR. CASSAN: One of the questions that we asked in our letter, and I don't know if you want to deal with it now or later, is what projects did you look at but decide not to do for 2007? I wonder if we get an idea of those, or if as you're going through this you'll say, you know, for MacKay there was something else that we've decided we're going to put off, and I'm wondering if that sort of ties into Rob's. Maybe some of those with the distribution end of the system.

MR. GAZANKAS: You know what, I don't know if I look at it in terms of that way. I don't look at it in terms of is it -- you know, I look at it in terms of what needs to be done and how it comes out of the ranking. If it so happens that it comes out that we need to do MacKay TS, which really is for the generators, then that's the way it is. If it turns out that, you know, we have to do Batchawana or Goulais, which is really feeding the distribution customers, then that's exactly what we're going to do. It's a -- you know, that's just part of the plan. Where they come out as part of our analysis is where we lay it. There's no --

MR. REID: I think part of the question, though, is how do you draw that line. Like, not so much between even different customers impact, but just, like, you've got a number of 9.6 million, you know, it could have been 30 million, but, you know, where do you -- where do you draw the line to say, okay, like, one there's going to be obviously some kind of overall budget consideration that you've got some kind of an envelope to work within, but then there's also some kind of risk analysis to say, well, the next project on the list, the risk associated with that was deemed to be acceptable that it could wait at least another year or whatever.

MR. GAZANKAS: That's all a part of when we do the health and safety, and, you know, all of that is a quantified process, if you will. You know, through looking at all our records and such, we try to somehow pull that together and rank it, and rank the project.

MR. CASSAN: So I guess the question is how do you do that and what -- where was the line drawn? What is put off? That's kind of one of the questions.

MR. REID: I guess, you know, you've told us that you've got a process and you've told us what the end result of the process is. You haven't given us much in between. That was where some of the concern previously came from was, how do we know that 11 million is the right number. Like, it could be higher or lower, and there's nothing --

MR. GAZANKAS: I guess that's hard, because I don't know how it would be -- how -- you know -- the question is, it's not only, you know, how these things work out health and safety wise, but also resource adequacy. So again, when I'm -- when all of this is pulled together, I don't know how --

MR. REID: If we maybe backup a step for a second. I think the -- correct me if I'm wrong here, but part of the issue around the settlement at the last hearing, my understanding was to try to get customers more on side with the plans and to have more of a preemptive sort of approach, so that when you do go for a rate hearing you know, or at least you have maybe more comfort level that people are buying into what you're doing. There was some real hesitancy historically to believe that was being done was sufficient. So now what I think we're looking for is some more assurance that this is the right plan. And at least --

MR. GAZANKAS: I guess dollars and cents wise, there's only so much we can throw out in a year. We're not a huge company, and internally, like, resources -- acquiring resource adequacy relies -- that's a huge -- you know, we can only do so much outside of everything else because of that. Obviously, you know, if we have an aging infrastructure and, you know, we have test results and maintenance records that we can justify as a prudent expenditure going to rate order, obviously we would love to be the hydro of the world and gear up and, you know, and do all of this. Provided, obviously, it's a prudent expenditure. We're not out to just spend money here. But I guess --

MR. CASSAN: You know what, let me tell you a little bit about our thoughts on the coalition, and Chris can kick me under the table if he can reach me. We're interested from sort of the customer's point of view in having low rates and in having a good system. And I understand that there is attention between those two things. I guess what we're saying to you is, you know, let us know what the other projects are, because you may end up in a situation where your customers are saying, gees, we think politically this is important. Maybe we've got something -- like, don't look at us only as an opponent who is going to be saying we want the rates down. What I'm saying is, we're interested in the system and we're interested in knowing what the potential problems are, because we may be saying, you know, yeah, the rates are going to go up, but this is a project that some community that's directly affected with it really wants you to proceed with.

MR. REID: So security and reliability are improved, and can people get a better product as a result of that. That's something that people will support as well, right.

MR. LAVOIE: Right. I guess, some of the struggle that we've had, I guess, maybe just understanding the Algoma Coalition's position on certain things. I guess bear with me here. When we look at directly connected customers, you know, we had one-on-one meetings. We've had them in a group with the stakeholdering. It's, I guess, an easier communication to deal with a single directly connected customer to say, you know, we talked about the asset, what -- what are the things that, you know, you're concerned about, power quality, all kinds of technical back and forth with respect to that. That certainly is something that I think is considered in all of this. You know, with distribution, you know, we've done it -- as Rob questioned before, we've done it with the same sort of connection between ourselves is that, you know, what are the issues that we've got to deal with from a transmission perspective that need to be put in the transmission plan because it's a transmission issue. We've done the same thing internally, and I guess this has been good for me to understand that I guess what you're really saying is that from a distribution perspective, this gives you an opportunity to speak for transmission things that should be addressed from a distribution perspective. Am I kind of reading --

MR. REID: Yeah, the whole reason for the coalition really was -- well, I shouldn't say the whole reason, but one of the major reasons was to be more of a proxy for the distribution customers to say that if you're looking at it internally, is there really the faith there that it got the proper look. So now there's a customer group that's saying, you know, we're keeping an eye on you to make sure that that is what happened. But it's not just from a cost, a low cost perspective as Paul said. It's both. Are we getting the right product as well as a good rate.

MR. WRAY: I think that there's another dynamic here that I just want to throw out on the table, and I'm going to be bluntly honest about it. From the end customer's point of view, I'm not talking about the direct customers on transmission line, but off the distribution system, there is a general feeling that -- or a general question out there, so you've got to do all this work now that they've deregulated everything or re-regulated everything, just what and the heck were you doing with all the money all these years? That is the general question. That's not a question from me. That's a question that I hear, and that's why these two gentleman have asked those supplementary to that, I guess to that. And that's really the issue. So I would suspect, as Paul has suggested, we want -- the customers want a well run system and they want low rates, and both of those things are -- I mean, they're pulling into opposite directions, right. But if you have them understand this stuff --

MR. CASSAN: Transparency is the issue.

MR. WRAY: Yeah, you're going to get much more support than you will if you don't. Because that question that I mentioned at the beginning of when I started talking is still out there.

MR. GAZANKAS: I guess we could take a look at what we've spent to date and then have a look at the reliability numbers that we've had since 2004, and, I mean, those numbers have gone down.

MR. WRAY: We're not -- I'm talking about for the last 40 years, right.

MR. GAZANKAS: I think they have to understand and be educated on historically, I guess, I don't know, how the difference is between deregulation and then prior to that, because I don't know how the transmitter operated prior to deregulation. And why -- so I can't answer that question.

MR. LAVOIE: I think really the most relevant thing that we're talking about here today is dealing with what needs to be done now. I mean, you can have a historical view of things. I think the fact of the matter is that the system was run in the past. It was run by

a different set of regulatory rules. It was run under different conditions, and it was run successfully then, and we can assure you that our plans moving forward are so that a) we meet all the requirements of the new system, b) that we continue to deliver reliable, and enhance reliability where required. I think there's definitely a change in requirements with respect to market rules and other things, and those are the things -- those are the plans that we're building now to address the current and future needs. So I think that's really the perspective that we can -- we have to look at this in.

MR. CASSAN: You certainly can't change what's been done in the past. I think transparency and allowing people to understand how you're dealing with it in the future, and I mean Chris's issues are on the table. I don't know -- I don't know the answer to that. I mean, one of the answers might be for the company to say, you know, it wasn't best utility practice in the past. Here's how we're mitigating that to the current customers. Because I'm sure that there must be --

MR. GAZANKAS: It was aging infrastructure, and to get that infrastructure up to the point where now we're under strict governance by the IESO, there's obviously a significant amount of capital involved with getting it up to that -- obviously that spot.

MR. LAVOIE: That's the current requirement.

MR. CASSAN: That goes back to our risk analysis and sort of the beginning of my question. I understand that there's probably a hundred times the number of projects that you've got on here that you might like to do. What we're interested in is, you know, why have you chosen not to do some of the others. What's the benefit that it may have had, what's the process for deciding that those aren't going to get done today. They're going to get done tomorrow or they're not going to get done.

MR. GAZANKAS: I think it goes back

to the way we rank our projects. I mean, we do -- we rank them. Like, we have the health and safety, we have the public safety, we have -- and that is ranked. It's a number at the end of the day and there's a dollar

associated with that. I guess at one point it may become subjective on the cusp, because -- even though it's a ranking system, and every ranking system, obviously, is subject to that. But, you know, we've got a lot of components in and around it that we feel that whatever we derive from it is the highest priority for this given year, and that we mitigate as much risk as possible by postponing the others ones.

MR. CASSAN: Can you tell us what the other ones are?

MR. GAZANKAS: I guess, I mean, we look forward -- I mean, I don't know what relevance there is to it, the only reason is, you know, we -- because it's an annual thing and it's a dynamic issue, we every year look at re-evaluating right from the bottom up. So at that point, even one that was pushed off may have an entirely different set of circumstances as the next year where I need three transformers, and that again, I can actually, you know, sleep at night thinking that I can push the project off for another year. Do you know what I mean? I mean, it's an annual bottom-up approach, and for me to provide you

with a list from now until 2025, or even the next ten years, it's --

MR. CASSAN: But you must have some of them, right. Like, with a long life system like this, you must have projects that you see are coming down the pipe. I know that you analyze it annually, and those priorities will change, you know. There will be an emergency that you've got to deal with next year that you don't see today, no question.

MR. LAVOIE: I guess what -- something that -- I guess we've certainly taken input from the other sessions on exactly how can we make these sessions better, and I think what I'm hearing is that we've got to really step back and think of a way to present the way we look at ranking projects and get -- determine a way that would be meaningful, or at least we can communicate to be meaningful for the stakeholders to understand, you know, exactly what's sort of coming up on the horizon. I guess, where I struggled was -- certainly when we saw the question was, how do we -- you know, do we just print off a list. Do we show numerical numbers? We certainly

felt that if we could really describe the process to you that that's really what you were looking for, is that we do consider every asset in our system with a long-term viewpoint. You know, we start looking across our system and say, well, you know, we did an investment here in 1962. There's some equipment here that needs to be replaced that we have targeted for roughly over the next five years that we're looking at it. However, when you look at health and safety, reliability, operability and all the other criteria, there really is clearly not -- it's not close to the line so to speak. So we really don't pay a whole lot of attention to something that clearly is in good condition. It's operating properly. So do we have a precise ranking on those projects, no. But ones that are a little more higher priority that as Gary is saying, you know, the transformer is coming up, obviously that priority changed over the last year as a result of a failure on the system. Okay, clearly now what -- you know, if we'd -- if we had this session a year ago you wouldn't have seen the transformer, and now it would be here. So

that's the kind of dynamic side of it that we were struggling with, saying how do we kind of show you a list of projects that are meaningful. Certainly it's something that we definitely, you know, will take back and work into our -- you know, we're certainly going to -- this is an annual process. Let's take a crack at it for 2008.

MR. WRAY: So, for example, when I'm doing my municipal capital budget, I'll do a budget for '07, and I'll do a forecast for '08, 9, 10, and 11, five years at a time, and that's the type of thing I think we're talking about here. I call it a forecast verses a budget, because God only knows what's going to happen particularly at the fifth year.

MR. LAVOIE: I think that's what we were struggling with too. We certainly don't call something a plan beyond a year. It's like a -- it's like a projected kind of -- anticipated as of today what it looks like for the next couple of years.

MR. CASSAN: I think that the two issues of greatest concern here are one to understand the process, and two to understand

probably even more important projects that were put off, the ones that are sort of right on the line, so that you're saying, you know, there is a safety component to it, there is an environmental component to it, there is whatever, but because it didn't rank -- how many have you got there, 12, because it ranked 13, we're not going to do it. I think around the line, the sort of array around the line is something that we'd be interested in hearing about.

MR. LAVOIE: Certainly it's something we'll take it and build it into something for the next stakeholder for sure.

MR. LEE: Let me add something here.

Some of this project that we're doing, we have to -- it's governed by the regulatory requirement.

MR. CASSAN: No question. I understand that.

MR. LEE: What I know from the last two years when I see the system, some of them were based on 30 years ago, and things as they keep going on, we have to operate the best utility practice. Like you say, there are some

project that we plan for 2009 or we can push back, because some of the protective relay are still in good working order. They are all not top of the line microprocessor. The time has come to be replaced, so I do when I analyze it to see, okay, is this still doing good? Can it last for another year or we need --

MR. CASSAN: But you know what, that information, going back to Chris's point, that would buy you so much political goodwill to say, you know what, we were going to do this, but because the system is working, the component is working better than we forecasted, or we're going to put that off. So we're saving the expenditure of a million bucks this year because things are working well. That can work in your favour.

MR. LAVOIE: Actually, very good point. I mean, that was one of the projects that was on our list last year, and based on we didn't need to do it because of condition and so, yeah.

MR. CASSAN: Because that kind of thing you can say, we're not going to do this right now so it's not going to raise your

rates.

MR. LAVOIE: That's great. I appreciate that. We certainly are learning from this process too, and something that we're looking at obviously trying to better it every year. And this being the kick-off has been a learning experience all the way through. So absolutely.

MR. GAZANKAS: More system improvement projects, again, you'll see line protections from Magpie TS, upgrading line protections. Actually, I'll let Alex speak to that. Before that, again the whole synergies thing, if you go one slide back, I believe in structure replacement at Magpie. There's outages associated with that. We've already contacted the industrial customer in the area and that sort of thing, so we're already starting to coordinate an effort. But, again, here's the synergies, but we're going to have a line out and we've got to make changes to minimize that impact.

MR. LEE: Okay. For this Magpie line protection outbreak, at the moment what is in the system, the protective relay, all electro

mechanical relay. We try to upgrade the line protection with more advanced halogen (sic) relays where it can give you the -- better capture the event of things happening. The electro mechanical, there's no -- if there's a fault you have to send a guy out there, and he's got to look for a little target indication, and that's it, you don't know whether it's really a legitimate fault or what. So with the new relay, we can actually pinpoint the fault. The relay are so intelligent, they can actually tell you where is the fault on the line, how many kilometer from this end to there. So in the past we keep on sending line crew, walk -- foot patrol that line, it costs money. That means the down time is too long. It's not feasible from the protection point of view.

Then on that one, in order to make it better, the line protection, at the moment we only share the line PT from the banks, now we're heading the line PT, on the dedicated, if that spot is on that line, that PT will assist the relay to see the direction is the place. At the moment what we have, when there's a

fault on any of the line leaving the Magpie station, it might give us a false tripping. Maybe the line is going to -- somewhere else and it trip, the wrong one, or it can trip all the breaker in the station, so, you know, it cause a bigger problem to analyze it. So that's why we have these two, the line PT and the Magpie protection going at the same time. So what will be done together with the line conductor, restructure and the full replacement. That's the plan to do it together so we don't have too many outages, okay.

The MacKay line and bus protection, that will be grouped together with MacKay TS refurbishment, at the same time, same project. We want to improve the line protection and the bus protection at the moment. When we change all the breaker we have extra CT's, so we have an A and B dedicated, A and B protection. At the moment we only have -- we have an A, A and B protection where it's only sharing the CT, which sometime it give you a false reading, and it cannot sense the direction of the fault. Especially if you have a ring pass -- very complex station so it could false tripping.

Say you have MacKay line down, it has a fault, it might trip a breaker for the line protection out at Third Line to the Sault. I've seen that happen in my last two years, two years in GLP.

So this is what we call the centralized information retrieval. Now, by putting all these in the top of the line relays, we can actually -- using -- spending this money, we have connected interface directly to the relay. So if there's a fault and -- in our office here, we can actually retrieve the information and analyze it and tell the line crew, okay, you have a line to ground fault so many kilometer off from this station. Go there and take a look, okay. Or it's just a simple lightening strike and we say, okay, I look at the fault level and away from it and say, okay, now you can reclose that line. You don't have to worry about it. In the past, the operator are not allowed to reclose the line right away. If you want to send a crew, maybe send ten guy running all over the place. It take a longer time to come back to restore the system. Now we're pretty okay.

MR. CASSAN: Have you quantified how much that's going to save you, because that sounds major?

MR. GAZANKAS: Well, it is because when you look at quantifying it it's tough, because it's a matter of how many faults we have on the system and that sort of thing, and events.

MR. CASSAN: Yeah, I know, but you

can just compare it to the past.

MR. GAZANKAS: Yeah, exactly, we could. To be honest with you, we could get numbers. The biggest driver behind the CIRS was our reporting requirement to the IESO. Every time there's an event we have 48 hours to investigate, head back. Well, for a technologist to drive from here to Anjigamy is, you know, two-and-a-half three hours, then to download the information from all the relays is probably six or seven hours, and then to drive back, he's already gone. The requirement is -- I mean, it's impossible to analyze. So that was the biggest driver behind it and now we're melding it all together. But there is significant savings absolutely in this. Have

we quantified it? We haven't at this point.

MR. LEE: Then to restore the system, if it's happening in December, January, you could have heavy snow storm, my technician is saying, no, no, I can't go there. I'll get stuck, right. So now we are on this system, we can actually retrieve and see, okay, it looks good. It's a legitimate fault. It's okay, then we'll produce a report to IESO, and then we know. At the moment we have a few station that has been connected to the information retrieval, and some station have a newer relay, and I noticed the number of outages is getting less and less from the past. My first year I came, it was a lot. I have to spend lots of time writing report. Now it seems that hardly write one in a month. I had to write three in a month. So I'm quite happy with that after put all this new relay. It's a good job. The transform station protection, we only have A and B. It's very simple. It's not -- it do the job, but we want to improve the system, so with the information retrieval it's -- in the past, when it tripped, got to call and say go take a look. It's okay at the regular working

hour. Sometimes outages always want to happen in the middle of the night, and you call a guy at two o'clock in the morning and he go there, come on, it's just a simple thing, you know, put it back. So it's pretty good to invest that money for that. So the transformer protection, we change it to a better relay in the micro processors, so we have A and B protection. In the previous design they only have -- we cannot separate the A and B. You need a separation between the A protection and B protection. So basically that's -- that station automation is to manage the system and maintain if there's any new software, help create.

MR. GAZANKAS: Also within that station protection automation we're looking at some of our components in there. We do have relays, even micro processor based relays that are aging. The life span, I think, on them are 15 years, and even RRT's we have some out there, terminal units that gather information from the field and then actually transmit information back to open, close breakers. Those are aging as well, so part of this

protection automation for feasibility study is to see, to plan for future years and what's coming.

MR. LEE: Just in case we have something new, better system, we can upgrade our system, study to see how we can move forward.

MR. WRAY: Can I ask, all this work on the lines and all that kind of stuff, does this reduce your line loss at all.

MR. GAZANKAS: No, because we're not re-conductoring.

MR. LAVOIE: I think the biggest impact on transmission line loss has occurred with the transmission reforcement project, where we actually went to a 230 kv voltage and --

MR. WRAY: Did that reduce line loss, Tim?

MR. LAVOIE: Absolutely, on the transmission system, yeah.

MR. LEE: Any questions?

MR. WRAY: Sorry, Tim, that work was done last year?

MR. LAVOIE: '05.

MR. WRAY: '05, that was the big one, 90 million, right?

MR. LEE: Yes. Do you have any questions?

MR. GAZANKAS: Going to our proposed

major maintenance program. Defining it, indicates maintenance projects and programs that are of significant magnitude that do not constitute a capital project, typically major equipment, repair overhauls, that sort of thing, vegetation and management programs, so is the issue with programs would fall in this category. For example, outside of this specifically would be to refurbish the transformer, that sort of thing, on big transformers, if we were doing a major overhaul on it of any magnitude. Completed on the basis of budget review, of course, stakeholder feedback, which is this purpose, eventually moving forward as we get feedback from yourselves. Outage planning and logistical planning, fairly similar to that of the capital program, of course.

MR. WRAY: What's a soils remediation program?

MR. GAZANKAS: Basically, we have an area where we potentially have contaminated soils.

MR. WRAY: Petroleum contamination,

or --

MR. GAZANKAS: Transformers.

MR. LEE: Transformer, oil spill, something that you can see the oil leak over the years, we have to clean that soil up.

MR. WRAY: Where does that soil go?

MR. GAZANKAS: It's actually two things, it could be cleaned on site and actually placed back, that's typically what we like, the process we like to use. And otherwise it can be taken away and then cleaned, by a recognized facility, and they take all the contaminated PCB's, whatever that may be, I don't know, out of the soil.

MR. WRAY: You guys don't use PCB's a lot anymore, though.

MR. GAZANKAS: Absolutely not.

MR. LAVOIE: Soil remediation are things that have been around for years. So you're looking at rehabilitating damage that could have occurred 40 years ago, but

nonetheless, it's there and we've taken responsibility to get it cleaned.

MR. WRAY: Okay.

MR. GAZANKAS: So for next year, of course, forestry vegetation management, in this area, this is a significant number. You know, this is based on historical, what we've done historically in the past. This by no means does our whole system. It's based on a cycle per section, because of the magnitude of our system and obviously the growth in this area. It's not like we're in farmers field in Southern Ontario or that sort of thing. There's a lot of foliage in this area, of course, so we manage it accordingly. So that's a number that we've derived for this forestry vegetation management on transmission system. There is actually forestry vegetation requirement by the IESO, new standard. We report on any vegetation outages and that sort of thing. Last year, I don't think -- even though if we had one last year on the transmission side of things. So these are statistics we'd obviously let you know, this is justified money. We are improving the

reliability of the system based on what we're doing here.

MR. CASSAN: So that number is the number from last year?

MR. GAZANKAS: I believe it's the same we spent last year indeed, yeah. Station overhauls, basically we're looking at, you know, the cycles of our frequency of maintenance. So we'll have a major overhaul at specific station. I think this year we'll have the breakers overhauled at Clergue TS and Magpie, that just constitutes more effort, more time spent on maintenance of these components. It's -- you know, it's a major type overhaul, but it's not the magnitude -- I guess it is major. Soil remediation again is just what we've explained earlier.

MR. CASSAN: That's a pretty small number. Are there particular sites that you're looking at for this year, because that looks -- I've been involved in some petroleum cases, and that number looks a lot like cleaning up a gas station.

MR. GAZANKAS: This here would be basically -- I don't think it's the remediation

part.

MR. LEE: I think it's for testing, testing.

MR. GAZANKAS: Testing. We've gone and done remediation in the past years. Now we can take a step back and say, well, yeah, it's part of prioritizing, you know, the way we do things. So now we're going to go out and we'll sample soils and sites where there had been some minor spills in the past. From that, you know, we'll have a plan, recommendation, developed for us with the cost associated with that moving forward into the next year so we have a decent idea of what it's going to cost us to clean this.

MR. LAVOIE: It will do two things. One, it will allow us to prioritize. Does it need to be done next year? And the second is, it will give us a pretty good idea on scope, exactly what so that we can size this properly.

MR. CASSAN: So this is the analysis phase.

MR. LAVOIE: Exactly.

MR. CASSAN: Got it.

MR. GAZANKAS: That's it for major

maintenance plan for 2007. Any questions? Pass it back to Tim.

MR. LAVOIE: Thanks, Gary.

MR. REID: Sorry, Tim, maybe before we get into that. The bigger picture around this and the rate application. I believe, like, the last rate application approved your '05 and '06 budget, correct? So this -- so your '07 budget is -- are you planning a rate application this year for that, or are you just -- you're going ahead with that with the assumption that it will get retroactively approved in your next rate application sort of thing?

MR. LAVOIE: Yeah. I mean transmission, there's no defined cycle like there is for distribution. However, I understand that, you know, I think the OEB is looking at some sort of frequency. However, having said that, certainly our commitment to the stakeholder or the settlement process was that we would have filed our next rate application by the end of 2008. So at this point there is no rate application planned for GLP out of 2007 at this point.

MR. REID: Okay, that's good.

MR. LAVOIE: All right. The other component of stakeholdering was to discuss the idea of transfer pricing, that was a concept that was talked about at the settlement process, and the agreement amongst the interveners at the time was that in this stakeholdering process we would gather information and feedback where the objective is that we would identify a third party consultant that will develop a report that will assess the accuracy of GLP's cost allocation and transfer pricing to its transmission and generation businesses. So this is where we certainly see the input coming into this consultant and the terms of reference. So I'll input the terms of reference as well as the available consultant to perform their review.

So what we did was, again, just to remind people of the cost sharing that occurs between our transmission and generation businesses is in the following areas. We have an Ontario system control centre which does dispatch operations on behalf of the IESO for our transmission system, simplistic terms, taking equipment in and out of service, and making adjustments under the direction of the IESO.

We have an integrated communications network. Simple terms, fibre optics and that network is shared. We also have a meter service provider, and for transmission for the time being is that the meter service provider is providing service to all the meters that are within our transitional period requirement. So down the road, in other words, over the next few years, there will be no requirement for transmission to have any services from the meter service provider, just for clarity on that. And then the other cost centre so to speak, is our vice-president of Ontario operations administration. Within that is obviously the line management organization. It does meet a common point at the vice-president level, and the cost is shared between the generation side of the business and the regulated side. And that was all discussed in the last rate application.

So the terms of a third party review, we have come up with these points as we think are important points to consider with this third party review. Is a review in a report obviously in writing on the fairness between the transmission, and then suggests a methodology of changes if required, so that we're assessing this thing and describing the methodology, and if some appropriateness needs to be changed, then that will be suggested changes within the report. So obviously it's not just looking at what we have. It's looking at a change if needed.

Maybe just back up. Is there any other components from the terms of reference that -- I guess a couple, I'll bring back a couple of points just for information based on the other past couple of sessions. One was that the -- in this particular case, that the methodology should also include distribution. So we take it one step further, there is a cost sharing in a similar fashion between generation and distribution, same list. Again, it's -- when you're assessing it, why not assess the whole thing, and that was a comment made. I think that's a good point.

MR. WRAY: Tim, what about

distribution transmission? Is that --

MR. LAVOIE: It's been described in all rate applications, absolutely. I mean, this is a division that share costs between transmission and distribution.

MR. WRAY: I'm just suggesting that if the report is commenting on the fairness in that methodology between transmission and generation, and distribution and generation, then what about transmission and distribution?

MR. LAVOIE: I guess my only point, comment, is that it wasn't part of the terms here, but I mean, certainly as a value added point is useful for us as well as interveners in a distribution or transmission. It wasn't raised as an issue on the transmission side, but I can certainly see the point from distribution, and certainly take it under advisement, absolutely.

MR. REID: The word fairness, I guess, I think -- I guess there's kind of two pieces to it, right. There's what do you pay for, and how is it split between different parties. And then the accounting value of what you pay for, then there's the actual sort of service list of what is it that you actually get. I know one of the issues that I think sort of prompted this was the system control costs, and transmission paying a percentage of essentially a fixed percentage of the cost, but -- and the cost has gone up significantly over the past few years. So the transmission cost has gone up a fair amount, but was there really any increase in service as a result of that. So how do you -- how do you offset those two things to say, yeah, we're paying more today, but we're also getting more for that money presumably is the answer, right. So I'm not sure if those words will generate that result, but I guess -- I think that's more of what we're looking for, right?

MR. REID: Let me just -- one thing, I guess, I'm concerned about is that we don't want somebody to just look at it and say, you know, I don't know the basis off the top of my head, I guess. But if they just say, well, you've split the cost according to percent of assets, and, yeah, that's a reasonable way to do it, that isn't going to answer the question, I guess, is where I'm going. So --

MR. LAVOIE: I guess that's -- you know, we -- if you flip back, assess the accuracy. When we were discussing the terms of reference, we used a different word and it was fairness, and that, in my mind, was what we were trying to say, that this is -- I mean, accuracy, it was accounted for correctly. I don't think that's what you want and I don't think that's what I want. I think what we want to -- when we talk about fairness, I think fairness is to Chris's point, you know, are you getting -- is that the right value to assign to that bundle of services, and I -- and I certainly -- our thoughts on fairness was the way to talk to that point.

MR. CASSAN: I wonder if we should put the word value in there.

MR. LAVOIE: Attach the value of it in terms of dollars, I would expect that would certainly be part of the thing, but, sure, yeah, that's not a problem.

MR. CASSAN: One of the things, and I'm not sure if I'm remembering it correctly, but we wanted to determine and understand whether this is actually a way for any of the three branches to earn income by, you know, billing out their line man at a premium to transmission. You know what I mean. You know when you hire a contractor, they charge you a mark-up. And I'm interested in finding out whether there is the same kind of --

MR. LAVOIE: I think here in the pricing methodology, that would talk to things like is it cost based, cost transfer. Is it purely the cost of the operators within the operating, you know, in the room, and just divide that. Is the cost then just divided up or are they marked up. This methodology piece would talk to that mark-up, percentages, how it's calculated.

The consultant for the third party review, the things that we thought were important, this is a review from a financial perspective. At the end of the day it's accounting concepts, accounting designation, and we feel it's an important piece to this thing. So an accountant or an accounting firm, and then the other piece which I thought with the concept of third party, that this isn't affiliated with GLP, an independent review is an independent review.

MR. REID: How far do you take that? Like, is it the accounting firm, different auditor this year than it was two years ago, or is it someone who's never worked for GLP or any of Brookfield's -- you know, I don't have an answer. I'm just asking how are you planning -- how far are you planning to take that.

MR. LAVOIE: I think definitely not our auditor. It wouldn't be someone that we have -- is a part of our business. I think the challenge in completely independent, never worked for the company, I think I'm not going to be able to get a report. I think especially if you look at affiliation from a legal term is, like, Brookfield. So I can tell you that with probably reasonable certainty that most accounting firms have worked for Brookfield at some point in time. So I think that's the challenge. I'm open to a little bit of language around this that we don't -- they don't audit our books. They're not a part of our company.

MR. CASSAN: Well --

MR. LAVOIE: I mean --

MR. CASSAN: It would fall under the new independence rules. The accounting field has changed a lot since --

MR. LAVOIE: Well, absolutely, our auditor wouldn't be able to do it.

MR. CASSAN: Your CA would have to -- your firm would have to do their due diligence and certify that they are independent. So that's, I think, the key. You've got to get the firm to certify that pursuant to their rules that there is no conflict.

MR. LAVOIE: Sure.

MR. CASSAN: They'll do all their internal investigation to make sure there's not and go with that. That's a pretty regulated area right now. What about adding an engineer on that, though. If you're talking about sort of the fairness concept. Do you need somebody who understands the process more than simply the financial numbers?

MR. LAVOIE: A point was brought up at a previous session that is tied into a very similar concept, was that they thought that someone from the industry should be someone who

reviewed it. I think -- I like the concept. I think it's an important concept that an understanding of the business process behind it is taken into account in this report, and I don't think it's meaningful unless it doesn't have that flavour to it. The problem that I see, again, is -- would be how many consultants would have industry or experience that also have an accountant that can certify independence.

MR. CASSAN: That's not what I'm suggesting. What I'm suggesting, perhaps, is that the CA retain -- the CA firm retain an engineer who I would expect you'd be able to find who has some knowledge about the industry, and can say here's what -- here's what they're talking about when they say this. Because I think if you're looking at fairness, you need to understand the relationship between the dollars and the process, in order to ascertain whether the value you're getting is fair.

MR. LAVOIE: Well, certainly we'll

take that down. I guess I would want to make sure that whoever could do that, that expert was also -- I think, would have to be

independent. So I just -- I'm thinking if we use words like -- the report should have -- or the -- when we go out and request this kind of service, that they consider that -- an independent knowledge of the industry would be required in order to complete the report, so that they are either maybe an accountant that did come from that kind of background, I feel, would understand the business and understand the process, or they would retain or do something in order to get that expertise.

MR. CASSAN: How would you do it? How would you do it? You've got that background.

MR. LAVOIE: Yeah, I'm not sure that the back -- when you look at the types of services we're talking about here, I'm not sure that industry specific knowledge is absolute. I think it's a lot of -- like, if you understand the activities that are going on within it, then it becomes a matter of looking at how would you cost this activity.

MR. CASSAN: Comparison analysis.

MR. LAVOIE: Yeah, and I think it does reflect a lot into cost methodology and

cost accounting principles, rather than really having to know specific -- really detailed specifics about the industry.

MR. REID: First I have to say that you need a lawyer on the team. Paul is there for the engineers. I do think that there's a question of the magnitude of what you get. Like, when you're talking about splitting up the VP's cost, yeah, that's really just what's a good basis to use and what's reasonable. Are you not padding that account somehow by putting other things in there that maybe shouldn't be there. When you're talking about system control costs and the operators and saying that, you know, if you're paying a certain percentage of that budget, essentially it relates to a certain percentage of bodies and technical equipment and those kinds of things. I do think you need to have an understanding of a transmission system of this size requires this kind of support. And if you're paying -- like a logical extension, I think, is somebody would say, well, if you're paying X number of dollars because you're doing it as an internal transfer, but you can get that same service

yourself as a business of this size for half of that amount of money, then people are going to say, well, why aren't you doing that instead of that, right. So I do think there needs to be some understanding from that level which really isn't so much of a cost, it's more about what are you actually getting for that amount of money and is it reasonable and that sort of thing. Again, not necessarily an engineer, maybe just that you've got a good -- an accountant with a lot of background in the industry, that might be good enough. But, yeah, something that recognizes the tasks that are being performed and how they fit into the overall picture.

MR. LAVOIE: We'll certainly take that into consideration and try to incorporate that. Those are valid points, absolutely. Timing, our plan, so to fit into our promised deliverable next rate application to -- which will occur in 2008, we thought a reasonable time frame would be to seek a consultant by the end of Q2 of this year, and have a specific deliverable report by the end of Q3, which then gives us the time to build this report into our

application and -- anyway, it fits timing wise with that.

MR. WRAY: I think that's pretty aggressive.

MR. CASSAN: I was going to say, do you think one quarter is enough to get that.

MR. LAVOIE: Well, I think at this point we have to go aggressive. I think it would be -- if at the end of it we get it in Q4, I think we still have time.

MR. WRAY: Whoever the consultant is, is going to tell you, I'm sure, whether they can do it in three months or not, right. But what's your contingency if they -- if you don't get somebody that can do it within three months.

MR. LAVOIE: We'll still proceed with the report and do the best we can.

MR. REID: I think especially if you're adding -- if you're going to add generation and distribution and transmission, distribution, that would be pretty tough.

MR. LAVOIE: I think we can ensure that -- I mean, those ones aren't required, so to speak, so we can definitely have this report

in this fashion delivered. That's the end of the presentation.

MR. CASSAN: What changes to the capital plan have you made, if any, from the previous two stakeholder?

MR. LAVOIE: Sorry?

MR. CASSAN: What changes have you made from the previous two stakeholder meetings?

MR. LAVOIE: The plan has been the same from....

MR. CASSAN: Are you going to make any?

MR. GAZANKAS: Potentially.

MR. LAVOIE: Well, I think as Gary has said, you know, if something occurs in our system that requires a change in priority, then we'll do it. There's nothing that we see at this point to -- that would give us reason to change anything on that plan.

MR. GAZANKAS: The biggest thing is usually it's the smaller projects that change. If something comes up that's small, it's usually in the under 250 range, maybe that's big, you know, we're working very hard and, you

know, you've got to push forward obviously with planning and so forth. But the smaller ones typically, if you see anything you'll see some minor, you know, 50,000, 70,000, maybe $150,000 kind of input. There will be something brought out. We always maintain that 11.2. We don't want to go over and above that if that was the plan, then we have to pull something out and take a look at again the priority. That's why we don't like to have it too dynamic after we have it set, because then we're pushing something into the next year.

MR. CASSAN: Are you going to present any kind of report to the stakeholder group of what's come out of this process? You're recording it. You said you're interested in some of the input. Are you going to say, you know, here's what we've learned and how we intend to proceed next time?

MR. GAZANKAS: I think with the feedback we've got, I think we're going to take that now and revise what we've done here in this presentation, and when we do this next year earlier, obviously, that's one thing obviously right off the top. But we'll take

down and re --

MR. LAVOIE: Our intention is to build on the process on an annual basis.

MR. CASSAN: One of the suggestions that I would have would be to have this kind of a meeting in October or November of this year, planning forward for '08.

MR. LAVOIE: Thanks for bringing it up. It's certainly something that I was going to close with is that I think that's one thing we've definitely learned. We're dealing with a larger group, you know, and obviously schedules and time frames. You can't always pull everybody together you want. And, you know, this -- we would have liked to have this much earlier than we are right now.

MR. CASSAN: If we could now start saying, you know, second week in November meet at the Water Tower, you know, you'll have a better turnout guarantied.

MR. LAVOIE: I guess thankfully, I mean, I think I can count the number of direct customers and I think three, out of all the interveners and direct customers maybe three that actually chose not to partake. So really

I'm glad that it did work out in terms of getting people, not all together at the same time, which I think was some of the things that we thought was a good thing. So I think that's an important point and taken we -- our plan is, and we've already talked about it, to get things together early. Can we say October, November, I think that's sort of what we were thinking, and we'll definitely get something out much earlier than what we did this time.

MR. CASSAN: I think, you know, it seems like you've got an interested group of stakeholders, and I think you can take great advantage of that, sort of bouncing ideas off them, and that's going to really improve your political capital, no question.

MR. LAVOIE: Absolutely. Great.

MR. REID: Just another interest question. Do you have sort of magnitude how much you're doing in-house verses outside?

MR. GAZANKAS: Well --

MR. REID: A lot of it is equipment cost too, right.

MR. GAZANKAS: It is.

MR. LAVOIE: A good portion of it.

MR. GAZANKAS: Is out. We don't have a very big group in-house, and really their time is for maintenance, when you think of how big, you know, transmission and distribution system.

MR. LAVOIE: Having said that, though, we do have a few projects of the smaller magnitude that they are working on.

MR. CASSAN: It's not really a maintenance question or capital, but have you looked at the idea of changing Dubreuil's line from distribution to transmission? You don't have to have this on the record. It's just something that we discussed at the end of the settlement conference.

MR. LAVOIE: Why don't we talk to you briefly afterwards.

MR. WRAY: Well, thanks, guys.

MR. LAVOIE: Thank you for coming.

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CERTIFIED CORRECT:

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Francine Wolfe, CSR

GREAT LAKES POWER

STAKEHOLDERS MEETING 2008

Monday, January 14, 2008

PEGGY LUND: Thank you. Welcome everyone. My name is Peggy Lund and I'm in customer relations at Great Lakes Power. I'd like to introduce to you our speakers. Probably all of you know most of the faces here from last year's meeting if you attended, but we have Alex Lee right here. He's our Manager of Transmission Engineering. We have Gary Gazankas, he's our Transmission System Planner; and Tim Lavoie is our General Manager sitting over here. So we do welcome you, even on a snowy day. I think most of those who said they would be attending are here, so thank you very much.

The purpose of the stakeholder session that we're having is preliminarily to discuss our annual program with all of you to let you know what our capital plans are, as well as our major maintenance for our transmission system. So this is what we'll be discussing today. It's also something that we wanted to reiterate to you, the fact that we are still committed to retaining the independent third party as part of our rate application that will be submitted. The third party will report on accuracy and cost allocation, and in transfer pricing between our transmission and our generation businesses. So very much we're still committed to doing that.

We consider all of our stakeholders, our direct customers also, our stakeholders in the process. Part of the idea that we also do on the annual basis is we want to meet with those direct customers, and very much when we have discussions with those direct customers, and many of you here are part of that group, we want to make sure that we keep our lines of communication open with this group of people. We want to make sure that we develop plans around outages, if need be, as part of our capital work and part of our maintenance, so that you are aware and we can work with you individually around timing and so forth.

Also, we like to discuss individual needs in these meetings. So it's important that we have the individual meetings also. For those who we haven't already set up meetings this year with our direct customers, either today I can set up a tentative time, or I'll be contacting you directly by phone after this meeting in order to see if we can't get together with you on that. It is our customer's choice whether to attend the stakeholder meetings or whether to have the individual meetings, but we just want to make sure that we're clear that we're offering both to direct customers. With that being said, Tim, I guess it's your time to take the floor.

TIM LAVOIE: Great, thanks, Peggy. Again, welcome, everybody. Certainly as general manager of Great Lakes Power I look forward to these sessions, because it's an opportunity for myself to interface directly with those that we serve as well as those that are interested in the utility, that being transmission of Great Lakes Power Limited.

One of the things that struck me last year was we put together our stakeholdering process based on basically an agreement that we had with the last rate application. But as part of that it was our first cut of it and we certainly had some input with respect to what the session, the content of the session, and some of the things that the stakeholders would like to see with respect to future stakeholdering. So some of the input that we had in terms of a recap of last year was in our capital and maintenance plan development, a little better depth in terms of how projects are selected, how projects are prioritized, and we've taken a stab at that for this year to give a little better flavour on how the utility looks at things from a development perspective, as well as our prioritization of capital projects. And then what we're calling our future outlook is basically a data base of projects that we have, and we'll give you a little bit of depth of what we're seeing in terms of the horizon of capital projects for upcoming in the future, beyond 2008.

So first on plan development, basically we look at our assets of our system. It's a comprehensive look at our system so we have basically all of the assets in our system. We look at the integrity of the system, performance of it, and we assess them on an ongoing basis. So assessment is a multifaceted approach where we look at field and aerial inspections, infrared inspections, condition assessment, and that can be condition assessments that we've done internally with our own staff and our engineering staff, or externally consultant based, engineering consultants that are specialized in certain areas. We rely on our operations and maintenance reports that come in from the field. We rely heavily on our trade staff in the field to be eyes and ears with respect to our assets and how they're operating and the conditions of them and report back those types of things to us, take those into consideration. Remaining life estimates, it's listed assets that we have. We estimate and try to re-estimate remaining useful life and economic life of those assets so we've got at least a guideline with respect to what we would expect to see out of our assets, and then base a lot of the details on the assessments of them.

System planning activities, the system is a dynamic system. There are things added, there are loads added, there are supplies added to the system. We have to take those into account and they do drive a lot of what we need to do, at least in the future.

Direct customer input and stakeholdering, again this is the form that we can use for that type of feedback on the plan itself as well as the direction that we're taking it. Then lastly, certainly not least, the customer delivery point performance standards, which is a system that -- basically a system that has been created and approved by the Ontario Energy Board with respect to delivery points and how we can interface with the direct customers with respect to the performance of those delivery points.

Prioritization of the projects are based on a set of criteria. The criteria that we use are first and foremost the public and worker safety issues, to deal with any problems that might be out there or situations that we want to avoid. Addressing significant environmental issues, environmental perspectives on our assets and, of course, maintaining our diligence in that area with respect to any changing environmental legislation. Consideration of equipment age, again, how old is this equipment. Is it performing the way we need to with respect to current standards? And kind of leads into the next one, compliance with legislative and regulatory requirements. Certainly the IESO has a series of market rules, and the market rules do talk a lot about technical requirements and performance that they would expect from the system. And being part of a market participation in that with respect to the IESO, we need to maintain or be heading in the direction of compliance in all areas with respect to the market rules.

Improving system reliability, maintainability and operability, so on reliability, of course, for the local supplies to our customers is a very important point that we want to continue to invest in an area that maintains or increases our reliability. Maintainability, we need to be able to maintain our equipment, so we take into aspects of developing projects that allow us to access to our equipment without minimal amount of interruption to the customer and make it such that we can maintain our assets in all major respects. Operability, I mentioned IESO operational criteria as well as our own criteria with respect to ensuring that we can operate our equipment under all conditions. So that's a prioritization of projects that we have.

Second piece of this, which is an important piece, is a logistics and efficiency reviews. There are times when you have a project that you could consider an important project to do, but due to lead time of materials, equipment availability or manpower, internal, external, it becomes a very challenging thing to put together with respect to the project, and synergies with respect to doing a project in an efficient manner. So there are things that we're doing -- there are a number of projects that need to occur at a particular site that may not necessarily fit all of the prioritization, but at the same time if we're interrupting a customer to do this, it probably makes a lot of sense to capture as much as we can in that particular site to deal with outage situation where we can deal with

maybe more, or sometimes a more focused

approach to capital at that particular site. So a little bit of juggling goes on in the efficiency and logistics categorizations that allow us to slide things reasonably within a couple of years to achieve the best outcome. So the projects are ranked based on this criteria, and then a logistics and efficiency factors overlay. So it represents a complete approach to developing projects and we think a pretty comprehensive approach.

So the expected outcome, we want to best allocate our resources to meet the greatest needs, so we use the system that we described earlier. The risks are managed in a systematic manner. We believe unexpected expenditures are significantly reduced and the outlook continues to be developed as conditions change. Regulatory requirements change, asset assessments bring new information to the table, and, of course, stakeholder concerns and input with respect to our process and procedures. So if there's any way we can incorporate those at the end of the day to make, again, the best allocation of resources to the greatest needs.

Our proposed capital budget for 2008 is about

8.6 million.

And I'll turn the floor over to Gary who will take us through the detailed projects.

GARY GAZANKAS: Thanks, Tim. All right. What I'm going to discuss now is 2008, what we're proposing to do this year. Systematically each -- there's a set of groups here. We've got compliance, refurbishing, replacement, system improvement, and tools and equipment replacement. The first category falls under compliance. These projects are required to meet current standards. The first one, Steelton TS ground grid refurbishment, that's located here in Sault Ste. Marie down at Patrick Street by ASI. We feel that there's a need to improve the ground grid at that site. We believe from reports that we've had done for us that there's 'I triple E' issues. They're not within 'I triple E' standards and we have to stay in touch with potential issues we believe at this point. So our intent there is to bring that station up to standard. That's the first one. Again, if anyone's got any questions as I go forward, just by all means

interject so we can discuss this as we go. No sense saving questions to the end.

CHARLIE LEISHMAN: Gary, was that with respect to gravel, amount of gravel, the six inch?

GARY GAZANKAS: That will definitely help. We have found during cable locates with the breaker replacement projects, we had assumed that there was good ground grid in place during the cable locates. We found the ground grid to be insufficient. So from that we've done some tests and we believe that obviously that's part of it, vegetation, getting rid of all that, and of course, bringing -- there is an adequate stone there. I think we need at least six inches of crushed stone, even ESA, so that's part of it. But again, we'll get a full design done and that may require additional copper and ground rods at every three meters, whatever the design comes in at. So that's the first one.

The next one is oil containment refurbishment. Last year we installed oil containment at Goulais, and actually that was a major milestone for us. In our transmission

system we now have no other oil containment to be installed. What we did during this in parallel is we hired a consultant firm to go through and just to have a look at our existing containment, because these -- I guess the systems that were designed in the past may not meet the current needs. So what we've done is identified any issues we have remaining with the -- with the remaining oil containment, and we're going to go through and make sure we're in a hundred percent compliance with the Ministry of Environment.

Next one, right away management data base is a creation of -- IESO requires an annual report with respect to vegetation management, and we do have a fairly significantly sized system, and to manage that we believe we need to collect electronic data and manage the system accordingly moving forward to become more effective at managing that right away.

The last one is SF6 gas storage facility. This will go up Third Line TS here in Sault Ste. Marie. We'll, in 2010, reach another milestone where we'll have no more bulk

oil breakers in our system and everything will be that of the SF6. So with that increased SF6 gas into the system, we feel that we improved or enhanced the storage and handling facility just to ensure our employee safety, make sure we're meeting our regulatory reporting requirements to the Ministry of the Environment as well.

Next category is under the refurbishment replacement section. The first two you've seen last year, and they're a continuation of last year's projects as we put forward last year. Third Line TS is again in Sault Ste. Marie, MacKay TS is the Montreal River area. These are breaker and switch replacements. These are old bulk oil end of life breaker replacements. We also at the switches as well, there are a number of issues surrounding the breakers and switches on both places. Voltage concerns is one where they have a rating of 121 KV maximum now, all switches and breakers. There's the interrupting capability, is not as per IESO as well. Getting spare parts should one, I guess, not operate correctly is a challenge now, and

maintaining them properly and handling the oil is another issue. So doing many major overhauls is a costly venture. So moving forward, our maintenance cycle should decrease where the frequencies would be, you know, as opposed to a four year or a three year, we would -- that would increase to a six year. So less maintenance on any new equipment coming in, and more condition based maintenance where we would look at operations and faults through that breaker on any given time. Manufacturers nowadays with respect to the new SF6 breakers, they're basically saying not to touch them. They're saying to exercise the manual (sic) leave it, but basically, you know, use your judgement in terms of how much it's been operated and the fault levels that have actually gone through it.

The next one, T2 transformer overhaul at Third Line. Last year we replaced a transformer successfully there so we have a new transformer. This is the other one, and basically what this is going to do is extend the life of this transformer. We feel that there's no issue with it. We do have T1, the

older transformer as our system spare. Mind you, because of the fault we had on the reactor on the tertiary winding, we can't use it in that manner. So it's a system spare for Third

Line and MacKay only and not Echo River, but it is a system spare nonetheless. If we need parts that we can't get, we will basically take it off the T1 transformer and refurbish this T2 transformer. So basically what this is doing is extending the life of that transformer. We feel that it's still a decent transformer and that we don't need to purchase a new one as of yet. I think you'll see that moving forward in five or ten years, eventually the purchase of another transformer, and that's depending on load growth in the area as well. That's that one. Northern Avenue --

SPEAKER FROM THE FLOOR: Just before you leave that one, are you expecting bus outages for extended periods in that or how are you logistically planning it?

GARY GAZANKAS: No, we shouldn't have bus outages, and at this point bus outages should be probably kept to a day. That's basically all we can get for the most part

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anyway, just because of system loading and so forth, and LSP being up or down. So the loading on the Algoma circuits is the big issue for the bus outages, so I wouldn't suspect it would cause that much disruption. There will be bus outages in need.

SPEAKER FROM THE FLOOR: I guess maybe a better question would be, load restrictions on the bus caps or size?

CHARLIE LEISHMAN: Has the time line been put in?

GARY GAZANKAS: Tie breaker?

CHARLIE LEISHMAN: Yeah, tie breaker from north and southwest.

GARY GAZANKAS: The project has been completed. It's not in service yet, we're just waiting, working with the IESO on that right now. We're suspecting it's going to be in service by March. We've also got the Algoma load rejection, that project as well, that's -- that was put forward in the past. That's another one of interest to you, Charlie. But sorry, Kevin.

SPEAKER FROM THE FLOOR: I'm thinking more in the request we've been receiving to

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alter our load for withdrawal, in terms of bus side.

GARY GAZANKAS: We're hoping to have that configuration back to normal by March or April. We're hoping to have resolved issues with the bus by April. So there will be -- and with respect to this transformer, I -- things have to happen in stages where the bus resolution will have to come first and will come first, and the transformer will be after the fact. We are headed into a breaker replacement at Third Line, so strategically what we'll do is when we're replacing the transformer breakers for T2, at that point that's when we'll do the overhaul on it. It makes sense to do it in that manner. So the load will hopefully have been shifted back to normal historical loading configuration by the time we go into that project.

Transformer overhaul at Northern Avenue TS, this is the same idea here. This is right outside our office. We believe that it is in need of major overhaul, and in doing so we believe it's going to extend the life of that transformer.

The next one, minor fixed assets, and you'll also see transmission line emergency work and building upgrades. You'll see this is repetitive. This was last year as well. These are based on historical spending trends.

Minor fixed assets, you're looking at, you know, drawings, cabinets, storage at the TS's, just that sort of -- that's an example of what we'd be spending that money on, those monies on. Transmission line emergency work, every year we typically could have an issue. Not last year, but the year before I believe we had, I think, you guys were down for the day. It wasn't last year, it was the year before we had a failure on the cross arm. So that's what this -- that's what this is for and that's -- and it's not like we're anticipating it, however, storm damage, it is classed as emergency work. So that's what those dollars are for. Building upgrades, same thing, historical spending, that's what these are based on. KTS, if it needs a new roof, if it's leaking. If it's a major ticket, that sort of thing, that's what those monies are slotted for, allotted for.

The next one is system improvement. The first project, the Algoma lines engineering, what's happening right now is it's always been happening. We found obviously that with the new requirements the IESO and the N minus one, that it seems as though with the loading in that corridor, it wasn't designed for N minus one, where at any given time with LSP down and ASI, and GP Flakeboard and St. Mary's loading up, we are overloading more into N minus one. And high -- lack of generation, high loading. So what's happening here and for the customers in that corridor, based on our customer connection process which is now posted, I believe, Alex, on our website.

ALEX LEE: CCP.

GARY GAZANKAS: We'll probably be sending our letters very shortly with respect to that CCP, customer connection process, and we'll be going into an expansion study. This is based on reviewing the load, the total normal supply capacity verses the historical load in that area, and it seems as though we need to look further into what we're going to do down there moving forward. So I guess one

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customer down there again can expect a letter moving forward with respect to that expansion study. The customer connection process is now posted on our website, so if you want to take a look at that and how we go about doing and moving forward with this process, it is there for your information.

Projects pre-engineering, this is, again, historical value, but in order for us to meet timelines and project schedules, we have to start our pre-engineering early every year to ensure that we have a smooth transition and a flow of projects the following year. So this is historical spending. This is getting prepared for the upcoming year.

The next project, station protection replacement, this is a review of our protections in our system. We will have no more electrical mechanical relays in this system after next year. And having said that, we do have some vintage microprocessor based relays as well. So we've got to take a look historically and statistically on these -- on the earlier microprocessor based relays. Meantime between failure and compile a

comprehensive plan or develop a comprehensive plan of how we want it to move forward, possibly potentially moving -- the moving of replacements of these older microprocessor based relays. This will give us a really good indication of what we have in the system. I guess we know that now, but it will help us plan the replacement moving forward, and this is system wide.

T2 on-line monitoring at MacKay TS. Last year, this was in the budget last year for the T1 or T2 transformer at Third Line, and it's a dissolved gas analysis on-line monitor. And it samples the gas continuously, or the oil continuously, and provides on-line monitoring for the dissolved gasses in the transformer, which is really a look into the transformer and the condition and what's happening inside of it. And the installation was fairly successful -- well, it was extremely successful last year, and we believe that this is a way of extending the life of the assets, by getting a very comprehensive look of what's happening on the inside of it. It's very accurate and we want to install this at MacKay TS on that new

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transformer just so we can trend its condition moving forward. Any questions?

The last one, facilities, tools and equipment, again the components, you've seen that last year as well. This would be purchase of spare relay, potentially a spare breaker. You know, SF6 breakers are running somewhere between 70 and $80,000 now. So potentially if we need a spare breaker we can get one, or a PT or a CT, that sort of thing. So that's what this is, this falls under. Relays are fairly expensive nowadays. This is based on historical spending as well.

The last one is just an enhancement of the existing data base we have now. We did a Lidar of our systems years back and that was inputted in a CAD program, and it's a lines plan and profile management system, and this is really just completing our system. It hasn't been input in the past, all the lines were done, but hadn't been input, so this is where we're moving forward with this one to have the complete package for our engineering team.

The next section, this was based on some input last year from the stakeholders.

This is an outlook of what we're looking at doing, moving forward. Basically, what you've just seen for 2008 was ranked against all of these projects. A lot of them are similar in their continuation of something that already started. However, everything is a blank slate. We have a list of projects. We rank them on the criteria and then we look at what makes sense, what's reasonable, look at the logistics and the efficiency. These projects were all on the level playing field going into this year, and these are the ones that we didn't chose to go with this year for one reason or another, the criteria and the logistics and efficiency. One specifically, obviously, was the transmission line replacement. It ranked -- ranks fairly high, but that's a very complex job in planning and nature and moving forward to do any refurbishment on the Algoma circuits. We have PUC under bill. We probably would have to go to leave to construct with the OEB. There's a lot involved and that's going to be fairly comprehensive in planning outages with our customers potentially, if any. So we felt that we needed measures in place first. For

example, the tie breaker and the load rejection, automatic load rejection, we need those things in before going into this project. Plus the enhancement of the current caring capability of the breakers, the ratings of the breakers, we didn't want them to be the limiting factor. So that's, I guess, one example of the project that was on the cusp that wasn't chosen for 2008. That was pushed into 2007 based on the ranking and logistics.

I can go through each of these. The right-of-way management, IESO reporting standards. Once we do our data base, then moving forward, probably this is going to involve enhanced mapping, maybe GIS, that sort of thing, but based on what we get this year, we'll have a better plan. These are proposed, so we'll have a better idea of where we're going to go with this moving forward. The bus replacement at Third Line TS, we have identified some issues there, so likely what will happen is that will move forward next year with the bus replacement. That's going to involve a lot of scheduling, of course, outages and so forth, because the existing

configuration is -- I guess it's very hard to work with at this point. So we're looking at a full bus replacement there with IBDS or something similar potentially, just to make it more operable, more maintainable and that sort of thing. As well, we'd like the bus to not be the limiting factor. It is a critical asset. It is a network asset. If we have 2,000 amp breakers, we don't want bus that is limiting.

We'd like equipment to be the limiting factor.

The next project is at Third Line TS. This is really a place holder and we're looking into this right now. The cap banks right now we have issue with on the tertiary of the transformers, and we believe that they require replacement because the rating on the caps are inadequate, the voltage rating. They're based on 20 KV ultimately, and with the higher system voltages, they're subject to older voltages and that's normally all the time. Then you have a fault on one of the caps, and all of a sudden the voltage goes up even higher and they're subject to that much more overvoltage.

What we're looking at here, I think this is still really in conceptual stages. We

look at the system swings and load, and we're talking not GLP system. We're looking at the east west tie and tie them to Toronto. When you look at low loading and heavy loading, at specific times of the day the voltages are all over the place. So I think with respect to that we can, I think, better manage the voltage on the 115 KV bus with the static bar compensation, replacement caps at Third Line, and potentially remove the caps at -- on the PUC properties. And again, this is conceptual. I think this is what would be best case scenario, because then it's -- we no longer have to maintain equipment that's not on our property. I think that's our desired outcome. With the new transformer we got a bigger rating on the tertiary, so we do have the capability of more -- of an additional of our output at TS. So that's what we're conceptually looking at this year. We don't know, I guess it's -- you have to do all the engineering on it yet, but it's proposed. And only for the reason that we believe we have to replace the capacitor banks, anyways, so.

The next one is just protections

upgrades at Echo River TS, and that's removing the last of the microprocessor based -- or sorry, the electrical -- electromechanical relays. The relays are still decent. They're maintained, however, we do have reporting requirements with the IESO. The reason why these were last on the list is because Echo River is -- if we do have an event and we have to report within 48 hours, it's close. That's why we decided to do our information retrieval.

Everything's in place, but we still can't grab data from those relays. They're not smart. So that's why this one was left for last, because Echo River's 20 minutes away. It's not Anjigami, Wawa, which is three hours away. There's no way we can meet that reporting requirement, that's why we reported in that manner. Questions so far?

Third Line TS switch yard refurbishment, this is just again -- this year we're doing seven breakers. I should have went back and did that MacKay. We're removing five, replacing five breakers. Third Line we're only doing seven. We feel that putting it in stages is less impact to the customers, and there's

also resource issues internally, externally that we have to manage as well. And we think that seven, replacing seven is acceptable, and so this is a continuation of that project where we have 14 there, 14 bulk oil breakers. We'll just replace the last seven following. We're still not sure which one. Next year you'll see how we've decided or ranked the bus replacement and/or the switch line, switch gear because the bus refurbishment is so complex in nature, I don't think I would want to tackle both at the same time. I've got to look into that to see what the synergies are, and if it does make sense for me to do it, we may. It's still up in the air. We've got to look into that this year and do a lot of planning around that.

Then again the last one I mentioned earlier with respect to historical design. We do have very old structures from Third Line to Northern Avenue, all wood structures. So those have to be replaced outside of the N minus one even. So these are -- this isn't a load growth capacity issue, this is existing historical loads. This is based on end of life and not meeting current requirements with the IESO, but

again this would be a very challenging project. Next I'll hand it over to Alex where he will discuss the 2008, thanks.

ALEX LEE: Thank you, Gary. For the major maintenance defined, major maintenance include maintenance projects or programs that are of significant magnitude that do not constitute capital project. Major equipment repair overall project, vegetation management program, and soil remediation project fall under this category. We plan to complete the project on the basis of budget review, stakeholder feedback, and outage planning and logistic planning. And all this major maintenance, we try to minimize any outage when we do the maintenance. We try to coordinate with other projects in conjunction together. And here on the major maintenance plan we have the forestry vegetation management, insulator washing, and Clergue and Algoma circuit for the clear line and Algoma circuit. We have our insulators have a lot of contamination due to the nature of the environment around the area. Then we have switch gear inspection in Watson TS. We have few report from our technicians and

identify that some of the breakers might have some crackings and in the bus, so that's why we need more inspection and try to fix it and maintain it.

Then we have transformers, transmissions circuit infrared scan. This is basically we have a fly over the transmission to scan any hot spot or weak spot that we need to address the issue. Then we have soil remediation activity, this is ongoing and year to year we have to go check to see to make sure our soil -- or oil containments are in good working order. That concludes my -- do you have any questions?

TIM LAVOIE: Great, thanks Al. I guess as a recap. Last year we had quite a section in the presentation dealing with the third party review with respect to allocation mechanism between transmission and generation. And certainly a lot of feedback came from the stakeholdering process, which we incorporated into the RFP for the study. I can say at this point that our study has been coming later -- in later than what we had originally anticipated. A Q3 time frame has been deferred

to about a Q1, Q2 of this year. So I can safely say that the RFP has been issued, that the independent consultant has been chosen, and they're now underway with respect to the study, and I expect the report out again no later than Q2 of this year. I don't know if there's anything other than that. So at this point, any questions that the group may have. Dave?

DAVE JENNINGS: 2007, if I recall, I think the budget was about $11 million.

TIM LAVOIE: Yes.

DAVE JENNINGS: How close to budget

were you and how many projects -- I think there are six or seven major projects. Have they all been completed?

TIM LAVOIE: I can safely say we have achieved fairly close to the budget number that we had set out to do. Certainly the big projects, and I can defer the question to Gary with respect to specifics, but all the major projects have achieved the scope we have. The two bigger projects, again, were the MacKay and Third Line projects were a multi year, but we did achieve what scope we had wanted to for the budget dollars we had allotted for in 2007.

GARY GAZANKAS: The transformer specifically is a big one that's in and done. So that's been completed on time and on budget. And Tim had mentioned MacKay and Third Line, we wanted to get the cable trenching system in. It's in and both stations are done. We had some civil work to do at MacKay, and that's all complete. So basically the target dollars that we had set forth last year in terms of spending for those projects, we achieved for the most part what we wanted to do.

DAVE JENNINGS: One sort of interest

is the transmission line structure at the Magpie.

GARY GAZANKAS: That's a good example. That's one that did not -- I guess it's not in the multi million dollar range. I'm sorry, I didn't pay attention to that. We had a lot of planning with respect to that project last year. We had extreme difficulty in coordinating outages with our customer and the generators. So we treat the customer and the generators the same way. There's no -- last year we didn't manage to get the outages we required to replace those structures. That

project is carrying on this year. We are talking now. We've been talking since early December to make sure that we're moving forward with that. It's just a select number of structures plus woodpecker holes and some insulators that need replacing. So that I hope to report to you next year that that will be done, and it looks like it will be.

TIM LAVOIE: It certainly speaks to the complexity of some of the jobs. Gary talks about complexity on the Algoma circuits, you know, very similar issue. It's dealing with outages and coordination and it -- we definitely have to -- we recognize that we need to be at the table a lot ahead of the game in order to make sure these things occur.

GARY GAZANKAS: Any other examples I missed?

CHARLIE LEISHMAN: Gary, you mentioned the automatic load rejection scheme. How does that correlate with the $308,000 allocated for the Algoma line engineering?

GARY GAZANKAS: It doesn't. What it does, the two separate entities entirely. The automatic LR scheme is to be in place shortly.

In our customer meetings I think they've accepted so far, ASI has, direct customers. Anyway, when we do our direct meetings we certainly have to discuss exactly that functionality because it was put forth years back and it's finally in its implementation stage. It's just pending further IESO review, typically beat these things to death. So we need to have that in place. That's going to facilitate us in the -- moving forward in order to plan for the Algoma circuits replacement. In that regard it's -- it has to come before we go into that project, project basically. But that's the only correlation. It's not a part of that job. It's already something that is -- has been completed. It's pretty much ready to go, just waiting for IESO and, of course, customer approval and so forth. Does that answer? Is that okay?

CHARLIE LEISHMAN: Yeah, good. Thank you.

MR. GAZANKAS: Quiet bunch, must be Monday.

DAVE JENNINGS: I guess at the start you said the budget was 8.6 and you added

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another 2.2. Is that part of that 8.6 or are you back up at 11 million this year?

ALEX LEE: That's maintenance, not capital.

DAVE JENNINGS: 8.6 is capital.

TIM LAVOIE: And then the 2.2 under major maintenance, yeah. Certainly for those who are direct customers here, we certainly look forward to our direct customer meetings. Again, that's been our process that we fine tuned based on feedback over the years, and we certainly look forward to those meetings coming up. I had endeavored to make this stakeholder meeting, advance it into the fall of '07. It's an extremely challenging time of year for us, but I do believe that's the right time of year for it, prior to the start of the fiscal. I'll credit myself one month, but again our plan for next year is to have some correspondence out November, early November timeframe so that we can achieve this before the end of the year. So that's our -- that's again our intent next year, just to give some expectation for next year. Again, I appreciate everyone's time here today and look forward to a prosperous 2008.

Thank you.

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CERTIFIED CORRECT:

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Francine Wolfe, CSR

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GV/pv

GLPL TRANSMISSION STAKEHOLDER SESSION

HELD AT: Ogilvy Renault
Royal Bank Plaza,
South Tower
200 Bay Street
Suite 3800
Boardroom D

HELD ON: January 16, 2008

A P P E A R A N C E S:

GARY GAZANKAS)	-- For Great Lake Power
TIM LAVOIE)	
PEGGY LUND)	
ALEX LEE)	
CHARLES KEIZER	-- Counsel for Great Lakes Power
HENRY ANDRÉ	-- With Hydro One Networks Inc.
MICHAEL R. BUONAGURO	-- Counsel for VECC
DAVID MacINTOSH	-- With Energy Probe Research Foundation
CARL BURRELL	-- With IESO

INDEX OF PROCEEDINGS

--- upon convening at 10:00 a.m.

--- upon commencing at 10:16 a.m.

INTRODUCTION BY MS. LUND:

MS. LUND: Thank you very much for coming out. What I will do first is introduce our group who is here today from Great Lakes Power. Tim Lavoie is our General Manager. Gary Gazankas is our Transmission System Planner. Myself, Peggy Lund, I am Customer Relations at Great Lakes Power. And Alex Lee sitting right down here is our Manager Transmission of Engineering.

One of the reasons for...the object of these sessions that we are having is primarily because we want to make sure that we put out our annual budget, our annual program and you can see what sort of capital work we are going to be accomplishing in 2008 as well as what sort of major maintenance that we are accomplishing. We also wanted to make sure that we reiterated to everyone here that we do very much have the commitment that we will be retaining an independent third party to review and report the accuracy of our cost allegations and transfers between our generation business as well as our transmission, between those two businesses. That particular commitment will be basically in place and with the filing of our next rate applications and transmissions. So, I just wanted to make sure you were aware of that.

Also, on top of these meetings, we will be contacting each of our direct customers. They were invited to these meetings as well, as we are going to be having meetings with them if they are so inclined. Because we feel that it is very important that we continue keeping communication lines open with them. We do consider them to be our stakeholders also. And we also want to work with them on an individual basis because sometimes there is concerns between the connections and outages that may occur just due to maintenance or capital work that we want to make sure that we inform the customers very much directly with what sort of programs we have in place. So those meetings will take place after these particular stakeholder meetings, just so that you are aware of that. And with that being said, Tim is going to give the next few screen presentations.

PRESENTATION BY MR. LAVOIE:

MR. LAVOIE: Thanks, Peggy. Again,

welcome everyone. It is nice to see some familiar faces at our second annual stakeholder session. I guess one of the things that we certainly started this stakeholder session with, an agreement as part of the settlement of our last transmission rate application, we committed to take the stakeholdering forward, some of the discussions at the stakeholder sessions last year provided some input in sort of the general content makeup of the sessions and so we have taken this input into account.

I think it is important to enhance our presentation to deliver information in a format and address some questions that come up during the session. So we have adapted some of the feedback that we had received last year and just in some eye-level discussion, we had some questions around the planned development in terms of our capital plan itself and so we have got a little bit deeper information with respect to how to get a better understanding of how that has developed.

The plan, in terms of its prioritization and how that works and then this thing we call our "Future Outlook." I will give you a little more future looking context to some of the capital projects that we have anticipated in doing in the future. And I guess the other thing around timing of this stakeholdering, I think are some of the discussion last year around the timing of the stakeholdering session which occurred in...Carl?

MR. BURRELL: Quick question. "Future Outlook," what sort of time horizon are you thinking of? Is it within five years, ten years?

MR. LAVOIE: We have about a five to ten year kind of a vision on the list and when we get to the list, we will see that it is some of the major initiatives that we are thinking about. The timing of this session, wanted to assure the group that our direction is to move this thing into the year previous to the year that we are talking about. The stakeholder session that occurred last year was in the February to April time frame. Clearly, we want to move this into the November time frame. Unfortunately for us, it's an incredibly busy time of year but nonetheless, it is our intent to move it there, just to set some expectation for the group that that is our intent. Peggy assures me that we will have invitations out in the late October, early November time frame.

Our planned development in our asset management strategy, integrity of each asset and the system performance are assessed on an ongoing basis so obviously, the integrity of our system is a very important piece of what we want to achieve as a transmitter. So we have to do this in various ways. So we try to use as much information that we have in-house but we do rely on consultants and contractors to help us out in a few areas.

This assessment is based on a field and aerial inspection, infrared inspection, condition assessments and condition assessment can be done with either in-house engineering, in-house field staff or external third party consultants or engineering firms that help us out with some of the specific areas of expertise.

Our maintenance and operation reports, so as we are operating and maintaining our equipment, any reports that come back from the field with respect to asset condition repairs, corrective maintenance would be incorporated into our plan and potentially have a capital impact depending on the assessment.

Remaining life estimates give us the age of the equipment, give us some idea of what we should expect, the types of equipment, manufactured dates, manufactured specifications certain areas and types of equipment do give us some idea of what we could expect in terms of remaining useful light.

System planning activities, taking account our entire system and how its functioning integrated with Hydro One, the ISO market rules specifications and allows us to determine what sort of enhancements to the system might be required.

Direct customer input, certainly direct customers and meeting the needs and expectations of the customers we try to incorporate into our planning. And then something a little more recently submitted through an OEB process is the Customer Delivery Point Performance Standards, the tracking of those standards, the sharing of that information to direct customers and taking that into account in the networks.

Prioritization of projects based on a criteria. We tried to look at aspects of prioritzation, public safety, safety of workers, environmental aspects and issues, consideration of equipment age, compliance with legislative and regulatory requirements, improving reliability, maintainability and operability. So looking at being able to design a system in all cases we can maintain and operate without interrupting customers and their operation is important prioritization.

Then we look at a review of projects from a logistics and efficiency standpoint. If there are opportunities...first off, adequacy of resource in lead time of equipment, manpower availability, internal and external. There are certain trends in the market place with respect to lead times that need to be taken into account or taken very seriously in order to achieve the plan that you have. And Synergies, if you have a situation where you are going to reduce your capacities or look at interrupting customers, we need to look at synergies. So how can we wrap as much into an interruption in a customer sense as possible. So it gives you a little bit of guide with respect to deferring a project or accelerating a certain project in order to deal with a certain site at a particular time. So that assessment is done to be able to deliver the capital project as effectively and efficiently as we can. So that criteria, projects are ranked. A year's worth of capital is compiled on that basis.

Expected outcome, obviously we want to achieve the best allocation of resources with the greatest needs so we are putting capital into the highest priority areas and achieving obviously a good result as expected. We believe doing it in this approach, we are addressing risks in a systematic manner. We are reducing unexpected expenditures and becoming much more predictable in terms of performance and system integrity.

So Outlook continues to be developed as conditions change, regulatory requirements change, asset assessments indicate new information when they are completed and of course, stakeholder concerns and/or issues that come up. I incorporate those into our thought process and prioritzation. In summary, before Gary gets into some details, this is our 2008 capital plan for 2008 is $8.6 million.

PRESENTATION BY MR. GAZANKAS:

MR. GAZANKAS: Thanks, Tim. I am going to go over, specifically the 2008 project, what we are proposing to do in 2008. Under the first category, under "Compliance", a list of projects here. The first one is Steelton TS ground grid refurbishment. This is actually located within the city of Sault Ste. Marie, adjacent to Algoma Steel. Just through an independent party, we had studies done on the station and found that we are not within the IEEE standards on that and ESA. From that, we are going into design build contract where we will have the ground grid refurbished as to meet IEEE standards. This will ensure our employee and public safety with respect to the fence grounding and such.

The next one is oil containment refurbishment. Last year, GLP had a milestone event where we had installed oil containment on Goulais TS, if you can recall. That was our last oil containment to be installed on the transmission side. After that, we felt that we needed to revisit all the aging transformers and have a look, a revisit of the existing oil containment to see historically if any changes were required. We came up with a listing of possible potential refurbishments and that is what you see here.

The next one, the right of way...

MR. ANDRÉ: Sorry, Gary, is that all of the transformer and oil containment refurbishment cases that need to be done or is this just an await program and there is still more that needs to be worked on?

MR. GAZANKAS: Sorry, what that is is for the most part, I believe it's probably 85 percent of it. There is one site specifically that the historic design we do not believe is adequate. So what we are going to do is probably...well, we will get an engineering design and funding wise we will probably present it next year. We will see...we are working on it now. We are going to see where the tendering process comes in. The RFPs that come back, we will see what, in terms of dollars where we sit and potentially we might be able to get it in. These were rougher estimates last year but we knew at least we could get the engineering portion of it done. We will see how significant once we get into it, how that will be.

The next one, right-of-way management database. This is to assist us in the ISO reporting requirement. I believe it is Form 1625. It is an annual report and right now it's a very labour intensive effort for us to compile data and to submit this report. Like our information retrieval project that was done two years ago with respect to the reporting requirements on events, this is going to lead into the same...along the same lines where this will allow us to become more efficient at our vegetation management moving forward.

The last one, right now, we have I believe 20...I do not know the exact number.

MR. LEE: 2010 is the mandate, so I assume breakers should be coming out from our system.

MR. GAZANKAS: But numbers wise, we only have after 2010, we will have no more bulk oil breakers in our system. All of which will now be SF6 gas. We have a few breakers now that are SF6. We are going through a massive refurbishment. I will get into the Mackay TS and Third Line TS in a moment to replace the remaining bulk oil aging breakers. So having said that, we believe that there's a requirement to ensure that we are following regulatory reporting requirements and storage and handling requirements from the Ministry of Environment moving forward. And we want to be prepared for the amount of SF6 gas we are going to introduce into our system.

Next category is the refurbishment/ replacement category. I believe these were all in the list last year. The first two: Third Line TS and Mackay TS. Third Line TS is in Sault Ste. Marie, Mackay TS is located in Montreal River region. These are very similar in region where we have breakers that range in age from 60 to 40 years old. They are all bulk oil breakers.

First we are replacing them with life assets. First and foremost, they are aging. It is hard to get spare components. Second, there is an environmental concern with respect to the bulk oil in the breakers that we are eliminating out of system. Liability wise as well, we have had some maintenance reports come back stating that some of the breakers are sceptical so we are keeping a close watch on them. However, should we get into a situation where spare parts are required, it might be hard, they might be hard to come by. So that is the nature of those two projects. They are a continuation from last year. We did identify them last year.

What we did was we are on track with last year's spending and last year's...what we said we were going to do in terms of last year, I believe we said that we were going to install cable charge systems on both sites and those systems are in. You know, removal of some older cables just in preparation. Civil works were done at the Canadian Third Line, so in preparation, we are on track and on schedule, on budget with these two projects here.

Mackay will be a hundred percent complete after this year. Third Line, this year we are replacing seven breakers and there is 14 in total. Because it is situated in Sault Ste. Marie, we felt it's fairly complex in nature just to change all 14 in one year so we thought the best approach would be phasing this project so this year we will see the replacement of seven. Next year, potentially the year after, we will see the replacement of the remaining seven. I will get into that when we get in to our Outlook. There is another project that we are potentially looking at that may push the replacement of the last seven into 2010 but I will get into that in a moment.

Going into the next one, the T2 Transformer Overhaul, last year we presented the replacement of our T1 Transformer. We had a fault on the reactor or the tertiary winding which actually forced one of our Cap banks out of service for an entire year. We replaced that transformer, it is in service at this time. What this is, is we believe that by doing an overhaul on this transformer, we are going to be extending its life. That is the intent, is to extend the life of this transformer prior to buying a new one. We did keep the T1 Transformer. It is at our TS right now, it is our system spare. However, if we see the need to take components off of T1 to refurbish this and extend its life, we will do so.

The next one is similar in nature. It's at Northern Avenue TS. We believe that by overhauling that transformer, we are extending its life. The last three, minor fixed assets, transmission line emergency work and building upgrades, these were all last year. They were all...these are not new. These are continuation annually. We put them out based on...the numbers are based on historic spending and it changes accordingly as we trim that spending.

The next is "System Improvement." The first on the list is just the engineering portion of the Algoma circuits. The Algoma circuits feed Algoma Steel, they feed St. Marys' Paper and GP Flakeboard as our industrial customers. Temporary...not temporary, but studies at this point are indicating that the circuits were never designed for N-1. So, at this point, they at times can be overloading. So we are looking at a study here to see the options, what is best for us moving forward in that corridor. That is in Sault Ste. Marie.

The next one, projects pre-engineering. We have this, this is an annual spending again. You have seen this before. This is just for us in preparation...it allows us to better prepare and timelines to put out the 2009 capital program. We are already working on the 2009 program. That is based on historic spending as well.

Next, the station protection replacement. In 2009, we will earmark the replacement of all of our electromechanical relays. However, we do have some vintage microprocessor based relays in our system. We have some older hard-to-use that are aging. So we have to take a look at our system not only from an electromechanical perspective but from the microprocessor perspective as well and look at a replacement program for those potentially. So what this is is to review what we have in the age and document, all of our microprocessor-based relays in the system and to develop the program moving forward. It may not start until 2010, it may start next year depending on the amount we have, statistics on each relay, could be lean time between failure...all of this comes into effect, so this is what this project is for.

The last one is at Mackay TS, the transformer at Mackay TS. We are installing an online monitoring system. This is dissolved gas analysis. Last year we had the same project for the old T2 that we are refurbishing in the slide...the back one where we feel it will enable us to better trend anything happening in the transformers. It will allow us to maintain it properly. It will allow us to react prior to any severe damage. The one that we had installed at Third Line on T2 has been working very well for us. It reduces the need for annual sampling and sending it off to a lab and that sort of thing. It gives us 4-hour sampling, a very good piece of machinery. We believe it is going to help us extend the life and maintain our asset moving forward.

MR. ANDRÉ: Did you say this was the second one that you installed?

MR. GAZANKAS: This is the second one...that's correct. Actually, no, I am mistaken. It's the third...with the new transformer, we had one installed with the new one as well at their line just because it's a new transformer. We felt it would be nice to trend gases from the beginning. Obviously if we have any issues, we could go back from August 1st point to see what the issues were. It is nice to have to pinpoint on a new machine. There is always the bathtub curve where the initial certain years are...you may expect failure, so it's nice to trend results within that period.

MR. ANDRÉ: What do you use those results for? Does it drive how much maintenance you do on it in the future?

MR. GAZANKAS: Potentially, it is corrected. It would be a conditional-based maintenance because really, a dissolved gas analysis if you are looking at the key gases that are created in the transformer, whether it is due to arching or corona and so forth. Those reports, we can view them daily. Typically, for a new transformer, we have been looking at the reports on a bi-weekly basis just to see. That's probably overkill, but since it is new, we want to really get a good snapshot up front. And as we notice trends, we haven't noticed any so far, we can jump on our maintenance and do more condition-based moving forward.

MR. LAVOIE: I think to supplement Gary's presentation on this particular point is, this certainly...I think our thought is that as part of our risk-based approach to reliability and asset management, these particular transformers 230 and 115, incredibly important, critical pieces of equipment in our system for the adequate and supply. And these types of monitoring tools allow you to, in a predictive sense, it may indicate that you have got to do some maintenance, but it would also allow you to proactively determine how better to deploy my spare, because I have an issue with the transformer. So in a controlled environment, to be able to actually respond ahead of the curve in terms of... ahead of a failure.

MR. GAZANKAS: Next, under "Facilities Tools & Equipment" category; again, "Components" is based on historic spending. This could be spare relay battery test equipment, so for a spare breaker potentially. Again, this is based on our history spending moving forward. The next one is another tool for engineering and operations. We need to...we have a software that is PLS CAD. It is a transmission line software. We basically have our system, plan of profiles in that software. However, this was the only one that has not been done yet. They have done it systematically and now we are coming to an end where we will have all our lines digitized, if you will.

As Tim mentioned earlier, this is our outlook. I have taken a lot of the historic spending which you...like the categories where you see building upgrades, components. I peeled those out of here because it would have made the list a lot longer. These are higher profile, bigger-picture type projects that we gather information on annually and lay them on the table. We rate each project based on that predefined set of criteria Tim has mentioned. We also look at the logistics and the efficiency and these were the ones that did not make the cut this year. Obviously, the Third Line switchyard replacement, that's the phase I was talking about for the remaining seven. That is just there. It will happen, but we are not sure when.

If you notice "115 kV Bus Replacement." We have a bus configuration that is not favourable for outages and maintenance. We have some limiting issues with that bus. So upgrading a critical asset, a network asset, the breakers will all be 2000 upgraded as per ISO or at least 145 kV at 40 kA fault levels. However, we want to ensure that the bus is the not the limiting factor, of course. We would rather have the equipment the breakers and such, as being a limiting factor.

So having said that, we are not sure strategically where that bus replacement is going to fit. We may do the seven breakers and the bus replacement all at once. Based on customer outage, scheduling and so forth, that might be fairly tricky. So we may break them into another project, the bus replacement of...because I think it's significant in magnitude. It's not... structurally or construction-wise it's not complex. However, the planning portion of that project in order to minimize outages and impact to the customer, it is very complex in nature.

Right-of-way management, going back to managing our right-of-ways. The first step was to gather the information in the database. Our right-of-ways, we believe are in decent shape. However, once we identify other areas, we may be looking at...standing the right-of-ways, and so forth, depending on encroachment and that sort of thing. This is just a continuation or a further look into what we are going to define from the database created.

Next, I am kind of jumping around, I apologize. The SVC installation of Third Line TS.

Right now, we have two Cap banks on the tertiary linings of our transformer. We believe that the voltage rating on them is insufficient. We have had a number of events with respect to the fuses blowing on the Cap banks. That being said, that it is a very critical part of our system, we have not only customer loading swings but we also have, obviously, the east-west tie and the voltage swings we have from it.

So at this point, we are not sure if we are going to go with something dynamic like this or we are going to go back into the...just a regular Cap bank on-and-off situation. However, I thought I would put it down as a placeholder, because this is what we are investigating. I think ultimately, we would like to see something dynamic in nature like this, and remove the Cap banks we have, not only on GLP site but we also own Cap banks on PUC that we have to get permission and maintain. So ultimately if we have something big enough and dynamic enough that can handle the voltage concerns, it may see the elimination of the other Cap banks on our customer's property, thus eliminating a lot of maintenance and issues we have getting on to maintain them and so forth.

T1 Bus and breaker failure, protections at Echo River. Protections, upgrades, basically, I mentioned the electromechanical relays. This would be the last...see the replacement of the last one in the system. It will allow us to install our information retrieval to that site. The reason why it was left to last is because it is only a short distance from Sault Ste. Marie. So, strategically, we had the information retrieval system installed for our remote sites like Anjigami which is three hours away, as opposed to this one, prioritized lower on completion. So now it is set up here. Place the electromechanical relays, hook up our information retrieval, and we will have that completed.

I went through the switchyard refurbishment again, it's a continuation. It's the last seven breakers and protection enhancements and such. The last one here is the Algoma 115 kV line replacement. That's the engineering part, I had talked previously of, the Algoma Line's engineering. Basically, we are looking at this year, options, what are our options...it is very complex. Again, because it is right in the City of Sault Ste. Marie, we have customer underbuild. There is double circuits, so it's very, very complex and a lot of planning needed in order to move forward with that project, of course. I think that's it.

MR. BURRELL: I have a question on that slide. Are all those projects for the most part just normal system reinforcement, expansion, maintenance, are some of these to incorporate say, generation from OPAs contracts?

MR. GAZANKAS: I think all of these projects, I would...I would categorize them as end of life or system improvements.

MR. BURRELL: Okay, I see.

MR. GAZANKAS: An example, obviously, is the switchyard. The breakers are old, they do not have the interrupted capability that the ISO requires. They have voltage levels that are insufficient, so there is one example. Algoma lines refurbishment, again, we have major customer loading down there. The loading hasn't changed much. But historically, I do not know that the system was designed for N-1. I can't answer that. The lines aren't...it can't handle N-1. So there is an issue with reliability right there.

MR. BURRELL: So to the point of my question then, this list is likely to grow if there are additional reinforcement required that is identified that is associated with some of these contracts that OPA is entering into.

MR. LAVOIE: Only to the extent that we would be burdened with the cost.

MR. BURRELL: Right, that's basically what I was trying to get at.

MR. MacINTOSH: So you do not know now whether you are going to have to do any transmission upgrade due to the IPSP?

MR. BURRELL: Or even prior to the IPSP?

MR. LAVOIE: I guess we respond to customers and generators based on the process established with...so until there is someone coming to the table, we cannot formally address any of those needs. IPSP, certainly we are paying attention to the IPSP.

MR. MacINTOSH: I was just wondering whether they had identified anything to you. The OPA that would require you to upgrade.

MR. LAVOIE: The extent of the IPSP has some implications through our area from the way that the report is structured but nothing that would be in a short term horizon like this.

MR. MacINTOSH: Right. So your capital

spending is about your average 8.69 or 8 to 9 at the end of the year?

MR. LAVOIE: In 2007, it was 11 million range. This year it's 8.6. From a reasonability, in terms of being able to accomplish it, it is a range that we are comfortable with accomplishing. And certainly we would not need to spend to that extent if the needs were not there.

MR. MacINTOSH: But your revenue is set, so you have to work within depending on how you prioritize your projects?

MR. LAVOIE: This spending in 2008...well, actually, I would expect having done the revenue requirement expectation, that it will likely put our revenue requirement up slightly. It does exceed the depreciation number.

MR. GAZANKAS: Anything else? I will give it over to Alex. He will discuss the maintenance program.

PRESENTATION BY MR. LEE:

MR. LEE: Thank you, Gary. For the major maintenance, we define it as indicates maintenance projects or programs that are significant value of significant magnitude and that do not constitute a capital project. Major equipment repair/overhaul projects, vegetation management programs and soil remediation programs fall under this category. For most of these maintenance programs are completed on the basis of a budget review, stakeholder feedback, outage planning and logistic planning. Most of the projects for the maintenance we completed in the time schedule in that year.

For the major maintenance plan, we have forestry and vegetation management. Insulator washing on the Clergue and Algoma circuits. Somehow, our transmission line passing through a place to Algoma still in that area, we have lots of contamination in the surrounding. So we would like to wash the insulator to help get a better reliability of performance on that transmission line.

Switchgear inspection in Watson TS, from our field reports from our technician, the have noticed during their last inspection, they found some...the switchgear have some kind of tracking or the cables on the 34.5 kV looks like it's going to be failed. We will go for a new proactive action to maintain this.

Then we have transmission circuit infrared scan. This one we do...every year we do a scanning on our insulators, our transmission circuits, to make sure we do not have any hot spots out there.

And then the other one, soil remediation, is ongoing and every year we have to go out and check if any of our soil have contamination. Yes?

MR. BUONAGURO: Maybe we are going to get to this, but I think there is $350,000 missing from the list.

MR. LEE: Is there? I doesn't add up?

MR. BUONAGURO: Looks like there is 1800 on the list. Sorry, 1.8 million...

MR. LEE: Okay.

MR. GAZANKAS: That is my mistake. That is what happens when you cut and paste.

MR. LAVOIE: It should add up to what the list...

MR. BUONAGURO: So, it's the 2.15 that is wrong.

MR. GAZANKAS: Yes.

MR. LEE: Thank you for that.

MR. LAVOIE: Just as a recap to the last item that Peggy had mentioned about the...and we talked about it at great lengths, last year was the retaining of a third party review of our cost allocation mechanisms between Transmission and Generation. Just as an update to the group, the schedule of that has been later than what we had originally anticipated. However, an RFP was issued so I guess a specification of our RFP was, we had a number of inputs to that with respect to the type of consultant, the scope, the methodology and that was incorporated into the RFP. It was issued to a number of firms. We have awarded the RFP and it is currently under way.

So our expectation based on the requirements of the RFP is that we will have something delivered to ourselves in the Q2 time range of this year and our expectation is that it is going to be in well advance of our filing... application filing that we are committed to complete prior to the end of this year. It is currently under way.

MR. ANDRÉ: Tim, did you say the cost allocation between your Generation and Transmission, is distribution a totally separate subsidiary, or is that part of it?

MR. LAVOIE: No, it is not a separate subsidiary however, it was not part of the scope with respect to the study. There was some discussion around, is there a natural progression of the study to do that. We have taken that into account. But, at this point, we are delivering as required or requested and agreed to with the stakeholdering process.

MR. BUONAGURO: Just going back slightly here. The forestry/vegetation management is obviously the bulk of the cost. I do not have the numbers from last year. How does that compare to the last couple of years?

MR. LAVOIE: That number...major maintenance is one of these items that...I call it lumpy. It is something that is...you know, very discreet. Right away, management, I am not sure we have categorized it a hundred percent appropriately when I say that it has lumpiness to it. There is a cycle to it and there is various activities that you do with respect to this. There, what I would suggest as a core activity that you do on right-of-way management and a lot of that core activity is application of herbicide treatment and the encouragement of the right type of growth because we do have mature and adequately sized right-of-ways, for the most part.

However, you do have activities that do occur on a less frequent basis that deal with encroachment so as the sides of your right-of-way push in, there is sort of times that make sense to really go at that encroachment and this would be one of those years. So compare...the total dollars compared to last year...I am going off the top of my head, is in the $700,000 to $800,000 range. This year, at 1.5 million. We are assessing, further assessing based on the database that Gary is putting together in the capital plan for this year a better measurement with respect to encroachment.

So if I was to predict the future, I would probably suggest that we are going to see a little bit more encroachment activities because we do have some mature growth on the sides of the right-of-ways. There's probably in a little more areas than we we expect...or what we have seen at this point, will have much more visibility on the total right-of-way in a much more detailed fashion. So it is up quite a bit but it's dealing with it as a significantly different activity than it was in 2007.

So we are actually removing big mature growth from the sides of the right-of-way instead of just applying a right-of-way. We try to do this in a cycle approach so we do...the intent is to get the encroachment activities in a cycle as well. The idea is to try and spread it in a much more...less lumpy fashion. But I do see that even depending on the scope of each cycle, a different scope with respect to encroachment in any particular year.

MR. MacINTOSH: This is done by outside contractors...the cutting?

MR. LAVOIE: We do have a combination. We have what I call highly skilled arborists that deal with particularly hazardous tree removals or specialized tree removals with specialized equipment. That's with a fairly small group in the 10-person range. The balance of our application of herbicide, dealing with the bulk of encroachment tree growth is done with external contractors. I certainly appreciate everyone's attendance here and participation today. It certainly...I mentioned earlier, something I definitely look forward to because I think there is a good interaction with people who are...folks who are very interested, and have...in a lot of cases, a vested interest in our transmission business. And I think this is a good opportunity to have, share some plans and have good dialogue. I think certainly...this is a very valuable tool.

MR. MacINTOSH: So you are planning your next one just before you file?

MR. LAVOIE: That's probably what will occur. Again, to that point, it is hard to predict exactly when you are going to get that filing in, but I think it would probably be worth while.

MR. BUONAGURO: I know you sent us an e-mail last week. I have not had any chance to look at the attachments. Is this slide presentation in it?

MR. LAVOIE: No. We had... that was the transcription from the sessions last year.

MR. MacINTOSH: I was able to open that but there were two other attachments that I could not open.

MR. LAVOIE: There is some sort of text file.

MR. MacINTOSH: My computer did not recognize it.

MR. LAVOIE: We will have a look at that and see if we can convert it into a different format that everyone could use.

MR. MacINTOSH: I did get the

transcription.

MR. LAVOIE: Okay.

MR. ANDRÉ: Is this material, this presentation available?

MR. LAVOIE: We can send it out to the group, sure.

MR. BUONAGURO: That would be great.

MR. BURRELL: Can you just give a couple of minutes, an update as to where the restructuring plan is? You have got your go-ahead from the OEB now. Internally, where are you at in implementing that?

MR. LAVOIE: The Brookfield Infrastructure transaction from a corporate perspective has...there was an announcement at the beginning of this week that the transaction has been...there's a record date in terms of the issuance of those securities on the New York Stock Exchange, so that sets the stage for the transaction that will occur between Great Lakes Power Limited and the subsidiary of Brookfield Infrastructure Partners. And the OEB approval has been set, so everything is there. Right now, we are going through sort of the final review of documentation agreements and debt instruments to make sure that is all in order. The expectation, I think, is end of January, early February to have the close with respect to that transaction. Our information systems and accounting systems are being updated right now anticipating that close. Really business as usual for the folks at the division, but the legal and financial transactions are being prepared.

MR. MacINTOSH: That will not make much difference in the way you operate internally?

MR. LAVOIE: Our expectation is that it will not...it will make very little difference with respect to that. We have not adjusted the organization. I guess, it has an impact on myself. I do report to a different person than I did before. It's actually someone out of Toronto under the Brookfield Infrastructure Partner structure. However, there is no change with respect to Great Lakes Power organization as a result of this. We will continue at this point with our transaction with the Generation and the shared service at this point. I guess that's it for the transcription part.

--- upon concluding at 11:05 a.m.

REPORTER'S NOTE:

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I hereby certify the foregoing to be a true and accurate transcription of the above noted proceedings held before me on the 16th DAY OF JANUARY, 2008 and taken to the best of my skill, ability and understanding.

} Certified Correct:

} Greg Vaughan
} Verbatim Reporter

RD/sp

GREAT LAKES POWER LIMITED

TRANSMISSION STAKEHOLDER

SESSION

Held on: November 18, 2008
Held at: Ogilvy Renault
Royal Bank Plaza
South Tower, 38th Floor
Toronto, Ontario

A P P E A R A N C E S :

TIM LAVOIE }	---	for Great Lakes Power
GARY GAZANKAS}		
DUANE FECTEAU}		
DAVID MacINTOSH	--	for Energy Probe Research Foundation
MICHAEL BUONAGURO	---	for V.E.C.C.

ALSO PRESENT :
Charles Keizer

INDEX OF PROCEEDINGS

--- upon convening at 10:00 a.m.

--- upon commencing at 10:15 a.m.

MR. LAVOIE: Welcome to our 2008 stakeholders session. This is the second session in our series this year. The first one was held up in Sault Ste. Marie last week, and as I was mentioning earlier, it was successful from the standpoint of well-attended and good dialogue between direct connect customers, some intervening groups and ourselves. So it was certainly a worthwhile experience.

At the same time, I think the time lines...one of the comments that was made at the group last week was to get a little more predictable in terms of when these stakeholders sessions are. A group up north suggested that the November time frame works well, and encouraged the utility to keep it in, you know, a window of time frame just to be a little bit more predictable in terms of being able to anticipate when those meetings were so that key people were available. We are going to float that sort of concept here, as well.

Certainly, our perspective is that the November time frame works well for the utility. By that point in time we are fairly comfortable in terms of our proposals for the following year on our capital and major maintenance, and so it works well for us. So we float that out there.

MR. MacINTOSH: For us, you are probably best to look at what the board has going on that week or two.

MR. LAVOIE: Right.

MR. MacINTOSH: So that you don't conflict with...

MR. LAVOIE: Exactly. So we will, in concept, look at that November time frame, and then look at, also, the board calendar, and we can certainly converse with you.

MR. MacINTOSH: You are actually better to speak to somebody at the board because their calendar does not seem to be...

MR. LAVOIE: Oh, is that right?

MR. MacINTOSH: You know, the one that is on the website.

MR. LAVOIE: Do you have a contact that you normally use that administrates that?

MR. MacINTOSH: Well, Marika Hare has taken over as managing director for applications. So she would know.

MR. LAVOIE: Good. As far as an agenda for today, similar to last year, dealing with our asset management strategy, our plan development prioritizations, expected outcomes, keep everyone familiar with the approach that we take, and then jump into our proposed projects for 2009 in the categories that are listed in the agenda.

We will get a little bit more of an outlook on proposed projects for the future, and then our proposed 2009 major maintenance plan, updates on our...actually, we will do the update on transfer pricing right upfront.

So in terms of our presentation, again, administratively, myself, Tim Lavoie, the general manager of Great Lakes Power. Sitting to my left is Gary Gazankas, our manager of transmission and distribution system planning and engineering. Peggy Lund sends her regrets, as she normally attends with us. In her place I have with me on my right is Duane Fecteau, our director of administration with Great Lakes Power, and certainly welcome to you guys.

The object of our stakeholders session was...this all started back as part of a settlement item in our current rate order that has been approved with the Ontario Energy Board, and the settlement agreement that was sent out.

We agreed with stakeholders that we should have a dialogue on an annual basis regarding the capital budgeting process and conduct stakeholder meetings with stakeholders to consider the capital plan that we are embarking upon in the following fiscal year, and together with that, consideration of our major maintenance plan, and that was set out in section 1.2 of the settlement agreement.

The second...and again, it was a process that was agreed to with stakeholders, was that the retaining of a third party consultant to review and report on the accuracy of cost allocation and transfer pricing between generation and transmission businesses, and the results of which will be filed in our next transmission rate application.

As an update, that report has...as you might recall from last year, we talked about the consultant that had been chosen, and the report...or exercise had been undertaken, and we now have a draft final report in our hands that we are, I guess, prepared for the next steps, which will be filed with our application.

MR. BUONAGURO: Can you tell us who

the...it is probably in the packet. Who is the...

MR. LAVOIE: The consultant?

MR. BUONAGURO: ...consultant?

MR. LAVOIE: Navigant was the...selected. We also undertake...in combination with these stakeholder things, we do encourage our direct connect customers to have individual meetings with us, as well, to consider...obviously considering them as stakeholders, but looking at developing effective lines of communication with those of which we serve, and working with those customers on an individual basis. Obviously connection points and specific requirements of customers are of importance to us, as well as meeting those needs.

So things that either aren't appropriate for a group setting or allow a little more direct interaction we encourage direct meetings with those customers. They have also attended our annual stakeholder sessions like I suggested earlier in the Soo.

We have had very good luck with both of them in terms of establishing good lines of communication.

In terms of our plan development, we look at our system from an integrity perspective, and look at our system performance, and make an assessment on an ongoing basis. That assessment is based upon, kind of, the following criteria, that we look at...I guess you look...we looked, first off, at how old any particular asset might be, and those assets that have ages that are reaching what we would see as end of life, or reaching a mature age. We certainly pay particular attention in those particular cases to field and aerial inspections, maintenance and operation records, to try to determine whether the asset still is fitting the useful requirements of the system.

We also encompass our annual operating and maintenance procedures, and look at field and aerial inspections on all our assets, and that can take the place of infrared inspections and condition assessments, and develop some sort of opinion on the assets in terms of their useful...and identify problems that might exist and develop a plan in order to correct any issues or develop some sort of a capital replacement or refurbishment plan.

We look at system planning activities, you know, from a system perspective, as are we serving the needs from a system perspective as well as we can, and then develop plans again from that; direct customer input, again, meeting the needs of customers and their specific requirements, and dealing with any issues that might exist on specific delivery points; and then of course, the customer delivery point performance standards that we are tracking information in, and ultimately to stay within acceptable criteria.

MR. BUONAGURO: Question?

MR. LAVOIE: Sure.

MR. BUONAGURO: Remaining life estimates, at any point in time do you have an individualized remaining life estimate for each one of the assets, or is it something that you are not...

MR. LAVOIE: I guess that is certainly what we would like to get to, but we don't have that specific documentation now. It is more looking at assets from...ones that...a lot of installations in northern Ontario, and I think probably system-wide transmission assets, there was a large investment in transmission that was done in the '50s and '60s, and certainly northern Ontario is very much like that.

So we had categories of assets, like our bulk oil breakers and...often of a very similar vintage. So we looked at staging our replacement to a programmed approach. So it is mostly components that we have looked at.

MR. GAZANKAS: For the most part, at this point, we look at the age of an asset, and typically what we are replacing here is assets that are 40 to 50 years old. We will...there is nothing, you know, 10, 15 years old, in that range, that we are even looking at.

It is obviously on the horizon, but...so from a perspective of, you know, do you track that, the value of that, I think Tim said, yes, we are going to get a lot better at that, but I think right now our concern is basically the replacement the assets that are at end of life.

So moving forward, we need to be cognizant of the fact that we do have assets that are in that middle range. We have got to ensure that they are replaced when they need to, and not prior to that. So that is obviously where we are headed, but right now, I guess it is fairly easy for us because we have a very old system, not necessarily meaning that it is bad, but you know, proactively replacing that aging equipment is obviously important at this point.

MR. MacINTOSH: So when it was originally built, it wasn't tracked in the same way? The reason I ask that is Toronto Hydro...

MR. BUONAGURO: That is why I asked it.

MR. MacINTOSH: They had all kinds of assets they didn't know, because they amalgamated partly, when they came into Bruce. In fact, at one point, they told us they didn't have telephone poles beyond a certain age, and of course, an engineer who knows could drive down the street and point them out.

MR. LAVOIE: I guess maybe I misunderstood the question. I think what I was thinking was more...like, just for example, let's just say we have a rule of thumb, like Gary has suggested, that we should really be looking at breakers that are 50 years old, and you know, from a functionality perspective, are they really going to operate when they need to, not fail catastrophically.

That is a rule of thumb. You can look at a specific piece of equipment and say, okay, this particular breaker, we know from the nameplate and our asset records that it is 50 years old. So yes, we absolutely know the age of our assets in a major component sense, and I am sure we can find components within our system that we would question in terms of the exact era did they go in.

However, I guess it was more building a system that says, "Hey, I have got an asset that is 50 years old, but it is operating well. There is no concern around it. It has been maintained, and therefore, I am going to extend my expectation," or likewise, I have an asset that is 30 years old, you know, or 20 years old. We are having trouble with it. You know, it doesn't meet its original nameplate criteria, and so we have to phase this particular component out, because it is just not...so therefore you shorten your expectation of life based on similar criteria.

So it was more of an adjustment of remaining time than asset-based information.

MR. BUONAGURO: The sense I got is that on an item by item basis, you don't necessarily have individualized estimates for the lifespan until you get to a certain general assumption about the assets. So if a class of assets has a lifespan of 50 years, and you are in year 40, that is when you start looking at individual ones.

MR. LAVOIE: Exactly.

MR. BUONAGURO: And then start doing individualized life estimates.

MR. LAVOIE: That is certainly the driver, or you have some sort of unexpected event with a type of asset, and so, "We have had an issue with that one, and we have had an issue with that one." So you start to generalize an opinion about a particular era or asset class, and then investigate further through conditions...more detailed condition assessment.

MR. GAZANKAS: Look at how much faults potentially the breaker could have interrupted, how many times it has been operated. I mean, you can have a breaker in the system that is 15 years old, and operated more than a breaker that has been in the system for 40. So it is more condition-based than anything.

MR. LAVOIE: So this information that we talked about in the previous slide is put together and used for prioritization. So we try to prioritize our projects based on...again, sort of a risk-based...addressing in public and worker safety issues, addressing any significant environmental issues to ensure that we are adhering to those regulations, consideration of equipment age, compliance and all regulatory requirements that have changed over time, improvement in reliability or maintainability or operability of the system.

The review of projects that then occurs is...I call to the doability factor in looking at logistically and efficiently deploying that capital plan. So can we obtain the resources necessary to do that scope of work from either equipment or manpower availability, internal or external, and then look at synergies.

I mean, that is some of the things that we have found with dealing with direct connect customers, is that when you are...if you are going to interrupt service or interrupt reliability on a specific site, to do it in a fashion that minimizes that impact, and so there is a possible grouping, either of tasks due to maintenance and capital at one particular site, or in an area to minimize that impact.

Then projects are ranked based on criteria and logistics and efficiency and represents, you know, a complete approach to evaluating our proposed projects.

What we expect out of this thing is that we are allocating our resources to the greatest needs we have, things that we need to address, and we are allocating inputs in order to achieve that end.

Risks are managed in a systematic manner, so trying to avoid any unexpected expenditures, and/or unexpected events. We certainly don't want any unexpected service interruptions. So you mitigate that.

Outlook continues to be developed as conditions change, regulatory requirements change. Asset assessments occur and change our outlook with respect to different components and our system performance, and then of course, incorporating stakeholder concerns of the direct customers and the groups here, so dealing with that aspect. For 2009 our capital expenditure plan is about $12,000,000.

MR. BUONAGURO: You are going to go into a little more detail on the 12 million?

MR. LAVOIE: Absolutely. That is the subsequent slides. Actually, Gary goes into quite a bit of detail later on.

MR. GAZANKAS: Projects are broken into categories, and you will see that. I will go through each project and each category sequentially after the slide. The four categories are legislative compliance, refurbishment/replacement, system improvement and then lastly, facilities, tools and equipment. The legislative compliance, obviously, is capital costs incurred to meet legislative and regulatory requirements prescribed by those following groups, up to but not limited to those groups, of course.

We do have one project in this category this year in the cyber security, but I will get into that in a moment.

Next is the refurbishment/replacement category, and we are looking at replacement of end-of-life equipment and facilities that are listed in this category. We look at replacement in accordance with good utility practices, obviously for reliability purposes, and health and safety reasons, avoiding catastrophic failures, and to maintain integrity of the assets, of course.

We also look at...and I will get into some more details on our Third Line project. Replacements are supplemented with configuration changes where we believe that these changes will improve reliability, maintainability and flexibility of facilities.

The next category is system improvements. It is comprised of upgrades and additions to the system, improved efficiency of operations, quality of service, reliability, maintainability, flexibility, outage response, and data-gathering analysis capabilities.

The last category, it is the facilities, tools and equipment, and these primarily involve procurement of maintenance and test equipment, major tools, spare parts, other miscellaneous components.

We look at examples...I do have some projects or expenditures in this category. One worth noting...I will get to it in more detail, is the PLC test equipment, which is power line carrier, and I will get into that in a minute.

Just moving into the actual projects, the first one is the aforementioned...the only project we have in this category this year is the cyber security requirements. This is a NERC requirement. The IESO has obviously backed that. There are nine of them, I believe, and basically...I will name each one. You can find this on the IESO website.

These are requirements for cyber security. It includes also physical security of the assets. This is actually...we need to have full compliance by the end of 2009. So this is quite important that this is completed. Again, you can find additional information on the IESO website.

Just to list them quickly, we looked at

critical cyber asset identification. That is one. Security management controls is another. Personnel and training is another category. Electronic security perimeters, which is quite substantial, but it is another, the physical security of the cyber assets, system security management, and how do you manage that security, incident reporting and response planning, and recovery plans for cyber assets.

So there is a lot of planning in there, planning documentation, but there is also a lot of physical work. You look at a station that is remote, and you have to start looking at cameras and physical securities, logging into stations and so on and so forth. So it is quite an extensive project, and to be full compliant by 2009, so we are...

MR. MacINTOSH: So this is a North American grid compliance issue?

MR. LAVOIE: The standard that was developed by NERC and applied, I guess, pretty much North America-wide. IESO adopted that standard, and then, of course, now through an evaluation stage, recognized that there were standards that we needed to implement, but were not in place.

MR. GAZANKAS: I am assuming that this

probably all stemmed from either 9/11 or the blackout, as well. So any more questions on that?

MR. MacINTOSH: No.

MR. BUONAGURO: Just purely out of interest, the standards apply universally to every single utility across North America, right, but not necessarily...you wouldn't have the same need across North America. I would assume that GLP might be in an area that you are not at risk the same way that, say, downtown Toronto is at risk of cyber terrorism.

MR. GAZANKAS: You are absolutely right.

MR. BUONAGURO: Just off the top of my head and for interest's sake.

MR. MacINTOSH: We don't know who is lurking in the weeds in our territory.

MR. GAZANKAS: Well, and I guess maybe you look at the bulk flow of power across the province, and we are part of that, with the...

MR. MacINTOSH: Being close to the border.

MR. GAZANKAS: And we are close to the border, as well. So I guess from that perspective, you know, they have identified, I guess...

MR. LAVOIE: The IESO does the identification of what assets are required...that should have specific attention paid to it, and then that is from which then you develop your plans from.

I don't know, you know, exactly, the process that they went through. However, they had an evaluation stage, and obviously it must be related to things like Gary has suggested, that...there is, you know, certainly a fundamental load pocket there. It is a border community, and it does form interconnection points with...it forms part of the east-west tie-in. So there is obvious criteria that they must have met to...

MR. BUONAGURO: Well, it is interesting, because then what you are telling me is that it is not just a blanket...

MR. LAVOIE: Right.

MR. BUONAGURO: ...requirement that is imposed on everybody. They actually individualize your requirements, based on your system and where your system fits into the overall picture.

MR. GAZANKAS: For the most part, yes.

MR. BUONAGURO: Okay.

MR. GAZANKAS: Now, looking at the refurbishment/replacement and the following list, I will go down this list and...I mean, I can go through the whole list. I will go obviously through the more significant projects, once I get down to below 250. If you want me to carry on, fine, I can, there is no problem there, but again, I don't want to put you to sleep today, so I will try not to.

Looking at the first project, and this is quite extensive, the Third Line TS refurbishment and rearrangement, as we mentioned in the previous slides, we also not only look at the assets, but we look at the system configuration, and the Third Line TS, configuration of that station is not as per provincial standard.

It was never designed as such. It is a historic station. If you were to build a new station in today's day and age, there is no way we would configure it in that manner. That is a historical station, and was grandfathered in at the time.

So what we have done is we have looked at the assets at the station specifically first, and we have said, "Okay, we have got bulk oil breakers here, with environmental issues potentially with the breakers because of the oil. We have breakers that are 40 years old. We also have breakers that have potentially inadequate fault-interrupting capability, plus when we look at the breakers' ratings, the voltage ratings on the breakers, they were only rated 121 kV."

The system in northern Ontario fluctuates anywhere, or can fluctuate anywhere from 132 down to...well, 118 kV. So normally we are in the range of 122 kV, and possibly a little higher. So the breakers really are subject to over-voltages, you know, ongoing, and likewise, the disconnect switches are of the same rating.

So we had concerns there to begin with, and then we took a step back, and said, "Now, let's look at the station and the configuration," and basically our customers...the station feeds the entire city of Sault Ste. Marie, plus it feeds all our load customers, all our industrial companies, ASI, St. Mary's Paper and Flakeboard.

Now, the design is such that when you take a breaker out for maintenance we lose that transmission circuit. So obviously, at any given time for maintenance purposes, we reduce reliability of supply to our customers during that process.

Likewise with the city of Sault Ste. Marie, any time we take breakers out, we actually reduce their reliability of supply.

If we look at the actual setup of the

station, we have a north and a south bus with conductors strung over top. It is not a desirable situation, because, for maintenance purposes, looking at maintaining that busworks, we basically have to take a city-wide outage in order to maintain the conductors above the live bus underneath, for safety reasons. So the station really is not equipped for maintenance purposes.

We recently had done...on an annual basis, we do our infrared inspections. Last year, there was no issues. This year we do have hot spots that are showing up, and we are stepping up the frequency on the monitoring of the bus to ensure that we are not going to have a catastrophic failure.

However, we may have difficulty in trying to fix that, the spots that are heating up, due to the fact that we cannot actually access it because of the main bus underneath.

So from that aspect, we felt that we better take a look at that station in whole, since it does, you know, feed through Sault Ste Marie entirely, and at this point, what we have come up with is a greenfield station on the 115 kV side that is a scheme as per the IESO criteria.

So if you look at their recommended breaker and a third, or a breaker and a half scheme, that is what we are looking at at this point. We have already discussed this with the IESO, and they seem to be, actually, very happy with us moving forward with this project, and look at doing a system impact assessment very soon.

Another...actually, one other fact is that we did have issues with the ratings of the overhead cross bus, and recently we had to string additional bus underneath in the station, just so we alleviated any overloading of circuits on the overhead conductors that could result in failure of that, and failure of the station.

So again, we have taken a comprehensive look at this. This will be a multi-year project. The dollars you see here are just the beginning. We will look at procurement of long lead items, breakers, disconnect switches, six to eight months in delivery, you know, steel structures, copper conductor, and then we will look at starting construction in 2010, and moving into 2010, and then finishing off in early 2011, cutting the circuits over the...the transmission circuits into the new station.

We believe this provides us with a station that not only gives us the flexibility that we need for maintenance and operational purposes, but it also...we have looked at future growth in Sault Ste. Marie, and we do have provision for any future additions as well.

MR. MacINTOSH: What is the full cost over three years?

MR. GAZANKAS: Well, from a high level estimate right now, and that is all we have, because we did have a third party consultant look at this for us, and provide us with three options. The new greenfield station, we are probably looking at...this is a wide range, but this is all I can give you at this point.

We are probably looking at anywhere between 18 and 30 million dollars. I am suspecting that it is going to land somewhere in the middle, so maybe 22. It is fairly comprehensive, but we felt that, you know, if we go into breaker replacement, which we needed to, and switch replacements, which we needed to do anyways, because of the end-of-life and the ratings, you are looking at basically 12 to 14 million just in replacement of that existing equipment, like for like.

MR. LAVOIE: And then, of course, not

achieve that operability or maintainability requirement that we just felt the gap was large on.

I think the other...I don't know if you touched on it that much, Gary, was just the...I think you did, the capital to do an in situ replacement of the bus and then associated switching and breaker equipment. Because operability and maintainability is limited due to the configuration, it would be very costly and impact the reliability over long periods of time for groups of customers connected to that point.

So it is a little bit of an intangible, but from a direct connect perspective, certainly meaningful consideration.

MR. GAZANKAS: Right, and we have looked at that option. Those are the three options. One is as-is or in situ, and at this point, I think from the constructability standpoint, it is probably unacceptable, just because of the reliability, and potentially safety of workers would be severely compromised, but we are looking at that, and have. Any questions on that project? No.

The next project I have is the...it is a ground grid refurbishment. Just to tell a bit of a story here, as we have mentioned in the past, we do go around annually and perform comprehensive condition assessments of our stations. The engineering group performs this.

We have criteria. We look at all aspects of the station, including the yard and the civil works, the drainage condition, the vegetation growing within, if there is any, you know, fence heights, ground conductor condition. Based on those, we either...that either spawns further investigation, more detailed analysis from an engineering group, or we feel that it is adequate.

With respect to Batchawana, in looking at our condition assessments, we felt that it required further analysis. So we hired an independent third party group that came in and actually did a measured test on the ground grid, and from that, the results came back that there were inadequate, I guess...their touch potential.

So what that means is at any given time, if there is a fault in the station, if an individual was up against or leaning against part of the steel, it could be such that the current flowing through that person, if that happened, would be such that that individual would obviously be injured, of course.

So the results stated that these potentials exceed the IEEE standards. From a health and safety perspective, we felt that we needed to do something, and obviously proactively upgrade the station.

So what we have done is looked at the station from a comprehensive approach, and this is going to involve not only the ground grid under the ground, it will involve fence grounding. We will look at equipment grounding and the drainage, so that, you know, in ensuring that the soils aren't washing away a year later, and that sort of thing. So this is really the story behind this project. Any questions on that?

MR. LAVOIE: And now we will go through the same scenario for the Steelton ground grid refurbishment.

MR. GAZANKAS: The Steelton refurbishment is exactly the same. So we did identify stations with this issue, and we are just prioritizing the ones we do first based on the severity, and location as well. Steelton is in the city of Sault Ste. Marie, so obviously you look at public safety as part of that earlier criteria. Any more questions? No.

The next project is the MacKay 115 kV bus upgrades and CVT replacement. Last year we had a project to replace the actual breakers and switches. We felt at the time that the bus was adequate.

As we moved into that project, we found that the busworks that connected the breakers are now limiting the breaker capabilities, if the station were to run with the maximum capability of the breakers.

We also have issues whereby configuration, if there are pieces of equipment that are out of service, we could, with maximum generation in the area, we could, not overload, but we could run the bus and the components and the connectors connecting the bus to the breakers to the maximum levels, and obviously the busworks and the connectors are 30 years old. So running them to the extreme, we feel that we could compromise reliability and there would be subsequent failures and so on.

The next part of that is we also...in that refurbishment project, we didn't believe we had an issue with our CVTs. So as we headed into the breaker replacement project, we felt the CVTs at the time were in decent shape, and we felt it wasn't a prudent expenditure at the time.

As we got into this project, we have had three failures of them in the last year, and they are of the same vintage and make. So we talked about synergies in the past, and taking outages on the bus potentially. We believe that these two projects fit well together. That is the history on that project. Questions?

Okay, I discussed the Steelton ground grid. It is the same as Batchawana. We looked at component storage facility. We do have a large number of components right now, spare components. A lot of our critical pieces of equipment...our new transformer came with spare components. We have breakers that need to be stored inside.

We do rent containers right now. They are like rail car containers. I guess they are called C-cans, and...but there is no environmental control in there.

We found that some of the components have been...because of that exposure, have been rusting, breaker mechanisms and such. These are critical components and a part of our plan, you know, emergency response, and we have to make sure that, from that perspective, that they are maintained accordingly, as well as it is an asset, and it is a new asset. They are part of the spare list that we need to maintain in order to ensure that that life cycle is met, and that because of exposure to the environment, that we are not, you know, discarding these earlier than expected.

MR. BUONAGURO: Just a clarification. Is it that you need to...your storage space need is increasing, or is it that you have been using these storage bins for some of your storage, and you don't want to do that any more?

MR. GAZANKAS: I guess it is both.

MR. MacINTOSH: Are you doing a building?

MR. GAZANKAS: Well, yes, we are looking at a structure, yes, and I think it is a little bit of both. I think that the need has increased. Like, we went through some of the bigger projects. We do specify...we have got a lot of spare components, but we do...for a critical piece of our transformer, we got...I mean, the high voltage breakers. We will have one component spare. So as the system is upgraded, a lot of our aging components, they are discarded with the old...like, we didn't in the past have as many spares, and I think the requirement is, from a reliability perspective, is a lot more stringent now than potentially in the past.

MR. LAVOIE: And I think the other thing is the type of equipment is changing. A lot of the older equipment was bulk oil breakers, large equipment you typically didn't store inside.

The SF6 system, it is pretty much more compact and more component-oriented than what we had previously. So it does create a new need with respect to some of the newer equipment.

MR. GAZANKAS: So really that is the driver behind the component storage project. The next project, we have capital dollars set aside for building upgrades. Obviously we have a number of stations remotely.

Within the condition assessments, as I mentioned, we obviously look at and assess the buildings. What we found is in two sites in particular we have humidity issues. In one of the stations where we had to proactively replace the conductors because of damage to them, and as well, the breakers and components and the switchgear that are...they have been also subject to the humidity and have caused potential issues and faults within the switchgear.

So we are looking at a phased approach to the humidity issues in one station, where we will look at a first phase, do what we think is necessary, and we will let it, I guess, settle, and see if that solved the problem. Then if it doesn't, we will go to the next phase. We just...we felt it better to tackle it in that manner, instead of just throwing, I guess, a lot at it to see what worked.

That is one station. Another station we have ventilation that is inadequate as well. So we are replacing the ventilation in another station, another remote station, and every year we have...we do that, we go through the system and identify what parts or portions of buildings need upgrades. That is it for that.

The next project we have, communication upgrades. With the GLP system control, we...like every other component in the system, SCADA system is an integral part of transmission system, and we need to ensure that communication facilities are acting accordingly. We look at aging equipment, and we have earmarked this amount for the replacement of those components next year.

The next few projects, battery replacement...do you want me to still step through these one-by-one? Did you want to that?

MR. MacINTOSH: Could you just tell us

how you got the Magpie name?

MR. LAVOIE: We are adjacent to the river system.

MR. GAZANKAS: Magpie River system. Magpie TS, yes, Magpie TS battery replacement, again, end of life. We are looking at just the age of that asset, again, looking at good utility practice and manufacturer's recommendations for replacement on that.

Clergue circuits, we have components replacement. We have had failures in one specific area on 115 kV circuits, and we need to replace a number of components and do some modifications to the circuit to ensure that we don't have any of these catastrophic failures. It is right in the city of Sault Ste. Marie and could pose a potential safety hazard.

Transmission system emergency work, this is an annual allotment responding to emergency-type conditions. Last year we had two blizzards and that sort of thing, so the system is holding up fairly strong, but these emergency type responses do obviously occur in any system.

Then minor fixed assets, we look at, again, as I defined it, we look at spare parts, you know, test equipment in this category.

MR. BUONAGURO: Some general questions. I don't have the numbers in front of me. How did this level of spending compare to last year against this year, 2008? I remember sitting in a room and seeing a similar chart last year. I am just...if you know off the top of your head?

MR. LAVOIE: It is similar, but we didn't come prepared to answer your question, but in a general sense, numbers of magnitude?

MR. GAZANKAS: I think we are higher this year.

MR. LAVOIE: But not like...

MR. BUONAGURO: Not astronomical?

MR. GAZANKAS: No, not double, or...

MR. LAVOIE: Similar scope, but I think...again it comes down to logistics and just what amount of work is achievable and reasonable.

MR. BUONAGURO: Maybe you cannot answer this off the top of your head, but again, we had the similar list of projects last year. Can you give me a sense of how you did? Like, were you able to fit all the projects you anticipated in 2008? I don't think you mentioned any of these being spillovers specifically from 2007, even though some of them are connected to work you did in 2007.

MR. LAVOIE: Again, in a general sense, I think we are achieving what we set out to achieve. There is always a project or two that...I guess a good example was on the Third Line that Gary talked about earlier, that we set out to do something. We talked about it last year in terms of switchyard work, and with further consideration, we chose to not move forward for the sake of doing a better job in the future, so manage the short-term list and not do the project.

MR. MacINTOSH: But you are going to have to come before the board to get money for the rest of the Third Line TS.

MR. LAVOIE: Oh, absolutely.

MR. GAZANKAS: Oh, yes.

MR. MacINTOSH: It is too big to fund on what your revenue is now.

MR. GAZANKAS: There is no question.

MR. BUONAGURO: The last question, I understand this is the list of things you hope to do for 2009 after you prioritize, right?

MR. LAVOIE: Right.

MR. BUONAGURO: Can you give me a sense of, if you didn't have a spending limit, how much more you would have done in 2009, like things that you had to cut...what kind of spending did you have to cut out because of priority, either for spending, or I guess, manpower resources? Like, is there a project, "I really wish we could do this in 2009, but we cannot"?

MR. GAZANKAS: Well, I think if I look at it...not in terms of, I guess, numbers, but if I look at the ground grid projects and prioritizing specifics, that one probably comes to mind. You know, we prioritized those projects in terms of, you know, what...how severe the issues were and the condition of the station.

So you know, I guess from that perspective, we probably potentially would have liked to maybe do those, but they would be pushed off until next...the year after, but I am not too sure of magnitude or other projects that fall into that. I mean, it is hard to know.

MR. BUONAGURO: Thanks.

MR. GAZANKAS: Okay, I guess we can look at system improvement. So here we have projects required to enhance system operation. The first project we have is Echo River protections upgrades. We are looking at end of life replacements here, coupled with communications enhancements and we look at reporting requirements for...when we have events on the system, and IESO requirements say that in 48 hours we need to look at having reports issued.

If we have to drive to stations and download the information, the standard becomes quite difficult to comply with, not to mention the fact that the relays here don't provide that capability. They are older, electromechanical relays. So they don't record the events like the newer relays do.

So basically this project involves having communications necessary to enable us to access events remotely, as well as replacing end of life equipment.

Our next project is the Third Line. It is a series reactor installation. You recall in 2007 we replaced the transformer that was damaged, had a fault inside it. It was one of our 250 MVA transformers that feed Sault Ste. Marie.

We replaced that transformer, but we were obviously concerned prior to putting it back...or the new one into service, that what really caused that fault. So we had initiated an engineering study on it from a third party, and the results were there are issues on the system...the tertiary system that the capacitor banks...on the transformers and that they recommended installing these reactors in series with the capacitors.

Next, we look at the Algoma lines. Those are the three 115 kV circuits that link from Third Line TS down through the city,, and feed our industrial customers, Algoma Steel or ESSAR, St. Mary's Paper and Flakeboard.

Basically, from section 6.2, which I have here, transmission system code, the transmitter has to look at the available capacity on their transmission circuits. Just to read from here:

> "...To ensure that there is sufficient available capacity on the transmission connection facility, and the transmitter shall conduct an expansion study where it considers it necessary to ensure that it can meet this obligation..."

So what we have done is we have taken a look at the total normal...what we can supply, and we have taken a look at the customer loading, and we are still involved in this right now, and what it has driven is an expansion study, and that is what this is a part of it.

Basically what it says historically is not with the customers adding load, but due to the load that was there upon market opening, that the available capacity...well, basically there is none, and we have actually exceeded the total normal supply capacity based on the calculation here.

So what we are doing is just following the process of the system code and following through this. This is a study to ensure that we are meeting this obligation within the code.

MR. BUONAGURO: A technical question: That sounds like it is compliance of a sort, or is it because it is more operating...

MR. LAVOIE: It is like it establishes, call it a trigger point, for further...

MR. GAZANKAS: Further investigations.

MR. BUONAGURO: Okay.

MR. GAZANKAS: I guess it could be considered both because it is compliant with the code, but I guess all of these projects are, in some fashion, compliance with the code, if you look at good utility practice and regulatory and end of life, you know what I mean. So this is just an excerpt out of there just to better explain where we are in the process in terms of the expansion.

MR. LAVOIE: The idea is to keep moving

toward that reliability factor of N-1, ensuring that we are kind of moving in that direction.

MR. GAZANKAS: Next is annual engineering. This is the engineering studies. In the year prior, leading into this, better prepares its estimates, ensuring that the designs are adequate as per IESO standards and so on and so forth, helps us prepare annually for the projects for the upcoming year.

MR. MacINTOSH: Is this external?

MR. GAZANKAS: It is both. It is both. Typically, for Great Lakes Power, we do use a lot of consulting groups. We are not a big entity, so we don't have a very large engineering group to manage design, smaller design potentially, but anything significant is usually through a consultant.

The next project is our information retrieval upgrades. We had a project a few years back with respect to...I mentioned before in the Echo River project, where it retrieves the information.

We have stations that have been upgraded recently with relays. So now as part of ensuring this product is online and capable of interrogating the newer relays that have been upgraded in stations like MacKay, potentially Third Line...we need to ensure that. So this project is basically to look at what was upgraded, and then reconnect the system to the new equipment.

Now we look at facilities, tools and equipment. Obviously these projects are required to assist in the maintaining of the system. The first purchase, we look at GIS software. Currently in the transmission system, we do not have a GIS system, geographic information system. So storing our spatial data, we believe that in order to better manage our right-of-ways, better manage our transmission circuits, better manage our landowner agreements, better manage our access, that we need to have an updated overview of our system that will help us move forward with a lot of regulatory compliance issues, when we look at vegetation management and those types of standards.

Also I think the big driver behind this is emergency response. We want to better equip our crews with maps displaying accurate access points to specific structures on a right-of-way. We do live in Sault Ste. Marie. It is not farm country. So obviously with the Canadian Shield and the terrain, it is extremely rugged and access is difficult. So the main driver behind this is emergency response.

MR. MacINTOSH: So your crew can receive this in the field?

MR. GAZANKAS: The field, no, but I think potentially that is where we may head with it. I think one step at a time, we will have this information available to our control centre.

If we do have an event, they dispatch the crews, whoever is on call. They obviously have to come to the station, back to GLP to grab the trucks. So first we make it the process that came in, grab the maps, and then head out into the field. So now they are equipped. They understand.

We do have the new relays that actually can pinpoint distance of a fault from a station somewhat, so it gives them a ballpark. So we have much better response time, and obviously, you know...

MR. LAVOIE: If you can envision a crew heading out. It is typically not just a few minutes away. It, you know, could be an hour or better before it responds. So the crew starts out. In the meantime, technical people can start looking at the relay, say, "Oh, it is five miles down the line." You can then look at the GIS coordinates on that particular structure, then start back plotting where the crew might access that point through this path or that access point.

So the thought process is to take a lot of hunt and pecking out of the system, or response through use of helicopter at fairly expensive rates, and direct your efforts more efficiently.

MR. MacINTOSH: Okay.

MR. GAZANKAS: The next project we have is a vegetation management system, and essentially this will tie into the GIS eventually. Basically we are looking at this system as a requirement in order to maintain compliance with the standard that is out there right now, the vegetation management standard with NERC and the IESO. It is FAC 003. I do have it here. I will just read the purpose of that standard. It is:

"...To improve reliability of electric transmission system by preventing outages from vegetation located on the rights-of-way, minimizing outages from vegetation located adjacent to the right-of-way, maintaining clearances between transmission line and vegetation on and along the right-of-way, and reporting vegetation-related

outages of the transmission system to the
respective reliability organization..."

which is the IESO and NERC. So it is a fairly comprehensive standard, and we believe moving forward to enhance our ability to maintain compliance with that, and to adjust to any changes that are made to that standard, we believe that this project will assist us in doing so.

MR. LAVOIE: A very high percentage of our right-of-ways are vegetation-managed, and they are not, again, under...in communities. Yes, we do have lines in communities, but from a percentage basis, but out of 550 kilometres...I don't know if I have a number, but it has got to be a majority of those corridors are managed on both sides.

MR. MacINTOSH: What is your cycle?

MR. GAZANKAS: Six years.

MR. MacINTOSH: Six years?

MR. GAZANKAS: Yes, at this point, and this will lead into one of the other projects down below, but basically what happens is we have a helicopter that flies the line, and it Lidars the entire system. So it actually tells you where spatially the transmission circuits lie with respect to the vegetation that is there.

So it can give us very accurate detail on exactly where a tree is with respect to a conductor in space. So I believe it is...

MR. MacINTOSH: It will refine...

MR. GAZANKAS: Definitely refine it, because there are minimum clearances. There is a radius from conductor, a minimum radius from a conductor to a tree stand. Well, how do you accurately, from the ground, determine? So obviously you want to be...the way we are now is extremely conservative, but conservative means obviously costs, right.

So if we have a more accurate portrayal in...or a more accurate detail on exactly how close that really is to the conductor, we can better manage that vegetation on the right-of-way.

MR. BUONAGURO: Do you expect that will have the effect of, on average, extending the cycle or reducing it? It would extend it?

MR. LAVOIE: There is a number of moving pieces with that. It drives you certainly to a more efficient deployment of resources. I think what we find, there is quite a variety of vegetation. So growth rates and types of vegetation, and where you are with respect to encroachment.

A right-of-way, if you establish a certain width, you typically don't have to do a whole lot with the edges of your right-of-way until trees become fairly mature, and then it becomes quite a chore to deal with what we call encroachment on the right-of-way.

So you know, Gary's process of being able to identify areas...zero in on vegetation type and distances allow you to better anticipate those cycles, so that, you know, in certain areas where you have softwood versus hardwood growth, you probably vary those cycles.

MR. GAZANKAS: I think there is probably two distinct parts here. The first part is the actual right-of-way management, and the growth rates, and that is part of the cycle. Then you also have to look at danger trees within that are existing, and again, looking at our area, that is a significant number.

So I guess I may have more or less talked to the danger tree issue, and not so much the cycles, because I don't think the cycles would change. I think that is just based on the growth rates and that program is on track.

MR. LAVOIE: To be able to efficiently

deploy the danger tree...

MR. GAZANKAS: That is correct, yes.

MR. BUONAGURO: Okay. Does anybody else...are you aware of anybody in Ontario using that system?

MR. GAZANKAS: Hydro One is...there is a vendor that they are using, is Geodigital, who we are looking at obviously...jumping onboard, so to speak, with them, because obviously they are working with Hydro One. So we know that product is supported.

So we are being somewhat cautious with this as we move forward, of course, because we want to make sure that this does...you know...

MR. MacINTOSH: Is that a satellite system, Geodigital?

MR. GAZANKAS: It is a company, actually, Geodigital, sorry, but yes, Hydro is using their technologies, and we will look at what is done, what they have done with Hydro first, and then we will look at deploying that.

MR. LAVOIE: Let me say that we believe that Hydro is...

MR. BUONAGURO: The idea of flying helicopters over and tracking vegetation that way has never come up in a hearing that I have been in yet. So I was just curious if you knew.

MR. GAZANKAS: I believe they do...in the U.S. it is done I think fairly comprehensively, because there are fairly stringent regulations surrounding the events down there, up to and including fines and so on. So we are not to that point, but I think they are utilizing this technology more so than us.

MR. BUONAGURO: Okay.

MR. GAZANKAS: Next we look at asset management software. This is just software upgrades to better...just from a business perspective, better planning. We look at the existing...the system we have is an aging database. We do have stability issues with it. We want to make sure that we have the right system to better move us into the future, provide a more comprehensive asset management tool.

The next project, we have replaced a number of our bulk oil breakers in the past number of years, and have upgraded with SF6 breakers. We look at clearance issues, and the new breakers have been installed on stands, just to meet the minimum...the requirements of EUSA, I believe, for maintaining safe working distances.

So now that...if you can envision an SF6 breaker in the air on a stand, the mechanical box that houses all the components inside, is now lifted...or is now elevated to the point where it is only accessible via stepladder. We believe from a safety perspective, that working from a stepladder under certain conditions is unacceptable, and we are looking at installing platforms.

We have do have them on our 230 kV breakers, the platforms. Basically it is just a stair with a platform, just to make sure that it doesn't infringe upon the limits, that is going to better provide access to those mechanism boxes on our breakers in the system.

The next project is really coupled with the vegetation management system. What happens is we will fly the line once, you know, collect, I guess, a number of data points, probably a billion, but what that includes is the vegetation, give us a vegetational outline, but it also gives us a profile of the transmission system.

That profile data is then loaded into software. It is an engineering design software for sags, tensions. It is plan and profile drawings. We have done it for a majority of our system, but we have had upgrades over the last few years that we have not updated, or I guess not updated, but we never had input that data in originally.

So this is basically one of...a synergies type of action where we utilize that data for two separate pieces of software. So we are now flying the line again, to update the engineering software.

The next project we have...I guess, purchase, we have...this is specific to power line carrier equipment. This is a communications piece of equipment that is for protections...used for protection on a 230 kV system. So obviously it is out of the bulk system, and it is...there are testing requirements for this equipment.

What we are doing here is purchasing a piece of equipment to obviously better maintain, ensure that the liability is not compromised on that piece of equipment. It is a substantial expenditure for test equipment. So we actually left it out of the minor fixed assets, just to point out the magnitude dollars-wise for this project. The last...

MR. LAVOIE: Just again in remote areas we can strategically place a trailer based on...there are different times of the year where we might expect an emergency to take place, and have various equipment to clean up spills and address any environmental issues on dealing with that emergency.

MR. GAZANKAS: So if we look at our outlook, and again, I have discussed at a minimum the start of that Third Line project, and obviously, I guess, I discuss it here just a little bit more, so that you are understanding the magnitude of that station.

Again, we looked at prior to going into the configuration, we looked at the breaker and switch replacement, and felt that we needed to, again, have a station that provided us with additional flexibility, maintainability and operability in the system, being that it is a fairly critical asset for GLP. The driver initially was the replacement of the aging equipment, and the equipment had inadequate ratings, but again, once we took a more comprehensive look at the station, we believe that we require a new configuration in order to provide us with all of those enhancements. Any other additional questions on that project in particular?

The next project is static VAR compensation project, and what this is is like a capacitor bank. It provides voltage support in the local area. We do have capacitor banks on the system. They are aging. We do have capacitor banks that we own that are located on public utilities corporation property, and require additional maintenance, just because of age, and constant monitoring.

We believe that we are getting close to a replacement of those capacitor banks, and that, from a system perspective, that this technology here would be better suited to the local area, Sault Ste. Marie, and provide that support, that voltage support. We will probably look at this project in 2010 or 2011.

Obviously, I mentioned the...we have placeholded here for the Algoma circuits upgrades. We talked about the available capacity, and the available capacity procedure, and the expansion study that we are in now.

We believe that we do...there is work required on those circuits at this point, but to the extent we are not sure, that is where we are at with that expansion study.

So next year when we come back to this forum, we will more than likely have a better indication of where we need to go on that project.

The next project is our on 230 kV right-of-way, and based on condition assessments, we believe that...we have a structure replacement program in the future for that 230 circuit.

MR. LAVOIE: That should be P21G on that.

MR. GAZANKAS: So basically it is based on condition assessments, and we are now heading into more comprehensive planning for this project potentially.

The last project is...it is twofold. It is Clergue TS. It is located in Sault Ste. Marie. It is a station that supplies St. Mary's Paper. What we are looking at here is we do have a station with metal clad switchgear. It is 11 kV.

The issues are that the switchgear is obsolete. I believe it is probably, I think, 20 years old. It is not old by any stretch, but if we have a failure on any one of the breakers, we have no spare components, and we can no longer get the breakers.

So at this point, we do maintain it more frequently to ensure that we don't have any failures on that, because if we do, then obviously, you know, reliability of supply is affected severely.

MR. LAVOIE: It is an availability of spares issue.

MR. GAZANKAS: Right, and I guess the next component to this is the ESA and CSA, and you look at the arc flash regulations, and we are looking at switchgear in general in our stations, and whether or not it is capable of handling the fault levels that are...the fault magnitudes at that specific station.

So if the energy that is present there exceeds the rating of the switchgear, then obviously there is a health and safety issue surrounding that. So we are looking into that right now at this point.

From a high level perspective, that is our outlook. We should see those projects as we move forward here. Any questions on that capital program proposed?

MR. MacINTOSH: The area that you are operating in, is the economy affecting your load?

MR. LAVOIE: I was going to say it is probably too early to tell, you know. Two or three months ago, I think if you had asked me that question, I would have optimistically said that we are probably going to...we were thinking that we were going to see an increase in load based on some of our customers and their outlook, from their perspective.

In more recent times, over the last month or so, I wouldn't...I certainly don't share that same expectation. So it is really...again, it is really difficult to tell. I think that there certainly is, from what we understand, we haven't been formally notified in any respect, but certainly from what we hear around the community, that there is certainly manufacturing and commodity-based impacts that are being felt in the short run here, that could have an impact on the long run perspective.

MR. GAZANKAS: Anything else before I get into the maintenance program? Now we are going to look at our 2009 proposed maintenance program, so major maintenance defined...indicates maintenance projects or programs that are of significant magnitude, and that do not constitute a capital project. Major equipment repair, overhaul projects, vegetation management programs, soils remediation programs fall in this category.

If we look at vegetation management programs, obviously a program in implementation would be capitalized, but any upgrades to that moving forward is obviously a part of major maintenance. You will see how I have split that out based on the Lidar portion of it, when you get into the actual projects.

Here is the plan overall. Look at the forestry and vegetation management side of things, and we are looking at 1.5 million. Again, we are on cycle at this point, six-year cycle. This addresses the herbicide application, the actual cycles with respect to the growth rates, and also looking at the danger tree identification and removal of them, as well.

If you look at major overhauls in stations, so we do have, for the most part, a six-year cycle of our maintenance program, where we will look at a given station and the major equipment contained within, and based on manufacturer's specifications or recommendations, usually six-year for the new SF6 breakers, we will perform an overhaul, work and test on that equipment to ensure that it is meeting the manufacturer's specifications.

Next, we look at right-of-way access, and of course, the access is very important, not only from managing the right-of-way from a vegetation management perspective, but we look at emergency response as well. If the access is not managed accordingly, we could have issues or there could be times when the crews get out and find that the road has been washed out. So it is really not desirable to let that go, and it is imperative that we maintain those access roads annually.

The next is an annual circuit inspection. We use Hydro One's equipment. They come up. They quote us a price, and what we do is infrared scan of our transmission circuits via helicopter, and we just identify any potential issues or hot spots on the lines, on the circuits. It has worked out well so far for us.

Then we look at soil remediation activities. In the past, if there is any...from an environmental perspective, if there was any staining of a station, the transformer leaked at one point, or a bulk oil breaker, we would go do our soil testing, and from that determine the remediation, soil remediation activities and develop action plans surrounding that.

The last project is the process of Lidar data. You will notice in the capital projects I had processing of Lidar data, and that was specifically for an individual transmission circuit that had never been processed before.

What we will do here in the maintenance

category is...the data that was processed in the past, but as we do changes to do the system, we are not flying the line every year and collecting the data, but now when we fly the line, we will have that information, but we will just update to the existing information that we have, just to make sure that any changes are accounted for accordingly. So that is how we have separated that. Any questions on the major maintenance plan? Any questions in general?

MR. BUONAGURO: I snuck most of the questions in as we went along.

MR. LAVOIE: Yes. Well, great, I guess we will close the session for 2009. I certainly thank you for participating. Certainly we will expect that sort of time frame for next year, November time frame, and we will certainly take those comments into consideration that you have given throughout the presentation, as well as with respect to the board calendar in trying to schedule next year's session. Okay, thanks.

I hereby certify the foregoing to be a true and accurate transcription of the above noted proceedings held on the 18th DAY OF NOVEMBER, 2008 and transcribed to the best of my skill, ability and understanding.

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} Certified
Correct:
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} Robert Dudley
} Certified
Verbatim Reporter
}

May-09

TRANSMISSION

		Potential Increases (Decreases)				
		Operations	Maintenance	Admin	Major Mtce.	
Trans. Asset Management Engineering	0330	(58,553)				Labour & Allocation Changes
Project Manager (as of M/E April)	0330	14,300				
Senior Management	0320			(30,075)		Labour & Expenses & Transmission allocation change not accounted for in earlier 2009 changes.
Accounting/HR/Procurement	0345			50,537		Labour & Expenses/Contract
Information Technology	0349			(11,163)		Correction to allocation from Previous changes
Planning & Maintenance Services	0550			(35,972)		
Sackville Building Share	0325	(7,314)				Miscellaneous items. Reduction not as significant as in Distribution as we did not allocate any rent as planned to Canadian Operations OSC or MSP
System Control & Communications	0359	(120,800)				
Rating Mtce. Fees	0325			25,000		Not included in original budget
Insurance	0325			54,977		Rates increased following budget prepartion.
Lines Operations & Mtce. Activities						
Lines Major Maintenance - Infra Red Scan	0335				(80,000)	
Stations Operations & Mtce. Activities						
Transm. Stations - Major Maintenance "Station Major Overhauls"	0331, 0332 & 0333				(98,985)	Based on Historic levels total estimated cost of major overhauls is too high and work continues to get rolled in with regular maintenance.
Transm. Stations - Major Maintenance "Land Remediation"	0331, 0332 & 0333				(50,000)	To date no areas requiring remediation in 2009 have been identified.
Forestry Major "ROW" Maintenance	0336				(400,000)	
						Total Increase (Decrease)
		(172,367)	**-**	**53,304**	**(628,985)**	**(748,048)**

GLP Criteria For FIT Data **June 26, 2009**

1. Radial 115kV Lines and 115kV Transformers

1.1. Criteria:

1.1.1. Minimum Load is based on SCADA data for June, July, August and Sept 2008 which shows the customer loads each hour on the hour (see data below).
1.1.2. Maximum Generation based on GLP Generation table using the "MW between limiting PF and 0.90 PF" column (see data below).
1.1.3. Line MW ratings are based on Amp rating @ 25^0C with 4km/hr wind at an inclination of 20^0, PF = 0.9 and 122kV (normal maximum at these stations).
1.1.4. All GLP 115kV lines are strung to 90^0C with no long-term emergency ratings.
1.1.5. GLP transformer ratings are based on nameplate MVA ratings and where available 10-day LTR's.
1.1.6. GLP transformers limited to 60% (same as Hydro One) back feed based on 60% of transformer MVA rating plus minimum load minus existing connected generation.
1.1.7. Assumed no additional G/R schemes only existing G/R schemes without any modifications.
1.1.8. Actual linear analysis was not performed so MW's are approximate and based on simple calculations assuming at a single contingency.
1.1.9. A lines MW available was limited to the limits of upstream 115kV lines
1.1.10. Auto transformers at MacKay TS and Third Line TS were not included in the transformer list

1.2. Radial 115kV Lines:

GLP has three systems of Radial 115kV lines within its system:

1.2.1. Lines from Anjigami TS
- – No.1 and No.2 High Falls lines in parallel to D.A Watson TS
- – Magpie line radial to Magpie TS
- – Mission, Harris and Steephill lines radial from Magpie TS

1.2.2. Lines from MacKay TS
- – No.1 and No.2 Gartshore lines in parallel to Gartshore TS
- – Gartshore, Andrews and Hogg lines radial from Gartshore TS

1.2.3. Lines from Third Line TS
- – No.1, No.2 and No.3 Algoma lines in parallel to Steelton/Patrick St. TS's
- – No.1 and No.2 Clergue lines in parallel to Clergue TS
- – Leigh's Bay Line radial from Patrick St. TS

1.2.4. In addition to these systems there are the following:
- Hollingsworth 115kV in parallel with Hollingsworth TS, Limer 44kV line from Hollingsworth TS and Anjigami 44kV line from Anjigami TS
- No.3 Sault in parallel with 230kV between MacKay TS and Third Line TS
- Northern Ave. line radial from Third Line TS

1.3. Minimum Load

Based on SCADA hourly data from June, July, August and September 2008:

1.3.1. Load associated with lines from Anjigami TS:

No.1 and No.2 Wawa feeders (D.A. Watson TS)	3 MW
River Gold Mines	1 MW

1.3.2. Load associated with lines from MacKay TS:

Andrews TS	0 MW

1.3.3. Load associated with lines from Third Line TS:

ESSAR Steel Algoma Inc. (Patrick St. TS)	82 MW
Saint Marys Paper Corp. (Clergue TS)	22 MW
Flakeboard & Wallace Terrace (Leigh’s Bay Line)	2 MW

1.3.4. Load associated with other lines:

Batachawana TS and Goulais Bay TS (No.3 Sault)	2 MW
Limer 44kV and Anjigami 44kV (Anjigami TS)	3 MW
No.1 and No.2 Bruce Mines feeders (Echo River TS)	3 MW
Northern Ave. TS	0 MW

1.4. Maximum Generation

Based on data provided by GLPL Generation and Facility Registration Data:

1.4.1. Generation associated with lines from Anjigami TS

R.A. Dunford GS G1	22.50 MW	D.A. Watson TS
R.A. Dunford GS G2	22.50 MW	“
Scott GS G1	8.00 MW	“
Scott GS G2	8.00 MW	“
McPhail GS G1	6.93 MW	“
McPhail GS G2	6.93 MW	“
Harris GS G1	15.50 MW	Harris 115kV line
Mission Falls GS G1	15.50 MW	Mission 115kV line

Steephill Falls GS G1	15.50 MW	Steephill 115kV line

1.4.2. Lines from MacKay TS

Andrews GS G1	9.30 MW
Andrews GS G2	9.20 MW
Andrews GS G3	27.80 MW
Gartshore GS G1	23.00 MW
Hogg GS G1	15.00 MW

1.4.3. Lines from Third Line TS

Clergue GS G1	18.00 MW	
Clergue GS G2	18.00 MW	
Clergue GS G3	18.00 MW	
LSP GS GT1	47.00 MW	
LSP GS GT2	47.00 MW	
LSP GS SG1	26.10 MW	
AELP GS	limited to total ESSAR load (maximum 103MW)	Patrick St. TS

1.4.4. Other lines

Hollingsworth GS G1	20.00 MW	Hollingsworth TS

2. 230kV System Studies

2.1. Criteria:

2.1.1. East-west line flow at 325 MW flow east (see Figure 1 for the minimum load case)

2.1.2. Minimum Load was based on SCADA data for June, July, August and Sept 2008 which shows the customer loads each hour on the hour and by scanning this data the June 02, 2008 reading taken at 15:00 hour of 231 MW (220 MW with ASITUBE at 0 MW) was evaluated as the weekday daytime peak.

2.1.3. Maximum Load was also based on SCADA data for June, July, August and Sept 2008 which showed maximum load of 345 MW at 15:00 hour on August 25, 2008. Table 1 section 2.4 gives the min & max loads studied.

2.1.4. Maximum Generation based on IESO load flow P max multiplied by 90% for hydroelectric units, maximum wind & solar, max gas at AELP and LSP studied at 0 MW & at max. MW.

2.1.5. Line ratings are based on Amp rating @ 25^0C with 4km/hr wind and MW calculated at 220 kV and unity power factor which is equivalent to calculating the MW at 244kV and 90% power factor.

2.1.6. Assumed no additional G/R schemes only existing G/R schemes without any modifications.

2.1.7. PSSE TLTG linear analysis performed at the terminal stations of GLP Lines (section 2.2). The available capacity of the line was based on the minimum of the generation which could be connected at either terminal end or the more limiting of up/downstream limits respecting single 230 kV line contingencies outlined in section 2.3. Only GLP 230 kV lines and No 3 Sault 115 kV line were monitored.

2.2. 230kV Lines Monitored:

W23K Wawa TS to MacKay TS
K24G MacKay TS to Heyden SS to Third Line TS
P21G Third Line TS to Mississagi TS
P22G Third Line TS to Echo River TS to Mississagi TS

W23K is in series with K24G and in series with the parallel P21G and P22G lines form part of the East-West Tie as they are in parallel with the Hydro One lines P25W and P26W.

Also, T2 at MacKay TS plus No.3 Sault 115kV plus T1 and T2 autotransformers at Third Line TS are in parallel with K24G 230kV line.

2.3. 230kV Line Outages:

W23K Wawa TS to MacKay TS
K24G MacKay TS to Heyden SS to Third Line TS
P21G Third Line TS to Mississagi TS
P22G Third Line TS to Echo River TS to Mississagi TS
P25W Wawa to Mississagi TS

2.4. Minimum & Maximum Load Tables

Table 1	Loading conditions evaluated :			Minimum Load Case		Maximum Load Case	
Load Flow Bus #	Load Flow Bus Name	Voltage	GLP System Station Name	LF Load (MW)	LF Load (MVAR)	LF Load (MW)	LF Load (MVAR)
10110	ECHORIV1	34.5	Bruce Mines	3.6	1.55	4.1	1.55
10124	DAWATSO	12	Wawa	3.6	1.55	3.3	1.55
10153	HWY1017	7.2	No. 4 Weyer	6.7	2.88	5.2	2.88
10156	NORTHAV	12	N/A	0	0	0	0
10157	NORTHAVN	34.5	N/A	0	0	0	0
10159	GOULAIS	12	Batch Goulais	1.5	0.65	1.9	0.65
10161	BATCHAW	12	Batch Goulais	1	0.43	1	0.43
10166	MACKY G3	12	N/A	0	0	0	0
10177	ANDRW LT	25	N/A	0	0	0	0
10179	PATRICK1	34.5	A.S.C.	0	12.9	25	12.9

Table 1	Loading conditions evaluated :			Minimum Load Case		Maximum Load Case	
10180	PATRICK2	34.5	A.S.C.	0	12.9	25	12.9
10181	PATRICK3	34.5	A.S.C.	0	10.75	20	10.75
10182	PATRIC 1	12	A.S.C.	0	3.44	5	3.44
10183	PATRIC 6	12	A.S.C.	0	1.72	0	1.72
10184	PATRIC 7	12	A.S.C.	0	1.72	0	1.72
10188	STMARY12	34.5	P.U.C	14	6.02	14	6.02
10189	STMARY34	34.5	P.U.C	0	0	0	0
10192	TARENT12	34.5	P.U.C	0	0	6	3
10193	TARENT34	34.5	P.U.C	0	0	0	0
10196	ASITUB	12	Leigh's Bay	0	0	30.2	15
10198	FLAKEBO	12	Leigh's Bay	3.4	1.46	3.4	1.46
10200	CLERGUE	12	St Marys	26	11.18	40	20
			Totals	220	MW	345	MW

At Patrick TS the new AELP 101 MW generation was netted out of the load in both the minimum and maximum load cases.

At St Mary's & Tarentorus, PUC transformer stations, 60 MW of contracted solar power was netted out of the min & max load cases.

For the min load case the ASITUB load was assumed off. However, in the max case the load was assumed at maximum.

2.5. Generation Dispatched

Dispatch of Generation without LSP (0 MW)

Bus #	Station Name GS	Voltage	Dispatch	Peak MW
10130	HOLINGG1	12	18	20
10137	MCPHALG1	12	4.5	5
10138	MCPHALG2	12	4.5	5
10141	SCOTT G1	12	9.18	10.2
10143	SCOTT G2	12	9.72	10.8
10147	MISSIOFL	6.6	12.51	13.9
10149	HARRISG1	6.6	10.08	11.2
10151	STEEPHL	6.6	10.53	11.7
10165	MACKYG12	12	8.1	9
10165	MACKYG12	12	8.1	9
10166	MACKY G3	12	20.25	22.5

Bus #	Station Name GS	Voltage	Dispatch	Peak MW
10169	GARTSHO	12	18	20
10171	HOGG G1	12	13.5	15
10173	ANDREWG3	12	20.25	22.5
10174	ANDREWG2	12	8.28	9.2
10175	ANDREWG1	12	8.28	9.2
10203	CLERG G1	4.2	16.92	18.75
10204	CLERG G2	4.2	15.57	17.3
10205	CLERG G3	4.2	16.92	18.75
10217	HIFLSRG1	12	20.25	22.5
10218	HIFLSRG2	12	20.25	22.5
10257	PRINCE1	0.575	24	24
10258	PRINCE2	0.575	24	24
10259	PRINCE3	0.575	25.5	25.5
10260	PRINCE4	0.575	25.5	25.5
10261	PRINCE5	0.575	24	24
10262	PRINCE6	0.575	25.5	25.5
10263	PRINCE7	0.575	25.5	25.5
10264	PRINCE8	0.575	25.5	25.5

Total Generation	473.19	503.5

LSP in-service at 115 MW (Other stations dispatched as in the LSP 0 case)

Bus #	Station Name GS	Voltage	Dispatch	Peak MW
10207	LKSUPGT1	13.8	45	47
10208	LKSUPGT2	13.8	45	47
10209	LKSUPSG1	13.8	25	26.1

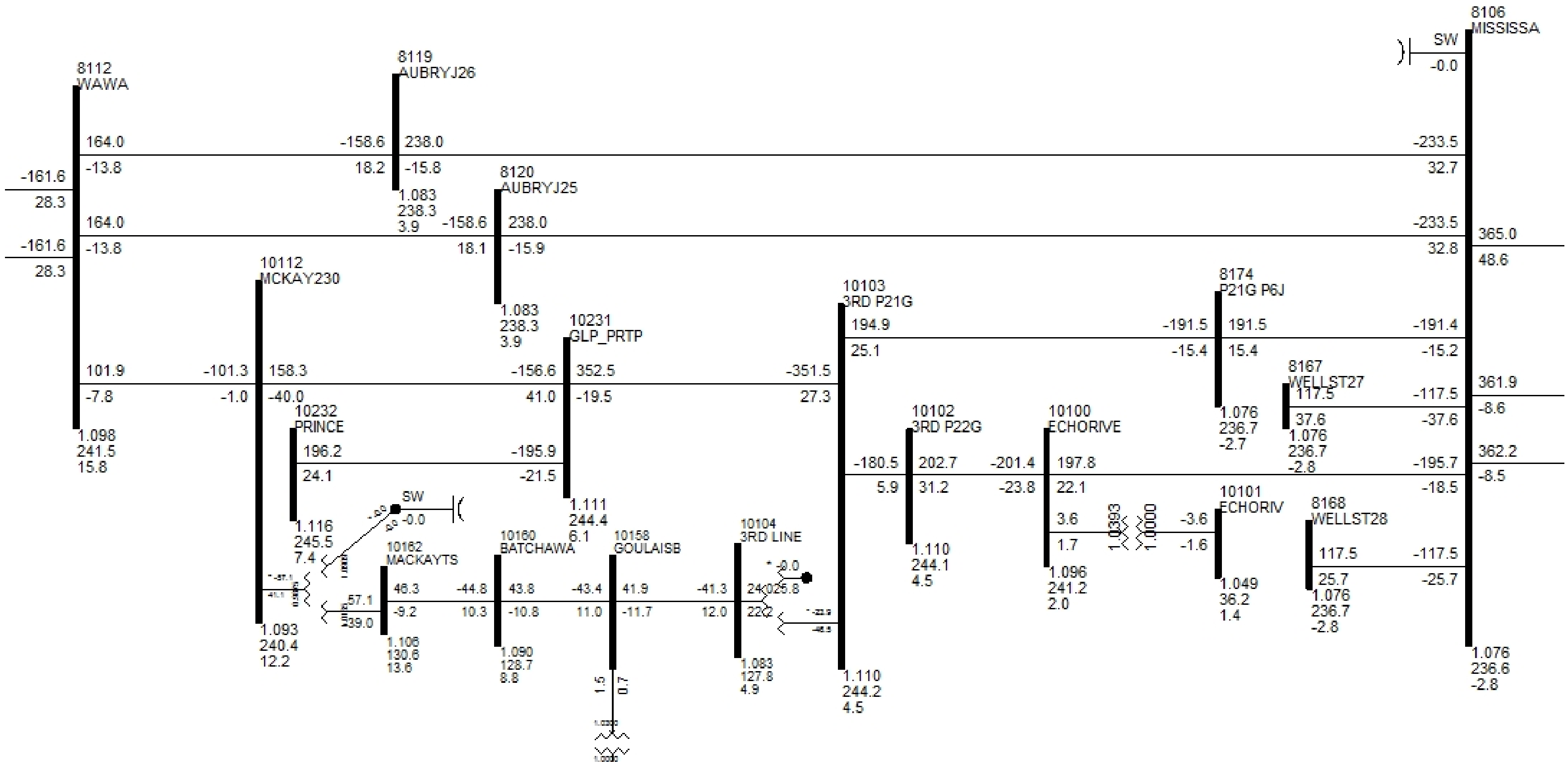
LSP Generation	115	120.1

Generation in-service netted from customer load

Bus #	Station Name GS	Voltage	Dispatch	Peak MW
Patrick St. TS	AELP GS	34.5	101	103
PUC TS's	Solar	34.5	60	60

LSP Generation	161	163

2.6. Base Flow Condition with LSP O/S (0 MW) and Minimum Load (220MW)



10562014.1
35306-2001

2.7. Sample Linear Analysis base factors for transfers from Third Line TS to Darlington GS, and line loading with LSP O/S (0 MW) and Minimum Load Case (220 MW)

LOADINGS AT OR ABOVE 100.0 %
OF RATING ARE MARKED WITH '*'

FROM			TO			CKT	TOTAL TRANS CAPAB	RATING A	BASE CASE PRE-SHIFT MW	BASE CASE POST-SHIFT MW	BASE CASE LIMIT CASE MW	DISTR. FACTOR
	INTERFACE MFE						-40.1	1000	1041.8*	1141.9*	1000.0*	1.00054
10102	3RD P22G	220.00	10100	ECHORIVE	220.00	1	411.0	381	201.8	245.7	183.5	0.43835
8106	MISSISSA	220.00	10100	ECHORIVE	220.00	1	424.7	382	-196.1	-240.0	-177.8	-0.43835
10103	3RD P21G	220.00	8174	P21G P6J	220.00	1	446.6	382	191.9	234.5	174.0	0.42664
8106	MISSISSA	220.00	8174	P21G P6J	220.00	1	446.8	382	-191.8	-234.5	-174.0	-0.42664
8112	WAWA	220.00	10112	MCKAY230	220.00	1	4310.2	482	101.1	87.5	106.7	-0.13533
10112	MCKAY230	220.00	10231	GLP_PRTP	220.00	1	5653.7	480	156.5	145.2	161.2	-0.11265
10160	BATCHAWA	118.05	10158	GOULAISB	118.05	3	5953.3	92	43.4	41.1	44.3	-0.02267
10162	MACKAYTS	118.05	10160	BATCHAWA	118.05	3	6020.6	92	44.8	42.6	45.8	-0.02267
10158	GOULAISB	118.05	10104	3RD LINE	118.05	3	6110.1	97	41.3	39.0	42.2	-0.02267
10103	3RD P21G	220.00	10231	GLP_PRTP	220.00	1	7392.6	481	-351.4	-340.1	-356.1	0.11265

GREAT LAKES POWER TRANSMISSION INC.

- and -

BROOKFIELD CANADA INFRASTRUCTURE HOLDINGS INC.

GREAT LAKES POWER TRANSMISSION LP

LIMITED PARTNERSHIP AGREEMENT

May 17, 2007

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LIMITED PARTNERSHIP AGREEMENT

THIS AGREEMENT made this 17th day of May, 2007.

B E T W E E N:

GREAT LAKES POWER TRANSMISSION INC.

(the "General Partner")

- and -

BROOKFIELD CANADA INFRASTRUCTURE HOLDINGS INC.

(the "Original Limited Partner")

ARTICLE 1
INTERPRETATION

1.1 Definitions

In this Agreement, except as otherwise expressly provided, the following words or expressions will have the following meanings:

(a) **"Agreement"** means this agreement and all schedules attached to this agreement, in each case as it or they may be amended, supplemented, replaced or restated from time to time.

(b) **"Business Day"** means any day except Saturday, Sunday, or any statutory holiday in Toronto, Ontario;

(c) **"Capital"** means the total capital of the Partnership which is raised pursuant to subscriptions of Class A Units and Class B Units.

(d) **"Capital Contribution"** means the aggregate amount contributed as capital to the Partnership by a Partner.

(e) **"Cash Available for Distribution"** means Partnership Cash from Operations and Partnership Capital Receipts.

(f) **"Class A Unit"** means a unit in the form attached as Schedule A that is held by a Limited Partner and represents the right, title and interest of such Limited Partner in and to the Partnership. All Class A Units outstanding at any time represent, in the aggregate, a 99.9% interest in the Partnership.

(g) **"Class B Unit"** means a unit in the form attached as Schedule B that is held by the General Partner and represents the right, title and interest of the General

Partner in and to the Partnership. All Class B Units outstanding at any time represent, in the aggregate, a 0.1% interest in the Partnership.

(h) **"Declaration"** means the declaration of limited partnership, as it may be amended from time to time, filed with respect to the Partnership pursuant to this Agreement and the requirements of the Limited Partnerships Act.

(i) **"General Partner"** means, at any particular time, the party to this Agreement who has executed the Agreement as General Partner and is then holding office as General Partner.

(j) **"Income Tax Act"** means the *Income Tax Act* (Canada), as amended, and any re-enactments, replacements or substitutions thereof.

(k) **"Limited Partner"** means any of the limited partners of the Partnership. As at the date hereof the Original Limited Partner is the sole Limited Partner holding 100 Class A Units.

(l) **"Limited Partnerships Act"** means the *Limited Partnerships Act* (Ontario), as amended, and any re-enactments, replacements or substitutions thereof.

(m) **"Partner"** means the General Partner or any Limited Partner, and **"Partners"** means, collectively, the General Partner and all Limited Partners.

(n) **"Partnership"** means the Great Lakes Power Transmission LP formed pursuant to the Declaration.

(o) **"Partnership Capital Receipts"** means the net amounts received by the Partnership on account of capital less any amounts required for capital expenses and reserves which the General Partner determines are necessary or desirable.

(p) **"Partnership Cash From Operations"** means the net cash received by the Partnership from the Partnership's operations and investments, after the expenses and liabilities of the Partnership are paid and after an allowance is made for reasonable reserves which the General Partner determines are necessary or desirable.

(q) **"Person"** means an individual, sole proprietorship, partnership, unincorporated association, unincorporated organization, unincorporated syndicate, trust, body corporate, and a natural person in his or her capacity as trustee, executor, administrator or other legal or personal representative.

(r) **"Subscription"** means a subscription for Class A Units or Class B Units, as applicable, in a form acceptable to the General Partner, pursuant to which, among other things, the Person acquiring such Units, if not a Partner, agrees to be bound by this Agreement in the same manner as if it had been an original party hereto.

(s) **"Subscription Price"** means the amount per Class A Unit or Class B Unit, as applicable, to be determined at the relevant time by the General Partner, that is to be contributed to the Capital in consideration for the issuance of the particular Class A Units or Class B Units.

(t) **"Transfer"** means to sell, assign, surrender, gift, transfer, pledge, mortgage, charge, create a security interest in, hypothecate or otherwise encumber any Unit or any interest, whether legal or beneficial, in a Unit, whether voluntary, involuntary, by operation of law or otherwise.

(u) **"Unit"** means either a Class A Unit or a Class B Unit.

1.2 Construction

In this Agreement, except as otherwise expressly provided:

(a) All words and personal pronouns relating thereto are to be read and construed as the number and gender of the party or parties require and the verb is to be read and construed as agreeing with the required word and pronoun.

(b) The division of this Agreement into articles and sections and the use of headings is for convenience of reference only and does not modify or affect the interpretation or construction of this Agreement or any of its provisions.

(c) When calculating the period of time within which or following which any act is to be done or step taken pursuant to this Agreement, the date which is the reference day in calculating such period is excluded. If the last day of such period is not a Business Day, the period in question ends on the next succeeding Business Day.

(d) All dollar amounts expressed are in Canadian funds.

(e) Any accounting terms that are not specifically defined are to be construed in accordance with generally accepted accounting principles as prescribed by the Handbook of the Canadian Institute of Chartered Accountants.

ARTICLE 2
FORMATION, NAME, PLACE OF BUSINESS, FISCAL YEAR

2.1 Formation

The Partners hereby confirm that the Partnership was formed in accordance with the Limited Partnerships Act and is amended by this Agreement. The Partnership will be effective as a limited partnership from the date upon which the Declaration is filed in accordance with the Limited Partnerships Act until such time as is determined in accordance with Article 3.

2.2 Name

The name of the Partnership is Great Lakes Power Transmission LP. The Partnership will carry on business under that name or such other name as the General Partner may from time to time determine, provided the use of such name conforms to all applicable laws.

2.3 Place of Business

The General Partner will determine the location of the principal place of business of the Partnership and all additional places of business of the Partnership from time to time. The General Partner will give notice in writing to the Limited Partners of any change in the principal place of business of the Partnership.

2.4 Fiscal Year

The fiscal year of the Partnership will be the calendar year.

ARTICLE 3
PERIOD OF PARTNERSHIP

3.1 Date of Termination

The Partnership will be dissolved and its affairs wound-up at the time specified in and in accordance with Article 13.

3.2 Events Not Causing Dissolution

Subject to the provisions of section 13.1, the Partnership will not be dissolved or terminated by the addition, resignation, removal, death, mental incapacity, insanity, bankruptcy, insolvency or receivership of any Partner or by the dissolution, liquidation or winding up of any Limited Partner.

ARTICLE 4
BUSINESS AND POWERS OF THE PARTNERSHIP

4.1 Business

The Partnership will carry on the business of acquiring, owning, operating and developing power transmission assets in Canada, and may carry on any business incidental thereto or in furtherance thereof as the General Partner deems desirable. The Partnership may enter into such agreements as the General Partner considers necessary or advisable in respect of the business of the Partnership.

4.2 Powers

In connection with carrying on its business, the Partnership has the power to do and perform all things necessary for or incidental to or connected therewith.

4.3 Limited Authority of Limited Partner

No Limited Partner in its capacity as a Limited Partner may:

(a) take part in the management or control of the business of the Partnership;

(b) execute any document which binds or purports to bind the Partnership or any Partner;

(c) hold itself out as having the power or authority to bind the Partnership or any Partner;

(d) undertake any obligation or responsibility on behalf of the Partnership; or

(e) bring any legal action for partition or sale in connection with any property or assets of the Partnership, whether real or personal, or register or permit any lien or charge in respect of such property or assets.

ARTICLE 5
LIABILITY OF PARTNERS

5.1 Limited Partners

The liability of each Limited Partner for the debts, liabilities, obligations and losses of the Partnership is limited to the Capital Contribution of that Limited Partner plus its *pro rata* share of the undistributed income of the Partnership. Subject to the provisions of the Limited Partnerships Act, a Limited Partner has no further liability for any debts, liabilities, obligations or losses of the Partnership and is not liable for any calls or assessments or further contributions to the Partnership.

5.2 General Partner

The General Partner has unlimited liability for all of the debts, liabilities, obligations and losses of the Partnership. The General Partner is not liable to the Limited Partners for any of its acts, omissions or errors in judgment, except those resulting from its gross negligence, wilful misconduct or disregard of its obligations or breach of its duties under this Agreement.

5.3 Indemnification of Limited Partners

Subject to the limitation in section 5.2, the General Partner hereby indemnifies and holds harmless each Limited Partner for any costs, damages, liabilities, expenses or losses suffered or incurred by a Limited Partner that result from or arise out of the Limited Partner not having a limit to its liability as required by section 5.1, other than any lack of limited liability caused by any act or omission of the Limited Partner.

ARTICLE 6
UNITS AND CAPITALIZATION

6.1 Authorization of Units

The Partnership is authorized to issue an unlimited number of Class A Units and Class B Units.

6.2 Capitalization by General Partner

The General Partner hereby subscribes for one Class B Unit at a price of $1, and acknowledges on behalf of the Partnership that the Partnership has received the sum of $1 in full satisfaction of the Subscription Price for such Class B Unit. All Class B Units outstanding at any time collectively represent a 0.1% interest in the Partnership. The General Partner is not obligated to make any additional contributions of capital to the Partnership or to subscribe for any additional Units.

6.3 Class A Units

The 99.9% interest in the Partnership of the Limited Partners will be divided into and represented by Class A Units, provided that if at any time, no Class A Units are outstanding, the 99.9% interest in the Partnership will be divided equally among the Limited Partners. Each Class A Unit shall entitle the holder thereof to the same rights and obligations as to the holder of any other Class A Unit, and no Limited Partner shall be entitled to any privilege, priority or preference in relation to any other Limited Partner

6.4 Initial Capitalization by Limited Partners

The Original Limited Partner hereby subscribes for 100 Class A Units at a price of $1 per Class A Unit, and the General Partner hereby acknowledges receipt of the sum of $100.00 in full satisfaction of the Subscription Price therefor. All Class A Units outstanding at any time collectively represent a 99.9% interest in the Partnership.

6.5 Additional Capitalization

No Limited Partner is obligated to make any additional contributions of capital to the Partnership or to subscribe for any additional Units. Any Limited Partner may, at any time upon notice to the other Partners and with the consent of the General Partner, increase its respective Capital Contribution by subscribing for additional Class A Units, on such terms and conditions as are agreed to at the relevant time by the General Partner in its sole discretion. No Limited Partner shall be entitled to demand a return of its Capital Contribution or require the Partnership to retract or redeem Class A Units unless such return of capital is pursuant to the dissolution provisions as set forth in Article 13. The General Partner may agree to return capital to a Limited Partner in its sole and absolute discretion.

6.6 Admission of New Limited Partners and Issuance of Additional Units

The General Partner may admit any Person as a Limited Partner at any time and from time to time in its sole discretion, subject to the receipt of a Subscription and payment in full of the Subscription Price for the Class A Unit(s) subscribed for.

6.7 Additional Subscriptions for Class A Units

Each subscriber for additional Class A Units shall submit a Subscription to the General Partner. The General Partner shall have the right to accept or reject Subscriptions in whole or in part.

6.8 Transfers of Class A Units

Subject to the requirements of section 15.1, a Limited Partner may transfer any or all of its Class A Units if (a) the transferee delivers or causes to be delivered to the General Partner the unit certificate(s) representing the Class A Units being transferred, duly endorsed for transfer, together with a duly completed and executed transfer and assumption agreement, in a form approved by the General Partner, pursuant to which, among other things, the transferee agrees to be bound by this Agreement as a Limited Partner as if it had been an original party hereto, and (b) all filings and recordings required by law with respect to such transfer have been duly made.

ARTICLE 7
ACCOUNTS

7.1 Capital Account

There will be established for each Partner on the books of account of the Partnership a capital account which will be credited or charged with the net income or loss of the Partnership and with distributions made to Partners.

Each Partner's respective share of the net income or loss of the Partnership will be credited or charged to that Partner's capital account in accordance with section 8.1 and will be charged with distributions and credited with repayments made as required by Article 9.

7.2 No Right to Withdraw Amounts

No Partner will have the right to withdraw any amount or receive any distribution from the Partnership, except as expressly provided in this Agreement.

7.3 No Interest Payable on Accounts

No interest will be paid to any Partner on any amount in that Partner's capital account.

ARTICLE 8
DETERMINATION AND ALLOCATION OF NET INCOME OR LOSS

8.1 Determination and Allocation of Net Income or Loss

The net income or loss of the Partnership for each fiscal year will be determined in accordance with generally accepted accounting principles and allocated as the end of each fiscal year among the Partners as follows:

(a) 0.1% of the net income or loss of the Partnership will be allocated to the General Partner; and

(b) 99.9% of the net income or loss of the Partnership will be allocated among the Limited Partners of record at the end of the fiscal year in proportion to the number of Class A Units held by each of them or, where no Class A Units are then outstanding, according to their respective interests.

8.2 Computation of Income or Loss for Tax Purposes

In computing the income or loss of the Partnership for tax purposes, the General Partner may adopt such method of accounting as it deems appropriate, may adopt different treatments of particular items and may make and revoke elections on behalf of the Partnership and the Partners as the General Partner may deem to be in the best interests of the Partners. In respect of any fiscal year, the General Partner may claim such capital cost allowance in respect of depreciable property of the Partnership and such deductions and reserves as are permitted under the Income Tax Act and as it deems would be in the best interests of the Limited Partners.

8.3 Tax Returns

Each Partner will prepare and file such documents as may be required under the Income Tax Act and will include in its computation of income the income or loss of the Partnership for tax purposes as may be determined and allocated to it pursuant to this Agreement.

ARTICLE 9
DISTRIBUTION OF CASH AND RETURN OF CAPITAL TO PARTNERS

9.1 Determination of Cash Available For Distribution

The General Partner will determine the Cash Available For Distribution and will distribute such Cash Available For Distribution in such amounts and at such times as it sees fit, in its sole discretion. Distributions of Cash Available for Distribution will be paid to the Partners in the same proportions as set out in section 8.1.

9.2 Distributions Resulting in Debit Balances in Capital Accounts

Distributions made in accordance with this Article may result in debit balances in the capital accounts of the Partners. The existence of a debit balance in the capital account of any Partner will not operate to terminate the interest of such Partner in the Partnership.

9.3 Return of Capital Contribution

No Limited Partner shall be entitled to demand a return of its Capital Contribution unless such return of capital is pursuant to the dissolution of the Partnership pursuant to Article 13. All Partners will look solely to the assets of the Partnership for the return of their respective Capital Contributions or any other distributions with respect to their Units. If the assets remaining after the payment or discharge of all debts and liabilities of the Partnership are insufficient to return to Partners their Capital Contributions or to make any other distribution to the Partners, no Partner will have any recourse against the personal assets of any other Partner for that purpose except in respect of the obligations of the General Partner pursuant to section 5.2 or section 5.3.

9.4 Repayment

If the Partnership has paid any Partner an amount in excess of an amount to which it is entitled pursuant to this Article, that Partner will reimburse the Partnership to the extent of the excess without interest within 30 days after notice by the General Partner. The General Partner may set-off and apply any sums otherwise payable to a Partner against amounts due from the Partner, provided that there will be no right of set-off against a Limited Partner in respect of amounts owed to the Partnership by the predecessor of that Limited Partner.

ARTICLE 10
THE GENERAL PARTNER

10.1 Representations, Warranties and Covenants of General Partner

The General Partner represents, warrants and covenants to each Limited Partner that, so long as it is the General Partner, it:

(a) is and will continue to be a corporation duly existing and in good standing;

(b) is and will continue to be duly registered and qualified to carry on business and has and will continue to have all requisite authority, licenses and permits to carry on the business of the Partnership and to enable the Partnership to own or lease property in all provinces of Canada in which the activities, or the property or assets of the Partnership, render or will render such registration, qualification, authority, licence or permit necessary;

(c) has and will continue to have the capacity and corporate authority to act as the General Partner of the Partnership;

(d) can fulfil its obligations as General Partner without violating the terms of its constating documents, by-laws or any agreement to which it is or will be a party or by which it is or will be bound or any law or regulation applicable to it;

(e) will carry out its powers and authorities as General Partner hereunder and manage and operate the Partnership and the undertaking, property and assets thereof in a reasonable and prudent manner;

(f) will devote as much time to the conduct of the business of the Partnership as is reasonably required for the prudent management of the business and affairs of the Partnership; and

(g) will not dissolve, wind-up or liquidate its business and affairs except with the unanimous approval of the Limited Partners.

ARTICLE 11
MANAGEMENT OF THE PARTNERSHIP

11.1 Duties of General Partner

The General Partner will carry on the business of the Partnership with full power and authority to manage, control, administer and operate the business and affairs of the Partnership and to represent the Partnership. The power of the General Partner to represent the Partnership to third parties is unrestricted and no Person dealing with the Partnership will be required to enquire into the authority of the General Partner to take any act or proceeding, to make any decision or to execute and delivery any instrument, deed, agreement or document for or on behalf or in the name of the Partnership.

11.2 Powers of the General Partner

Subject to the provisions of this Agreement, the General Partner has full power and exclusive authority for and on behalf of the Partnership to do all things in furtherance of or incidental to the business of the Partnership or that are provided for in this Agreement.

11.3 Borrowing Power

Without limiting the generality of section 11.2 the General Partner has full power and exclusive authority for and on behalf of the Partnership to, from time to time, (a) borrow money, (b) enter into guarantees and/or indemnities, (c) draw, make, execute and issue loan agreements, promissory notes, evidences of indebtedness and other negotiable or non-negotiable instruments, (d) secure the payment of any sums so borrowed, guaranteed or indemnified, (e) mortgage, pledge, charge, assign and hypothecate or assign in trust all or any part of, or any interest in, any of the undertaking, property or assets of the Partnership, (f) assign any money owing or to be owing to the Partnership, and/or (g) engage in any other means of financing.

11.4 Financial Assistance

Without limiting the generality of sections 11.2 and 11.3, the General Partner may, from time to time, for and on behalf of the Partnership:

(a) give financial assistance to any Person by means of a loan, guarantee or otherwise for any purpose, including without limitation, for the purpose of or in connection with a purchase of an interest in the Partnership, and the Capital Contribution of any Limited Partner;

(b) give a guarantee to secure performance of an obligation of any Person; and

(c) mortgage, hypothecate, pledge or otherwise create a security interest in all or any property of the Partnership, owned or subsequently acquired, to secure any obligation of the Partnership or any other Person.

11.5 Exercise of Powers and Discharge of Duties

The General Partner will exercise the powers and discharge the duties of its office honestly, in good faith and in the best interests of the Limited Partners and the Partnership.

11.6 Delegation

The General Partner may contract with any Person to carry out any of the duties of the General Partner under this Agreement, and may delegate to such Person any power and authority of the General Partner hereunder, but no such contract or delegation will relieve the General Partner of any of its obligations under this Agreement.

11.7 Reimbursement of General Partner

The General Partner is entitled to reimbursement from the Partnership for all out of pocket expenses actually incurred by it in the performance of its duties in accordance with the terms of this Agreement.

11.8 Meetings and Approvals of Partners

The General Partner and any Limited Partner may call a meeting of the Partnership on not less than 5 Business Days notice to the other Partners. Such meetings may be held in person or by telephone conference call. A quorum for such meetings will consist of Limited Partners holding at least 51% of the Class A Units then outstanding. Any matter hereunder requiring the approval of the Limited Partners will be deemed to have been approved if the requisite number of Limited Partners have delivered their written approval of such matter to the General Partner.

ARTICLE 12
WITHDRAWAL OF GENERAL PARTNER

12.1 Assignment of Interest

The General Partner may not Transfer its Class B Units except with the prior unanimous approval of the Limited Partners.

12.2 Voluntary Resignation or Dissolution

So long as its resignation as General Partner or dissolution would not result in the dissolution of the Partnership, the General Partner may resign as General Partner or dissolve on not less than 180 days' written notice to all Limited Partners (or such shorter period as is accepted by the Limited Partners). Such resignation will be effective and the General Partner will cease to be General Partner upon the earlier of:

(a) the date specified in the notice; and

(b) the admission of a new General Partner by unanimous approval of the Limited Partners.

12.3 Deemed Resignation

The General Partner will be deemed to have resigned as the General Partner in the event of its bankruptcy, liquidation or winding-up (or the commencement of any act or proceeding in connection therewith which is not contested in good faith by the General Partner) or by the insolvency of the General Partner or by the appointment of a trustee, receiver or receiver and manager of the affairs of the General Partner or if a mortgagee or other encumbrancer takes possession of the property or assets of the General Partner, or a substantial part thereof, or if levy or execution or any similar process is levied or enforced against the property or assets of the General Partner. Such resignation will be effective and the General Partner will cease to be the General Partner upon the earlier of:

(a) 180 days after the Limited Partners are given notice in writing of the occurrence of such event or appointment; and

(b) the admission of a new General Partner by unanimous approval of the Limited Partners.

12.4 Removal

The General Partner may be removed as the General Partner at any time by written notice of unanimous approval of the Limited Partners, which approval must also admit a new General Partner. The removal of the General Partner will be effective upon the admission of the new General Partner.

12.5 Payment of Accounts

If the General Partner is removed pursuant to section 12.4, or if the General Partner resigns or is deemed to resign pursuant to sections 12.2 or 12.3 and the Partnership is not required to be dissolved pursuant to Article 13, the Partnership will pay to the General Partner that has resigned or been removed the amount of any credit balance then in its capital accounts. Such payment will be made to the General Partner that has resigned or been removed 30 days following the effective date of its resignation or removal. The General Partner that has resigned or been removed will also be entitled to its allocation of net income or loss and distribution of Cash Available for Distribution as provided in sections 8.2 and 9.1, respectively (pro rated on a daily basis to the effective date of such resignation or removal). Such allocation and distribution, if any, will be paid within 120 days of completion of the Partnership's fiscal year.

12.6 Transfer of Management

On the admission of a new General Partner to the Partnership, the General Partner that was removed or resigned will do all things and take all steps to transfer the administration, management, control and operation of the business of the Partnership and the books, records and accounts of the Partnership to the new General Partner and will execute and deliver all deeds, certificates, declarations and other documents necessary or desirable to effect such transfer.

12.7 Transfer of Title

On the resignation or removal of a General Partner and the admission of a new General Partner, the General Partner that has resigned or been removed will, at the cost of the

Partnership, transfer legal title to the Partnership's property to such new General Partner and will execute and deliver all deeds, certificates, declarations and other documents necessary or desirable to effect such transfer.

12.8 Release

Upon the removal or resignation of the General Partner, the Partnership will (a) reimburse the General Partner then resigning or being removed for all expenses incurred by it in accordance with this Agreement, and (b) release and hold harmless such General Partner from all claims, actions, costs, demands, losses, damages and expenses with respect to events which occur in relation to the Partnership after the effective date of such removal or resignation unless such events arise from the gross negligence or willful misconduct of the General Partner.

12.9 New General Partner

A new General Partner accepted hereunder must sign a counterpart hereof and thereupon will be bound by all of the provisions hereof and assume the obligations, duties and liabilities of the General Partner hereunder as and from the date the new General Partner becomes a party to this Agreement and will thereupon file an amending Declaration.

ARTICLE 13
DISSOLUTION AND TERMINATION

13.1 Events of Dissolution

The Partnership will be dissolved and its affairs wound up on the earliest of :

(a) the date specified in the notice given by the General Partner under section 12.2 if the Limited Partners have not appointed a new General Partner by unanimous approval prior to the date specified therein;

(b) 180 days following the date of a notice of the occurrence of an event specified in section 12.3 if the Limited Partners have not appointed a new General Partner by unanimous approval prior to the expiration of such 180 day period; and

(c) an election to dissolve the Partnership accepted by unanimous approval of the Limited Partners.

13.2 Receiver

The General Partner will serve as the receiver of the Partnership if its dissolution is authorized pursuant to the provisions of section 13.1, provided that if the General Partner is unable or unwilling to act in such capacity, the Limited Partners will appoint an appropriate Person to act as the receiver of the Partnership.

13.3 Liquidation of Assets

As soon as practicable after the authorization of the dissolution of the Partnership, the receiver of the Partnership will prepare or cause to be prepared a statement of the financial position of the Partnership which will be forwarded to each Limited Partner. The receiver of the Partnership will proceed diligently to wind up the affairs of the Partnership, and all assets of the Partnership will be liquidated as promptly as is reasonably possible. During the course of such liquidation, the receiver of the Partnership will operate the properties and undertaking of the Partnership and in so doing will be vested with all the powers and authorities of the General

Partner in relation to the business and affairs of the Partnership under the terms of this Agreement. The receiver of the Partnership will be paid its reasonable fees and disbursements incurred in carrying out its duties.

13.4 Order of Distribution of Net Proceeds

The net proceeds from the liquidation of the assets of the Partnership will be distributed in the following order of priority:

(a) to pay the expenses of liquidation and the debts and liabilities of the Partnership to its creditors;

(b) to provide for such reserves as the receiver of the Partnership may deem reasonably necessary for any contingent or unforeseen liabilities or obligations of the Partnership; provided, however, that any such reserves will be paid over by the receiver of the Partnership to an escrow agent to be held by such escrow agent for the purpose of the payment of liabilities or obligations of the Partnership and any balance remaining will be distributed, at the direction of the receiver of the Partnership, to the Partners in accordance with section 8.1; and

(c) to the Partners in accordance with section 8.1.

13.5 Partition of Assets

In no event and under no circumstances will a Partner be entitled, whether during the existence of the Partnership or after the commencement of the dissolution of the Partnership, to compel a partition, judicial or otherwise, of any of the assets of the Partnership to the Partners, either in kind or otherwise.

13.6 Return of Capital

Except as provided in this Agreement, no Limited Partner has the right to demand or receive a return of its *pro rata* share of the capital account in a form other than cash, provided, however, that nothing herein is to be construed to prohibit such a return of capital in a form other than cash.

13.7 Termination of Partnership

The Partnership will terminate when all of its assets have been disposed of and the net proceeds therefrom (after payment of or due provision for the payment of, all debts, liabilities and obligations of the Partnership to creditors) have been distributed as provided in this Article.

ARTICLE 14
ACCOUNTING AND REPORTING

14.1 Books of Account

The General Partner will keep and maintain, or cause to be kept and maintained, full, complete and accurate books of account and records of the Partnership with respect to the Partnership's business and financial affairs at its principal place of business or elsewhere as the General Partner may consider advisable. Such books of account and records will be retained by or on behalf of the General Partner for a minimum period of six years.

14.2 Reports

The General Partner will provide such reports, statements, financial statements and information relating to the Partnership as any Limited Partner may from time to time request, including any audited or unaudited financial statements requested by a Limited Partner with respect to any period.

ARTICLE 15
TRANSFERS OF UNITS

15.1 Transfers by Limited Partners

A Limited Partner will not Transfer any of its Class A Units without the prior written consent of the General Partner, which consent the General Partner may grant or withhold in its sole discretion.

ARTICLE 16
AMENDMENT OF AGREEMENT

16.1 Amendment

This Agreement may be amended in writing by the General Partner with the unanimous authorization and consent of the Limited Partners. Notwithstanding the foregoing, the General Partner may, without prior notice to or consent from any Limited Partner, amend any provision of this Agreement or add any provision, if such amendment or addition is, in the opinion of the General Partner, for the protection or benefit of Limited Partners or of the Partnership or to cure an ambiguity or to correct or supplement any provisions contained herein which may be defective or inconsistent with any other provision contained herein and if the cure, correction or supplemental provision does not and will not materially adversely affect the interest of any Limited Partner.

ARTICLE 17
NOTICES

17.1 Notice

Any notice or other communication required or permitted to be given hereunder will be in writing and will be given by prepaid first-class mail, by facsimile or other means of electronic communication or by hand-delivery as hereinafter provided. Any such notice or other communication, if mailed by prepaid first-class mail at any time other than during a general discontinuance of postal service due to strike, lockout or otherwise, will be deemed to have been received on the fourth Business Day after the post-marked date thereof, or if sent by facsimile or other means of electronic communication, will be deemed to have been received on the Business Day following the sending, or if delivered by hand will be deemed to have been received at the time it is delivered to the applicable address noted below either to the individual designated below or to an individual at such address having apparent authority to accept deliveries on behalf of the addressee. Notice of change of address will also be governed by this section. In the event of a general discontinuance of postal service due to strike, lock-out or otherwise, notices or other communications will be delivered by hand or sent by facsimile or other means of electronic communication and will be deemed to have been received in accordance with this section. Notices and other communications will be addressed as follows: if to the General Partner to the Partnership's principal place of business and if to a Limited Partner, to the last address of such Limited Partner as was provided to the General Partner.

17.2 Change of Address

A Limited Partner may change its address by giving written notice of such change to the General Partner, and the General Partner may change its address by giving written notice thereof to each Limited Partner.

ARTICLE 18
MISCELLANEOUS

18.1 Severability

If any Article, section or any portion of any section of this Agreement is determined to be unenforceable or invalid by arbitration or by the decision of any court of competent jurisdiction which is not appealed or appealable, for any reason whatsoever, that unenforceability or invalidity will not affect the enforceability or validity of the remaining portions of this Agreement and such unenforceable or invalid Article, section or portion thereof will be severed from the remainder of this Agreement.

18.2 Governing Law

This Agreement and its application and interpretation will be governed and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable herein, except in such cases and to such extent as the laws of another jurisdiction will necessarily control. Each Partner irrevocably attorns to the jurisdiction of the courts of the Province of Ontario.

18.3 Further Assurances

Each Partner will execute and deliver any and all documents and writings and do all things necessary or expedient in the creation of this Partnership and the achievement of its purposes.

18.4 Counterparts

This Agreement may be executed in counterparts. This Agreement may also be adopted in any subscription form or similar document signed by a Person, with the same effect as if that Person had executed a counterpart of this Agreement. All counterparts and adopting documents constitute one and the same agreement.

18.5 Time

Time is of the essence hereof and no extension or variation of this Agreement operates as a waiver of this provision.

18.6 Binding Effect

Each and all of the covenants, terms, provisions and agreements herein contained are binding upon and enure to the benefit of the Partners, their respective heirs, executors, administrators, committees and legal personal representatives, and to the extent permitted by this Agreement, their respective successors and assigns.

18.7 Entire Agreement

This Agreement constitutes the entire agreement between the parties with respect to all of the matters herein and its execution has not been induced by, nor do any parties rely upon or regard as material, any representation or writing not incorporated herein and made a part hereof.

IN WITNESS WHEREOF this Agreement is executed as of the date first above written.

GREAT LAKES POWER TRANSMISSION INC.

Per: ______________________

Name: Alan V. Dean
Title: Director

BROOKFIELD CANADA INFRASTRUCTURE HOLDINGS INC.

Per: ______________________

Name: Joseph Freedman
Title: Vice President

SCHEDULE A

UNIT CERTIFICATE

UNIT CERTIFICATE NUMBER	CLASS OF UNITS	NUMBER OF UNITS ISSUED
■	CLASS A	■

THIS IS TO CERTIFY THAT:

■ is the owner of ■ **(■) CLASS A UNIT(S)** in

GREAT LAKES POWER TRANSMISSION LP
FORMED UNDER THE *LIMITED PARTNERSHIPS ACT* (ONTARIO)

This Unit Certificate and the Class A Units represented hereby are subject to the terms and conditions contained in the Great Lakes Power Transmission LP Limited Partnership Agreement dated May 17, 2007 (the "Limited Partnership Agreement"), as amended from time to time.

The Class A Units represented hereby are not transferable solely by the execution and delivery of this Unit Certificate. Reference should be made to the Limited Partnership Agreement for full particulars of the manner and condition on which a transferee of any Class A Units becomes a Limited Partner. Restrictions on transferability include the transfer restrictions contained in the Limited Partnership Agreement.

DATED this ______ day of _______________, ■.

GREAT LAKES POWER TRANSMISSION INC., as general partner of **GREAT LAKES POWER TRANSMISSION LP**

Per: ________________________________
Name:
Title:

SCHEDULE B

UNIT CERTIFICATE

UNIT CERTIFICATE NUMBER	CLASS OF UNITS	NUMBER OF UNITS ISSUED
■	CLASS B	■

THIS IS TO CERTIFY THAT:

■ is the owner of ■ **(■) CLASS B UNIT(S)** in

GREAT LAKES POWER TRANSMISSION LP
FORMED UNDER THE *LIMITED PARTNERSHIPS ACT* (ONTARIO)

This Unit Certificate and the Class B Units represented hereby are subject to the terms and conditions contained in the Great Lakes Power Transmission LP Limited Partnership Agreement dated May 17, 2007 (the "Limited Partnership Agreement"), as amended from time to time.

The Class B Units represented hereby are not transferable solely by the execution and delivery of this Unit Certificate. Reference should be made to the Limited Partnership Agreement for full particulars of the manner and condition on which Class B Units may be transferred. Restrictions on transferability include the transfer restrictions contained in the Limited Partnership Agreement.

DATED this ______ day of _______________, ■.

GREAT LAKES POWER TRANSMISSION INC., as general partner of **GREAT LAKES POWER TRANSMISSION LP**

Per: ______________________________________
Name:
Title:

AMENDMENT TO GREAT LAKES POWER TRANSMISSION LP LIMITED PARTNERSHIP AGREEMENT

THIS AGREEMENT effective as of the 3rd day of December, 2007,

A M O N G:

GREAT LAKES POWER TRANSMISSION INC.

(the "**General Partner**")

- and -

BROOKFIELD INFRASTRUCTURE HOLDINGS (CANADA) INC.

(the "**Limited Partner**")

WHEREAS:

(a) By declaration of registration and a limited partnership agreement (the "**Limited Partnership Agreement**") dated May 17, 2007 between the General Partner and Brookfield Canada Infrastructure Holdings Inc. (the "**Original Partner**") the General Partner and the Original Limited Partner formed Great Lakes Power Transmission LP (the "**Partnership**");

(b) By a securities purchase agreement and a transfer and power of attorney each dated November 16, 2007 the Original Partner transferred to the Limited Partner 100 Class A units;

(c) The parties hereto have agreed to amend the Limited Partnership Agreement as hereinafter set forth.

NOW THEREFORE for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree:

1. All initially capitalized terms not otherwise defined herein have the meanings ascribed thereto in the Limited Partnership Agreement.

2. Section 1.1 (f) of the Limited Partnership is hereby amended by deleting "99.9%" in the last sentence and replacing it with "99.99%".

3. Section 1.1(g) of the Limited Partnership is hereby amended by deleting "0.1%" in the last sentence and replacing it with "0.01%".

4. Section 6.2 of the Limited Partnership Agreement is hereby amended by deleting "0.1%" in the second sentence and replacing it with "0.01%".

5. Section 6.3 of the Limited Partnership Agreement is hereby amended by deleting "99.9%" in the first and third line and replacing it with "99.99%".

6. Section 6.4 of the Limited Partnership Agreement is hereby amended by deleting "99.9%" in the last sentence and replacing it with "99.99%".

7. Section 8.1 (a) of the Limited Partnership Agreement is hereby amended by deleting "0.1%" and replacing it with "0.01%".

8. Section 8.1(b) of the Limited Partnership Agreement is hereby amended by deleting "99.9%" and replacing it with "99.99%".

9. This agreement shall be binding upon and enure to the benefit of the General Partner and the Limited Partner and each of their respective heirs, executors, administrators, committees and legal personal representatives and to the extent permitted by the Limited Partnership Agreement, their respective successors and assigns.

10. This Agreement and its application and interpretation will be governed and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable herein, except such cases and to such extent as the laws of another jurisdiction will necessarily control. Each of the General Partner and the Limited Partner irrevocably attorns to the jurisdiction of the courts of the Province of Ontario.

11. This Agreement may be executed in counterparts.

12. Except as otherwise set forth in this Agreement, all other provisions in the Limited Partnership Agreement remain in full force and effect.

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the date first written above.

GREAT LAKES POWER TRANSMISSION INC.

By: ______________________

Name: Sam Pollock
Title: Co-President

By: ______________________

Name: Bahir Manios
Title: Treasurer

BROOKFIELD INFRASTRUCTURE HOLDINGS (CANADA) INC.

By: ________________________
Name: Jeff Blidner
Title: Chairman

By: ________________________
Name: Bahir Manios
Title: Treasurer

Financial Statements

Great Lakes Power Transmission LP

Balance Sheet

as at Dec 31, 2009

thousands of CDN dollars	*Notes*		**Dec 31, 2009**		Dec 31, 2008
Assets					
Current Assets					
Cash		**$**	**393**	$	1,990
Accounts receivable			**3,193**		3,014
Prepaid expenses and other			**215**		-
Current portion of regulatory asset			**-**		1,649
			3,801		6,653
Regulatory asset			**1,003**		4,044
Property, plant and equipment, net	*7*		**215,401**		212,330
		$	**220,205**	$	223,027
Liabilities and Capital Account					
Current liabilities					
Accounts and other payables		**$**	**1,818**	$	505
Regulatory liability			**3,949**		2,512
Taxes payable			**1,735**		1,441
Due to related parties			**117**		2,080
			7,619		6,538
Trans senior bonds			**117,078**		119,079
Future income taxes			**7,846**		6,921
			132,543		132,538
Partners' Equity			**87,662**		90,489
		$	**220,205**	$	223,027

Great Lakes Power Transmission

Statement of Partners' Equity
as at Dec 31, 2009

thousands of CDN dollars	*Notes*	Three months ended Dec 31 **2009**	2008	Twelve months ended Dec 31 **2009**	2008
Balance, beginning of period		**$ 88,206**	$ 91,094	**$ 90,489**	$ 76,409
Net income		**56**	(605)	**4,953**	7,735
Contributed surplus adjustment	*4*	**-**	-	**-**	15,886
Dividends paid		**(600)**	-	**(7,780)**	(9,541)
Balance, end of period		**$ 87,662**	$ 90,489	**$ 87,662**	$ 90,489

Great Lakes Power Transmission

December 2009

Great Lakes Power Transmission LP

Statement of Income and Comprehensive Income

for the period ending Dec 31, 2009

thousands of CDN dollars	*Notes*	Oct/Nov 2009	Dec 2009	Three months ended Dec 31 2009	Three months ended Dec 31 2008	Twelve months ended Dec 31 2009	Twelve months ended Dec 31 2008
Revenues		$ 5,136	$ 2,966	$ 8,102	$ 8,459	$ 33,797	$ 35,074
Expenses							
Operating and administration		1,122	565	1,687	1,286	5,886	4,899
Maintenance		149	102	251	747	1,622	2,309
Extraordinary expenditures		145	11	156	58	357	122
Taxes, other than income taxes		93	9	102	475	496	529
		1,509	687	2,196	2,566	8,361	7,859
		3,627	2,279	5,906	5,893	25,436	27,215
Interest		1,284	742	2,026	1,908	7,885	7,787
Depreciation		1,166	561	1,727	1,623	6,973	6,549
Loss on disposal of property, plant and equipment		275	137	412	512	1,649	1,749
Other expenses / (income)		1,916	3	1,919	1	1,963	28
Net income before income taxes		(1,014)	836	(178)	1,849	6,966	11,102
Current tax provision		(489)	251	(238)	928	1,246	1,732
Future tax provision		2	2	4	1,526	767	1,635
Net income and comprehensive income		$ (527)	$ 583	$ 56	$ (605)	$ 4,953	$ 7,735

Great Lakes Power Transmission

Statement of Cash Flows
for the period ending Dec 31, 2009

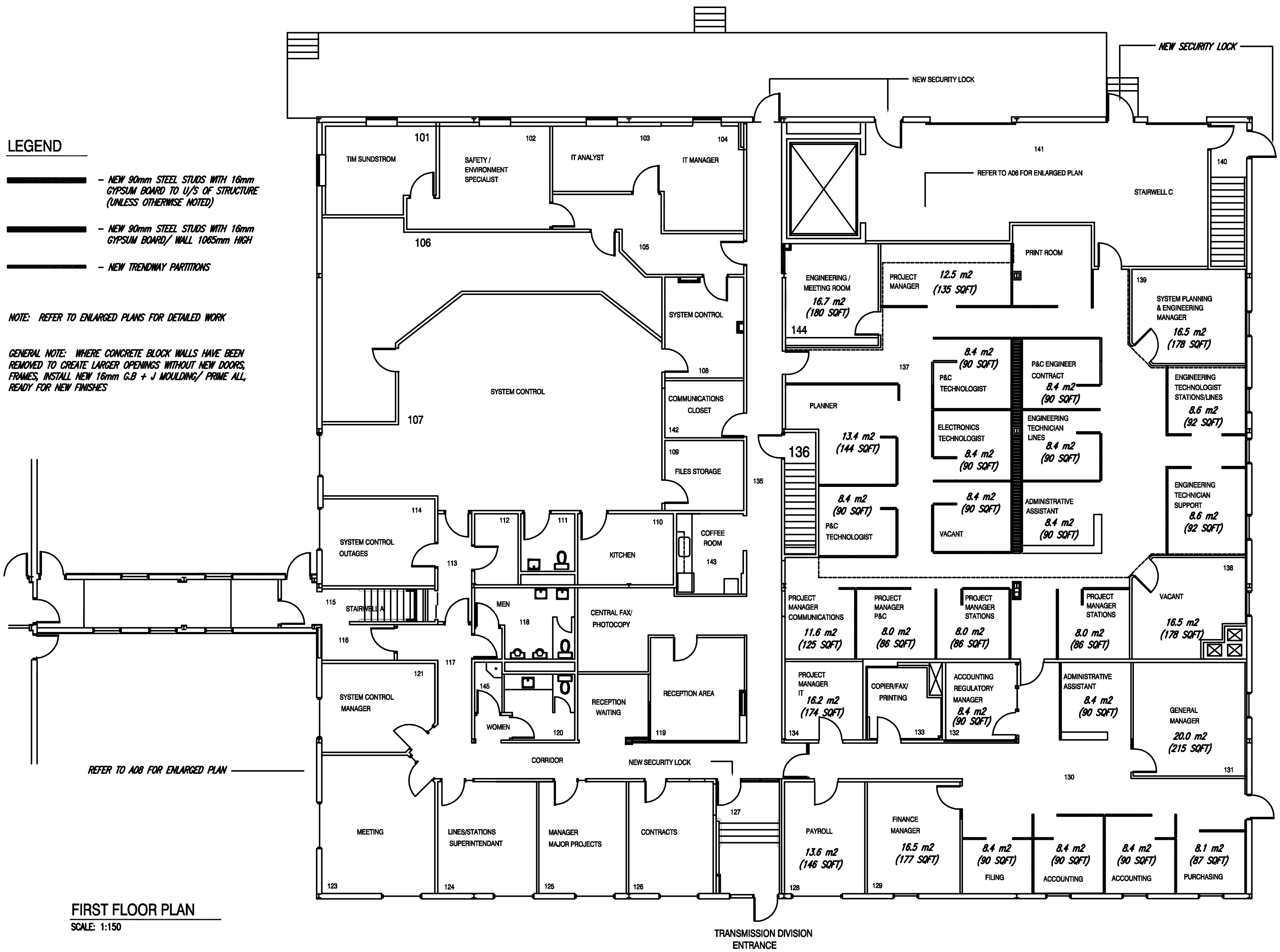
thousands of CDN dollars	*Notes*	Three months ended Dec 31 2009	Three months ended Dec 31 2008	Twelve months ended Dec 31 2009	Twelve months ended Dec 31 2008
Operating Activities					
Net income		**$ 56**	$ (605)	**$ 4,953**	$ 7,735
Items not affecting cash;					
Depreciation		**1,727**	1,623	**6,973**	6,549
Deferred financing fees		**165**	10	**197**	40
Future income taxes		**4**	1,526	**767**	1,635
Loss on disposal of property, plant and equipment		**412**	512	**1,649**	1,749
Net change in non-cash working capital and other		**(1,148)**	(1,859)	**2,043**	(3,986)
		1,216	1,207	**16,582**	13,722
Investing activities					
Receipt of amounts due from related parties		**62**	-	**-**	3,718
Proceeds on disposition of property, plant and equipment		**-**	7	**2**	7
Additions to property, plant and equipment		**(4,798)**	(2,890)	**(11,244)**	(13,538)
Changes in regulatory assets		**3,061**	(17)	**3,041**	(16)
		(1,675)	(2,900)	**(8,201)**	(9,829)
Financing activities					
Dividends paid		**(600)**	-	**(7,780)**	(9,541)
Deferred financing fees		**(2,198)**	-	**(2,198)**	-
Increase in borrowings		**-**	-	**-**	4,250
		(2,798)	-	**(9,978)**	(5,291)
(Decrease) increase in cash		**(3,257)**	(1,693)	**(1,597)**	(1,398)
Cash, beginning balance		**3,650**	3,683	**1,990**	3,388
Cash, ending balance		**$ 393**	$ 1,990	**$ 393**	$ 1,990

LEGEND

- NEW 90mm STEEL STUDS WITH 16mm GYPSUM BOARD TO U/S OF STRUCTURE (UNLESS OTHERWISE NOTED)
- NEW 90mm STEEL STUDS WITH 16mm GYPSUM BOARD/ WALL 1065mm HIGH
- NEW TRENDWAY PARTITIONS

NOTE: REFER TO ENLARGED PLANS FOR DETAILED WORK

GENERAL NOTE: WHERE CONCRETE BLOCK WALLS HAVE BEEN REMOVED TO CREATE LARGER OPENINGS WITHOUT NEW DOORS, FRAMES, INSTALL NEW 16mm G.B + J MOULDING/ PRIME ALL, READY FOR NEW FINISHES



FIRST FLOOR PLAN
SCALE: 1:150

CTA
CHRIS TOSSELL ARCHITECT
503 Queen St. East, Suite 301, Sault Ste. Marie, Ontario

seal

project

GREAT LAKES POWER TRANSMISSION LP
2 Sackville Road
Suite B
Sault Ste. Marie, Ontario

date	rev no.	revision	by	appd

THE CONTRACTOR IS TO CHECK ALL DIMENSIONS ON SITE

drawing name

FIRST FLOOR STAFF LAYOUT

drawing by	checked by
LMC	

date: FEBRUARY 2010
scale: 1:150
cad file no.: 2001-30AA05

project no.	drawing no.
2001-30A	A05

Great Lakes Power Limited – Transmission
Ontario System Control Centre Analysis

40% allocation:

Two factors mainly determine the 40% allocation to T&D: Operator staffing required to operate Generation vs T&D and secondly the number of actual facilities operated for each jurisdiction:

Operator Staff: (approximate)
T&D - requires 5 + 1 = 6
Gen - requires 5 + 3 + 1 = 9
6/15 = 40%
9/15 = 60%

Stations: (approximate (excludes number of units/trans at a station))
T&D = 14
Gen = 21 + Wind
Total = 35

14/35 = 40%
21/35=60%

Perspectives:

OSCC's Brief Description of Services provided by OSCC to GLP Transmission

OSCC provides 24/7 operating (control & monitoring) coverage for all GLP Transmission assets. It acts as the Controlling Authority for all GLP owned transformers, breakers, switches, capacitors, reactor and transmission circuits. It provides this with NERC certified Operating Personnel who interact continuously with the IESO and interconnected Transmitters (Hydro One), LDC's (PUC) and customers, (SMP, ASI, Flakeboard, River Gold, GLPD, Weyerhaeuser).
In order to ensure control is maintained OSCC also provides all required communications via fiber optic and radio communication system to GLP stations and staff. This is provided by 3 Technical staff that perform 24/7 technical support. Some of the day to day tasks include switching, work protection, system compliance and regulatory/market rule reporting, voltage and power flow control, emergency management, system security monitoring, IESO transmission system deployment, Hydro One coordination and customer coordination and outage coordination.

GLPL's Description of Services

Among others, here are some of the larger costs:

System Control and Operation

- Cost to operate the control Center 24/7 includes:
  - Operating the Transmission equipment on the transmitters behalf
  - Monitoring the Transmission system on the transmitters behalf
  - Communication with the directly connected customers on the Transmitters behalf
  - Outage scheduling with the IESO and directly connected customers
  - Cost to implement changes to Control room SCADA, screens, alarms, PI historian etc.
- Cost to Maintain the Control room
  - Equipment Maintenance, servers, PI historian, SCADA etc.
- Major Maintenance on equipment such as overhauls on PI historian, servers, etc.

Communication

- Costs associated with operating the Fiber System includes:
  - Maintaining Fiber Ring
  - Maintaining Station communication equipment, J-mux, ether10 cards etc.
- Major Costs to maintain Fiber Ring and station equipment which includes overhauls and testing

MSP

- Metering dept operating costs
  - Ensuring compliance with the IESO
  - Ensuring the IESO metering is operating correctly
- Maintaining IESO meters as per maintenance guidelines
- Ensuring the IESO metering is operating correctly

MSP Costs

I believe the MSP explanation above describes the types of costs included in the MSP allocation. The MSP costs per meter point were budgeted at approximately $8k per meter point in 2007. I believe this cost per meter point remains fairly flat over time.

ASSIGNMENT, ASSUMPTION AND RELEASE AGREEMENT

THIS AGREEMENT is made as of the 12th day of March, 2008.

AMONG:

GREAT LAKES POWER LIMITED, a corporation incorporated under the laws of the Province of Ontario

(hereinafter called the "**Assignor**")

- and -

GREAT LAKES POWER TRANSMISSION LP, a limited partnership formed under the laws of the Province of Ontario

(hereinafter called the "**Assignee**")

- and -

CIBC MELLON TRUST COMPANY, in its capacity as trustee for and on behalf of the bondholders (in such capacity, hereinafter called the "**Trustee**")

BACKGROUND:

A. The Assignor is indebted and otherwise obligated to perform certain obligations to the Trustee and the bondholders pursuant to a deed of trust made as of March 12, 2008 between the assignor and the Trustee, as supplemented by a first supplemental indenture dated as of March 12, 2008 (collectively, the "**Indenture**") pursuant to which the Assignor has issued Series 1 Senior Bonds in the aggregate principal amount of Cdn. $120,000,000 (collectively the "**Bonds**").

B. The Assignor is party to certain of the Operative Documents, including certain of the Security Agreements, pursuant to which the Assignor has provided certain security to the Trustee in respect of the Assignor's obligations under the Indenture and the Bonds (collectively, the "**Obligations**").

C. The Assignor proposes to transfer to the Assignee the Power Assets, including its rights under the Indenture and the Operative Documents to which the Assignor is a party, and to have the Assignee assume the Obligations and certain of the Assignor' obligations pursuant to a purchase and sale agreement between the Assignor and the Assignee dated as of December 11, 2007 (the "**Purchase Agreement**").

D. This Agreement is intended to reflect the agreement amongst the parties hereto with respect to such assignment and assumption.

NOW THEREFORE in consideration of the mutual obligations contained herein and for other consideration, the receipt and sufficiency of which are hereby acknowledged, the parties agree as follows:

1. INTERPRETATION

1.1 Defined Words

Words which are defined or given extended meanings in the Indenture and are not otherwise defined herein are used in this Agreement with the same respective defined or extended meanings. The Operative Documents, other than the Material Contracts, are hereinafter referred to as the "**Indenture Documents**".

1.2 References to Agreements

Each reference in this Agreement to any agreement (including this Agreement and any other defined term that is an agreement) shall be construed so as to include such agreement (including any attached schedules) and each change made to it at or before the time in question.

1.3 Headings and Titles, etc.

The division of this Agreement into Articles and Sections and the insertion of headings and titles are for convenience of reference only and shall not affect the construction or interpretation of this Agreement. The terms "this Agreement", "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section, Subsection, paragraph, subparagraph, clause or other portion of this Agreement.

1.4 Number and Gender

In this Agreement, words in the singular (including defined terms) include the plural and vice-versa (the necessary changes being made to fit the context) and words in one gender include all genders.

2. ASSIGNMENT, ASSUMPTION, CONSENT AND RELEASE

As of and from the date hereof and subject to the terms and conditions herein contained:

(a) the Assignor hereby assigns to the Assignee all of the rights of the Assignor under the Indenture Documents (herein called the "**Assigned Rights**");

(b) the Assignee hereby assumes obligations identical to the Obligations owing by the Assignor to the Trustee and each bondholder (herein called the "**Transferred Obligations**") and agrees to be bound by the Indenture Documents to which the Assignor and the Trustee are parties in the place and stead of the Assignor, and the

Assignee agrees to perform and be responsible for the Transferred Obligations, as well as all other Obligations which are now and may hereafter become due or owing by the Assignee under the Indenture Documents to the Trustee and the bondholders, (such Obligations together with the Transferred Obligations, the "**Secured Obligations**") as if the Assignee were named in the Indenture Documents to which the Assignor is party as an original party thereto in substitution for the Assignor in respect of such Secured Obligations;

(c) the Trustee on its own behalf and on behalf of the bondholders, hereby consents to the Assignor's assignment to the Assignee of the Power Assets and the Assigned Rights and the Assignee's assumption of the Secured Obligations pursuant to this Agreement and agrees to accept the Assignee as party to the Indenture Documents as party thereto in the place and stead of the Assignor;

(d) the Assignor hereby releases and forever discharges the Trustee and the bondholders of and from all obligations and losses and expenses arising under, by reason of, or otherwise in connection with the Assigned Rights and the Secured Obligations; and

(e) except as provided in Section 3 below, the Trustee hereby releases and forever discharges the Assignor of and from any and all obligations, covenants, liabilities, losses and expenses arising under, by reason of, or otherwise in connection with the Assigned Rights, the Indenture Documents and the Secured Obligations, such release to take effect immediately after the assumption by the Assignee of the Secured Obligations takes effect under paragraph (b) above.

3. TRANSFER OF SECURITY

Nothing in this Agreement is intended by the parties to, and shall not constitute, a discharge, satisfaction, release or novation of any Lien created in favour of the Trustee under the Security Agreements. The Assignee hereby confirms the validity and effect of the Liens created under the Security Agreements and agrees that such Liens continue in full force and effect and bind the Secured Assets transferred to the Assignee in accordance with the terms of the Security Agreements, and that such Liens shall secure the Secured Obligations.

4. REGRANT OF SECURITY

To secure the payment and performance of the Secured Obligations, the Assignee hereby mortgages, charges, assigns and grants a hypothec and security interest in all Secured Assets in which the Assignee now or hereinafter has rights to the Trustee pursuant to the Security Agreements, including its rights under the undertaking dated as of the date hereof provided to the Assignee by the Assignor, to the same extent, in identical terms and subject to the same conditions as the mortgages, charges, assignments and grants of hypothecs and security interests contained in each such Security Agreement, with references therein to obligations of the Assignor owing to the Trustee being construed as references to the Secured Obligations owing by the Assignee to the Trustee and the bondholders, together with such other changes thereto as may be necessary to reflect the substitution of the Assignee for the Assignor under such Security Agreements.

5. REPRESENTATIONS AND WARRANTIES

(a) The Assignee represents and warrants to each other party hereto that this Agreement constitutes a legal, valid and binding obligation on its part which is enforceable by each such other party against the Assignee in accordance with its terms, subject, however, to bankruptcy, insolvency, fraudulent conveyance and similar laws affecting creditors' rights generally, and general principles of equity (regardless of whether the application of such principles is considered in a proceeding in equity or at law).

(b) The Assignor represents and warrants to each other party hereto that this Agreement constitutes a legal, valid and binding obligation on its part which is enforceable by each such other party against the Assignor in accordance with its terms, subject, however, to bankruptcy, insolvency, fraudulent conveyance and similar laws affecting creditors' rights generally, and general principles of equity (regardless of whether the application of such principles is considered in a proceeding in equity or at law).

6. FURTHER ASSURANCES

Each of the Assignor, the Assignee and the Trustee agrees to do all acts and things and execute all agreements, instruments and other documents as may reasonably be requested by any other party hereto from time to time for the purposes of giving effect to the intent and purpose of this Agreement, including, without limitation, the release of the Assignor contemplated hereby, provided that in the case of the Trustee, the doing of all such acts and things shall be at the expense of the Assignor.

7. ENTIRE AGREEMENT

There are no representations, warranties, conditions, other agreements or acknowledgments whether direct or collateral, express or implied that form part of or affect this Agreement other than as expressed herein.

8. INVALIDITY

If any provision of this Agreement is determined to be invalid or unenforceable by a court of competent jurisdiction from which no further appeal lies or is taken, that provision shall be deemed to be severed herefrom, and the remaining provision of this Agreement shall not be affected thereby and shall remain valid and enforceable. Each of the Assignee and the Assignor, at the request of any other party hereto, shall enter into good faith negotiations to replace any invalid or unenforceable provision contained in this Agreement with a valid and enforceable provision which has the commercial effect as close as possible to that of the invalid or unenforceable provision, to the extent permitted by law.

9. TIME OF THE ESSENCE

Time is of the essence of each provision of this Agreement.

10. GOVERNING LAW

This Agreement shall be governed by, and construed and interpreted in accordance with, the laws in force in the Province of Ontario, including the federal laws of Canada applicable therein (excluding any conflict of laws rule or principle which might refer such construction to the laws of another jurisdiction).

11. COUNTERPARTS

This Agreement may be executed in any number of counterparts and by the different parties hereto in separate counterparts each of which when executed and delivered shall constitute an original but all the counterparts shall together constitute but one and the same instrument. Transmission of an executed signature page of this Agreement by facsimile transmission or by e-mail in pdf format shall be effective as delivery of a manually executed counterpart hereof.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF the parties hereto have executed this Agreement as of the day and year first above written.

GREAT LAKES POWER LIMITED,
as Assignor

By: ______________________
Name: Patricia Bood
Title: Vice President and Secretary

By: ______________________
Name:
Title:

GREAT LAKES POWER TRANSMISSION LP, by its General Partner
Great Lakes Power Transmission Inc.
as Assignee

By: ______________________
Name: Patricia Bood
Title: Secretary, Vice President of Legal Services and General Counsel

By: ______________________
Name:
Title:

CIBC MELLON TRUST COMPANY, as Trustee

By: ______________________________
Name: EUGENIA PETRYLA
Title: ACCOUNT MANAGER

By: ______________________________
Name: [illegible] AUGUST
Title: [illegible]MANAGER

FIRST SUPPLEMENTAL TRUST INDENTURE

Made as of March 12, 2008

Between

GREAT LAKES POWER LIMITED
as issuer

and

CIBC MELLON TRUST COMPANY
as trustee

Supplementing the Deed of Trust

made as of March 12, 2008

and

providing for the issue of

$120,000,000 aggregate principal amount of 6.60% Senior Bonds
due June 16, 2023 (Series 1)

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FIRST SUPPLEMENTAL TRUST INDENTURE

THIS FIRST SUPPLEMENTAL TRUST INDENTURE dated as of March 12, 2008,

BETWEEN:

GREAT LAKES POWER LIMITED
a corporation incorporated under the laws of Ontario (the "**Company**")

and

CIBC MELLON TRUST COMPANY
a trust company existing under the laws of Canada (the "**Trustee**")

RECITALS

WHEREAS the Company has entered into a deed of trust (the "**Indenture**" or "**Trust Indenture**") with the Trustee dated as of March 12, 2008 which provides for the issuance of one or more series of Bonds of the Company by way of supplemental indentures;

AND WHEREAS pursuant to Section 3.7 of the Indenture, the Company and the Trustee may enter into supplemental trust indentures providing for the issue of Bonds of any one or more series and for establishing the terms, provisions and conditions of a particular series of Bonds;

AND WHEREAS this First Supplemental Trust Indenture is entered into for the purpose of providing for the issuance of $120,000,000 aggregate principal amount of Series 1 Senior Bonds (the "**Series 1 Senior Bonds**") pursuant to the Indenture and establishing the terms, provisions and conditions of the Series 1 Senior Bonds;

AND WHEREAS all necessary resolutions of the directors and shareholders of the Company have been duly enacted and passed and other proceedings taken to make this First Supplemental Trust Indenture a valid and binding indenture; and

AND WHEREAS the foregoing recitals are made as representations and statements of fact by the Company and not by the Trustee;

NOW THEREFORE THIS FIRST SUPPLEMENTAL TRUST INDENTURE WITNESSES and it is hereby covenanted, agreed and declared as follows:

SECTION 1INTERPRETATION

1.1 To Be Read With Deed of Trust

This First Supplemental Trust Indenture is a supplemental indenture to the Indenture. The Indenture and this First Supplemental Trust Indenture will be read together and will have effect as though all the provisions of both indentures were contained in one instrument.

1.2 Headings etc.

The division of this First Supplemental Trust Indenture into Sections and clauses, the provision of a table of contents and the insertion of headings are for convenience of reference only and will not affect the interpretation thereof. Unless the context otherwise requires, the expression "Section" and "Schedule" followed by a number, letter or combination of numbers and letters refer to the specified Section of or Schedule to this First Supplemental Trust Indenture.

1.3 Definitions

All terms which are defined in the Indenture and used but not defined in this First Supplemental Trust Indenture have the meanings ascribed to them in the Indenture, as such meanings may be amended or supplemented by this First Supplemental Trust Indenture. In the event of any inconsistency between the meaning given to a term in the Indenture and the meaning given to the same term in this First Supplemental Trust Indenture, the meaning given to the term in this First Supplemental Trust Indenture shall prevail to the extent of the inconsistency. Subject to the foregoing, in this First Supplemental Trust Indenture and in the Series 1 Senior Bonds, the following terms have the following meanings:

(1) **"Canada Yield Price"** means a price for any Series 1 Senior Bonds to be redeemed, calculated at 10:00 a.m. (Toronto time) on the Redemption Price Determination Date, to provide a yield from the Redemption Date to maturity of the Series 1 Senior Bonds equal to the Government of Canada Yield plus (i) 0.40% until June 16, 2021, and 0.25% thereafter in the case of Series 1 Senior Bonds redeemed pursuant to Section 2.5 hereof, and (ii) 1.75% in the case of Series 1 Senior Bonds redeemed pursuant to Section 2.8 hereof.

(2) **"Date of Conversion"** means the March 12, 2008.

(3) **"Government of Canada Yield"** means, on any date, the then current mid-market yield to maturity on such date expressed as a rate per annum, assuming semi-annual compounding, which a non-callable Government of Canada Bond would yield if issued on such date in Canadian dollars in Canada at 100% of its principal amount on such date with a remaining term to maturity equal to the average life of the Series 1 Senior Bonds being redeemed. The Government of Canada Yield will be determined by two Investment Dealers selected by the Company.

(4) **"Indemnified Tax"** means Tax under Part XIII of the *Income Tax Act* (Canada) (as the same may be amended, supplemented or replaced) or any successor provisions (for instance in accordance with Section 803 of the Regulations to the *Income Tax Act* (Canada)) or any similar

tax imposed by any jurisdiction into which the Company continues or re-domiciles or in which the Company is or becomes organized resident or carries on business to the extent that the Tax is in respect of a payment by the Company to a holder of a Series 1 Senior Bond who, at the time of the payment, is a resident of the United States for purposes of the Canada-United States Income Tax Convention (as the same may be amended, supplemented or replaced) and holds in excess of $3,125,000 principal amount of Series 1 Senior Bonds, in respect of Series 1 Senior Bonds acquired by such holder otherwise than by way of a transfer, after a change in law, or the interpretation thereof, giving rise to the obligation of the Company to pay the additional amounts or the indemnity, as the case may be, from another holder of a Series 1 Senior Bond that is not a resident of the United States for purposes of the Canada-United States Income Tax Convention (as the same may be amended, supplemented or replaced). Notwithstanding the foregoing, no Indemnified Tax will be payable in respect of any Series 1 Senior Bonds in respect of which a waiver pursuant to Section 2.8 (a)(ii) has been made.

(5) **"Maturity Date"** means June 16, 2023.

(6) **"Original Indenture"** means the deed of trust dated June 16, 2003 between the Company and CIBC Mellon Trust Company, as trustee thereunder, as supplemented by a First Supplemental Trust Indenture dated as of June 16, 2003, a Second Supplemental Trust Indenture dated as of July 31, 2003, a Third Supplemental Trust Indenture dated as of June 30, 2006 and a Fourth Supplemental Trust Indenture dated as of March 12, 2008.

(7) **"Redemption Price"** means, in respect of any Series 1 Senior Bond being redeemed, the greater of the outstanding principal amount thereof to be redeemed and the Canada Yield Price of the principal amount thereof to be redeemed, together with accrued and unpaid interest up to but excluding the date fixed for redemption.

(8) **"Redemption Price Determination Date"** means the date of the determination of the Canada Yield Price for the Series 1 Senior Bonds to be redeemed which will be three business days prior to the Redemption Date following the date of the delivery of a pricing notice to the bondholders.

(9) **"Series 1 Original Senior Bonds"** means the 6.60% Senior Bonds due June 16, 2023 (Series 1) created pursuant to the Original Indenture.

(10) **"Series 1 Senior Bonds"** has the meaning given to that term in the recitals hereto.

(11) **"Series 1 Senior Bond Interest Rate"** means a rate of 6.60% per annum.

(12) **"Taxes"** means any taxes, duties, assessments, imposts, levies and other similar charges imposed by any Governmental Authority in Canada or the United States, including all interest, penalties, fines, additions to tax or other additional amounts imposed by any Governmental Authority in Canada or the United States in respect thereof, and including those levied on, or measured by, or referred to as, income, gross receipts, profits, capital, transfer, land transfer, sales, goods and services, harmonized sales, use, value-added, excise, withholding, business, property, occupancy, employer health, payroll, employment, health, social services, education and social security taxes, all surtaxes, all customs duties and import and export taxes, countervail

and anti-dumping and all employment insurance, health insurance and Canada, Québec and other government pension plan premiums or contributions.

SECTION 2SERIES 1 SENIOR BONDS – FORM AND TERMS

2.1 Conditions Precedent to the Creation of the Series 1 Senior Bonds

(1) The creation, issuance and execution by the Company and the certification by the Trustee of the Series 1 Senior Bonds to be issued upon the conversion of the Series 1 Original Senior Bonds will be subject to the satisfaction of each of the following conditions:

(a) The Company having delivered to the Trustee a title insurance policy (from the same insurer and providing the same coverage and endorsements as the title insurance policy originally delivered in respect of the Series 1 Original Senior Bonds) insuring the priority of the Security against the Power Real Estate in an amount equal to $120,000,000 (representing the aggregate outstanding principal amount of the Series 1 Senior Bonds);

(b) Compliance by the Company with the conditions precedent set out in the Indenture with respect to the creation, issuance and execution by the Company, and the certification by the Trustee, of the Series 1 Senior Bonds and the execution and delivery by the Company, the Nominee and 1228185 Ontario Limited, of the Security Agreements;

(c) Compliance by the Company with the conditions precedent set out in the Original Indenture and the Fourth Supplemental Trust Indenture (as referred to in the definition of "Original Indenture") with respect to the creation, issuance and execution by the Company, and the certification by the trustee thereunder of $264,000,000 aggregate principal amount of Series 2 Senior Bonds and $115,000,000 aggregate principal amount of Series 2 Subordinate Bonds pursuant thereto;

(d) The Company having furnished to the Trustee (i) a Written Order for the certification and delivery of Series 1 Senior Bonds having an aggregate principal amount of $120,000,000 and (ii) a Certified Resolution authorizing the entering into of this First Supplemental Trust Indenture and the creation, issuance and execution of the Series 1 Senior Bonds in the aggregate principal amount of $120,000,000, having the attributes set out in this First Supplemental Trust Indenture;

(e) Receipt by the Trustee of an Opinion of Company Counsel dated the date of such Written Order to the effect that (i) all of the conditions precedent provided for in Section 2.1(1) relating to the authorization, execution, certification and delivery of the Series 1 Senior Bonds have been complied with in accordance with the terms of this First Supplemental Trust Indenture , and (ii) the Series 1 Senior Bonds to be issued upon the conversion of the Series 1 Original Senior Bonds have been duly authorized and executed by the Company and, upon certification by the Trustee and delivery thereof by the Trustee or the Company, will be valid and legally binding obligations of the Company and will be secured by the Security, subject to customary qualifications and assumptions;

(f) Receipt by the Trustee of an Officers' Certificate stating that (i) all of the conditions precedent provided for in this Section 2.1(1) relating to the authorization, execution, certification and delivery of the Series 1 Senior Bonds have been complied with in accordance with the terms of this First Supplemental Trust Indenture, and (ii) so far as is known to the signers, after having made due enquiry pursuant to section 17.12 of the Indenture, no Default or Event of Default has occurred and is continuing or will result from the making or granting of the Written Order; and

(g) The Trustee shall have delivered a certificate signed by an authorized officer of the Trustee to the effect that: (i) the Trustee has performed and complied with all of its obligations under the Indenture in connection with the issuance of the Series 1 Senior Bonds; and (ii) the following representations are true and correct on and with respect to the Date of Conversion and shall survive the conversions of the Series 1 Original Senior Bonds and the issuance of the Series 1 Senior Bonds:

(i) at the date thereof, no winding up, liquidation, dissolution, insolvency, bankruptcy, amalgamation, reorganization or continuation proceedings have been commenced or are being contemplated by the Trustee and the Trustee has no knowledge of any such proceedings having been commenced or being contemplated in respect of the Trustee by any other person;

(ii) compliance by the Trustee with all of the provisions of the Indenture will not conflict with or result in any breach of any of the terms, conditions or provisions of, or constitute a default under the Letters Patent of the Trustee;

(iii) there is no conflict of interest between the Trustee's role as a trustee under the Indenture and its role in any other capacity (including its capacity as trustee under the Original Indenture) which would in any way affect it in performing its duties under the Indenture; and

(iv) the Trustee has duly certified the Series 1 Senior Bonds in accordance with Section 2.5 of the Indenture.

(2) Upon the issuance of the Series 1 Senior Bonds, the Trustee will provide to each bondholder a copy of this First Supplemental Trust Indenture along with all other documentation referred to in this Section 2.1.

2.2 Creation and Designation

The initial Series 1 Senior Bonds shall consist of and, exclusive of the Series 1 Senior Bonds issued upon any transfer of or any exchange or substitution for or by way of replacement of any Series 1 Senior Bonds previously issued, be limited to, Bonds in the aggregate principal amount not in excess of $120,000,000 to be designated as 6.60% Senior Bonds due June 16, 2023 (Series 1), to be issued upon the conversion of the Series 1 Original Senior Bonds.

2.3 Date of Issue and Maturity

The Series 1 Senior Bonds shall be dated the Date of Conversion and any Series 1 Senior Bond issued in substitution for or upon exchange or transfer of any Series 1 Senior Bond, as provided in Section 2.7 or 2.10 of the Indenture, will be dated the same date. The Series 1 Senior Bonds will become due and payable, together with all accrued interest and unpaid interest thereon, on the Maturity Date.

2.4 Principal and Interest

The principal amount of the Series 1 Senior Bonds will bear interest from the Date of Conversion at a rate per annum equal to the Series 1 Senior Bond Interest Rate (and, in the case of default, interest on all amounts overdue including overdue interest) calculated semi-annually in arrears. Interest shall be payable on June 16 and December 16 in each year commencing on June 16, 2008 and ending on the Maturity Date. Commencing on December 16, 2013, payments of principal will be paid semi-annually in accordance with the payment schedule attached hereto as Schedule "3" such that there will be paid on the Series 1 Senior Bonds equal blended semi-annual payments of principal and interest calculated on the basis of a 25 year amortization period. Upon any partial redemption of a Series 1 Senior Bond in accordance with the terms hereof, the equal semi-annual blended payments of principal and interest payable under such Series 1 Senior Bonds will be recalculated by the Company to reflect such redemption and the amount of principal payable on each payment date will be reduced proportionately. All payments of principal and interest due in respect of the Series 1 Senior Bonds will be paid in Canadian Dollars.

2.5 Redemption of Series 1 Senior Bonds

(a) The Series 1 Senior Bonds may be redeemed, at the option of the Company in whole at any time or in part from time to time, on not less than 30 days' and not more than 60 days' written notice (but for greater certainty only *pro rata* as among the holders of the Series 1 Senior Bonds) upon payment of the Redemption Price for the Series 1 Senior Bonds to be redeemed and otherwise in accordance with Article 5 of the Indenture. The written notice of redemption will be delivered to the holders of Series 1 Senior Bonds and will include, in addition to the requirements contained in Section 5.3 of the Indenture, a description of the method of calculating the Redemption Price as well as a sample calculation. On the date that is three business days before redemption, the Company must give to the Trustee and the holders of Series 1 Senior Bonds so to be redeemed notice of the actual Redemption Price showing in reasonable detail the computation of the Redemption Price for the Series 1 Senior Bonds.

(b) Upon the redemption of the Series 1 Senior Bonds as provided for hereunder and in the Indenture, notwithstanding anything to the contrary in the Indenture, the holder of a Series 1 Senior Bond will not be obligated to surrender such Series 1 Senior Bond to the Trustee or any other person except on receipt by such holder of the Redemption Price in respect to such Series 1 Senior Bond. This Section 2.5(b) constitutes a home office payment agreement for the purposes of Section 2.11 of the Indenture.

2.6 Government of Canada Yield

For the purposes of the determination of the Government of Canada Yield on a given date, the two Investment Dealers selected by the Company will confer with respect to such determination and will jointly report to the Company, the Trustee and each of the bondholders holding Bonds being redeemed the percentage figure they have determined for the Government of Canada Yield or, if the determinations are not the same, the arithmetic average (rounded to 4 decimal places) of the respective percentages and figures determined by each and such agreed percentage or average, as the case may be, will be the Government of Canada Yield for the purposes hereof.

2.7 Payment on Series 1 Senior Bonds Net of Withholding Imposts

(a) All payments by the Company under any Series 1 Senior Bond, whether in respect of principal, Make-Whole Amount (if any), interest, interest on overdue interest, fees or any other payment obligations, will be made in full, free and clear of and without any deduction or withholding for or on account of any present or future Taxes or duties of whatsoever nature <u>unless</u> the Company is required by Applicable Law to so deduct or withhold, in which event the Company will:

(i) forthwith pay to each holder of a Series 1 Senior Bond such additional amount so that the net amount received by the holder of such Series 1 Senior Bond after any deduction or withholding for or on account of any Indemnified Tax (including any deduction or withholding for or on account of any Indemnified Tax on additional amounts payable under this Section 2.7(a)(i)) will equal the full amount which would have been received by it had no such deduction or withholding for or on account of Indemnified Tax been made, and pay to such holder of such Series 1 Senior Bond such additional amounts so as to hold such bondholder harmless on an after-Tax basis from any Taxes payable by reason of the additional amounts payable pursuant to this Section 2.7(a)(i);

(ii) make the deduction or withholding required by Applicable Law (including any deduction or withholding from any additional amount paid pursuant to Section 2.7(a)(i));

(iii) pay to the relevant taxation or other authorities within the period for payment permitted by Applicable Law the full amount of the deduction or withholding (including the full amount of any deduction or withholding from any additional amount paid pursuant to Section 2.7(a)(i)); and

(iv) furnish to each holder of such Series 1 Senior Bond promptly, as soon as available, an official receipt of the relevant taxation or other authorities involved for all amounts deducted or withheld as aforesaid.

Any reference in the Indenture (including this supplemental indenture) to principal, Make-Whole Amount, interest, interest on overdue interest, fees or any other payment obligation of the Company will be deemed also to refer to any additional amounts payable pursuant to Section 2.7(a)(i).

(b) If as a result of any payment by the Company under any Series 1 Senior Bond, whether in respect of principal, Make-Whole Amount (if any), interest, interest on overdue interest, fees or other payment obligations, any holder of a Series 1 Senior Bond is required to pay any Indemnified Tax, then the Company will, upon demand by any such bondholder, and whether or not such Indemnified Taxes are correctly or legally asserted, indemnify each such bondholder for the payment of any such Indemnified Taxes, together with any interest, penalties and expenses in connection therewith, and for any Taxes on such indemnity payment. All such amounts shall be payable by the Company on demand and shall bear interest at the rate of interest per annum applicable to the Series 1 Senior Bonds per annum calculated from the date incurred by the bondholder to the date paid by the Company.

(c) If the Company is required to pay any additional amount to a holder of Series Senior 1 Bonds in respect of Taxes (other than Indemnified Taxes) under Section 2.7(a), then if such holder realizes any savings of any Taxes (by way of credit (including foreign tax credit), deduction, refund, exclusion from income or otherwise, which Tax savings were not taken into account in calculating the additional amount) as a result of the Taxes giving rise to the payment of any such additional amount, then if and to the extent of any such additional amount, the holder will, at the time it realizes such Tax savings, repay the amount of such Tax savings to the Company, together with the amount of any Tax savings resulting from payment under this section.

2.8 Optional Prepayment with Modified Make-Whole Amount

(a) If the Company is required to make payments to any holder of a Series 1 Senior Bond pursuant to Section 2.7(a)(i) hereof or make any indemnity payment to any holder of a Series 1 Senior Bond pursuant to Section 2.7(b) hereof, and, in each case, the Company would have been required to make such payments on the Series 1 Bonds even if the transactions contemplated by Section 2.1 hereof and by Section 2.1 of the Fourth Supplemental Indenture (as referred to in the definition of "Original Indenture") relating to the conversion of the Series 1 Original Senior Bonds and the transfer to the Company of the Transmission Business had not occurred, then the Company shall be entitled to redeem the Series 1 Senior Bonds so affected in whole upon payment of the Redemption Price for the Series 1 Senior Bonds to be redeemed, provided that:

(i) the Company's right to redeem under this Section 2.8(a) will terminate if the Company has not given notice of redemption under Section 2.8(b) on or before the later of (A) 9 months after the date that the Company is first called upon by any holder of a Series 1 Senior Bond to honour its payment or indemnity obligations under Section 2.7(a)(i) or (b), respectively, or (B) 9 months after the date that any legislation requiring the Company to make any deduction or withholding under Section 2.7(a)(i) hereof, or requiring any holder of a Series 1 Senior Bond to pay any Indemnified Tax as contemplated in Section 2.7(b) hereof, comes into force; and

(ii) the Company shall not be entitled to redeem under this Section 2.8(a) any Series 1 Senior Bond in respect of which the holder of such Bond thereof has, within 10 business days of receipt of a redemption notice made in accordance with Section 2.8(b), waived in writing the future obligations of the Company under Section 2.7(a)(i) or (b) hereof in respect to such deduction or withholding or indemnity for Taxes (without prejudice to accrued obligations thereunder).

(b) The Company will give each holder of a Series 1 Senior Bond whose Series 1 Senior Bonds it has elected to redeem pursuant to Section 2.8(a) irrevocable written notice of any redemption pursuant to Section 2.8(a) not less than 10 business days nor more than 60 business days prior to the Redemption Date, specifying (i) the Series 1 Senior Bonds to be prepaid, (ii) the Redemption Date (which shall be a business day), (iii) the total principal amount of the Series 1 Senior Bonds, and of the Series 1 Senior Bonds held by such holder, to be redeemed on such date, and (iv) stating that such redemption is to be made pursuant to Section 2.8(a). Notice of redemption having been given as aforesaid, the applicable Redemption Price, shall become due and payable on such Redemption Date.

2.9 Form of Series 1 Senior Bonds

(a) The Series 1 Senior Bonds will be substantially in the form set out in Schedule "1" hereto and shall bear such distinguishing letters and numbers as the Trustee shall approve.

(b) The Trustee understands and acknowledges that the Series 1 Senior Bonds have not been and will not be registered under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"). Each Series 1 Senior Bond originally issued in the United States or to a U.S. Person will be represented by a definitive certificate in the form set out in Schedule "2" hereto which definitive certificate, and each Series 1 Senior Bond certificate issued in exchange therefor or in substitution thereof, shall bear the following legend:

"THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT") OR STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, UNDERSTANDS AND ACKNOWLEDGES FOR THE BENEFIT OF GREAT LAKES POWER LIMITED (THE "COMPANY") THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO THE COMPANY, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE SECURITIES ACT, (C) PURSUANT TO THE EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 OR RULE 144A THEREUNDER OR (D) PURSUANT TO ANOTHER EXEMPTION FROM REGISTRATION, PROVIDED THAT IN THE CASE OF A TRANSFER PURSUANT TO (C) OR (D) ABOVE, A LEGAL OPINION SATISFACTORY TO THE COMPANY MUST FIRST BE PROVIDED.

A NEW CERTIFICATE BEARING NO LEGEND, MAY BE OBTAINED FROM CIBC MELLON TRUST COMPANY UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO CIBC MELLON TRUST COMPANY AND THE COMPANY, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE SECURITIES ACT";

If any Series 1 Senior Bonds are being sold or transferred outside the United States in compliance with the requirements of Rule 904 of Regulation S under the U.S. Securities Act, the legend may be removed by providing a declaration to the Trustee to the following effect (or as the Company may prescribe from time to time),

"The undersigned (A) acknowledges that the sale of the securities to which this declaration relates is being made in reliance upon Rule 904 of Regulation S under the United States Securities Act of 1933, as amended (the "U.S. Securities Act"), and (B) certifies that (1) it is not an "affiliate" (as defined in Rule 405 under the U.S. Securities Act) of Great Lakes Power Limited, (2) the offer of such securities was not made to a person in the United States and either (a) at the time the buy order was originated, the buyer was outside the United States, or the seller and any person acting on its behalf reasonably believe that the buyer was outside the United States or (b) the transaction was executed on or through the facilities of the Toronto Stock Exchange and neither the seller nor any person on its behalf knows that the transaction has been prearranged with a buyer in the United States, (3) neither the seller nor any person acting on its behalf has engaged or will engage in any directed selling efforts in connection with the offer and sale of such securities,

(4) the sale is bona fide and not for the purpose of "washing off" the resale restrictions imposed because the securities are "restricted securities" (as that term is defined in Rule 144(a)(3) under the U.S. Securities Act), (5) the seller does not intend to replace the securities sold in reliance on Rule 904 of Regulation S with fungible unrestricted securities, and (6) the contemplated sale is not a transaction, or part of a series of transactions which, although in technical compliance with Regulation S, is part of a plan or scheme to evade the registration provisions of the U.S Securities Act. Terms used herein have the meaning given to them by Regulation S."

If any Series 1 Senior Bonds are being sold or transferred pursuant to Rule 144 of the U.S. Securities Act, the legend may be removed by delivery to the Trustee of a written opinion of Counsel reasonably satisfactory to the Company to the effect that such legend is no longer required under applicable requirements of the U.S. Securities Act or state securities laws.

Prior to the issuance of Series 1 Senior Bonds, the Company will notify the Trustee, in writing, concerning which Series 1 Senior Bonds are to be certificated and are to bear the legend described above. The Trustee will thereafter maintain a list of all registered holders from time to time of legended Series 1 Senior Bonds.

2.10 Signatures on Series 1 Senior Bonds

The Series 1 Senior Bonds will be signed in accordance with the provisions of Section 2.4 of the Trust Indenture.

2.11 Certification

The certificate of the Trustee on any Series 1 Senior Bond will not be construed as a representation or warranty by the Trustee as to the validity of this First Supplemental Trust Indenture or of the Series 1 Senior Bonds (except the due certification thereof and any other warranties implied by law) and the Trustee will in no respect be liable or answerable for the use made of the Series 1 Senior Bonds or any of them or the proceeds thereof.

SECTION 3- MISCELLANEOUS

3.1 Acceptance of Trust

The Trustee accepts the trusts in this First Supplemental Trust Indenture and agrees to carry out and discharge the same upon the terms and conditions set out in this First Supplemental Trust Indenture and in accordance with the Indenture.

3.2 Confirmation of Trust Indenture

The Trust Indenture as amended and supplemented by this First Supplemental Trust Indenture is in all respects confirmed.

3.3 Indemnification of the Trustee

The Company indemnifies and saves harmless the Trustee and its officers, directors, employees and agents from and against any and all liabilities, losses, costs, claims, actions or demands whatsoever brought against the Trustee which it may suffer or incur as a result of or arising out of the performance of its duties and obligations under this First Supplemental Trust Indenture, including any and all legal fees and disbursements of whatever kind or nature, save only in the event of the negligent action, the negligent failure to act, or the wilful misconduct or bad faith of the Trustee. It is understood and agreed that this indemnification shall survive the termination or discharge of this First Supplemental Trust Indenture or resignation or removal of the Trustee. The Company hereby constitutes the Trustee as a trustee for the Trustee's officers, directors, employees and agents for the purposes of obtaining the benefit of this Section 3.3.

3.4 Counterparts

This First Supplemental Trust Indenture may be executed in counterparts, each of which so executed will be deemed to be original and such counterparts together will constitute one and the same instrument.

[SIGNATURE PAGE FOLLOWS]

IN WITNESS WHEREOF the parties hereto have executed this First Supplemental Trust Indenture under the hands of their proper signatories in that behalf:

GREAT LAKES POWER LIMITED

By: Pat Bood
Name: Patricia Bood
Title: Vice-President and Secretary

By: ____________________
Name:
Title:

CIBC MELLON TRUST COMPANY

By: ______________________

EUGENIA PETRYLA
ACCOUNT MANAGER

By: ______________________

LENNOX AUGUST
ASSOCIATE MANAGER

Schedule 1 – FORM OF SERIES 1 SENIOR BOND

No. S1-001

GREAT LAKES POWER LIMITED
(Incorporated under the laws of Ontario)
6.60% SENIOR BONDS DUE JUNE 16, 2023 (SERIES 1)

Issue Date •, 2008

Maturity Date June 16, 2023

Interest Rate Per Annum 6.60%

Interest Payment Dates June 16 and December 16 in each year

Initial Interest Payment Date June 16, 2008

Principal Payment Dates June 16 and December 16 in each year commencing December 16, 2013 based on a 25 year amortization period

Principal Amount $●

GREAT LAKES POWER LIMITED (the "**Company**") for value received hereby promises to pay to [name of bondholder/ the registered holder] hereof on June 16, 2023 (the "Maturity Date"), or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), this 6.60% Senior Bond due June 16, 2023 (Series 1) (the "**Series 1 Senior Bond**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 320 Bay Street, Toronto, Ontario, and to pay (i) during the period from the Issue Date until and including June 16, 2013, semi-annual payments of interest only on the Principal Amount outstanding at the Interest Rate Per Annum; and (ii) during the period from June 16, 2013 until and including the Maturity Date, equal blended semi-annual payments of principal and interest on the Principal Amount outstanding at the Interest Rate Per Annum, such amount to be calculated on the basis of a 25 year amortization period, at the address of the registered holder hereof appearing on the register of Series 1 Senior Bonds maintained by or at the direction of the Trustee (the "**Register**"). The remaining outstanding principal hereof will be due and payable on the Maturity Date. Interest will be payable semi-annually in arrears with the first such payment to be payable on the Initial Interest Payment Date, and if the Company at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Company will, at the request of the registered holder hereof, on the date on which principal and interest becomes due (or if such date is not a business day, the first business day preceding such day), (i) forward or cause to be forwarded by prepaid post to the address of the registered holder, or, in the case of joint holders, to one of such joint holders, one or more cheques (drawn on a Canadian chartered bank) for such principal or interest (less any tax required to be deducted or withheld plus any gross up required to be paid pursuant to any supplemental indenture) payable to the order of such holder or holders or, (ii) effect a wire transfer to the holder or, in the case of joint holders, to one of such joint holders, based on the wire transfer instructions provided by any such holder to the Company in the amount of such principal or interest (less any tax required to be deducted or withheld plus any gross up required to be paid pursuant to any supplemental indenture), in each case in immediately available funds for receipt not later than 12:00 (noon) Toronto time on the date such payment is due.

This Series 1 Senior Bond is one of an authorized issue of bonds designated as 6.60% Senior Bonds due June 16, 2023 (Series 1) and forming the series of bonds created and issued under a first supplemental trust indenture made as of March 12, 2008 (the "**First Supplemental Trust Indenture**") to a deed of trust (the "**Indenture**") made as of March 12, 2008, between the Company and CIBC Mellon Trust Company (the "**Trustee**"), as Trustee (the First Supplemental Trust Indenture and the Indenture collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 1 Senior Bonds are created and issued or may be created, issued and held and the rights of the registered holders of the Series 1 Senior Bonds, the Company and the Trustee, all of which terms and conditions are incorporated by reference in this Series 1 Senior Bond and to each of which the registered holder of this Series 1 Senior Bond, by acceptance hereof, agrees. Capitalized terms used but not defined herein shall have the meanings specified in the Trust Indenture.

The aggregate principal amount of Series 1 Senior Bonds that may be created and issued under the Trust Indenture is limited to $120,000,000 in lawful money of Canada.

The Series 1 Senior Bonds are direct secured obligations of the Company and will rank equally with each other and with all other Senior Bonds of every other series from time to time issued and outstanding pursuant to the Trust Indenture.

This Series 1 Senior Bond is redeemable, at the option of the Company, provided that no Default or Event of Default is continuing, in whole at any time or in part from time to time, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the Redemption Price (as defined in the First Supplemental Trust Indenture).

At any time when the Company is not in default under the Trust Indenture, the Company may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 1 Senior Bonds in the open market, by tender or by private contract, at any price. Series 1 Senior Bonds purchased by the Company will be cancelled and not reissued.

The Principal Amount may become or be declared due before the Maturity Date on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of Bonds issued by the Company pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of Bonds issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of Bonds issued by the Company pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 1 Senior Bond may be transferred only upon compliance with the conditions prescribed in the Trust Indenture and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer will be duly noted hereon by the Trustee or other registrar.

Recourse against the Company in respect to its obligations under this Series 1 Senior Bond is limited as provided for in the Trust Indenture.

This Series 1 Senior Bond will not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF GREAT LAKES POWER LIMITED has caused this Series 1 Senior Bond to be signed by its duly authorized signing officers.

GREAT LAKES POWER LIMITED

By: ______________________________

Name:
Title:

By: ______________________________

Name:
Title:

(FORM OF TRUSTEE'S CERTIFICATE)

TRUSTEE'S CERTIFICATE

This Bond is one of the Series 1 Senior Bonds referred to in the Trust Indenture referred to above.

CIBC MELLON TRUST COMPANY, Trustee

By: ______________________________
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 2 – U.S. FORM OF DEFINITIVE SERIES 1 SENIOR BOND

THE SECURITIES REPRESENTED HEREBY HAVE NOT BEEN REGISTERED UNDER THE UNITED STATES SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT") OR STATE SECURITIES LAWS. THE HOLDER HEREOF, BY PURCHASING SUCH SECURITIES, UNDERSTANDS AND ACKNOWLEDGES FOR THE BENEFIT OF GREAT LAKES POWER LIMITED (THE "COMPANY") THAT SUCH SECURITIES MAY BE OFFERED, SOLD OR OTHERWISE TRANSFERRED ONLY (A) TO COMPANY, (B) OUTSIDE THE UNITED STATES IN ACCORDANCE WITH RULE 904 OF REGULATION S UNDER THE U.S. SECURITIES ACT, (C) PURSUANT TO THE EXEMPTION FROM REGISTRATION UNDER THE SECURITIES ACT PROVIDED BY RULE 144 OR RULE 144A THEREUNDER OR (D) PURSUANT TO ANOTHER EXEMPTION FROM REGISTRATION, PROVIDED THAT IN THE CASE OF A TRANSFER PURSUANT TO (C) OR (D) ABOVE, A LEGAL OPINION SATISFACTORY TO THE COMPANY MUST FIRST BE PROVIDED.

A NEW CERTIFICATE BEARING NO LEGEND, MAY BE OBTAINED FROM CIBC MELLON TRUST COMPANY UPON DELIVERY OF THIS CERTIFICATE AND A DULY EXECUTED DECLARATION, IN A FORM SATISFACTORY TO CIBC MELLON TRUST COMPANY AND THE COMPANY, TO THE EFFECT THAT THE SALE OF THE SECURITIES REPRESENTED HEREBY IS BEING MADE IN COMPLIANCE WITH RULE 904 OF REGULATION S UNDER THE SECURITIES ACT.

No. S1-001

GREAT LAKES POWER LIMITED
(Incorporated under the laws of Ontario)
6.60% SENIOR BONDS DUE JUNE 16, 2023 (SERIES 1)

Issue Date •, 2008

Maturity Date June 16, 2023

Interest Rate Per Annum 6.60%

Interest Payment Dates June 16 and December 16 in each year

Initial Interest Payment Date June 16, 2008

Principal Payment Dates June 16 and December 16 in each year commencing December 16, 2013 based on a 25 year amortization period

Principal Amount $●

GREAT LAKES POWER LIMITED (the "**Company**") for value received hereby promises to pay to [name of bondholder/ the registered holder] hereof on June 16, 2023 (the "Maturity Date"), or on such earlier date as the Principal Amount (or a portion thereof) may become due in accordance with the provisions of the Trust Indenture (as defined below), this

6.60% Senior Bond due June 16, 2023 (Series 1) (the "**Series 1 Senior Bond**"), the Principal Amount in lawful money of Canada at the office of the Trustee (as defined below) at 320 Bay Street, Toronto, Ontario, and to pay (i) during the period from the Issue Date until and including June 16, 2013, semi-annual payments of interest only on the Principal Amount outstanding at the Interest Rate Per Annum; and (ii) during the period from June 16, 2013 until and including the Maturity Date, equal blended semi-annual payments of principal and interest on the Principal Amount outstanding at the Interest Rate Per Annum, such amount to be calculated on the basis of a 25 year amortization period, at the address of the registered holder hereof appearing on the register of Series 1 Senior Bonds maintained by or at the direction of the Trustee (the "**Register**"). The remaining outstanding principal hereof will be due and payable on the Maturity Date. Interest shall be payable semi-annually in arrears with the first such payment to be payable on the Initial Interest Payment Date, and if the Company at any time defaults in the payment of any principal or interest, to pay interest on the amount in default at the same rate, in like money, on demand, at the address of the registered holder hereof appearing on the Register. The Company shall, at the request of the registered holder hereof, on the date on which principal and interest becomes due (or if such date is not a business day, the first business day preceding such day), (i) forward or cause to be forwarded by prepaid post to the address of the registered holder, or, in the case of joint holders, to one of such joint holders, one or more cheques (drawn on a Canadian chartered bank) for such principal or interest (less any tax required to be deducted or withheld plus any gross up required to be paid pursuant to any supplemental indenture) payable to the order of such holder or holders or, (ii) effect a wire transfer to the holder or, in the case of joint holders, to one of such joint holders, based on the wire transfer instructions provided by any such holder to the Company in the amount of such principal or interest (less any tax required to be deducted or withheld plus any gross up required to be paid pursuant to any supplemental indenture), in each case in immediately available funds for receipt not later than 12:00 (noon) Toronto time on the date such payment is due.

This Series 1 Senior Bond is one of an authorized issue of bonds designated as 6.60% Senior Bonds due June 16, 2023 (Series 1) and forming the series of bonds created and issued under a first supplemental trust indenture made as of March 12, 2008 (the "**First Supplemental Trust Indenture**") to a deed of trust (the "**Indenture**") made as of March 12, 2008, between the Company and CIBC Mellon Trust Company (the "**Trustee**"), as Trustee (the First Supplemental Trust Indenture and the Indenture collectively referred to herein as the "**Trust Indenture**"). The Trust Indenture specifies the terms and conditions upon which the Series 1 Senior Bonds are created and issued or may be created, issued and held and the rights of the registered holders of the Series 1 Senior Bonds, the Company and the Trustee, all of which terms and conditions are incorporated by reference in this Series 1 Senior Bond and to each of which the registered holder of this Series 1 Senior Bond, by acceptance hereof, agrees. Capitalized terms used but not defined herein have the meanings specified in the Trust Indenture.

The aggregate principal amount of Series 1 Senior Bonds that may be created and issued under the Trust Indenture is limited to $120,000,000 in lawful money of Canada.

The Series 1 Senior Bonds are direct secured obligations of the Company and will rank equally with each other and with all other Senior Bonds of every other series from time to time issued and outstanding pursuant to the Trust Indenture.

This Series 1 Senior Bond is redeemable, at the option of the Company, provided that no Default or Event of Default is continuing, in whole at any time or in part from time to time, subject to the terms and conditions set forth in the Trust Indenture, at a price equal to the Redemption Price (as defined in the First Supplemental Trust Indenture).

At any time when the Company is not in default under the Trust Indenture, the Company may, subject to the terms and conditions set forth in the Trust Indenture, purchase Series 1 Senior Bonds in the open market, by tender or by private contract, at any price. Series 1 Senior Bonds purchased by the Company shall be cancelled and not reissued.

The Principal Amount may become or be declared due before the Maturity Date on the conditions, in the manner, with the effect and at the times set forth in the Trust Indenture.

The Trust Indenture contains provisions for the holding of meetings of registered holders of Bonds issued by the Company pursuant to the Trust Indenture and the making of resolutions at such meetings and the creation of instruments in writing signed by the registered holders of a specified majority of Bonds issued and outstanding pursuant to the Trust Indenture. Such resolutions and instruments will be binding on and may affect the rights and entitlements of all holders of Series 1 Senior Bonds issued by the Company pursuant to the Trust Indenture, subject to the provisions of the Trust Indenture.

This Series 1 Senior Bond may be transferred only upon compliance with the conditions prescribed in the Trust Indenture, and upon compliance with such reasonable requirements as the Trustee or other registrar may prescribe, and such transfer will be duly noted hereon by the Trustee or other registrar.

Recourse against the Company in respect to its obligations under this Series 1 Senior Bond is limited as provided for in the Trust Indenture.

This Series 1 Senior Bond shall not become obligatory for any purpose until it shall have been certified by the manual signature of the Trustee in accordance with the Trust Indenture.

IN WITNESS WHEREOF GREAT LAKES POWER LIMITED has caused this Series 1 Senior Bond to be signed by its duly authorized signing officers.

GREAT LAKES POWER LIMITED

By: ______________________________

Name:
Title:

By: ______________________________

Name:
Title:

(FORM OF TRUSTEE'S CERTIFICATE)

TRUSTEE'S CERTIFICATE

This Bond is one of the Series 1 Senior Bonds referred to in the Trust Indenture referred to above.

CIBC MELLON TRUST COMPANY, Trustee

By: ______________________________
Authorized Signatory

(FORM OF REGISTRATION PANEL)

(NO WRITING HEREON EXCEPT BY THE TRUSTEE OR OTHER REGISTRAR)

DATE OF REGISTRATION	IN WHOSE NAME REGISTERED	SIGNATURE OF TRUSTEE OR OTHER REGISTRAR

Schedule 3 – REPAYMENT SCHEDULE

See attached.

Transmission Bonds

$	120,000,000	0.3125
	6.60%	

Date	Interest	Principal	Total payment	Amount outstanding
June 16, 2003				
December 16, 2003	3,960,000	-	3,960,000	120,000,000
June 16, 2004	3,960,000	-	3,960,000	120,000,000
December 16, 2004	3,960,000	-	3,960,000	120,000,000
June 16, 2005	3,960,000	-	3,960,000	120,000,000
December 16, 2005	3,960,000	-	3,960,000	120,000,000
June 16, 2006	3,960,000	-	3,960,000	120,000,000
December 16, 2006	3,960,000	-	3,960,000	120,000,000
June 16, 2007	3,960,000	-	3,960,000	120,000,000
December 16, 2007	3,960,000	-	3,960,000	120,000,000
June 16, 2008	3,960,000	-	3,960,000	120,000,000
December 16, 2008	3,960,000	-	3,960,000	120,000,000
June 16, 2009	3,960,000	-	3,960,000	120,000,000
December 16, 2009	3,960,000	-	3,960,000	120,000,000
June 16, 2010	3,960,000	-	3,960,000	120,000,000
December 16, 2010	3,960,000	-	3,960,000	120,000,000
June 16, 2011	3,960,000	-	3,960,000	120,000,000
December 16, 2011	3,960,000	-	3,960,000	120,000,000
June 16, 2012	3,960,000	-	3,960,000	120,000,000
December 16, 2012	3,960,000	-	3,960,000	120,000,000
June 16, 2013	3,960,000	-	3,960,000	120,000,000
December 16, 2013	3,960,000	972,950	4,932,950	119,027,050
June 16, 2014	3,927,893	1,005,058	4,932,950	118,021,992
December 16, 2014	3,894,726	1,038,225	4,932,950	116,983,767
June 16, 2015	3,860,464	1,072,486	4,932,950	115,911,281
December 16, 2015	3,825,072	1,107,878	4,932,950	114,803,403
June 16, 2016	3,788,512	1,144,438	4,932,950	113,658,965
December 16, 2016	3,750,746	1,182,204	4,932,950	112,476,761
June 16, 2017	3,711,733	1,221,217	4,932,950	111,255,543
December 16, 2017	3,671,433	1,261,518	4,932,950	109,994,026
June 16, 2018	3,629,803	1,303,148	4,932,950	108,690,878
December 16, 2018	3,586,799	1,346,151	4,932,950	107,344,727
June 16, 2019	3,542,376	1,390,574	4,932,950	105,954,153
December 16, 2019	3,496,487	1,436,463	4,932,950	104,517,690
June 16, 2020	3,449,084	1,483,867	4,932,950	103,033,823
December 16, 2020	3,400,116	1,532,834	4,932,950	101,500,989
June 16, 2021	3,349,533	1,583,418	4,932,950	99,917,571
December 16, 2021	3,297,280	1,635,670	4,932,950	98,281,901
June 16, 2022	3,243,303	1,689,648	4,932,950	96,592,253
December 16, 2022	3,187,544	1,745,406	4,932,950	94,846,848
June 16, 2023	3,129,946	94,846,848	97,976,793	-

November 2009

Retirement Plan of Great Lakes Power Transmission LP

Report on the Actuarial Valuation for Funding Purposes as at July 1, 2009

MERCER

MMC MARSH MERCER KROLL GUY CARPENTER OLIVER WYMAN

Financial Services Commission of Ontario Registration Number: pending
Canada Revenue Agency Registration Number: pending

Consulting. Outsourcing. Investments.

Contents

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Summary of Results

Going-Concern Financial Position	July 1, 2009
Market value of assets (in-transit)	$10,839,900
Actuarial liability (in-transit)	$12,375,900
Funding excess (shortfall)	($1,536,000)
Solvency Financial Position	**July 1, 2009**
Adjusted solvency assets (in-transit)	$11,761,000
Solvency liability (in-transit)	$13,601,000
Solvency excess (deficiency)	($1,840,000)
Transfer ratio	80%
Ratio of solvency assets to solvency liabilities	80%
Wind-Up Financial Position	**July 1, 2009**
Market value of assets, net of termination expenses (in-transit)	$10,829,900
Total wind-up liabilities (in-transit)	$13,601,000
Wind-up excess (deficiency)	($2,771,100)
Funding Requirements (annualised)	**July 1, 2009**
Total current service cost	$343,500
Estimated members' required contributions	$113,000
Estimated employer's current service cost	$230,400
Employer's current service cost as a percentage of members' pensionable earnings	11.7%
Minimum special payments	$624,384[*]
Estimated minimum employer contribution for year	$854,784[1]
Estimated maximum employer contribution for year	$3,001,500[1]

[*] Special payments to be remitted once the transfer of assets and actuarial liabilities from predecessor plan has occurred.

2

Introduction

Report on the Actuarial Valuation as at July 1, 2009

To Great Lakes Power Transmission LP

At your request we have conducted an actuarial valuation of the Retirement Plan of Great Lakes Power Transmission LP (the "Plan") as at July 1, 2009. We are pleased to present the results of the valuation. **This report replaces the report dated July 2009.**

Effective July 1, 2009 employees of the "Transmission" division of Great Lakes Power Limited ("GLPL") were transferred to a separate company affiliated with GLPL, Great Lakes Power Transmission LP (the "Company"). These employees were members of the Retirement Plan of Great Lakes Power Limited (the "GLPL Plan") prior to July 1, 2009. The Plan was established for the current employees transferred to the Company and for future eligible employees of the Company. An application will be submitted to the Financial Services Commission of Ontario for the transfer of assets and liabilities from the GLPL Plan with respect to the transferred employees' benefits accrued prior to July 1, 2009 in the GLPL Plan as well as benefits in the GLPL Plan for inactive members formerly employed by the "Transmission" division of GLPL.

The purpose of this valuation is to determine:

- the funded status of the Plan as at July 1, 2009 on going-concern, solvency and wind-up bases, and
- the minimum and maximum funding requirements from July 1, 2009.

The information contained in this report was prepared for the internal use of Great Lakes Power Transmission LP 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 is not intended or suitable for any other purpose.

This report will be filed with the Financial Services Commission of Ontario and with the Canada Revenue Agency.

The next actuarial valuation of the Plan will be required as at a date not later than July 1, 2012 or as at the date of an earlier amendment to the Plan, in accordance with the minimum requirements of the *Pension Benefits Act of (Ontario)*.

There is a funding shortfall of $1,536,000, and solvency liabilities exceed solvency assets by $2,771,100. As such, the minimum monthly contribution that Great Lakes Power Transmission must make to the Plan from July 1, 2009 until the next valuation is as follows:

Monthly Employer Contributions
For current service: 11.7% of members' pensionable earnings
Minimum special payments for unfunded liability: $17,483
Minimum additional special payments for solvency: $34,549

On the basis of the members' estimated pensionable earnings, we have estimated the minimum total employer contribution for the 12-month period following the valuation date to be $854,784 or $71,232 per month.

The maximum contributions that the Company may make to the Plan in 12-month period following the valuation date is $3,001,500 which is comprised of the Company current service cost plus the greater of the funding shortfall and the wind-up deficiency.

However, until the transfer of assets and liabilities from the GLPL Plan is approved by the Financial Services Commission of Ontario, the Company will contribute to the Plan the current service cost only. When the transfer occurs, the Company will contribute in a lump sum, the difference between (i) the aggregate special payments due between July 1, 2009 and the date of transfer and (ii) the aggregate special payments made by the Company to the GLPL Plan over the same period.

The Plan is not fully funded on a wind-up basis. Emerging experience, including the growth of wind-up liabilities compared to the Plan's assets (including future contributions and investment returns), will affect the wind-up funded position of the Plan in the future.

This valuation reflects the provisions of the Plan as at July 1, 2009*. A summary of the Plan provisions is provided in Appendix D.

* Except for an ad-hoc increase in certain retired members' pensions effective September 1, 2009. The impact of that amendment is reflected in the valuation results as of July 1, 2009.

The assumptions used for purposes of this valuation are described in Appendix B. All assumptions made for the purposes of the valuation were independently reasonable at the time the valuation was prepared.

After checking with representatives of Great Lakes Power Transmission LP, 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. We note that the impact of the ad-hoc increase effective September 1, 2009 has been reflected in the valuation results as of July 1, 2009.

We have assumed that all plan assets are available to cover the plan liabilities presented in this report.

This valuation report may not be relied upon for any purpose other than those explicitly noted above or by any party other than the Company, the Financial Services Commission of Ontario or the Canada Revenue Agency. 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.

Over time, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people who are 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 this report, *actuarial assumptions,* as described in Appendix B, are used to select a single scenario from the range of possibilities. The results of 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. In addition, different assumptions or scenarios may also be within the reasonable range and results based on those assumptions would be different. Actuarial assumptions may also be changed from one valuation to the next because of changes in regulatory requirements, plan experience, changes in expectations about the future and other factors.

Because actual plan experience will differ from the assumptions, 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.

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 of (Ontario)*.

Respectfully submitted,

Luc Girard
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

November 30/2009
Date

John Marks
Associate of the Society of Actuaries

Nov 30/09
Date

Retirement Plan of Great Lakes Power Transmission LP

Registration number with the Financial Services Commission of Ontario and with the Canada Revenue Agency: pending

3

Financial Position of the Plan

Valuation Results – Going-concern Basis

When conducting a valuation on a going-concern basis, we determine the relationship between the respective values of assets and accumulated benefits, assuming the Plan will be maintained indefinitely.

Financial Position

The results of the valuation as at July 1, 2009 are summarized as follows:

Financial Position – Going-concern Basis

	July 1, 2009
Market value of assets (in-transit)	$10,839,900
Actuarial liability	
Present value of accrued benefits (in-transit) for:	
▪ active members	$5,852,500
▪ pensioners and survivors	$6,523,400
▪ deferred pensioners	$0
Total liability	$12,375,900
Funding excess (shortfall)	($1,536,000)

Valuation Results – Solvency Basis

When conducting a solvency valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities on a solvency basis, determined in accordance with the *Pension Benefits Act of (Ontario)*. The values of the Plan's assets and liabilities on a solvency basis are related to the corresponding values calculated as though the Plan were wound up and settled on the valuation date.

We have included the value of all benefits that may be contingent upon the circumstances of the postulated Plan wind-up.

Financial Position on a Solvency Basis

The Plan's solvency position as at July 1, 2009 is determined as follows:

Solvency Position

	July 1, 2009
Market value of assets (in-transit)	$10,839,900
Termination expenses	($10,000)
1. Solvency assets	$10,829,900
Present value of special payments for next five years	$931,100
2. Adjusted solvency assets	$11,761,000
Actuarial liability (in-transit)	
Present value of accrued benefits for:	
▪ active members	$6,696,400
▪ pensioners and survivors	$6,904,600
▪ deferred pensioners	$0
3. Solvency liabilities	$13,601,000
Solvency excess (deficiency) created as at valuation date (2. - 4.)	($1,840,000)
Transfer ratio (1. ÷ 3.)	80%

Payment of Benefits

Since the transfer ratio is less than one, the Plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the *Pension Benefits Act of (Ontario)* to allow for the full payment of benefits. Otherwise, the Plan administrator should take the actions prescribed by the *Act*.

Financial Position on a Wind-up Basis

The Plan's hypothetical wind-up position as of July 1, 2009, assuming circumstances producing the maximum wind-up liabilities on the valuation date, is determined as follows:

Wind-up Position

	July 1, 2009
Market value of assets (in-transit)	$10,839,900
Termination expense provision	($10,000)
Wind-up assets	$10,829,900
Present value of accrued benefits (in-transit) for:	
▪ active members	$6,696,400
▪ pensioners and survivors	$6,904,600
▪ deferred pensioners	$0
Total wind-up liability	$13,601,000
Wind-up excess (deficiency)	($2,771,100)

Impact of Plan Wind-up

In our opinion, the value of the Plan's assets would be less than its actuarial liabilities if the Plan were to be wound up on the valuation date. Specifically, actuarial liabilities would exceed the market value of Plan assets by $2,771,100. This calculation includes a provision for termination expenses that might be payable from the pension fund.

Pension Benefit Guarantee Fund (PBGF) Assessment

Until the asset transfer from the GLPL Plan occurs, the PBGF assessment is calculated as follows:

$1 for each Ontario member	$45
PLUS	
0.5% of PBGF assessment base up to 10% of PBGF liabilities	$0
PLUS	
1.0% of PBGF assessment base up to between 10% and 20% of PBGF liabilities	$0
PLUS	
1.5% of PBGF assessment base over 20% of PBGF liabilities	$0
PLUS	
2.0% of special PBGF assessment base	$0
PBGF assessment (taking into account the $100 limit per member)	$45

After the asset transfer from the GLPL Plan has occurred, the PBGF assessment is calculated as follows:

$1 for each Ontario member	$45
PLUS	
0.5% of PBGF assessment base up to 10% of PBGF liabilities	$6,801
PLUS	
1.0% of PBGF assessment base up to between 10% and 20% of PBGF liabilities	$13,601
PLUS	
1.5% of PBGF assessment base over 20% of PBGF liabilities	$614
PLUS	
2.0% of special PBGF assessment base	$0
PBGF assessment (taking into account the $100 limit per member)	$4,500

The PBGF assessment base and liabilities are derived as follows:

PBGF Assessment Base and PBGF Liabilities

PBGF liabilities	$13,601,000	(a)
Total solvency liabilities	$13,601,000	(b)
Ontario asset ratio	100%	(c) = (a) ÷ (b)
Market value of assets	$10,839,900	(d)
Ontario portion of the fund	$10,839,900	(e) = (c) x (d)
PBGF assessment base	$2,761,100	(f) = (a) - (e)

4

Funding Requirements

Current Service Cost

The estimated value of the benefits that will accrue on behalf of the active members for the 12-month period commencing July 1, 2009 is summarized below:

Employer's Current Service Cost

	July 1, 2009
Total current service cost	$343,500
Estimated members' required contributions	$113,000
Estimated employer's current service cost	$230,400
Employer's current service cost expressed as a percentage of members' pensionable earnings	11.7%

Special Payments

Going-concern Basis

In accordance with the *Pension Benefits Act (Ontario)*, the going-concern unfunded liability of $1,536,000 must be amortized over a period not exceeding 15 years. As such, special payments must be established at $17,483 per month until January 31, 2019 to amortize this going-concern unfunded liability.

Solvency Basis

In accordance with the *Pension Benefits Act (Ontario)*, each solvency deficiency must be eliminated by special payments within five years of the respective effective date. As such, special payments have been established at $34,549 per month until June 30, 2014 to eliminate the solvency deficiency of $1,840,000.

Total Special Payments

The following minimum monthly special payments must be made to the plan to eliminate any going-concern unfunded liability and any solvency deficiency as at July 1, 2009, within the periods prescribed by the *Pension Benefits Act (Ontario).*

Minimum Monthly Special Payments

Type of Deficit	Effective Date	Special Payment	Last Payment
Unfunded Liability	July 1, 2009	$17,483	January 31, 2019
Solvency Deficiency	July 1, 2009	$34,549	June 30, 2014
Total		$52,032	

Employer Contributions

There is a funding shortfall of $1,536,000 and solvency liabilities exceed solvency assets by $2,771,100. As such, the minimum monthly contribution that Great Lakes Plan Transmission LP must make from July 1, 2009 to June 30, 2012 as follows.

Minimum Funding Requirements

The minimum monthly required contributions from July 1, 2009 to June 30, 2012 are as follows:

Monthly Employer Contributions
For current service: 11.7% of members' pensionable earnings
Minimum special payments for unfunded liability: $17,483
Minimum additional special payments for solvency: $34,549

On the basis of the members' estimated pensionable earnings, we have estimated the minimum total employer contribution for the 12-month period beginning July 1, 2009 to be $854,784 or $71,232 per month.

However, until the transfer of assets and liabilities from the GLPL Plan is approved by the Financial Services Commission of Ontario, the Company will contribute to the Plan the current service cost only. When the transfer occurs, the Company will contribute in a lump sum, the difference between (i) the aggregate special payments due between July 1, 2009 and the date of transfer and (ii) the aggregate special payments made by the Company to the GLPL Plan over the same period.

Maximum Eligible Contributions

The maximum eligible employer contribution is equal to the employer current service cost plus the greater of the funding shortfall and wind-up deficiency.

Once the transfer of assets and liabilities from the GLPL Plan has occurred, we estimate the maximum eligible annual contribution will be $3,001,500.

Estimated Minimum Employer's Contributions until June 30, 2012

Year Ending	Current Service Cost	Minimum Special Payments
June 30, 2010	$230,400	$624,384
June 30, 2011	$238,500	$624,384
June 30, 2012	$246,800	$624,384

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Actuarial Opinion

With respect to the Actuarial Valuation as at July 1, 2009
of the Retirement Plan of Great Lakes Power Transmission LP
FSCO and Canada Revenue Agency
Registration No. pending

Based on the results of this valuation, we hereby certify that, as at July 1, 2009:

- The employer's current service cost for each year up to the next actuarial valuation should be calculated as 11.7% of members' pensionable earnings.
- The employer's current service cost for the 12-month period beginning July 1, 2009 is estimated to be $230,400.
- The Plan would be fully funded on a going-concern basis if its assets were augmented by $1,536,000.
- The Plan would be fully funded on a solvency basis if its assets were augmented by $2,771,100.
- In order to comply with the provisions of the *Pension Benefits Act (Ontario)*, the unfunded liability and solvency deficiency must be liquidated must be liquidated by monthly special payments at least equal to the amounts indicated, and for the periods set forth, below:

Minimum Monthly Special Payments

Type of Deficit	Effective Date	Special Payment	Last Payment
Unfunded Liability	July 1, 2009	$17,383	January 31, 2019
Solvency Deficiency	July 1, 2009	$34,549	June 30, 2014

- The Pension Benefits Guarantee Fund annual assessment under Section 37 of the Regulations to the *Pension Benefits Act of (Ontario)* for year beginning July 1, 2009 is $45 payable no later than September 30, 2010. The PBGF assessment base is $2,761,100. The PBGF liabilities are $13,601,000.

- The transfer ratio of the plan is 80%. The Prior Year Credit Balance on July 1, 2009 is $0.

- In our opinion,

  – the data on which the valuation is based are sufficient and reliable for the purposes of the valuation,
  – the assumptions are, in aggregate, appropriate for the purposes of determining the funded status of the Plan as at July 1, 2009 on going-concern and solvency bases, and determining the minimum funding requirements, and
  – the methods employed in the valuation are appropriate for the purposes of determining the funded status of the Plan as at July 1, 2009 on going-concern and solvency bases, and determining the minimum funding requirements.

- This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

- All assumptions made for the purposes of the valuation were independently reasonable at the time the valuation was prepared.

Luc Girard
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

November 30/2009
Date

John Marks
Associate of the Society of Actuaries

Nov 30/09
Date

Appendix A

Plan Assets

Sources of Plan Asset Data

The Plan assets are based on the amount of assets to be transferred from the Retirement Plan of Great Lakes Power Limited (the "GLPL Plan").

As per the actuarial report on GLPL Plan as at July 1, 2009, the amount of assets to be transferred from the GLPL Plan is $10,839,900.

Appendix B

Actuarial Methods and Assumptions

Actuarial Valuation Methods – Going-concern Basis

Valuation of Assets

For this valuation, we have used the amount of assets to be transferred from the GLPL Plan.

Valuation of Actuarial Liabilities

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 used the *projected unit credit actuarial cost method*. Under this method, we determine the actuarial present value of benefits accrued in respect of service prior to the valuation date, including ancillary benefits, based on projected final average earnings. This is referred to as the *actuarial liability*.

The *funding excess* or *funding shortfall*, as the case may be, is the difference between the market value of assets and the actuarial liability. An unfunded liability will be amortized over no more than 15 years through special payments as required under the *Pension Benefits Act of (Ontario)*. 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.

This actuarial funding method produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial funding method aims at keeping the plan fully funded at all times. This promotes benefit security, once any unfunded liabilities and solvency deficiencies have been funded.

When actuarial liabilities on a solvency basis exceed actuarial liabilities on a going-concern basis and the plan has a solvency deficiency, as are both true in this valuation, contribution requirements will be largely determined by the solvency funded position. This has several implications:

- Special payments are required to amortize solvency deficiencies over a maximum of 5 years;
- During the amortization period the plan is not expected to be 100% solvent; and
- Any future benefit improvements affecting past service will increase solvency liabilities and further reduce the solvency of the plan

In addition, the growth in solvency liabilities resulting from the additional accrual of benefits and development of the plan membership may be different than the growth of plan assets including future contributions and investment returns. This may result in further losses being revealed in future solvency valuations.

Current Service Cost

The *current service cost* is the actuarial present value of projected benefits to be paid under the plan with respect to service during the year following the valuation date.

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.

Employer's Contribution

Accordingly, the employer's contributions for this purpose are determined as follows:

Employer's Contributions

With a funding excess	With an unfunded liability
Current service cost MINUS Any funding excess applied to cover the employer's current service cost	Current service cost PLUS Payments to amortize any unfunded liability

Actuarial Assumptions – Going-concern Basis

The actuarial value of benefits 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. For this valuation, we have used the following assumptions.

Economic Assumptions

Investment Return

We have assumed that the investment return on the market value of the fund will average 6.0% per year over the long term. We have based this assumption on an expected long-term return on the pension fund less an allowance for investment expense and less a margin for adverse deviations, as described below.

We have assumed a gross rate of return of 7.17% consistent with market conditions applicable on the valuation date, based on estimated returns for each major asset class and on the target asset mix specified in the GLPL Plan's investment policy. Additional returns of 0.30% per year are assumed to be achievable due to active management.

We have allowed for investment expenses of 0.50% per year.

We have included a margin for adverse deviations, from all sources, of 0.97% per year.

Increases in the YMPE

Since the benefits provided by the Plan depend on the final average Year's Maximum Pensionable Earnings (YMPE) under the Canada Pension Plan, it is necessary to make an assumption about increases in the YMPE for this valuation. We have assumed that the YMPE will increase at the assumed rate of inflation of 3.0% from its 2009 level of $46,300.

Increases in the Maximum Pension Permitted under the Income Tax Act

The *Income Tax Act* stipulates that the maximum pension that can be provided under a registered pension plan will be increased to specified amounts up to 2009, and automatically, starting in 2010, in accordance with general increases in the average wage.

For this valuation, we have assumed that the maximum pension payable under the Plan will increase at the rate of 3.0% per year starting in 2010.

Increases in 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 2009 earnings and assumed that such pensionable earnings will increase at 3.5% per year.

This is based on:

- an inflation rate of 2.5% per year,
- productivity increases of 0.5% per year, and
- merit and promotional increases of 0.5% per year.

Indexation of Pensions in Payment

Pensions in payment are increased each year according to a formula related to increases in the Consumer Price Index (CPI).

For this valuation, we have assumed that the CPI will increase at the assumed rate of 2.50% per year. Consequently, pensions in payment are assumed to increase annually at the rate of 2.0% per year.

Interest Credited on Employee-required Contributions

Interest is credited on employee-required contributions. For this valuation, we have assumed that the interest rate to be credited on employee-required contributions will be 6.00% per year, over the long term. This rate is consistent with the assumptions underlying the investment return assumption.

Demographic Assumptions

Retirement Age

Because early retirement pensions are reduced in accordance with a formula, the retirement age of Plan members has an impact on the cost of the plan. We have assumed that 60% of members will retire at the earliest date on which they would be eligible for an unreduced pension, and the remainder of the membership were assumed to retire on their normal retirement date, which is their 65^{th} birthday.

Termination of Employment

We have not made an allowance for projected benefits payable on the termination of employment before retirement for reasons other than death.

Mortality

The actuarial value of the pension depends on the lifetime of the member.

The 1994 Uninsured Pensioner Mortality Table reflects the mortality experience as of 1994 for a large sample of North American pension plans. Applying projection scale AA provides an allowance for generational improvements in mortality after 1994. This table is commonly used for valuations where the membership of a plan is insufficient to assess plan specific experience and where there is no reason to expect the mortality to differ from that of other pension plans. Both are true for this Plan.

While there is strong evidence of continuing improvement in mortality, forecasts of the rate of future improvement are very uncertain. We have used the projection scale AA to reflect future improvements in mortality.

We have assumed mortality rates, both before and after retirement, in accordance with the 1994 Uninsured Pensioner Mortality Table with projection scale AA applied to reflect continuing future improvements in mortality. According to this table, the life expectancy at age 65, as of the valuation date, is 19.4 years for males and 22.0 years for females.

Disability

We have not made an allowance for projected benefits payable on disability retirement.

Family Composition

Benefits in case of death, before and after retirement, depend on the Plan member's marital status.

For this valuation, we have assumed that 80% of Plan members will have an eligible spouse on the earlier of death or retirement, and that the male partner will be three years older than the female partner.

Actuarial Valuation Methods and Assumptions – Solvency and Impact of Plan Wind-up

We have used the amount of assets to be transferred from the GLPL Plan in our valuation of the Plan for solvency purposes.

To determine the solvency actuarial liability, 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 July 1, 2009, with all members fully vested in their accrued benefits. No benefits payable on Plan wind-up were excluded from our calculations.

Benefits are assumed to be settled through a lump sum transfer for 70% of active and deferred members under age 55 and 40% for active and deferred members age 55 or older. The value of the benefits accrued on July 1, 2009, for such members is based on the assumptions described in *Section 3800 – Pension Commuted Values of the Canadian Institute of Actuaries Standards of Practice* effective April 1, 2009 and applicable for July 1, 2009 for benefits expected to be settled through transfer in accordance with relevant portability requirements.

Benefits are assumed to be settled through the purchase of annuities for all pensioners and the portion of active and deferred members who are not assumed to be settled through a lump sum transfer. The value of the benefits accrued on July 1, 2009, for such members is based on an estimate of the cost of settlement through purchase of annuities.

We have estimated the cost of settlement through purchase of annuities in accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2008 and December 30, 2009.*

In accordance with the *Pension Benefits Act of (Ontario)*, the members in receipt of a pension at the wind-up date, as well as members who have elected to receive an immediate or deferred annuity must be settled through the purchase of an annuity upon the wind-up of a Plan. However, it may not be possible to settle the liabilities at any reasonable cost through the purchase of annuities due to the current lack of competitive market for indexed annuities in Canada.

In light of these limitations, the above basis is equal to the non-indexed annuity proxy rate determined in accordance with the *Canadian Institute of Actuaries Education Note: Guidance for 2007 on Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2008 and December 30, 2009* reduced by an assumed inflation adjustment. The assumed inflation assumption is based on the implied inflation derived from the difference in long-term Government of Canada real return bonds and nominal bonds as at the date of the valuation.

We note that the above basis is theoretical and does not represent the cost at which CPI-indexed annuities can be purchased in today's market. We expect that if an insurance company were to take on these obligations that they would demand a significantly higher price.

However, the above basis may be consistent with the price that an insurance company would charge to provide pensions that increase at a *fixed* rate of 2.0% per year (the estimated long-term rate of inflation implied from the difference in long-term Government of Canada real return bonds and nominal bonds as at the date of the valuation capped in accordance with the plan's formula) instead of the actual increase in the CPI.

Assumptions are as follows:

Actuarial Assumptions

For benefits to be settled through a lump sum	
Mortality rates:	UP94 projected to 2020
Interest rate:	3.80% per year for the first 10 years following 7.1.2009, 5.80% per year thereafter
For benefits to be settled through the purchase of an annuity	
Mortality rates:	UP94 projected to 2015
Interest rates for benefits to be settled through immediate annuity purchase:	5.31% per year
Interest rates for benefits to be settled through deferred annuity purchase:	4.91% per year
For all benefits:	
Final average earnings:	Final average earnings on the valuation date
Family composition:	Same as for going concern valuation
Plan termination expenses:	$10,000

Pensions in payment are adjusted each January 1st according to a formula based on increases in the CPI for all members retiring after December 31, 1994. For the solvency valuation, we have assumed that the pension payments would be adjusted by 2.0% per year for such members.

In a solvency valuation, the accrued benefits are based on the member's final average earnings on the valuation date; therefore, no salary projection is used. Also the employment of each member is assumed to have terminated on the valuation date, therefore, no assumption is required for future rates of termination of employment.

For the purpose of determining the financial position of the Plan on both a solvency and hypothetical wind-up basis, termination expenses were assumed to be paid by the plan sponsor, except with regard to transaction fees related to the liquidation of the Plan's assets for which a provision was set. Such fees are difficult to assess and will vary depending on the nature of the assets held and market conditions at the time assets are liquidated.

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.

Appendix C

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at July 1, 2009, provided by Great Lakes Power Transmission LP.

We have applied tests for internal consistency, as well as for consistency with the data used for the valuation as at January 1, 2007 of the GLPL Plan. 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.

Membership Data

	July 1, 2009
Active and Disabled Members	
Number	27
Total pensionable earnings	$1,971,800
Average pensionable earnings	$73,000
Average years of pensionable service (in the GLPL Plan)	14.9 years
Average age	46.9
Accumulated contributions with interest (in-transit)	$1,580,500
Deferred Pensioners	
Number	0
Total annual pension	$0
Average annual pension	$0
Average age	0.0
Pensioners and Survivors	
Number	18
Total annual lifetime pension	$481,600
Average annual lifetime pension	$26,800
Total annual bridge benefit	$41,700
Average age	68.8

The Transmission of the active members by age and pensionable service as at July 1, 2009, is summarized as follows:

Transmission of Active Members
By Age Group and Pensionable Service as at July 1, 2009

	Years of Pensionable Service							
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30 +**	**Total**
Under 20								
20 - 24								
25 - 29								
30 - 34		1						1
35 - 39	2	4						6
40 - 44	1	1			2			4
45 - 49	1	2	1		1	2	1	8
50 - 54	1					1		2
55 - 59						3	1	4
60 - 64		1			1			2
65 +								
Total	**5**	**9**	**1**	**0**	**4**	**6**	**2**	**27**

The Transmission of the inactive members by age as at July 1, 2009, is summarized as follows:

Transmission of Inactive Members
By Age Group as at July 1, 2009

	Deferred Pensioners		Pensioners and Survivors	
Age	**Number**	**Average Pension**	**Number**	**Average Pension**
45 - 49				
50 - 54				
55 - 59			3	$31,583
60 - 64			4	$30,765
65 - 69			4	$31,163
70 - 74			4	$24,310
75 - 79			1	n/a
80 - 84			2	n/a
85 - 89				
90 - 94				
95 - 99				
100 +				
Total	0	$0	18	$26,758

Appendix D

Summary of Plan Provisions

Introduction

The Plan was created as of July 1, 2009 exclusively for members of the *Retirement Plan of Great Lakes Power Limited* (the "GLPL Plan") who are employed or were formerly employed in the Transmission business of Great Lakes Power Limited.

Eligibility for Membership

Each member of the GLPL Plan on June 30, 2009 who are employed or were formerly employed in the Transmission business of Great Lakes Power Limited becomes a member of the Plan on July 1, 2009.

Each full-time employee who is a member of the union becomes member of the Plan following completion of three months of Continuous Service.

Each employee, who is a member of the union and is employed on a less than full-time basis, may join the Plan following completion of 24 months of Continuous Service provided that the employee has:

(a) earned at least 35% of the YMPE; or

(b) worked 700 or more hours

in each of the two immediately preceding consecutive calendar years.

Employee Contributions

Members are required to contribute to the Plan at the rate of 5% Gross Earnings up to the YMPE and 7% of Gross Earnings in excess of the YMPE.

Members may make additional voluntary contributions to the maximum permitted under the *Income Tax Act*.

Retirement Dates

Normal Retirement Date

The normal retirement date is the first date of the month coincident with or next following the member's 65th birthday.

Early Retirement Date

Members who have attained age 55 may retire early on a reduced pension. The reduction is ¼ of 1% for each month prior to age 65. Members who have attained age 55 and for whom the sum of age plus continuous years of service amount to not less than 85, may retire early with an unreduced pension.

All members who retire early will also receive a temporary pension (payable for life but in no event past age 65) of 0.7% of annual gross earnings up to the average YMPE for the five calendar years immediately preceding the calendar year of retirement times years of credited service since January 1, 1966 (maximum 35 years).

Postponed Retirement

An active member may postpone retirement beyond the normal retirement date, but not beyond the end of the calendar year in which they attain age 71. Under these circumstances, members are entitled to continue membership in the Plan and have the right to continue to accrue pension benefits. The pension benefit accrued up to Normal Retirement Date shall be actuarially increased to reflect such postponement.

Retirement Benefits

Normal Retirement

Each member retiring at his Normal Retirement Date will be entitled to receive an annual pension benefit, payable monthly equal to:

(a) 2.0% of the member's average annual gross earnings for the five consecutive years, during the 10 calendar years preceding Normal Retirement Date that produce the highest such average, times the number of years of Credited Service (subject to a maximum of 40 years);

Less

(b) 0.7% of such earnings not in excess of the average YMPE for the five calendar years, immediately preceding the calendar year of the Normal Retirement Date, times the number of years of Credited Service since January 1, 1966, (maximum 35 years).

Credited Service is equal to Continuous Service from date of employment with the Company for members who joined the Plan when first eligible prior to January 1, 1991. For other members, Credited Service is equal to Continuous Service from the date of entry.

In no event, however, will the member's benefit exceed the applicable maximum pension limits as prescribed by the *Income Tax Act*.

Maximum Pension

The maximum pension provisions are as follows:

(a) Pre-1992 Service Maximum Pension

The member's pension shall not exceed the member's years of pensionable service, prior to January 1, 1992, to a maximum of 35 years multiplied by the lesser of:

(i) $1,715; and

(ii) 2.0% of the average of the member's best three consecutive years' remuneration from the Company.

(b) Post-1991 Service Maximum Pension

The member's pension shall not exceed the member's years of pensionable service, on or after January 1, 1992, multiplied by the lesser of:

(i) $2,444.44 or such greater amount permitted under the *Income Tax Act*; and

(ii) 2.0% of the member's highest average indexed compensation, as defined in the *Income Tax Act*.

Post Retirement Adjustments

Each member who retires from the Plan, will have their pension adjusted annually. The annual adjustment will be granted in January of each year, based on the increase in the Consumer Price Index (CPI) for the 12 months ending the previous September 30th. If the CPI increase is less than 2.0%, then the annual adjustment is equal to 100% of the CPI increase. Otherwise the annual adjustment is equal to 50% of the CPI increase, with a minimum adjustment of 2.0% and a maximum adjustment of 5.0%.

Members who have retired less than 12 months prior to the January adjustment will receive a pro-rata share of the increase based on the number of months since commencement.

As of September 1, 2009, the Plan is amended to grant an ad-hoc increase to certain retired members' pensions. The cost of this increase has been included in the liabilities at July 1, 2009.

Disability Retirement

A member who suffers total and permanent disability will receive, commencing at his normal retirement date, a deferred pension calculated as for normal retirement, except that:

(a) the service of the member with the Company will include the period during which the member is totally and permanently disabled; and

(b) it will be assumed that the member continued to receive remuneration from the Company at the rate of his earnings at the time of disability.

Survivor Benefits

Death Before Retirement

For Service Prior to January 1, 1987

In event of death before retirement the designated beneficiary will receive a lump sum refund of the member's contributions, if any, with interest.

For Service On and After January 1, 1987

In the event of death before retirement and prior to completion of 2 years of Credited Service, the designated beneficiary will receive a lump sum refund of the member's contributions, if any, with interest.

In the event of death before retirement and after completion of 2 years of Credited Service, the designated beneficiary will receive the commuted value of the deferred pension plus a refund of excess contributions, if any. Excess contributions are employee contributions, if any, plus interest, in excess of those required to fund 50% of the commuted value of the deferred pension.

Death After Retirement

Upon death of the member after retirement, the member's spouse, if then surviving, will receive an annuity for life equal to 50% of the pension that the member had been receiving. Under the *Pension Benefits Act of (Ontario)*, married members must receive a joint and survivor pension that pays at least 60% of the amount of pension that the member had been receiving, unless both the member and spouse waive this option. The amount of pension would be actuarially equivalent to the normal form of pension. In the case of a member without a spouse at retirement, the normal form of pension guarantees a minimum return equal to the member's contributions with interest to date of retirement. The member may also elect an optional form of pension prior to retirement.

Termination Benefits

For Service Prior to January 1, 1987

(a) If a member has not completed 10 years of Continuous Service, he is entitled to:

(i) a cash refund of his contributions, if any, with interest; or

(ii) a deferred pension commencing at his Normal Retirement Date, the amount of which can be provided by his contributions with interest, if any, with interest.

(b) If a member has completed 10 or more years of Continuous Service but has not attained age 45, he is entitled to:

(i) a cash refund of his contributions, if any, with interest; or

(ii) a deferred pension commencing at his Normal Retirement Date, calculated on the same basis as the retirement benefit but based on earnings and service completed to the date of termination.

(c) If a member has completed 10 or more years of Continuous Service and has attained age 45, he is entitled to a deferred pension commencing at his Normal Retirement Date, calculated on the same basis as the retirement benefit but based on earnings and service completed to the date of termination.

For Service On and After January 1, 1987

(a) If a member has not completed 2 years of Credited Service, he is entitled to:

(i) a cash refund of his contributions, if any, with interest; or

(ii) a deferred pension commencing at his Normal Retirement Date, the amount of which can be provided by his contributions with interest.

(b) If a member has completed 2 or more years of Credited Service, he is entitled to a deferred pension commencing at his Normal Retirement Date, calculated on the same basis as the retirement benefit but based on earnings and service completed to the date of termination.

In addition, a member is also entitled to a refund of excess contributions, if any.

Notwithstanding the above, a member who is required to or who elects a deferred pension may, in lieu of this deferred pension, elect to:

(i) transfer the commuted value of the deferred pension to another registered pension plan, if the other pension plan permits;

(ii) transfer the commuted value to a Locked-In Retirement Account; or

(iii) apply the commuted value to purchase an immediate or deferred annuity.

Appendix E

Employer Certification

With respect to the report on the actuarial valuation of the *Retirement Plan of Great Lakes Power Transmission*, as at July 1, 2009, I hereby certify that, to the best of my knowledge and belief:

- a copy of the official plan document as of July 1, 2009, was provided to the actuary,
- 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 July 1, 2009, and
- all events subsequent to July 1, 2009 that may have an impact on the results of the valuation have been communicated to the actuary.

Date

Signed

Duane Fecteau
Name

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

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

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