ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15 (Sched. B)

AND IN THE MATTER OF an application by Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2010 transmission rates and related matters.

EB-2009-0408

Great Lakes Power Transmission Inc.

on behalf of Great Lakes Power Transmission LP

November 30, 2009

EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS

Exhibit 1, Tab 1, Schedule 1

Exhibit List

EXHIBIT LIST

2 - RATE BASE

3 - OPERATING REVENUE

4 - OPERATING COSTS

5 - COST OF CAPITAL AND CAPITAL STRUCTURE

6 - CALCULATION OF REVENUE DEFICIENCY

7 - COST ALLOCATION

Exhibit 1, Tab 1, Schedule 2

Application

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15 (Sched. B)

AND IN THE MATTER OF an application by Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2010 transmission rates and related matters.

EB-2009-0408

1. Great Lakes Power Transmission Inc. ("GLPT") in its capacity as the General Partner of Great Lakes Power Transmission LP, a limited partnership formed under the laws of Ontario, carries on the business of owning and operating electricity transmission facilities in the vicinity of Sault Ste. Marie, Ontario.

2. GLPT hereby applies to the Ontario Energy Board (the "Board") for an Order or Orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998,* as amended (the "OEB Act"), approving just and reasonable rates for the transmission of electricity based on a 2010 forward test year.

3. The Applicant has followed the filing requirements set out in Chapter 2 of the Board's *Filing Requirements for Transmission and Distribution Applications.*

4. As indicated in GLPT's pre-filed evidence, GLPT's forecasted 2010 revenue requirement is $39,365,100. Based on current transmission rates and forecast load, GLPT forecasts a 2010 revenue deficiency of $4,668,900.

5. GLPT is seeking Board approval for updated Uniform Transmission Rates for Ontario so as to permit GLPT to recover its forecasted revenue requirement of $39,365,100.

6. GLPT requests that its current rates be made interim as of January 1, 2010.

7. GLPT requests that the proposed rates be made effective as of January 1, 2010. GLPT also requests an accounting order to establish a deferral account to record revenue requirement deficiencies incurred from January 1, 2010 until GLPT's proposed 2010 rates are implemented.

8. GLPT is seeking Board approval for the clearance of the December 31, 2009 balances of deferral accounts 1505, 1508, 1572 and 1574, as well as for the clearance of the December 31, 2009 balances of variance accounts 1562 and 1592.

9. GLPT is seeking Board approval for:

   (a) the continuation in the test period of variance account 1592 for tax changes;

   (b) the continuation in the test period of the sub-account for International Financial Reporting Standards transition costs, within account 1508;

   (c) the establishing in the test period of variance accounts for:

      (i) pension costs,

      (ii) Ontario Energy Board cost assessments, and

      (iii) property taxes and use and occupation fees; and

   (d) the establishing in the test period of a deferral account for:

(i) infrastructure investment, green energy initiatives and preliminary planning,

all of which are described more particularly in Exhibit 9, Tab 2, Schedule 1 of the pre-filed evidence.

10. GLPT is seeking direction from the Board as to the appropriate treatment of costs associated with an outstanding claim arising from a major capital project for which GLPT obtained leave to construct in EB-2003-0162, as more particularly described in section 3.0 of Exhibit 9, Tab 2, Schedule 1.

11. GLPT is requesting an amendment to the Order it received from the Board in EB-2004-0505 so as to remove the *Rebate and Exit Fee Schedule for Wholesale Meter Service*, which, as explained in section 3.0 of Exhibit 9, Tab 1, Schedule 3, is no longer applicable.

12. This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application. The Applicant, as part of the written evidence, has filed certain information in confidence in accordance with the Board’s Practice Direction on Confidential Filings.

13. The Applicant requests that, pursuant to Section 34.01 of the Board’s *Rules of Practice and Procedure,* this proceeding be conducted by way of written hearing.

14. The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

Great Lakes Power Transmission Inc.
on behalf of Great Lakes Power Transmission LP
2 Sackville Road, Suite B
Sault Ste. Marie, Ontario
P6B 6J6

Attention: Mr. Andy McPhee
Vice President and General Manager
Telephone: (705) 941-5661
Fax: (705) 941-5600
Email: amcphee@glp.ca

- and -

Mr. Duane Fecteau
Director of Administration
Telephone: (705) 256-3846
Fax: (705) 941-5600
Email: dfecteau@glp.ca

The Applicant's Counsel:

Torys LLP
79 Wellington Street West, Suite 3000
Box 270, TD Centre
Toronto, Ontario
M5K 1N2

Attention: Mr. Charles Keizer
Telephone: (416) 865-7512
Fax: (416) 865-7380
Email: ckeizer@torys.com

- and -

Mr. Jonathan Myers
Telephone: (416) 865-7532
Fax: (416) 865-7380
Email: jmyers@torys.com

DATED at Toronto, Ontario, this 30th day of November, 2009.

GREAT LAKES POWER TRANSMISSION INC. ON BEHALF OF GREAT LAKES POWER TRANSMISSION LP

By its counsel,

Charles Keizer

Exhibit 1, Tab 1, Schedule 3

GLPT Transmission Licence

VT INCEPIT FIDELIS SIC PERMANET
Ontario

Electricity Transmission Licence

ET-2007-0649

Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP

Valid Until

March 11, 2028

Original signed by

____

Kirsten Walli
Board Secretary
Ontario Energy Board
Date of Issuance: December 24, 2007
Effective Date: March 12, 2008
Date of Sch.1 Correction: March 13, 2008
Date of Amendment: November 19, 2008
Date of Amendment: May 5, 2009

Ontario Energy Board	Commission de l’énergie de l’Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th Floor	27e étage
Toronto ON M4P 1E4	Toronto ON M4P 1E4

Table of Contents **Page No.**

1 Definitions

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**Board**" means the Ontario Energy Board;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**Licensee**" means Great Lakes Power Transmission Inc. on behalf of Great Lakes Power Transmission LP

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**transmission services**" means services related to the transmission of electricity and the services the Board has required transmitters to carry out for which a charge or rate has been established in the Rate Order;

"**Transmission System Code**" means the code approved by the Board and in effect at the relevant time, which, among other things, establishes the obligations of a transmitter with respect to the services and terms of service to be offered to customers and provides minimum technical operating standards of transmission systems;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence to own and operate a transmission system consisting of the facilities described in Schedule 1 of this Licence, including all associated transmission equipment.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the Licensee are set out in Schedule 2 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; and

b) the Transmission System Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Requirement to Enter into an Operating Agreement

6.1 The Licensee shall enter into an agreement ("Operating Agreement") with the IESO providing for the direction by the IESO of the operation of the Licensee's transmission system. Following a request made by the IESO, the Licensee and the IESO shall enter into an Operating Agreement within a period of 90 business days, unless extended with leave of the Board. The Operating Agreement shall be filed with the Board within ten (10) business days of its completion.

6.2 Where there is a dispute that cannot be resolved between the parties with respect to any of the terms and conditions of the Operating Agreement, the IESO or the Licensee may apply to the Board to determine the matter.

7 Obligation to Provide Non-discriminatory Access

7.1 The Licensee shall, upon the request of a consumer, generator, distributor or retailer, provide such consumer, generator, distributor or retailer, as the case may be, with access to the Licensee's transmission system and shall convey electricity on behalf of such consumer, generator, distributor or retailer in accordance with the terms of this Licence, the Transmission System Code and the Market Rules.

8 Obligation to Connect

8.1 If a request is made for connection to the Licensee's transmission system or for a change in the capacity of an existing connection, the Licensee shall respond to the request within 30 business days.

8.2 The Licensee shall process connection requests in accordance with published connection procedures and participate with the customer in the IESO's Connection Assessment and approval process in accordance with the Market Rules, its Rate Order(s) and the Transmission System Code.

8.3 An offer of connection shall be consistent with the terms of this Licence, the Market Rules, the Rate Order, and the Transmission System Code.

8.4 The terms of such offer to connect shall be fair and reasonable.

8.5 The Licensee shall not refuse to make an offer to connect unless it is permitted to do so by the Act or any Codes, standards or rules to which the Licensee is obligated to comply with as a condition of this Licence.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its transmission system to the standards established in the Transmission System Code and Market Rules, and have regard to any other recognized industry operating or planning standards required by the Board.

10 Transmission Rates and Charges

10.1 The Licensee shall not charge for the connection of customers or the transmission of electricity except in accordance with the Licensee's Rate Order(s) as approved by the Board and the Transmission System Code

11 Separation of Business Activities

11.1 The Licensee shall keep financial records associated with transmitting electricity separate from its financial records associated with distributing electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

12 Expansion of Transmission System

12.1 The Licensee shall not construct, expand or reinforce an electricity transmission system or make an interconnection except in accordance with the Act and Regulations, the Transmission System Code and the Market Rules.

13 Provision of Information to the Board

13.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

13.2 Without limiting the generality of paragraph 13.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) business days past the date upon which such change occurs.

14 Restrictions on Provision of Information

14.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator, obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

14.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

14.3 Information regarding consumers, retailers, wholesalers or generators may be disclosed where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

14.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

14.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information is not be used for any other purpose except the purpose for which it was disclosed.

15 Term of Licence

15.1 The effective date of this Licence is March 12, 2008, and the Licence will expire on March 11, 2028. The term of this Licence may be extended by the Board.

16 Transfer of Licence

16.1 In accordance with subsection 18(2) of the Act, this Licence is not transferable or assignable without leave of the Board.

17 Amendment of Licence

17.1 The Board may amend this Licence in accordance with section 74 of the Act or section 38 of the Electricity Act.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 SPECIFICATION OF TRANSMISSION FACILITIES

This Schedule specifies the facilities over which the Licensee is authorized to transmit electricity in accordance with paragraph 3 of this Licence.

1. Great Lakes Power Inc. on behalf of Great Lakes Power Transmission LP's transmission facilities consist of:

   - 318.25 circuit km of 230 kV line and associated equipment;
   - 232.37 circuit km of 115 kV line and associated equipment; and
   - 11 circuit km of 44 kV line and associated equipment which was deemed by the Board as serving a transmission function under section 84 of the Act.

   .

SCHEDULE 2 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the licensee has been exempted.

Exhibit 1, Tab 1, Schedule 4

Contact Information

CONTACT INFORMATION

Applicant:

Great Lakes Power Transmission Inc.
on behalf of Great Lakes Power Transmission LP
2 Sackville Road, Suite B
Sault Ste. Marie, Ontario
P6B 6J6

Attention:

Mr. Andy McPhee
Vice President and General Manager
Telephone: (705) 941-5661
Fax: (705) 941-5600
Email: amcphee@glp.ca

Mr. Duane Fecteau
Director of Administration
Telephone: (705) 256-3846
Fax: (705) 941-5600
Email: dfecteau@glp.ca

Applicant's Counsel:

Torys LLP
79 Wellington Street West, Suite 3000
Box 270, TD Centre
Toronto, Ontario
M5K 1N2

Attention:

Mr. Charles Keizer
Telephone: (416) 865-7512
Fax: (416) 865-7380
Email: ckeizer@torys.com

Mr. Jonathan Myers
Telephone: (416) 865-7532
Fax: (416) 865-7380
Email: jmyers@torys.com

Exhibit 1, Tab 1, Schedule 5

Orders Sought

SPECIFIC APPROVALS REQUESTED

GLPT applies for an Order or Orders of the Board granting:

(a) Approval of updated Uniform Transmission Rates for Ontario so as to permit GLPT to recover its forecasted 2010 revenue requirement of $39,365,100;

(b) Approval for GLPT's current rates to be made interim as of January 1, 2010;

(c) Approval for GLPT's proposed rates to be made effective as of January 1, 2010;

(d) An accounting order to establish a deferral account to record revenue deficiencies incurred from January 1, 2010 until GLPT's proposed 2010 rates are implemented;

(e) Approval for the clearance of the December 31, 2009 balances of:

  (i) deferral accounts 1505, 1508, 1572 and 1574, and

  (ii) variance accounts 1562 and 1592;

(f) Approval for the continuation in the test period of:

  (i) variance account 1592 for tax changes, and

(ii) the sub-account, within deferral account 1508, for International Financial Reporting Standards transition costs;

(g) Approval for the establishing in the test period of:

(i) variance accounts for:

(A) pension costs,

(B) Ontario Energy Board cost assessments, and

(C) Property taxes and use and occupation fees, and

(ii) a deferral account for infrastructure investment, green energy initiatives and preliminary planning costs;

(h) Direction from the Board as to the appropriate treatment of costs associated with an outstanding claim arising from a major capital project for which GLPT obtained leave to construct in EB-2003-0162; and

(i) An amendment to the Order received in EB-2004-0505 so as to remove the Rebate and Exit Fee Schedule for Wholesale Meter Service which is no longer applicable.

Exhibit 1, Tab 1, Schedule 6

Issues List

PROPOSED ISSUES LIST

1. Calculation of Transmission Rate Base for the Test Year
   - (a) Capital Expenditures 2010
     - (i) Third Line Redevelopment Project
   - (b) Capital Expenditures 2009
   - (c) Capital Expenditures 2008
   - (d) Capital Expenditures 2007
   - (e) Working Cash Allowance
2. Transmission Operating Costs For the Test Years
   - (a) Operations, Maintenance & Administration
     - (i) Variance Analysis
   - (b) Depreciation and Amortization
   - (c) Capital, Property and Income Taxes
3. Operating Revenue
   - (a) Transmission Services Revenue
   - (b) Other Income
4. Transmission Cost of Capital For the Test Years
   - (a) Capital Structure
   - (b) Cost of Debt
   - (c) Cost of Equity

5. Rate Recovery of Revenue Requirement
   - (a) Cost Allocation
   - (b) Rate Design
     - (i) Charge Determinant Forecast
     - (ii) Calculation of Uniform Rates
6. Variance and Deferral Accounts
   - (a) Existing Variance and Deferral Accounts
   - (b) New Variance and Deferral Accounts
   - (c) Disbursal of Existing Variance and Deferral Accounts

Exhibit 1, Tab 1, Schedule 7

Procedural Orders, Correspondence & Notices

<u>PROCEDURAL ORDERS, CORRESPONDENCE & NOTICES</u>

Please see the attached for all procedural orders, correspondence and notices related to this transmission rate application.

Exhibit 1, Tab 1, Schedule 8

Accounting Orders

<u>ACCOUNTING ORDERS</u>

GLPT has attached as **Appendix "A"** the Board's Decision and Order in EB-2004-0505, which relates to Wholesale Meter Services Rebates and Exit Charges. GLPT wishes to address this Order in this proceeding by (1) disbursing from Account 1508 those funds arising from the Board's Order in EB-2004-0505 as described at Exhibit 9, Tab 1, Schedule 3; and (2) amending the Board's Order to remove the Exit Fee Schedule for Metered Service for the reasons set out in Exhibit 9, Tab 1, Schedule 3.

<u>APPENDIX “A”</u>

Decision and Order of the Board in EB-2004-0505

EB-2004-0505

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15 (Schedule B) (the "Act");

AND IN THE MATTER OF an amendment to a rate order with respect to Great Lakes Power Limited under s.79.9(3) of the Act to provide for Wholesale Meter Services Rebates and Exit Charges.

BEFORE: Paul Vlahos
Presiding Member

Bob Betts
Member

DECISION AND ORDER

On March 11, 2004, the Board issued an Order (RP-2003-0188/EB-2003-0233) amending Hydro One's Transmission Rate Order, prescribing rebates and charges related to Wholesale Meter Services Rebates and Exit Charges.

On April 22, 2004, the Board sent Great Lakes Power Limited ("GLPL") a copy of the Hydro One Order and a copy of the Board's Report to the Minister of Energy on this issue, dated November 23, 2003. The Board asked for GLPL's submissions on a similar arrangement for the Province's smaller transmitters. GLPL provided its submissions to the Board by letter on May 14, 2004.

On September 10, 2004, the Board's Report on Wholesale Metering Rebates and Exit Charges for Smaller Transmitters was submitted to the Minister of Energy with the Board's recommendations on this issue. The Board's recommended solution was for GLPL to provide a rebate to its customers who made or will make alternative arrangements for the provision of wholesale metering services in the amount of $5,700 and charge an exit fee equivalent to the net book value of the meter assets. GLPL would be permitted to set up a deferral account so that the difference between the rebate amounts and the avoided costs of not having to provide wholesale metering services would be recorded for later disposition.

On October 8, 2004 the Board received the Minister's response, in which the Board was asked to amend the rate order of GLPL in accordance with the recommendations included in the Board's report of September 10, 2004. The Board has assigned file no. EB-2004-0505 to this proceeding.

On November 24, 2004 the Board sent a letter of direction to GLPL by Priority Post. Subsequently, GLPL informed the Board that the letter had not been received.

On December 20, 2004, GLPL requested an extension to the original service dates. As a result, on January 7, 2005, the Board sent a revised Letter of Direction and a Notice to be served on affected parties. GLPL served the Notice, its submissions and other related material as directed by the Board. The intervention period expired on February 23, 2005. There were no intervenors.

On February 7, 2005, GLPL, in response to the revised Letter of Direction, submitted that its transmission rate order should be amended to reflect the following:

- exit fee should be based on the actual net book value of any meter and ancillary equipment that is stranded by a customer choosing to make its own wholesale metering arrangement;
- a rebate of $5,700 per metering point per year should be paid to any customer who stopped receiving wholesale metering services from GLPL since market opening or who may do so prior to the Board's decision on GLPL's next rates application; and
- a deferral account should be established to track the rebates and the avoided cost of not providing metering service to customers who have made their own arrangements.

On March 17, 2005, GLPL provided certain information on the methodology it uses to determine the net book value of its wholesale metering assets and how the exit fee is determined. It clarified, among other things, that the calculation includes the costs of the ancillary equipment and associated installation costs.

The Board finds that it is appropriate for GLPL to rebate $5,700 per metering point per year to metered market participants who stopped receiving wholesale metering services from GLPL. This rebate amount is the same as that approved by the Board in the case of Hydro One and recommended by the Board to the Minister. The Board notes GLPL's efforts to provide rebates to its customers retroactively since market opening along with those who may exit GLPL's metering service.

The Board notes that GLPL has been charging exit fees based on the net book value for each individual meter and ancillary equipment that are stranded by a metered market participant who has chosen to make its own wholesale metering arrangements. The Board accepts that this methodology is appropriate for GLP since such information is readily available to the utility.

The Board finds that the request to create a deferral account to be acceptable in the circumstances. The Board expects the deferral account to record all rebates paid out and the offsetting valuation of avoided costs. Since the exit fee is equivalent to the net book value of assets, it will be offset by a write off from capital assets and need not be recorded in the deferral account.

The Board reminds Great Lakes Power that the creation of this deferral account does not provide any suggestion of how or if its balance will eventually be recovered.

THE BOARD ORDERS THAT:

1) The rate order of Great Lakes Power Limited is amended with the rates set out in Appendix “A” of this Order, effective April 1, 2005**.**
2) Great Lakes Power Limited shall settle the accounting details of the deferral account with the Board’s Chief Regulatory Auditor as soon as possible.
3) Great Lakes Power Limited shall notify the metered market participants of the rate changes as they become applicable.

DATED at Toronto, April 5, 2005.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O’Dell
Assistant Board Secretary

Appendix "A"

EB-2004-0505

April 5, 2005

ONTARIO ENERGY BOARD

Great Lakes Power Limited

REBATE
And
EXIT FEE SCHEDULE
FOR
WHOLESALE METER SERVICE

Issued: April 5, 2005
Ontario Energy Board

APPLICABILITY:

This rate schedule is applicable to the *metered market participants* * that are transmission customers of Great Lakes Power Limited ("GLPL") and to *metered market participants* that are customers of a Local Distribution Company ("LDC") that is connected to the transmission system owned by GLPL.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

(a) Annual Wholesale Meter Service Rebate

The *metered market participant* in respect of a *load facility* (including LDC) shall be eligible to receive an annual rebate of $5,700 for each *meter point* that is not under the transitional arrangement for *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

The Wholesale Meter Service Rebate shall be retroactive from May 1, 2002 and , where applicable, shall be calculated by prorating on a monthly basis, taking into account the number of full months during which the *meter point* is not under the transitional arrangement.

(b) **Fee for Exit from Transitional Agreement**

The *metered market participant* in respect of a load facility (including LDC) or a *generation facility* may exit from the transitional arrangement for *metering installation* upon payment of a one-time exit fee equal to the actual net book value of the stranded meter and ancillary equipment required for the meter installation.

Exhibit 1, Tab 1, Schedule 9

Compliance with Uniform System of Accounts

NON-COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

GLPT is not aware of any non-compliance with the Uniform System of Accounts.

Exhibit 1, Tab 1, Schedule 10

Description of Utility Operations

DESCRIPTION OF UTILITY OPERATIONS

GLPT's transmission system, which is shown on the system map provided in *Figure 1-2-1 A* of Exhibit 1, Tab 2, Schedule 1, is located in northern Ontario and consists of the following:

- 318.25 circuit km of 230 kV line and associated equipment;
- 232.37 circuit km of 115 kV line and associated equipment; and
- 11 circuit km of 44 kV line and associated equipment which has been deemed by the Board as serving a transmission function under section 84 of the *Ontario Energy Board Act*.

A detailed description of GLPT's transmission system is set out at Exhibit 1, Tab 2, Schedule 1.

Exhibit 1, Tab 1, Schedule 11

Neighbouring Utilities

NEIGHBOURING UTILITIES

GLPT's neighbouring utilities are:

- PUC Distribution Inc. (ED-2002-0546)
- Hydro One Networks Inc. (ED-2003-0043, ET-2003-0035)
- Algoma Power Inc. (ED-2009-0072)

Exhibit 1, Tab 1, Schedule 12

Corporate and Utility Organization

CORPORATE & UTILITY ORGANIZATION

1. Utility Organizational Structure

GLPT's current internal organizational structure is presented in **Appendix "A"**.

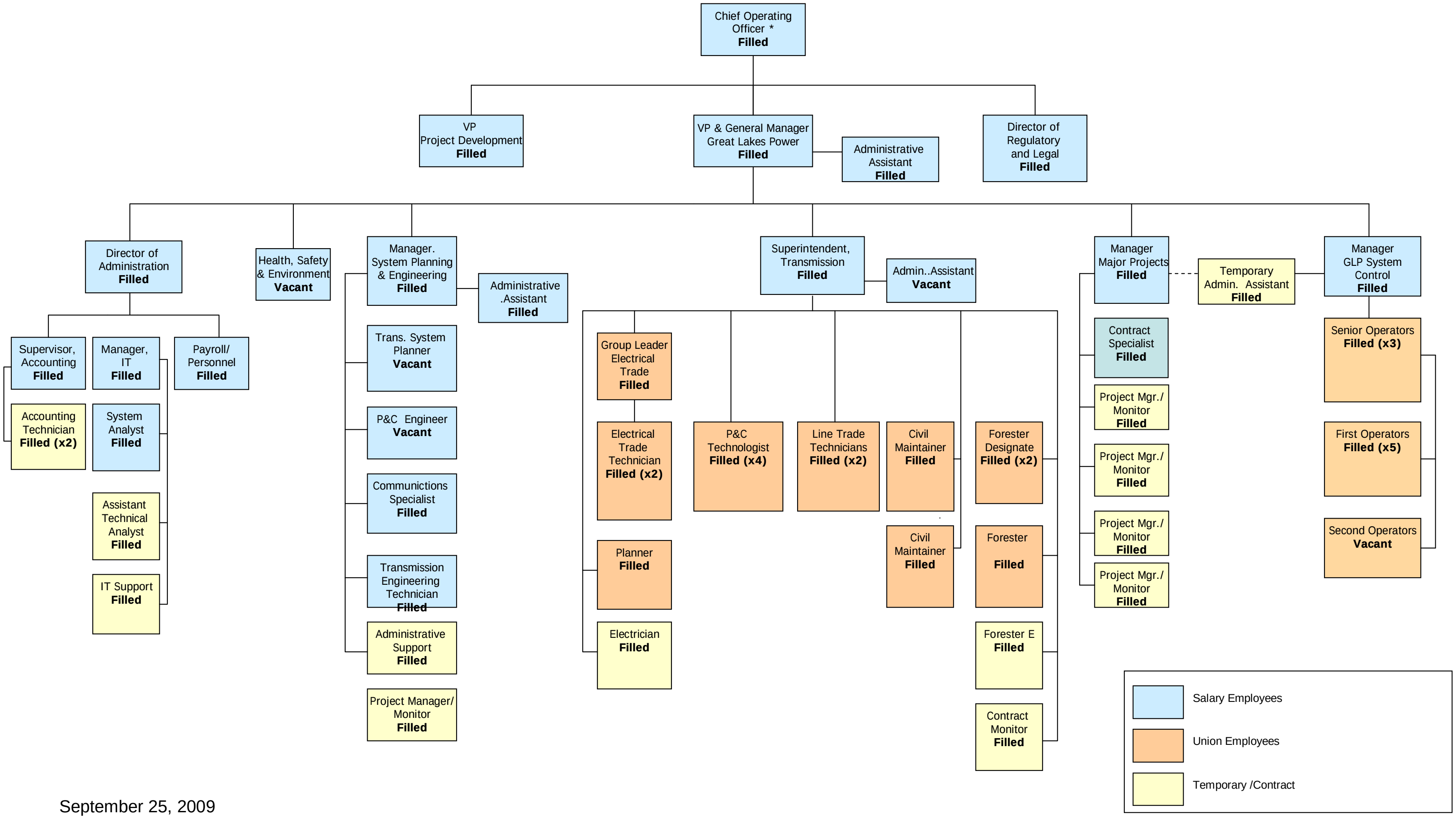
2. Corporate Entities Relationship Chart

A corporate entities relationship chart for GLPT, shown in two parts, is provided in **Appendix "B"**.

APPENDIX "A"

GLPT ORGANIZATIONAL STRUCTURE

Great Lakes Power Transmission LP



September 25, 2009

* Chief Operating Officer and Senior VP responsible for North American Transmission, Brookfield Infrastructure Partners

APPENDIX "B"

CORPORATE ENTITIES RELATIONSHIP CHART

Chart #1

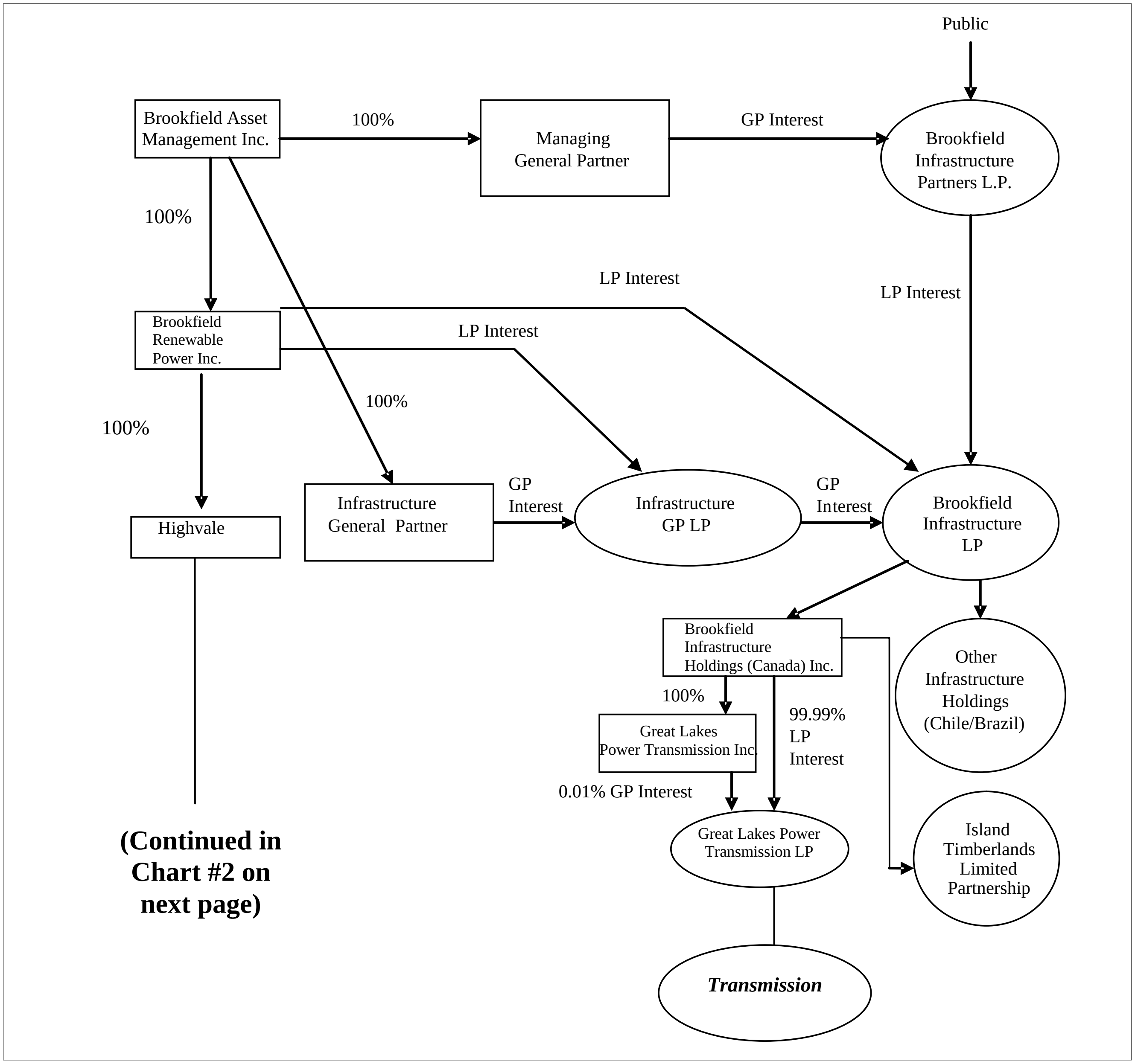
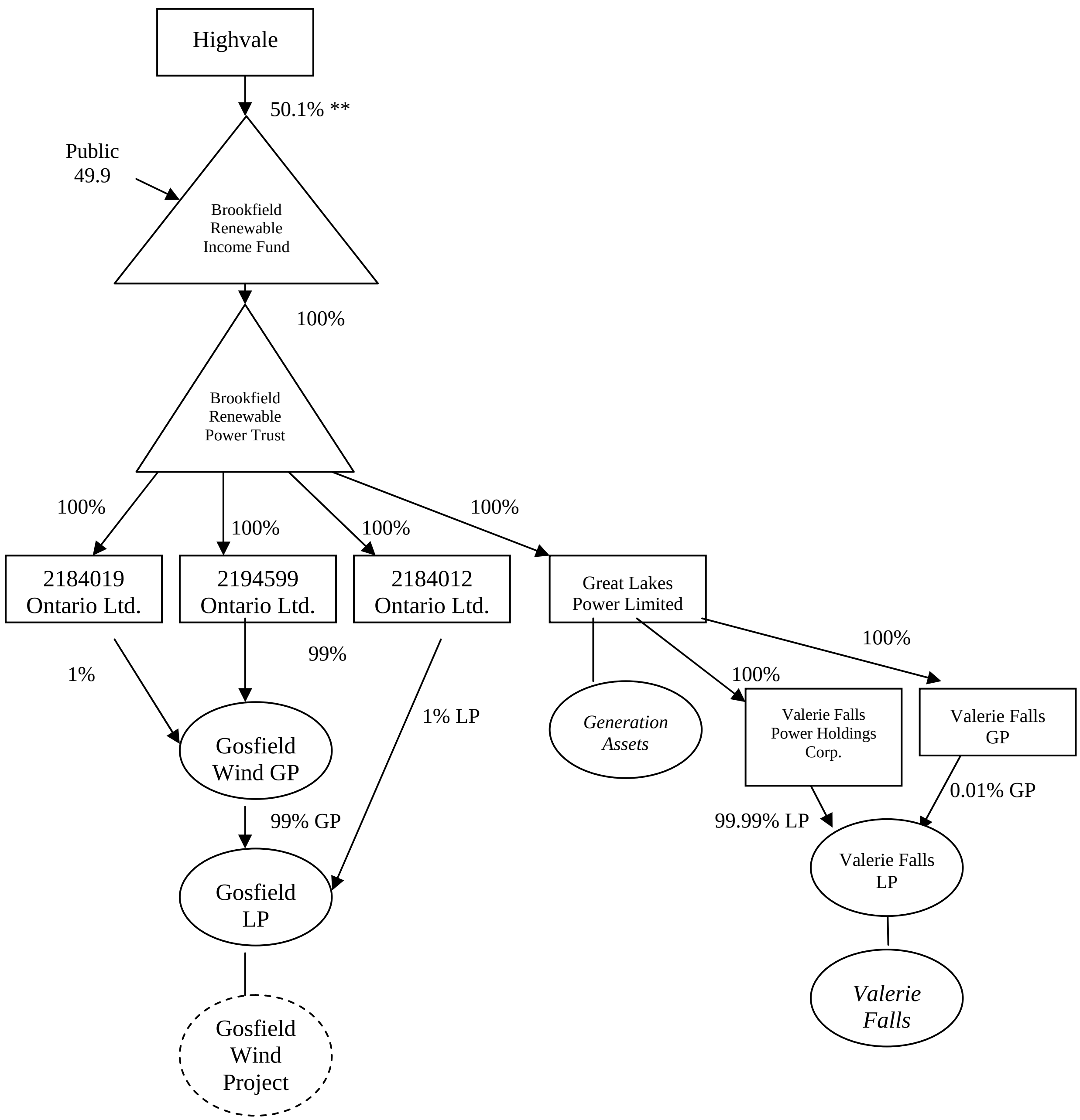

Public
Brookfield Asset Management Inc.
100%
Managing General Partner
GP Interest
Brookfield Infrastructure Partners L.P.
100%
LP Interest
LP Interest
Brookfield Renewable Power Inc.
LP Interest
100%
100%
Highvale
Infrastructure General Partner
GP Interest
Infrastructure GP LP
GP Interest
Brookfield Infrastructure LP
Brookfield Infrastructure Holdings (Canada) Inc.
Other Infrastructure Holdings (Chile/Brazil)
100%
Great Lakes Power Transmission Inc.
99.99% LP Interest
0.01% GP Interest
Great Lakes Power Transmission LP
Island Timberlands Limited Partnership
(Continued in Chart #2 on next page)
Transmission

Chart #2



** Includes units that are issuable on exchange of shares of Great Lakes Power Holding Corporation. Great Lakes Power Holding Corporation owns the Fund's Prince and Pingston Creek assets.

Exhibit 1, Tab 1, Schedule 13

Status of Board Directives

STATUS OF BOARD DIRECTIVES

1.0 Wholesale Meter Services Rebates

In the Decision and Order dated April 5, 2005,[1] the Board directed Great Lakes Power Limited ("GLPL") to provide Wholesale Meter Services Rebates (the "Rebates") in the amount of $5,700 per metering point per year to any customer who was not receiving wholesale metering services from GLPL. The amount of $5,700 per metering point reflected the rebate of meter service provider costs recovered by Hydro One Networks Inc. ("HONI") in its revenue requirement. HONI was also directed to provide similar Rebates through an exclusive Order issued March 11, 2004.[2]

November 1, 2007 saw the introduction of new Uniform Transmission Rates in Ontario.[3] Along with the new Uniform Transmission Rates, the Board approved a new Wholesale Meter Service and Exit Fee Schedule for HONI.[4] This new schedule eliminated the requirement for HONI to pay the Rebates. GLPL made an interpretation of this particular order and, based on the facts available, concluded that the elimination of the Rebates would extend to GLPL's customers as well. Therefore, GLPL discontinued the Rebate payments as of November 1, 2007. GLPT is requesting that the Board discontinue the Wholesale Meter Order dated April 5, 2005.

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[1] EB-2004-0505
[2] RP-2003-0188/EB-2003-0233
[3] EB-2007-0759
[4] EB-2006-0501

GLPT is also seeking to disburse part of the balance in its Account 1508 in respect of the Wholesale Meter Service Rebates in respect of the Board's Order in EB-2004-0505.

For additional information on the deferral account created as a result of these Rebates, please see Exhibit 9, Tab 1, Schedule 3.

2.0 Report on Cost Allocation and Transfer Pricing and Other Matters in Settlement Proposal

As a part of the settlement proposal that was accepted by the Board in EB-2005-0241 (the "Settlement")(See **Appendix "A"**), GLPL committed to retain 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 would be filed at its next transmission rate application. GLPT has attached this report at Exhibit 4, Tab 2, Schedule 5 of this Application.

GLPL also committed to do the following in the Settlement:

a) Per Section 1.2 of the Settlement, GLPL agreed to conduct stakeholder meetings as part of its capital budgeting process for 2007 and annually thereafter. These stakeholder meetings have been held annually for each budget year. Presentations were conducted in Toronto and in Sault Ste. Marie.

b) Per Section 6 of the Settlement, GLPL agreed that it would apply to the Board for its next transmission rate application within three years of the date of the Board's order in that proceeding. Prior to this deadline, GLPT filed a letter with the Board stating that as part of the move to a stand-alone transmitter, the operational aspects and potentially the underlying costs could vary. Consequently, instead of filing a rates application in December 2008 and then a further rates application relating to the re-organization, GLPT submitted that it would be more efficient and cost effective to defer its transmission rate filing.

c) Also per Section 6 of the Settlement, GLPL agreed to consider whether to include as part of its upcoming distribution rate application the deeming of the 44kV distribution facilities serving Dubreuilville Forest Products Ltd. as transmission facilities for rate making purposes. Subsequent to the 2005 proceeding, GLPL filed a distribution rate application where this consideration was addressed (EB-2007-0744).

3.0 Revenue Deficiency Deferral Account

In a Partial Decision and Order related to EB-2005-0241 dated March 22, 2005, the Board ordered that GLPL establish a deferral account in which to record the revenue deficiency incurred by GLPL, plus carrying charges, under currently approved transmission rates beginning January 1, 2005.

The Board approved GLPL's revenue requirement and revenue deficiency on September 15, 2005 through its acceptance of the Settlement. The Settlement proposed setting the commencement date for recording the revenue deficiency to April 1, 2005.

In an Order dated November 14, 2005 (see **Appendix "B"**), the Board outlined specific guidance for recording the revenue deficiency, and GLPL followed the specific guidance in recording the deficiency in account 1574. For the purposes of that Order, the 1574 account definition was amended to include the following:

> The Company shall record the revenue deficiency based upon the difference between the approved monthly revenue requirement and the monthly revenue forecast as calculated using currently approved rates as directed by the Ontario Energy Board in its partial decision (EB-2005-0241) dated March 22, 2005 and approved accounting order.

Upon recovering the balance of the account, GLPL was to track any potential over-recovery such that any outstanding balance could be credited to the benefit of ratepayers in GLPL's next rate proceeding. As a result of over-recovery, GLPT is requesting disbursal of a balance in account 1574, as described in Exhibit 9, Tab 1, Schedule 4.

APPENDIX “A”

Settlement Agreement from EB-2005-0241

SETTLEMENT PROPOSAL

SEPTEMBER 15, 2005

TABLE OF CONTENTS

[1] In this Settlement Proposal, the term "Test Years" refers to the periods from January 1 to December 31 of 2005 and 2006.

PREAMBLE

This Settlement Proposal is filed with the Ontario Energy Board ("OEB" or "Board") in connection with an application by Great Lakes Power Limited ("GLPL" or the "Company") pursuant to section 78 of the *Ontario Energy Board Act, 1998* for an order or orders approving or fixing just and reasonable rates for the transmission of electricity. A Settlement Conference was held from September 12 to 13, 2005 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* (the "Rules") and the Board's *Settlement Conference Guidelines* ("Settlement Guidelines"). This proposal arises from the Settlement Conference.

GLPL and the following intervenors (collectively, the "parties"), as well as Ontario Energy Board technical staff ("Board Staff"), participated in the Settlement Conference in respect to all of the issues contained in this proposal:

- Vulnerable Energy Consumers Coalition ("VECC")
- Energy Probe Research Foundation ("Energy Probe")
- Association of Major Power Consumers in Ontario ("AMPCO")
- Independent Electricity System Operator ("IESO")
- Algoma Coalition ("Algoma")
- St. Marys Paper Ltd ("SMP")
- Power Workers' Union ("PWU")

The following intervenors did not participate in the Settlement Conference:

- Hydro One Networks Inc.
- Algoma Steel Inc. ("ASI")
- Niagara West Transformation Corporation ("NWTC")[2]

The Settlement Proposal deals with all of the issues listed in the Table of Contents set out above. These issues have been agreed upon by the parties and serve as a break-down of the issues described in Appendix "B" to the Board's Procedural Order #1, dated June 7, 2005:

1. Great Lakes Power Limited's transmission-related revenue requirement for its 2005 and 2006 fiscal years.

2. Great Lakes Power Limited's proposed methodology for recovery of its transmission-related 2005 and 2006 revenue requirement.

[2] At the time of the Settlement Conference, NWTC did not have intervenor status. NWTC was granted intervenor status by the Board on September 14, 2005.

We are pleased to inform the Board that all the Parties reached a comprehensive agreement on all issues. No issue is left unsettled.

The Settlement Proposal describes the agreements reached on the settled issues and identifies the parties who agree, or alternatively who take no position on each issue. In accordance with the Rules and the Settlement Guidelines, Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Proposal.

The Settlement Proposal provides a direct link between each issue and the supporting evidence in the record to date. In this regard, the parties who agree with the individual settlements are of the view that the evidence provided is sufficient to support the Settlement Proposal in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings on the settled issues.

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit A, Tab 2, Schedule 1, Page 3 (commencing page) is referred to as A-2-1-3. A concise description of the content of each exhibit is also provided. In this regard, GLPL's response to an interrogatory (IR) is described by citing the name of the party and the number of the interrogatory (e.g., Board Staff Interrogatory #1). The identification and listing of the evidence that relates to each issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

According to the Settlement Guidelines (p.3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. GLPL and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

All of the issues contained in this proposal have been settled by the parties as a package (the "package") and none of the provisions of these issues are severable. If the Board does not, prior to the commencement of the hearing of the evidence accept the package in its entirety, then there is no settlement (unless the parties agree that any portion of the package that the Board does accept may continue as part of a valid Settlement Proposal). None of the parties can withdraw from this proposal except in accordance with Rule 32.05 of the Rules. Finally, unless stated otherwise, the settlement of any particular issue in this proceeding is without prejudice to the rights of parties to raise the same issue in any future proceeding.

Attached at Appendices A and B are spreadsheets that reflect the quantitative impacts that result from this proposal for the 2005 and 2006 test years respectively.

ISSUES

I) GLPL's transmission-related revenue requirement for its 2005 and 2006 fiscal years

1 Rate Base for the Test Years

1.1 Capital Expenditures 2005 - the Reinforcement Project (the "RP")

1.1.1 The RP (excluding Mackay TS)

Complete Settlement: There is an agreement to settle this issue as follows:

On September 22, 2003, GLPL applied to the Board (the "Leave Application") for leave to construct in two phases a 164 km 230 kV wood-pole transmission line including all associated station work and ancillary line upgrades on an existing right-of-way currently occupied by GLPL, and extending from:

(a) Hydro One Networks Inc.'s ("Hydro One") Wawa Transformer Station ("TS") in Wawa, Ontario to GLPL's MacKay TS in Montreal River, Ontario (the "Anjigami Section"); and

(b) from the MacKay TS to Third Line TS in Sault Ste. Marie, Ontario (the "Sault Section").

In addition, GLPL indicated that it intended to refurbish its existing 230 kV Transmission System (known as P21G and P22G) that runs from Third Line TS to Mississagi TS. This involves replacing wood-pole structures and, if necessary, adding some new wood-pole structures to improve clearances and raise this line's rating.

The Board found the Reinforcement Project to be economically feasible, yielding a net present value of approximately $10 million, without the need to add other positive externalities resulting from the project, including the enhanced reliability of the Province's transmission system.

In this transmission rate application, GLPL has applied to the Board for an order allowing GLPL to include in rate base its costs associated with the Reinforcement Project, being $80.54 million. This amount includes costs associated with Mackay TS. The recovery of the costs associated with Mackay TS are dealt with separately in section 1.1.2 of this settlement proposal.

The cost of the Reinforcement Project is no greater than that considered by the Board as part of the leave to construct proceeding. As well, the timing of the in-service dates of the components of the Reinforcement Project is consistent with the timing contemplated by the Board in the leave to construct proceeding. The Anjigami Section came into service on February 24, 2005, and GLPL continues to expect that the Sault Section will be fully in-service by December, 2005.

The Parties agree that the Reinforcement Project's costs, excluding the incremental switching component costs associated with the reinforcement of Mackay TS dealt with below, were prudently incurred and should be included in GLPL's rate base. This amount is $78.3116 million ($80.5400 million - $2.2284 million = $78.3116 million).

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO and the PWU who take no position.

Evidence: The evidence in relation to this issue includes the following:

B-1-1-2	Overview of the RP
C-1-1-1	2005 revenue requirement increase attributable to the RP
C-1-1-2	2006 revenue requirement increase attributable to the RP
C-1-1-2	2005 revenue deficiency attributable to the RP
C-1-1-2	2006 revenue deficiency attributable to the RP
D-1-1-3	Description of the RP, Rationale for the RP, explanation of the Board's leave to construct decision for the RP, the RP's costs, retirements related to the RP
D-1-2-1	Property, Plant & Equipment - Summary of Averages 2005
D-1-3-1	Property, Plant & Equipment 2005
I-1	The Board's leave to construct decision for the RP
Board Staff IR	#4, #9, #10, #12, #15, #29, #33, #42, #43, #44
Energy Probe IR	#1, #2, #3, #4, #6, #9, #10, #12
VECC IR	#7, #10

1.1.2 Mackay TS

Complete Settlement: There is an agreement to settle this issue as follows:

In regard to Mackay TS, the Board in its leave to construct decision stated:

> When such application (rates application) is made, it is the Board's expectation that the following matter raised in this proceeding should be addressed. We note AMPCO's argument that the $2.2 million cost in additional switching facilities at the Mackay TS over the IMO's minimum requirement are 'almost entirely' for the benefit of GLP Generation and should be paid for by GLP Generation. We also note GLP's argument in support of including this cost as part of the project. Clearly the issue is one of cost responsibility. We reiterate the Board's comment in its January 27, 2004 letter to AMPCO that this is a matter to be dealt with under the Transmission System Code, which is currently the subject of another proceeding. We add that, if that proceeding is not at a stage where guidance can be provided on this question, another venue for its determination is the proceeding that will deal with GLP's revenue requirement and rates.

While GLPL and AMPCO maintain their respective beliefs regarding cost responsibility, the Parties agree, for the purpose of settlement, that one third of the incremental switching component costs associated with the reinforcement of Mackay TS being $0.7428 million be included in GLPL's rate base, and that the remaining two thirds being $1.4856 million not be included in GLPL's rate base.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO and the PWU who take no position.

Evidence: The evidence in relation to this issue includes the following:

I-1
AMPCO IR #1

1.2 Capital Expenditures 2005 - Other

Complete Settlement: There is an agreement to settle this issue as follows:

There are 28 capital projects proposed for 2005 (not including the Reinforcement Project), totaling $11.8850 million. The larger capital projects planned for 2005 (i.e. over $1 million) are:

- Hollingsworth TS Refurbishment ($1.8355 million)
- Northern Avenue TS Refurbishment ($2.5000 million)
- Andrews TS Redevelopment ($1.4550 million)
- New 115kV Tie Breaker - Third Line TS ($1.0725 million)

The balance of the capital additions in 2005 (6%) will be on smaller capital projects, ranging in cost from $22,000 to $886,000.

The Parties agree that GLPL's proposed capital additions for 2005 as described herein being $11.8850 million are prudent and should be included in GLPL's rate base.

GLPL agrees that as part of its capital budgeting process to conduct stakeholder meetings with stakeholders to consider its capital plan, together with its major maintenance plan pursuant to section 3.1.3 of this proposal, for the year commencing 2007, and conduct annual stakeholder meetings thereafter.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

D-1-1-10	Description
D-1-2-1	Property, Plant & Equipment - Summary of Averages 2005
D-1-3-1	Property, Plant & Equipment 2005

Board Staff IR	#17, #39, #40, #41, #42, #43
Energy Probe IR	#7, #9
Algoma Coalition IR	#5, #6
VECC IR	#10

1.3 Capital Expenditures 2006

Complete Settlement: There is an agreement to settle this issue as follows:

There are 11 capital projects proposed for 2006, totaling $16.9922 million. The larger capital projects planned for 2006 (i.e. over $1 million) are:

- Gartshore TS – Phase 2 ($7.2600 million)
- Patrick St. TS Refurbishment ($4.8690 million)
- P21G Refurbishment ($3.600 million).

The balance of the capital additions in 2006 (7%) will be on small capital projects, ranging in cost from $70,000 to $341,000.

The Parties agree that GLPL's proposed capital additions for 2006 as described herein being $16.9922 million are prudent and should be included in GLPL's rate base.

GLPL agrees to conduct the stakeholder process as described in section 1.2 of this proposal.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

D-1-1-11	Description
D-1-4-1	Property, Plant & Equipment - Summary of Averages 2006
D-1-5-1	Property, Plant & Equipment 2006
Board Staff IR	#17, #39, #40, #43
Energy Probe IR	#8, #9
VECC IR	#10

1.4 Capital Expenditures 2002-2004

Complete Settlement: There is an agreement to settle this issue as follows:

2002: There were 22 capital projects in 2002, totaling $1.7870 million ranging in cost up to $494,000. The Parties agree that the capital additions for 2002 being $1.7870 million were prudently incurred and should be included in GLPL's rate base.

2003: There were 52 capital projects in 2003, totalling $9.5770 million. The capital additions in 2003 were on smaller capital projects, ranging in cost up to $980,000. The Parties agree that the capital additions for 2003 being $9.5770 million were prudently incurred and should be included in GLPL's rate base.

2004: There were 44 capital projects in 2004, totalling $3.9966 million. The Parties agree that the capital additions for 2004 being $3.9966 million were prudently incurred and should be included in GLPL's rate base.

GLPL agrees to conduct the stakeholder process as described in section 1.2 of this proposal.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

D-1-1-12	Description
Board Staff IR	#17, #39, #40, #43
Energy Probe	#5
VECC IR	#10

1.5 Working Cash Allowance / Working Cash Study

Complete Settlement: There is an agreement to settle this issue as follows:

The working cash allowance for the test years has been calculated by GLPL using the results of a working cash study. In GLPL's 2001 rate proceeding (RP-2001-0385/EB-2001-0135) working cash allowance was based upon a balance sheet approach instead of 15% of the O&M expense as prescribed by the 2001 filing requirements. The Board in its reasons for decision had directed GLPL to complete a working cash study for its next rate filing.

The working cash study used for the purpose of calculating working cash allowance (Exhibit D, Tab 1, Schedule 8) is accepted by the parties, subject to the following two adjustments:

1) The working cash study utilized forecasted revenues for calculating the GST lag on revenues. The intervenors took the position that the proposed revenue requirement should be used for calculating the GST lag. The parties agree that the proposed revenue requirements should be used in the calculation of the working cash allowance.

2) The GST lag on capital expenditures was based on capital additions rather than capital expenditures. The intervenors took the position that capital expenditures rather than capital additions should be utilized in the calculation of working cash allowance. The parties agree that the capital expenditures in 2005 and 2006 be used in the calculation of the working cash allowance.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO and the PWU who take no position.

Evidence: The evidence in relation to this issue includes the following:

D-1-1-13	Description
D-1-6-1	For the test years
D-1-8-1	Working Cash Study
Board Staff IR	#45, #46, #47
VECC IR	#10, #13

2 Cost of Capital for the Test Years

2.1 Cost of Debt

Complete Settlement: There is an agreement to settle this issue as follows:

In its application, GLPL proposed a deemed debt rate of 7.00% for the test years, consistent the Board's decision in RP-2001-0035/EB-2001-0385. GLPL's actual third-party cost of debt is 6.6% as indicated in the response to Board Staff's interrogatory #49..

The Parties agree that a 6.6% cost of debt should be adopted by the Board for the purpose of settling GLPL's transmission rates.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO and the PWU who take no position.

Evidence: The evidence in relation to this issue includes the following:

E-1-1-1	Numerical summary and description
Board Staff IR	#11, #19, #20, #48, #49
Energy Probe IR	#25
VECC IR	#14

2.2 Cost of Equity

Complete Settlement: There is an agreement to settle this issue as follows:

In its application, GLPL proposed a return on equity of 9.88%, consistent the Board's decision in RP-2001-0035/EB-2001-0385.

Board Staff calculated the return on equity for each of the test years in accordance with the methodology contained in the Board's 2006 Electricity Distribution Rate Handbook and the Board's Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities.

Based on Board Staff's calculations, the Parties agree that for GLPL's 2005 test year a 9.24% return on equity should be adopted by the Board. The Parties also agree that for GLPL's 2006 test year an 8.62% return on equity should be adopted by the Board.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO and the PWU who take no position.

Evidence: The evidence in relation to this issue includes the following:

E-1-1-1	Numerical summary and description
Board Staff IR	#11, #19, #20, #48
Energy Probe IR	#25
VECC IR	#4, #14

2.3 Capital Structure

Complete Settlement: There is an agreement to settle this issue as follows:

In its application, GLPL proposed a capitalization of 55% debt and 45% equity.

The Parties agree that a capitalization of 55% debt and 45% equity should be adopted by the Board.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

E-1-1-1	Numerical summary and description
Board Staff IR	#11, #19, #20, #48
Energy Probe IR	#25
VECC IR	#14

3 Cost of Service for the Test Years

3.1 Operations, Maintenance & Administration

3.1.1 Sharing of Expenses Between Generation and Transmission

Complete Settlement: There is an agreement to settle this issue as follows:

GLPL has implemented a cost sharing arrangement with its business units to achieve the spirit of the Affiliates Relationship Code (ARC) as well as maintain an internal economy of scale for each service.

Common services between GLPL's transmission and generation businesses include dispatch operations, integrated communication network, meter service provider and VP Ontario Operations Administration.

The Parties agree that the allocation of expenses and transfer pricing between GLPL's transmission and generation businesses proposed for the test years be adopted by the Board. GLPL commits to retain 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 described in section 1.2 of this proposal will provide input into setting the terms of reference of the review and choosing the third party consultant. GLPL agrees to provide a copy of the report to the stakeholder consultation group prior to its next transmission rate application.

GLPL will be seeking an order for the approval of a deferral account to track its stakeholder related costs for the matters described in this section and section 1.2 of this proposal. The Parties agree that a deferral account for that purpose is appropriate.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

B-2-1-3	Description of GLPL
I-2	Transmission Division financial statements
Board Staff IR	#6, #7, #18, #21, #22, #32,
Energy Probe IR	#16, #17, #18, #19, #20
Algoma Coalition IR	#1, #3
VECC IR	#1, #2, #8, #12, #15

3.1.2 Sharing of Expenses Between Transmission and Distribution

Complete Settlement: There is an agreement to settle this issue as follows:

GLPL's transmission business employs staff and systems contained in GLPL's distribution business. To ensure appropriate cost allocation, cost allocation methods used by GLPL include factors such as occupied square footage, number of transactions and direct employee time, as determined by a review of the actual experience in the previous year. The transportation and work equipment, IT systems, operations and tools are items provided by GLPL's distribution business to the transmission business at cost and are paid for from the O&M budget of the transmission business.

The Parties agree that the allocation of expenses and transfer pricing between GLPL's transmission and distribution businesses proposed for the test years is appropriate.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

B-2-1-2	Description of GLPL
I-2	Transmission Division financial statements
Board Staff IR	#6, #7, #18, #21, #22, #32,
Energy Probe IR	#16, #17, #18, #19, #20
Algoma Coalition IR	#1, #3
VECC IR	#1, #2, #8, #12, #15

3.1.3 2005 & 2006 Expenses

Complete Settlement: There is an agreement to settle this issue as follows:

GLPL's forecasted OM&A amounts for 2005 and 2006 are $6.0091 million and $5.9270 million respectively. GLPL employs the accounting methodology of the Accounting Procedures Handbook ("APH") to define its cost account categories as well as the processes and protocols to ensure consistency and correct cost allocation to each account. The APH account describes the detailed costs that should be allocated to each account.

GLPL has estimated its transmission OM&A costs during the 2005 and 2006 test years based on the Operating Budget Methodology described at Exhibit F, Tab 1, Schedule 2 and accounted for using the APH as described above.

The Parties agree that GLPL's forecasted OM&A amounts for 2005 and 2006, being $6.0091 million and $5.9270 million respectively are appropriate. GLPL agrees that as part of its major maintenance program planning, it will conduct stakeholder meetings as described in section 1.2 of this proposal.

For the purpose of this proposal, “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.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

F-1-1-1	Numerical summary of cost of service
F-1-1-3	O&M cost variances
F-1-3-1	2002-2003 O&M variance
I-2	Transmission Division financial statements
Board Staff IR	#21, #22, #23, #24, #25, #26, #27, #28, #34, #35, #36, #52, #59
Energy Probe IR	#14, #15, #16, #17, #18, #19, #20
Algoma Coalition IR	#3, #8, #9
VECC IR	#1, #2, #8, #9, #12, #15, #16, #17, #18

3.2 Write-off of Assets Retired by the Reinforcement Project

Complete Settlement: There is an agreement to settle this issue as follows:

Included in GLPL's cost of service is an expense related to the write-off of readily identifiable assets that were replaced by the Reinforcement Project. This is in accordance with the Board's decision in the leave to construct proceeding in which the Board indicated that assets that were no longer used or useful should be written off. GLPL proposes that these assets and their related accumulated depreciation be removed from GLPL's rate base. The expense associated with the write-off for accounting purposes is normally accounted for in the year of the write-off. To minimize the rate impact of the write-off expense, GLPL proposes to recover the expense over a 5 year period.

GLPL proposes to debit account 1505 – Unrecovered Plant and Regulatory Study Costs. The amortization of the balance in account 1505 will be charged to account 5730 – Amortization of Unrecovered Plant and Regulatory Study Costs.

The Parties agree that GLPL's proposal in regard to this matter should be adopted by the Board.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

D-1-1-14	Retirements related to the RP
F-1-1-1	Numerical summary of cost of service
F-1-1-4	Assets retired by the RP
F-1-1-7	Rate mitigation of write-off
Board Staff IR	#15, #29, #33
VECC IR	#19

3.3 Depreciation and Amortization

Complete Settlement: There is an agreement to settle this issue as follows:

GLPL depreciates and amortizes its assets in accordance with GAAP and the APH.

The Parties agree that, as a result of the settlement of issues contained in this proposal, GLPL's proposed depreciation and amortization figures for the test years require adjustment. The Parties agree that the adjusted depreciation and amortization figures contained in Appendices A and B are appropriate.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

F-1-1-1	Numerical summary of cost of service
F-1-1-8	Numerical summary of depreciation and amortization
Board Staff IR	#30, #37
VECC IR	#11

3.4 Capital, Property and Income Taxes

Complete Settlement: There is an agreement to settle this issue as follows:

The Parties agree that, as a result of the settlement of issues contained in this proposal, GLPL's proposed capital, property and income tax figures for the test years require adjustment. The Parties agree that the adjusted capital, property and income tax figures contained in Appendices A and B are appropriate.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

F-1-1-1	Numerical summary of cost of service
F-1-1-9	Numerical summary of capital and property taxes
F-1-1-10	Numerical summary of income taxes
Board Staff IR	#31, #32, #33
VECC IR	#20

4 Revenues and Charge Determinant Forecast

4.1 Revenues and Charge Determinant Forecast

Complete Settlement: There is an agreement to settle this issue as follows:

GLPL employed a forecast for provincial charge determinants in 2005 and 2006 to prepare its revenue forecast for the 2005 and 2006 test years. GLPL relied on the monthly peak provincial load forecast in normal weather conditions contained in the IESO's demand forecast titled *18-Month Outlook: An Assessment of the Reliability of the Ontario Electricity System - From January 2005 to June 2006* (the "18-Month Outlook").

Because the 18-Month Outlook did not include load forecast for the last six months of 2006, GLPL proposed that the corresponding monthly forecasts in 2005 be used for 2006. The Parties proposed that an adjustment be made to the load forecasts for the last six months of 2006 based on the 2006 forecast for the first six months of the year compared to the same period in 2005.

GLPL has recalculated the 2006 normal peak total amount (Exhibit G, Tab 1, Schedule 2, Page 5) to be 272,103 MW based on Board Staff's proposed methodology. The following table shows the resulting forecasted charge determinants based on the methodology outlined in table 4 of Exhibit G, Tab 1, Schedule 2, Page 5:

Forecasted Charge Determinants (MW)	Forecast	Forecast
	2005	**2006**
Network	268,468,500	270,026,900
Line Connection	253,265,900	254,734,700
Transformation Connection	219,005,400	220,275,500

The Parties agree that the forecasted charge determinants adjusted in accordance with Board Staff's proposal should be adopted by the Board.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO and the PWU who take no position.

Evidence: The evidence in relation to this issue includes the following:

G-1-1-1	Numerical summary of revenue
G-1-1-2	Forecasted charge determinants
G-1-2-1	Methodology for calculating charge determinant forecast
Board Staff IR	#50,#52, #53, #54, #55, #56, #57, #58, #61
Energy Probe IR	#26, #27
Algoma Coalition IR	#4
AMPCO IR	#2
VECC IR	#21

II) GLPL's proposed methodology for recovery of its transmission-related 2005 and 2006 revenue requirement.

5 Rate Recovery of Revenue Requirement

5.1 Proposed Methodology for Rate Recovery of Revenue Requirement

5.1.1 Cost Functionalization

Complete Settlement: There is an agreement to settle this issue as follows:

GLPL allocated its incremental revenue requirement to the asset pools by applying the same proportions as was determined by the Board in RP-1999-0044 and set out by the Board in its May 29, 2001 Filing Guidelines and adopted by the Board in GLPL's last transmission rate filing.

The Parties agree that GLPL's allocation of its incremental revenue requirement to the asset pools should be adopted by the Board.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO who takes no position.

Evidence: The evidence in relation to this issue includes the following:

H-1-1-1	Methodology
H-1-1-2	Allocation factors
H-1-1-3	The adjustment factor
H-1-5-1	Calculation of the adjustment factor
Board Staff IR	#38
Energy Probe IR	#11, #23
Algoma Coalition IR	# 10
VECC IR	#5

5.1.2 Revenue Requirement Deferral Account

Complete Settlement: There is an agreement to settle this issue as follows:

On March 22, 2005, the Board issued a Partial Decision and Order in this proceeding in which it ordered GLPL to establish a deferral account in which to record the revenue deficiency incurred by GLPL under currently approved transmission rates beginning January 1, 2005. The Board also ordered that GLPL is entitled to include carrying costs on the balance in the deferral account with such carrying cost being the short-term interest rate included in GLPL's revenue requirement for 2005. GLPL was directed to prepare and submit a draft accounting order to the Board. GLPL submitted a draft accounting order to the Board, but has not yet received an accounting order.

GLPL will amend its application to seek approval to dispose of the deferral account as part of this proceeding. The Parties agree that it is appropriate that GLPL seek the recovery of deficiencies accrued in the deferral account for the period commencing April 1, 2005 to the date the revised 2005 transmission rates are implemented.

GLPL will file as part of this proceeding a proposal for the disposition of the deferral account. The proposal will seek recovery of the deferral account balance as part of the 2006 uniform transmission rates. The proposal will also provide for the tracking of any potential over recovery of the deferral account balance such that any such balance can be credited to the benefit of ratepayers in GLPL's next rate proceeding.

GLPL does not as part of this application have a short-term interest rate. The Parties agree that the short-term interest rate referred to in the Board's Partial Decision and Order be the rate of prime minus 50 basis points posted by CIBC on April 1, 2005 and adjusted annually.

Approval: All participating parties accept and agree with the proposed settlement of this issue except the IESO and the PWU who take no position.

Evidence: The evidence in relation to this issue includes the following:

C-1-1-1	Revenue Requirement and Revenue Deficiency
Board Staff IR	#2, #9, #12, #14, #29, #55, #58, #60, #62
Energy Probe IR	#23
Algoma	#4
VECC IR	#3, #5

5.2 Implementation

Complete Settlement: There is an agreement to settle this issue as follows:

To allow sufficient time to implement a Board order which amends the transmission rate schedule, the parties agree that any such amendment shall be prospective and shall be effective:

(a) where there is a minimum of 21 days between the release of the amended transmission rate schedule and the start of the next IESO billing period, the first day of the next IESO billing period, and
(b) where there is less than 21 days between the release of the amended transmission rate schedule and the start of the next IESO billing period, the first day of the second IESO billing period following the release of the amended schedule.

Approval: All participating parties accept and agree with the proposed settlement of this issue.

6 Other Matters

GLPL agrees that it will apply to the Board for its next transmission rate application within three years of the date of the Board's order in this proceeding.

GLPL also agrees to consider whether to include as part of its upcoming distribution rate application the deeming of the 44 kV distribution facilities serving Dubreuilville Forest Products Ltd. (re Algoma IR #2) as transmission facilities for rate making purposes.

APPENDIX “B”

Order of the Board in EB-2005-0241

EB-2005-0241

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B;

AND IN THE MATTER OF the Accounting Procedures Handbook for Electricity Distributors as amended for the purposes of this Order;

AND IN THE MATTER OF a request by Great Lakes Power Limited, for an Accounting Order to establish a deferral account in its books of account to capture the revenues that would have been collected had their current rate application been effective April 1, 2005.

O R D E R

In a partial decision and order dated March 22, 2005, the Ontario Energy Board ordered that Great Lakes Power Limited (the "Company") establish a deferral account in which to record the revenue deficiency incurred by the Company, plus carrying charges, under currently approved transmission rates beginning January 1, 2005. The Board assigned file number EB-2005-0241 to the partial decision and order. The Board stated that the Company must prepare and submit a draft accounting order reflecting this order. Subsequently, the Board approved the Company's revenue requirement and revenue deficiency on September 15, 2005 through its acceptance of a settlement agreement reached between the parties to the proceeding. In addition, the proposal in the settlement agreement that the commencement date for recording the revenue deficiency be changed to April 1, 2005, was accepted by the Board.

The Board has reviewed all the evidence and Board staff's recommendation to approve the Accounting Order.

THE BOARD ORDERS THAT:

1. The Company is hereby authorized to establish a deferral account, Deferred Rate Impact Amounts account ("DRIAA"), to capture the associated revenue deficiency arising had the amounts collected in rates, effective April 1, 2005,

been implemented as approved under EB-2005-0241. This is with respect to the revenue requirement and deficiency and effective date approved by the Board on September 15, 2005. Also, the natural volume variability will be reflected in the Company's revenues received during the period. The recording of this revenue deficiency will cease when a new transmission rate approved by the Board is implemented.

The actual provincial charge determinants will differ from the approved determinants. Accordingly there will be a natural variance. Under normal circumstances, the Company would accept the risk/reward of this variance; therefore, the Board will allow the Company to earn revenues on this basis while ensuring that the approved revenue deficiency is accrued.

For each month commencing April 1, 2005, the Company will record the revenue deficiency based upon the difference between the approved monthly revenue requirement and the monthly revenue forecast at current rates. The forecasted revenue requirement will be calculated based on the charge determinants and IESO 18-month forecast included in the settlement agreement accepted by the Board on September 15, 2005 and use current approved rates. The approved monthly revenue requirement will be calculated using the approved revenue requirement as accepted by the Board on September 15, 2005.

2. Details of the accounting entries hereby authorized shall be in accordance with Appendix "A" attached hereto.

3. The Company shall dispose of the DRIAA balance over the authorized collection period in accordance with the recovery methodology to be approved by the Board in Phase II of the proceeding. Any over recovery of the deferral account balance will be tracked, such that any such balance will be credited to the deferral account and will be included in the rate recovery in the Company's s next rate proceeding so that the benefits will be accrued to the benefit of the rate payers.

DATED at Toronto, November 14, 2005

ONTARIO ENERGY BOARD

Original signed by

John Zych
Board Secretary

APPENDIX “A” TO

ORDER

BOARD FILE NO. EB-2005-0241

DATED: NOVEMBER 14, 2005

EB-2005-0241
Appendix "A"

GREAT LAKES POWER LIMITED

Accounting Entries to Recognize Revenues That Would have Been Collected Had the Rates Been Effective April 1, 2005
(Deferred Rate Impact Amounts Account - "DRIAA")

1. To record the difference between the approved monthly revenue requirement and the actual monthly revenue requirement in rates.

   Debit Account 1574, DRIAA

   Credit Account 4110, Transmission Services Revenue

   For the purposes of this entry, the DRIAA shall be calculated as follows:

   DRIAA = approved monthly revenue requirement (network revenues + line connection revenues + transformation connection revenues) – monthly revenue forecast at currently approved rates

2. To record simple interest on the opening monthly balance of the DRIAA account at a rate of interest of prime minus 50 basis points[1].

   Debit Account 1574, DRIAA, Sub-account Carrying Charges

   Credit Account 4405, Interest and Dividend Income

3. To drawn down the account balance for recoveries in rates over the collection period authorized by the Board.

   Debit Account 4110, Transmission Services Revenue

   Credit Account 1574, DRIAA

[1] Posted by CIBC on April 1, 2005 and adjusted annually, per EB-2005-0241 Receipt of Settlement Proposal dated September 15, 2005, as approved by the Board.

The accounts in this order are prescribed by the Board for use under the Accounting Procedures Handbook (“APH”) for Distribution Utilities.

For the purposes of this order, the 1574 account definition has been amended to include the following:

> The Company shall record the revenue deficiency based upon the difference between the approved monthly revenue requirement and the monthly revenue forecast as calculated using currently approved rates as directed by the Ontario Energy Board in its partial decision (EB-2005-0241) dated March 22, 2005 and approved accounting order.

Exhibit 1, Tab 1, Schedule 14

Witnesses & Witness CVs

WITNESSES & WITNESS CVs

A list of witnesses and the curriculum vitae for those witnesses will be provided at such time as witness selection is completed.

Exhibit 1, Tab 2, Schedule 1

Summary of the Application

SUMMARY OF THE APPLICATION

1.0 Introduction

This transmission rate application (the "Application") filed by Great Lakes Power Transmission LP ("GLPT") is based on a 2010 test year. GLPT requests that the existing transmission rates be made interim, with proposed rates effective as of January 1, 2010 and implementation at a later date. Among other things, GLPT is applying for rates that will allow GLPT to recover its forecast 2010 revenue requirement in the amount of $39.365 million. The approval of GLPT's revenue requirement, less the balances of certain deferral and variance accounts payable to ratepayers, will result in a 0.30% change in the overall revenue requirement used in the calculation of Uniform Transmission Rates. The rate in the Network pool will increase by $0.01 per kW from $2.66 per kW to $2.67 per kW. The rate in the Line Connection pool will remain the same at $0.70 per kW. The rate in the Transformation Connection pool will increase by $0.02 per kW from $1.57 per kW to $1.59 per kW.[1] This change in the Uniform Transmission Rate results in a 0.015 % change to a typical residential customer's total bill, or approximately $0.01 per month.

GLPT is a limited partnership duly registered in the Province of Ontario, the partners of which are Great Lakes Power Transmission Inc., as general partner, and Brookfield Infrastructure Holdings (Canada) Inc., as limited partner. GLPT is a licensed transmitter under licence number

[1] Change arising partly to revenue requirement increase and partly to past acquisition of transformation equipment by large industrial customer.

ET-2007-0649. This is the first transmission rate application by GLPT. As result of required compliance with Section 71 of the *Ontario Energy Board Act, 1998* (the "OEB Act"), GLPT became the owner and operator of the transmission system through the reorganization of Great Lakes Power Limited ("GLPL"). An overview of GLPT's corporate origins is set out at Appendix "A" to this Schedule.

GLPT has organized and filed its materials in accordance with Chapter 2 of the Board's *Filing Requirements for Transmission and Distribution Applications* dated May 27, 2009.

In the summary that follows, GLPT has identified key aspects of the Application that the Board should be mindful of in its consideration of the Application. The summary also sets out a general overview of the Application.

2.0 Key Aspects

In considering this Application, GLPT believes that it is important for the Board to consider the following key aspects:

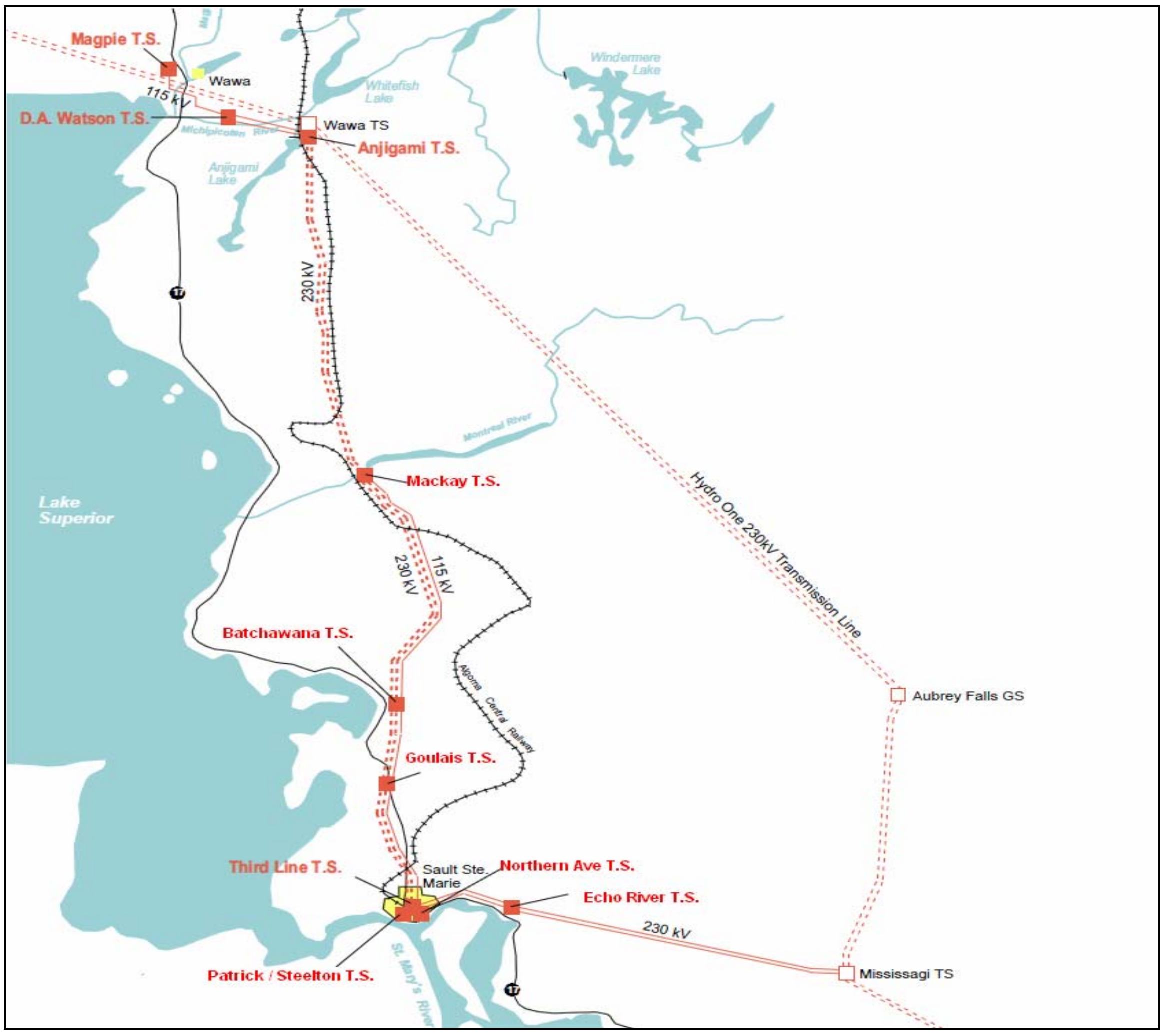
- GLPT's transmission system is located entirely in an area of dense vegetation and rugged terrain of the Canadian Shield;
- GLPT's transmission system is critical to the reliability of the Ontario bulk power system; and
- The aforementioned aspect, coupled with the fact that there is up to 630 MW of wind resource in and around GLPT's transmission system, results in GLPT having to consider and plan for various development activities related to the *Green Energy and Green Economy Act* and the Ontario Power Authority's Feed in Tariff Program, as well as, potentially, a future Integrated Power System Plan.

All of these aspects impact the revenue requirement for which GLPT is seeking approval, either in respect of GLPT's rate base additions or its cost of service.

2.1 Physical Location

GLPT's transmission system is located in the Algoma district of Ontario with its system extending from in and around Sault Ste. Marie, north to Wawa, and east from Sault Ste. Marie to a remote area at which Hydro One Networks Inc.'s ("HONI") Mississagi TS is located. A map of GLPT's system is shown in *Figure 1-2-1 A*, below.

Figure 1-2-1 A - GLPT System Map



This area is located in the Canadian Shield and is predominantly located in forest zones with dense vegetation and steep elevations in places. GLPT's transmission system extends through two forest zones. The southern portion of the system is in the Great Lakes-St. Lawrence forest zone, which is characterized by red and sugar maple, yellow birch, red oak, hemlock, red and white pine. The northern part is in the Boreal forest zone, characterized by black and white spruce, tamarack, aspen, white birch, balsam fir and jack pine. The terrain and vegetation present challenges to GLPT with respect to its vegetation management programs, as well as various aspects of its operations and maintenance.

Vegetation management in rights of ways ("ROWs") is an essential component of maintaining the reliability of GLPT's transmission system because contact between vegetation and transmission lines can result in outages. Moreover, properly maintained ROWs allow for access to transmission facilities, which is needed to carry out inspections and maintenance activities, as well as to facilitate emergency response. GLPT relies on the use of specialized, outside contractors for the performance of the various components of vegetation management. GLPT targets a six-year cycle for completion of all brush removal, tree trimming and tree removal activities needed on its system's ROW including ROW floors and edges, as well as buffer zones, which are areas in which standard methods of vegetation management cannot be used due to terrain or environmentally sensitive features.

The clearing of ROWs is a highly regulated activity as GLPT is required to comply with the IESO's reliability compliance program, which is generally aligned with NERC's transmission vegetation management program. In addition, GLPT must comply with the highly prescriptive licensing and approval requirements under the *Pesticides Act* and relevant regulations. There are also restrictions under the provincial species protection legislation in respect of certain at-risk species that inhabit areas within GLPT's network of ROWs. The highly-regulated nature of this activity is a factor in driving GLPT's ROW maintenance cost.

In 2006, GLPT elevated its vegetation management program by introducing a fully integrated vegetation management program. As a fully integrated program, brush removal from ROW floors, tree trimming and tree removal along ROW edges and vegetation management in buffer zones are all carried out in a systematic and coordinated manner, within the six-year cycle. As part of this program, beginning in 2006, particular focus has been given to tree trimming and tree removal to address encroachment on the sides of the ROWs and to re-establish the edges of GLPT's active ROWs. As part of this effort, and beginning in 2007, GLPT incurred additional costs associated with identifying and defining the sizes and location of buffer zones situated within the ROWs. The location of GLPT's transmission system, combined with regulatory changes that increased the operating restrictions around buffer zones have had a particularly significant impact on GLPT. In such buffer zones, GLPT must employ slower, more labour intensive and more costly techniques using different equipment and sometimes different work crews in order to perform necessary vegetation management activities. Spot spraying, hand cutting and the use of alternative herbicides are required.

In 2009, GLPT maintained its six-year cycle, but as part of a cost-cutting measure reduced its activities associated with encroachments and buffer zones. However, for reliability purposes, GLPT needs to restore the prior level of activities in these areas for 2010 and beyond.

2.2 GLPT's Significance to the IESO-Controlled Grid

GLPT's transmission system is a fundamental part of the bulk power system and the IESO-controlled grid. GLPT's transmission system is a critical link in that part of the IESO-controlled grid which extends from the Manitoba border to Sudbury, Ontario (Algoma TS, Hanmer TS) which, for the purpose of this evidence, is defined and referred to as the "Northwest Transmission System". As such, the condition and operation of GLPT's transmission system has a fundamental impact on the Northwest Transmission System.

The Northwest Transmission System can be divided into three sections:

- Manitoba to Wawa TS;
- Wawa TS to Mississagi TS; and
- Mississagi TS to Algoma TS (Sudbury).

(a) ***Manitoba to Wawa TS***

This section of the Northwest Transmission System evacuates generation comprised of a mix of hydraulic and thermal units.

The generation in excess of load in the Northwest section combined with any imports from Manitoba, is evacuated predominantly to the east through the HONI double circuit lines from Thunder Bay (Mackenzie TS, Lakehead TS) to Marathon (Marathon TS) to Wawa (Wawa TS). The interface between Marathon TS and Wawa TS is defined by the IESO as the East-West Tie ("EWT"). The east-to-west or west-to-east power flows along this interface are limited by post-contingency voltage stability considerations at Wawa TS. Power flow across the EWT is predominantly eastbound, delivering excess power from northwestern Ontario to Wawa TS.

(b) ***Wawa TS to Mississagi TS***

GLPT's and HONI's transmission systems run in parallel between Wawa TS and Mississagi TS (as shown in *Figure 1-2-1 A*). They affect each other's capability, operation and transmission system limits.

GLPT's transmission system runs 73 km north-south from Wawa TS to MacKay TS, 91 km from MacKay TS to Third Line TS and 76 km east-west from Third Line TS to Mississagi TS. It is comprised of a 230 kV line running from Third Line TS to MacKay TS denoted as K24G and a 230 kV line running from MacKay TS to Wawa TS denoted as W23K. There are two 230 kV lines running east-west from Third Line TS to Mississagi TS ("P21G and P22G").

Third Line TS is GLPT's largest station. The station has two sections, a 230 kV section and a 115 kV section. As part of the IESO-controlled grid, if either of the 115 kV or the 230 kV sections of Third Line TS were to be degraded, destroyed, or otherwise made unavailable, the reliability and operability of the Ontario bulk power system could be adversely affected and thereby threaten the supply of power to numerous customers throughout the province. The station is also a connection point that facilitates a parallel circuit with the HONI transmission system, as shown in *Figure 1-2-1 A* above.

Emanating from Third Line TS are three 230 kV circuits and nine 115 kV circuits, which connect various loads and generation facilities. The station serves the largest loads in the GLPT system, as it supplies power to the City of Sault Ste. Marie and to large industrial loads that include ESSAR Steel Inc., St. Marys Paper Inc. and Flakeboard Inc.

The HONI transmission system runs east-west for 204 km from Wawa TS to Mississagi TS. It is comprised of one double-circuit 230 kV line.

For the most part, the load directly connected to GLPT's transmission system is supplied via 115 kV circuits off of Third Line TS. The GLPT system's peak load is approximately 315 MW in summer and 445 MW in winter. Installed generation capacity connected to GLPT's transmission system is 674 MW. Therefore, during peak periods, the generation in excess of the GLPT load is evacuated predominantly to the east to Mississagi TS and added to the peak generation of 335 MW connected to the HONI transmission system in the Wawa-Mississagi Section.

(c) ***The Mississagi – Sudbury Section***

Mississagi TS is connected to Algoma TS (Sudbury) via HONI's double-circuit 230 kV line and to Hanmer TS (Sudbury) via HONI's single-circuit 230 kV line.

In provincial peak periods, the predominantly eastbound power flow across the EWT interface into Wawa TS, the excess generation out of GLPT's network and the generation from Aubrey Falls GS and Wells GS on HONI's transmission system converge at Mississagi TS to be transferred east to Sudbury and on to southern Ontario. As a result of the amount of energy deliverable to Mississagi TS through the GLPT transmission system, GLPT's system is critical with respect to the transmission of power from the Northwest Transmission System to southern Ontario.

In March 2004, the transmission division of GLPL obtained approval for the construction of the Transmission Reinforcement Project, which included, among other things, the construction of the 230 kV transmission lines running between Third Line TS and Wawa TS (K24G and W23K) and the refurbishment of the east-west line P21G running from Third Line TS to Mississagi TS.

This project provided a number of benefits. In particular, the IESO-controlled grid benefited by:

- eliminating transmission constraints and thereby increasing transfer limits to permit the full evacuation of generation from GLPT's system during system peak;
- eliminating the weakest link in the east-west system between Wawa TS and Mississagi TS;
- improving voltage stability at Wawa TS to increase the EWT east limit for specific generation collections and voltage stability at Mississagi TS to increase the Mississagi limit;
- eliminating the possibility of severing GLPT's system because of a double circuit outage on HONI's system, which in turn would result in severing the EWT; and
- allowing for future reinforcement of the EWT and Mississagi TS limits.

As noted above, the Third Line TS is a key component of GLPT's transmission system. As part of this Application, GLPT has proposed a redevelopment project which involves the construction of a new 115 kV section for Third Line TS. The new section will be constructed in part on the existing station site and in part on undeveloped GLPT lands immediately to the west of the existing station. The work is strictly in relation to the 115 kV section of the station and no changes are planned for the 230 kV section.

GLPT proposes that the redevelopment project be carried out in three phases at a total estimated cost of $23,500,000. Of this, the estimated cost of Phase I, which is to be completed during 2010, is $10,230,000. The estimated cost of Phase II, to be completed during 2011 is $12,000,000 and the estimated cost of Phase III, to be completed during 2012, is $1,270,000. In this Application, GLPT seeks approval from the Board for all phases of the redevelopment project. GLPT further seeks the Board's approval for the addition of $1,230,000 into rate base in 2010. This amount reflects the portion of the Phase I project costs that are associated with the elements of the redevelopment project that will go into service during 2010. In particular, this amount is associated with the development and construction of fencing and ground grid, which would be tied into the existing fencing and ground grid. The redevelopment project, which carries an estimated cost that is in excess of 10% of GLPT's current rate base, is a very significant undertaking for GLPT. As such, although the fencing and ground grid will become part of the existing station and be in service in 2010, this rate base addition is conditional upon the Board determining the need for all phases of the redevelopment project in this proceeding. Upon receiving approval in this proceeding for all phases, GLPT would seek to bring the cost of the Project into rate base as part of a future application for 2011 and 2012 rates, which it intends to file in 2010.

2.3 Green Energy and Green Economy Act

The *Green Energy and Green Economy Act* (the "GEA") has prompted significant changes for transmission and its planning and development. In addition to GLPT's current role in respect of the Ontario Power System, GLPT's role has been enhanced by the GEA and the initiatives arising from Ontario's green energy policy. Pursuant to section 25.36 of the *Electricity Act, 1998* (as amended), a transmitter is obliged to connect a renewable generator facility to its transmission system if the generator requests the connection in writing and meets the applicable technical, economic and other requirements prescribed by regulation, the Market Rules or by an order or code of the Board. Under section 26(1.1), a transmitter is obliged to provide priority access to its system to a renewable generation facility that meets the requirements prescribed by regulation.

In addition, section 70(2.1) of the *Ontario Energy Board Act* deems as part of the transmitter's license the requirement to provide priority connection access to its transmission system for renewable energy generation facilities. Furthermore, section 70(2.1)(2) requires transmitters to prepare plans for the expansion or reinforcement of the transmission system to accommodate the connection of renewable energy generation facilities.

It is estimated that there is up to 630 MW of new wind resources in and around the GLPT transmission system. Preliminary conclusions suggest that any connection of wind resources above 40-60 MW would trigger the need for an upgrade on GLPT's system, including the construction of new network 230 kV lines.

In addition, based on September 2009 announcements by the Minister of Energy and Infrastructure (the "Minister"), HONI has been asked to pursue certain transmission projects, including "East-West Tie: Nipigon by Wawa" and "Sudbury Area by Algoma Area". Both of these projects will affect GLPT's transmission system. The Minister has encouraged HONI to pursue partnerships in respect of various projects. It is GLPT's intention to seek to partner with HONI in respect to these and other projects, including projects that may not necessarily be located in close proximity to GLPT's transmission system.

It is also GLPT's intention to pursue designated transmitter status under the Transmission System Code in respect of various enabler transmission line projects and projects that could arise from an amended IPSP.

As a result of the forgoing, GLPT presently and throughout 2010 will incur expenditures relating to green energy initiatives and a future IPSP that could ultimately be capitalized as part of future capital projects or be treated as OM&A expenses. As a result, GLPT has sought from the Board by way of letter dated November 27, 2009 permission to establish a deferral account on the same basis as HONI in EB-2008-0272.

GLPT has made the same request in this Application for establishing a deferral account relating to infrastructure investment, the GEA and planning at Exhibit 9, Tab 2, Schedule 1.

The work that may be undertaken in respect of these activities will be comprised primarily of preliminary engineering, data collection, options assessments, cost estimating, stakeholder and other consultations, as well as other related activities required to prepare project submissions for environmental assessment and leave to construct approvals. Planned expenditures are material.

At this time, GLPT has no assurance that capital assets will in fact materialize as a result of such expenditures. Accordingly, GLPT faces the risk of not recovering its investment. GLPT believes that it satisfies the criteria of causation, materiality, management inability to control and prudence, which have been articulated by the Board as the bases for establishing such an account. GLPT's activities are clearly driven by current Ontario energy policy as set out in the amended *Electricity Act*, OEB Act and the OPA's Feed-in Tariff Program. Any amended IPSP may also be a factor. As an integral part of Ontario's bulk power system, GLPT will have to respond to the statutory and regulatory directives established as part of Ontario's energy policy.

3.0 General Overview

3.1 Rate Base

GLPT's rate base for 2010 has been forecasted to be $208.999 million, being the total of the average of the forecasted opening and closing net fixed assets ($208.598 million) and allowance for working capital ($0.401 million). This represents an increase in rate base over the 2006 approved rate base of approximately $12.265 million. Descriptions for the capital expenditures in the years 2007 through to 2010 are set out at Exhibit 2, Tab 1, Schedule 1 of this Application.

As noted above, a key capital expenditure program in 2010 is the Third Line TS redevelopment project (the “Redevelopment Project”).

3.2 OM&A Expenses

GLPT’s OM&A expenses are estimated to be $11.106 million for 2010. This is an increase over the $7.99 million forecasted for the 2009 bridge year and the $5.927 million approved in EB-2005-0241.

To provide the Board with context for GLPT's OM&A expenses, GLPT retained First Quartile Consulting, LLC ("FQC") to perform a benchmarking study. In performing its study, FQC performed analysis to determine how GLPT compares against a panel of utility companies with respect to transmission line, transmission substation and administrative and general expenses. Normalized on a cost per asset basis, GLPT generally falls below the average of the comparison panel, reflecting lower costs on average on per asset basis.

In considering combined administration expenses and operation and maintenance expenses, FQC found that GLPT remains below the average of the comparison panel, reflecting lower costs on average, and is within the second quartile. The second quartile is the second lowest cost tier. With only administration expenses on a per asset basis, GLPT is well below the average of the comparison panel and is primarily in the second quartile.

GLPT is also generally within the second quartile with respect to transmission lines and substation operation and maintenance costs, excluding administration costs. GLPT's costs per asset trend upwards in 2009 and 2010. This relates primarily to vegetation management expenses by GLPT, as well as GLPT expenditures that are recorded in CWIP and not yet in the asset base. As a result of the expected lower maintenance costs arising from capital expenditures in 2010 and the increment in the asset base in 2011, this upward trend is expected to lessen in 2011.

The FQC study is consistent with the view that GLPT's operation and maintenance expenditures are reasonable and that GLPT has established a corporate structure with an executive and management team that is reasonably sized. FQC's report is set out at Appendix “A” of Exhibit 4, Tab 2, Schedule 1.

Operations

From an operations perspective, OM&A expenses are primarily driven by costs incurred under Account 4810 - Load Dispatching, Account 4815 - Station Buildings and Fixtures, and Account 4805 - Operation Supervision and Engineering. With respect to load dispatching, these costs are driven by the Ontario System Control Centre (“OSCC”), which allows for the operation of the GLPT transmission system. The OSCC was jointly used by the generation, transmission and distribution businesses of GLPL. The generation business no longer uses the OSCC. As a result, costs that were formerly shared between the generation and transmission businesses of GLPL (and minimally with the distribution business) are now fully funded by GLPT as the OSCC is fully dedicated to transmission. Further particulars relating to this expense are set out at Exhibit 4, Tab 2, Schedule 1.

In addition, cost changes were driven by changes to GLPT's premises. The office complex which houses GLPT in Sault Ste. Marie is configured as two separate structures separated by a breezeway. The complex is owned by GLPL and leased to GLPT at market rates. GLPT is responsible for approximately 55% of the office complex costs (being one of the two structures) and subleases the remaining portion to Algoma Power Inc. Up to and including 2008, approximately 12% of the costs related to the office complex were allocated to GLPL's transmission business. The difference between this allocation of 12% of costs and the current allocation of 55% of costs is attributable to a more accurate allocation of space than previously used. In addition, the transmission business was not previously responsible for any portion of the capital cost related to the office complex. GLPT is now responsible for the lease cost, which is incremental to the cost previously assumed by the transmission business. All lease rates are based on square footage occupied and are charged at the median rates determined by a third party appraiser who prepared a report specifically for the complex.

Maintenance

As noted above, because of the significance of GLPT's ROW vegetation management program, the maintenance expense is driven primarily by activities that are under Account 4940 - Maintenance of Overhead Lines (Right of Way) and Account 4916 - Maintenance of Transformer Station Equipment. The maintenance of Right of Ways ("ROWs") is an ongoing challenge that is of particular importance to GLPT because of the unique character of its transmission system.

Administration

With respect to administration, costs are driven primarily by activities accounted for in Account 5605 - Executive Salaries and Expenses, Account 5615 - General Administrative Salaries, and Account 5630 - Outside Services Employed.

GLPT has established a corporate structure with an executive and management team that is reasonably sized, reflective of the overall company needs and structure, and which includes the appropriate level of experience and expertise for a transmission utility of the size and nature of GLPT. GLPT has a wide range of needs, some of which are basic business needs and some of which are driven by GLPT's business as an electricity transmitter in Ontario. As a result, some new positions were added part way through 2009. The full impact of these staff additions, together with partial offsets, are reflected in the 2010 forecast. Previously, the transmission business of GLPL was partially sheltered from these costs as the costs were shared with the generation business and distribution business of GLPL.

3.3 Operating Revenue

GLPT is forecasting operating revenue of $34.696 million for 2010. Variances in operating revenue are driven primarily by variations in the provincial peak loads from year to year. GLPT's operating revenue forecast is set out at Exhibit 3, Tab 1, Schedule 1 and GLPT's charge determinant forecast is set out at Exhibit 8, Tab 1, Schedule 1 of this Application. GLPT is forecasting a slight decline in the network annual charge determinants and a marginal increase in the line connection charge determinants. However, due to a sale of transformation equipment to a large industrial customer within GLPT's service territory in late 2006, the transformation connection pool has decreased significantly and GLPT's transformation charge determinants reflect a significant decline for 2010.

3.4 Cost of Capital

GLPT is proposing a capital structure of 57.5% debt and 42.5% equity for the 2010 test year. This capital structure reflects a two year phase-in from GLPT's most recently approved capital structure of 55% debt and 45% equity to the Board's deemed structure of 60% debt and 40% equity.

GLPT currently holds $120 million in long term debt in the form of third party, series one bonds, with interest payable at a rate of 6.6%. GLPT proposes a rate of interest on debt equal to the effective interest rate on its debt, which incorporates both interest payments and recovery of financing fees related to the issuance of additional debt and the establishment of a new deed of trust. GLPT's actual effective rate of interest is 6.874%, which is approximately 0.746% lower than the current deemed rate for a long term debt of 7.62%.

GLPT has used a rate of return on equity ("ROE") of 10.5% for its 2010 test year. At the time of filing this Application, the Board is conducting its consultation process on the cost of capital. It is GLPT's position and the position of others that the current formulaic approach to calculate ROE is flawed. As a result, GLPT proposes to use 10.5%, which is consistent with reports filed by GLPT's expert, Power Advisory LLC and others participating in the Board's consultation on cost of capital.

GLPT's total cost of capital, described in detail at Exhibit 5, Tab 1, Schedule 1 is $17.587 million.

GLPT notes that the ROE sought above relates to the carrying on of the transmission business in the ordinary course. This request is without prejudice to GLPT's submissions (attached in Appendix "B" of Exhibit 5, Tab 1, Schedule 1) in the Board's consultation process on the regulatory treatment of infrastructure investments (EB-2009-0152), in which GLPT requested the Board move expeditiously to establish incentive cost recovery mechanisms and adders to ROE in respect of infrastructure investments. This is essential to attaining the infrastructure investments necessary for Ontario to achieve its transmission goals.

3.5 Deferral and Variance Accounts

GLPT is seeking to disburse its December 31, 2008 audited balances in its existing deferral and variance accounts, along with forecasted accruals and carrying charges to the date of disbursal on December 31, 2009. GLPT proposes to disburse the aggregate balance of these accounts over a three-year period. The accounts and the circumstances that gave rise to them are described at Exhibit 9, Tab 1, Schedules 2 through 6. The proposed methodology for their disbursal is set out at Exhibit 9, Tab 3, Schedule 1.

GLPT is also seeking a series of new variance and deferral accounts as described at Exhibit 9, Tab 2, Schedule 1. These accounts relate to the following:

- pension cost variances;

- OEB cost assessment variances;
- infrastructure investments, the GEA and planning costs;
- property taxes and use and occupation fee variances; and
- IFRS transition costs.

3.6 Rate Design and Rates

Aspects related to rate design, including the charge determinant forecast, calculation of the Uniform Transmission Rates, variances in those rates and rate reconciliation are set out at Exhibit 8, Tab 2, Schedules 1 through 3. In calculating the Uniform Transmission Rates, GLPT has used the revenue requirement sought in this Application of $39.365 million, less the forecasted annual disbursal related to regulatory liabilities of $0.988 million, for a total of $38.370 million. As shown in these schedules, the resulting Uniform Transmission Rates arising from this Application are as follows:

- Network Rate: $2.67 per kW
- Line Connection Rate: $0.70 per kW
- Transformation Connection Rate: $1.59 per kW

As indicated above, this 2010 forward test year Application by GLPT results in a minimal change to the Uniform Transmission Rate and a negligible impact on a typical residential customer.

APPENDIX "A"

Evolution of the Transmission Business

EVOLUTION OF THE TRANSMISSION BUSINESS

GLPT is an electricity transmission company that is solely in the business of owning and operating its electricity transmission system in accordance with Section 71 of the OEB Act. GLPT became the owner and operator of the transmission system through a reorganization of GLPL. Up to and including March 2008, GLPL operated the transmission system as a division, financially separate from its distribution and generation businesses. Under Section 5(4) of Ontario Regulation 161/99, GLPL was exempt from Section 71 of the OEB Act until December 31, 2008 and, as a result, was permitted to carry on the activities of transmission and distribution, together with generation, within the same corporation until such date.

GLPL was controlled by Brookfield Power Inc. (later "Brookfield Renewable Power Inc." or "BRPI"), which in turn was controlled by Brookfield Asset Management Inc. ("BAM").

In anticipation of the expiry of the Section 71 exemption regulation and subsequent to market opening in May 2002, GLPL began taking steps to fully separate the businesses of generation, transmission and distribution. Between 2002 and 2007, GLPL financially and, for the most part, operationally separated its generation, transmission and distribution businesses within the same legal entity. However, by the end of the 2002 to 2007 period, there remained five areas that were not operationally separate: (1) the Ontario System Control Centre, (2) the integrated communications network, (3) the meter service provider, (4) Ontario Operations Administration, and (5) the services provided by distribution employees to the transmission business.

In early 2007, in anticipation of the expiry of the Section 71 exemption regulation, a reorganization was initiated that culminated in the transmission assets of GLPL being transferred to GLPT in March 2008. This was approved by a Decision and Order of the Board issued on December 24, 2007 (EB-2007-0647). At this time, GLPT became a licensed transmitter (ET-2007-0649) in respect of ownership only, and GLPL remained a licensed transmitter as the operator of the GLPT-owned transmission system. This completed the first phase of moving toward compliance with Section 71.

After March 2008, the full scope of operational services provided by GLPL to GLPT was captured in an OM&A Agreement between the parties. Pursuant to the OM&A Agreement, services were provided at cost, with no additional fees and based upon the cost allocation and transfer pricing established in the Board's Order in EB-2005-0241. In effect, GLPL was the agent of GLPT with respect to the operation of the transmission facilities.

As part of the movement towards full Section 71 compliance, to eliminate the need for two licensed transmitters for the one transmission system, as well as to provide greater transparency of costs, a full internal operational split of employees, fleet assets, building, office and information technology equipment was undertaken. The objective was to create two regulated standalone operating utilities within GLPL - one for distribution and one for transmission. Employees that were shared between the transmission and distribution businesses were instead dedicated to one of either the transmission or the distribution business. Some limited sharing remained, but only in respect of some corporate services, premises, IT licenses and the Ontario System Control Centre.

A further operational split from the generation business of GLPL occurred in 2008 when GLPL's generation business vacated the premises housing the transmission and distribution businesses in Sault Ste. Marie, at which time the Ontario System Control Centre became dedicated to the transmission and distribution businesses only.

As noted, GLPL's exemption from Section 71 of the OEB Act expired on December 31, 2008. Because GLPL has continued to operate as a licensed generator, compliance could not be maintained as licensed transmission and distribution activity would have been carried on in conjunction with licensed generation activity. Consequently, GLPL and GLPT filed applications with the Board in March 2009 to further reorganize to permit compliance with Section 71 of the OEB Act. To comply, GLPL transferred the distribution assets and the employees responsible for distribution to a newly formed entity, Great Lakes Power Distribution Inc. ("GLPDI"), and the employees responsible for transmission were transferred to GLPT. GLPL then became solely responsible for generation and GLPT and GLPDI became a standalone transmitter and a standalone distributor, respectively. In a Decision and Order dated May 5, 2009, the Board approved the transfer of the distribution assets, cancelled GLPL's electricity transmission licence (ET-2008-0342) and amended GLPT's electricity transmission licence (ET-2007-0649) to permit GLPT to own *and operate* its transmission system. These changes became effective as of the closing of the commercial transaction which transferred the distribution assets to GLPDI.

That transaction closed on July 1, 2009. Full compliance with Section 71 was realized when the distribution business was transferred to GLPDI and the transmission and distribution activity was carried on in two stand alone entities - GLPT and GLPDI, respectively. Subsequently, on October 8, 2009, the shares of GLPDI were sold to FortisOntario Inc. and GLPDI was renamed Algoma Power Inc.

Exhibit 1, Tab 2, Schedule 2

Budget Overview

BUDGET OVERVIEW (CAPITAL AND OPERATING)

1.0 Operations and Administration

When preparing its operations and administration budget for an upcoming year, GLPT uses a bottom up approach that considers the needs and requirements of the organization for the upcoming year in order to arrive at a budget that addresses those needs and requirements. To the extent possible, planned human resources, purchased services, materials and other costs are all identified and accounted for. GLPT forecasts its budget based on a review of its historic costs with consideration of required and available resources, both internal and external.

GLPT seeks to maximize its use of internal resources before relying on external resources. When external resources are required, GLPT typically uses them on a temporary or contract basis to minimize overall costs.

1.1 Maintenance

With respect to its maintenance budget, GLPT uses the information gathered through the implementation of the asset management plan, which is described at Exhibit 2, Tab 5, Schedule 1. Information is gathered from various sources, including through inspections, testing and asset condition assessments. The information is reviewed in consideration of required and available resources, and is compared to historical spending patterns. To the extent possible, planned human resources, purchased services, materials and other costs are all identified and accounted for.

The resulting maintenance budget assists GLPT in implementing an effective maintenance program that is expected to maximize the operational life of assets in service, and comply with reliability standards for the benefit of ratepayers in Ontario.

2.0 Capital Budget

For details on GLPT's capital budgeting process, please refer to the Asset Management schedule at Exhibit 2, Tab 5, Schedule 1. As indicated, GLPT has a comprehensive program for managing its existing assets through the inspection and maintenance of lines and stations and the undertaking of asset condition assessments. GLPT also has a rigorous process for optimizing the replacement of assets by ensuring that projects are appropriately prioritized.

3.0 Economic Assumptions Used

By using a bottom up approach in preparing its operating budget, the only economic assumption made by GLPT is related to labour rate negotiations.

Exhibit 1, Tab 2, Schedule 3

Methodology and Changes to Methodology

METHODOLOGY AND CHANGES TO METHODOLOGY

1.0 Introduction

GLPT has made one change to its methodology as compared to the methodology used in the EB-2005-0241 application by GLPL (the "2005 Application"). The change in methodology relates to the calculation of average fixed assets.

2.0 Average Fixed Assets

In the 2005 Application, significant rate base additions in the two test years (2005 and 2006) were forecasted. The applicant in the 2005 Application elected to use the average of the 12 months of the rate year for purposes of calculating the average net fixed assets. In accordance with the filing requirements, in the current Application GLPT has calculated average fixed assets as the average of the opening and closing balances in the test year.[1]

[1] As set out in Chapter 2 of the Board's *Filing Requirements for Transmission and Distribution Applications*.

Exhibit 1, Tab 2, Schedule 4

Schedule of Overall Revenue Deficiency/Sufficiency

SCHEDULE OF OVERALL REVENUE DEFICIENCY/SUFFICIENCY

($000's)		2006 Approved	2006 Actual	2007 Actual	2008 Actual	Bridge 2009	2010 Test Year - Revenue Forecast	2010 Test Year - Revenue Requirement
Operating Revenue *		$34,785.4	$34,686.2	$35,567.6	$35,073.4	$31,958.2	$34,696.2	$39,365.1
Operation, Maintenance & Admin.		5,927.0	5,661.1	6,089.6	7,201.9	7,994.1	11,105.6	11,105.6
Depreciation & Amortization		6,000.8	5,492.4	6,085.3	6,511.6	6,936.6	7,406.9	7,406.9
Retirement of Readily Identifiable Assets		1,855.8	1,649.1	1,649.1	1,649.1	1,649.1	0.0	0.0
Property Taxes		133.3	62.0	69.2	66.4	108.0	125.0	125.0
Payments in Lieu of Taxes to First Nations		134.8	133.1	133.2	129.1	128.8	133.2	133.2
Provincial Capital Tax		410.0	503.1	423.7	436.5	436.4	145.5	145.5
Total Costs & Expenses		14,461.7	13,500.8	14,450.1	15,994.7	17,252.9	18,916.2	18,916.2
Utility Income Before Taxes		20,323.7	21,185.4	21,117.5	19,078.7	14,705.3	15,780.0	20,448.9
LCT Tax		188.4	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes		5,360.7	5,390.4	4,590.8	3,229.9	1,798.1	1,414.1	2,861.5
Utility Income	**[A]**	14,774.6	15,794.9	16,526.7	15,848.8	12,907.1	14,365.9	17,587.4
Utility Rate Base	**[B]**	196,734.2	175,370.7	197,980.6	205,702.0	208,934.3	208,999.2	208,999.2
Indicated Rate of Return	**[C]** = [A] / [B]	7.51%	9.01%	8.35%	7.70%	6.18%	6.87%	8.42%
Approved/Requested Rate of Return	**[D]**	7.51%	7.51%	7.51%	7.49%	7.49%	8.42%	8.42%
(Deficiency)/Sufficiency in Return	**[E]** = [C] - [D]	0.00%	1.50%	0.84%	0.22%	-1.31%	-1.54%	0.00%
Revenue (Deficiency)/Sufficiency	**[F]** = [B] * [E]	(0.1)	2,624.6	1,660.4	448.9	(2,734.7)	(3,221.5)	0.0
Provision for Income Taxes		(0.1)	1,540.4	995.2	280.3	(1,323.5)	(1,447.4)	0.0
Gross Revenue (Deficiency)/Sufficiency		(0.2)	4,165.0	2,655.5	729.1	(4,058.2)	(4,668.9)	0.0
Service Revenue Requirement:		**34,785.6**	**30,521.2**	**32,912.0**	**34,344.2**	**36,016.4**	**39,365.1**	**39,365.1**
Less: Revenue from Other Sources		0.0	349.0	34.9	(128.4)	(51.9)	7.2	7.2
Base Revenue Requirement:		**$34,785.6**	**$30,172.2**	**$32,877.2**	**$34,472.7**	**$36,068.3**	**$39,357.9**	**$39,357.9**

* For 2010, Operating Revenue includes Transmission Services Revenue and Interest and Dividend Income

Exhibit 1, Tab 2, Schedule 5

Numerical Description of the Deficiency/Sufficiency

NUMERICAL DESCRIPTION OF REVENUE DEFICIENCY/SUFFICIENCY

Table 1-2-5 A - Numerical Description of Revenue Deficiency/Sufficiency

Cost of Capital	**($000's)**	**($000's)**
Rate Base	$208,999.2	
Requested Rate of Return	8.42%	$17,587.4
Cost of Service		
Operations, Maintenance & Admin	11,105.6	
Depreciation & Amortization	7,406.9	
Property Taxes	258.2	
Capital Taxes	145.5	
Income Taxes	1,414.1	20,330.3
Operating Revenue		
Transmission Services Revenue	34,696.2	
Net Revenues from Merchandising, Jobbing, Etc.	0.0	(34,696.2)
Gross (Deficiency)/Sufficiency		(3,221.5)
Income Taxes on (Deficiency)/Sufficiency		(1,447.4)
Gross Revenue (Deficiency)/Sufficiency		**($4,668.9)**

Exhibit 1, Tab 3, Schedule 1

Audited Financial Statements - Historical (2006 - 2008)

Financial Statements

GREAT LAKES POWER LIMITED TRANSMISSION DIVISION

December 31, 2007

Deloitte & Touche LLP
Brookfield Place
181 Bay Street
Suite 1400
Toronto ON M5J 2V1
Canada

Tel: (416) 601-6150
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Auditors' Report

To the Directors of
Great Lakes Power Limited

We have audited the balance sheet of Great Lakes Power Limited Transmission Division (the "Division") as at December 31, 2007 and the statements of capital account, income and comprehensive income, and cash flows for the year then ended. These financial statements are the responsibility of the Division's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Division as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

Toronto, Ontario
March 14, 2008

GREAT LAKES POWER LIMITED TRANSMISSION DIVISION
BALANCE SHEET
As at December 31

thousands of CDN dollars	Notes		**2007**		2006
Assets					
Current assets					
Cash		**$**	**3,388**	$	4,937
Accounts receivable			**3,200**		3,512
Due from related parties	5		**3,719**		8,500
Prepaid expenses and other			**157**		157
Current portion of regulatory asset	8		**1,649**		1,649
			12,113		18,755
Regulatory asset	8		**2,762**		3,299
Property, plant and equipment, net	6		**210,312**		195,954
		$	**225,187**	$	218,008
Liabilities and Capital Account					
Current liabilities					
Accounts and other payables		**$**	**10,578**	$	5,159
Regulatory liability	8		**2,391**		-
Taxes payable			**1,094**		4,501
Due to related parties	5		**587**		6,173
			14,650		15,833
First mortgage bonds	7		**114,789**		115,750
Future income taxes	11		**19,339**		21,513
			148,778		153,096
Capital account			**76,409**		64,912
		$	**225,187**	$	218,008

See accompanying notes to financial statements

GREAT LAKES POWER LIMITED TRANSMISSION DIVISION
STATEMENT OF CAPITAL ACCOUNT
Year ended December 31

thousands of CDN dollars		**2007**		2006
Balance, beginning of year	**$**	**64,912**	$	53,136
Net income		**11,497**		11,776
Balance, end of year	**$**	**76,409**	$	64,912

See accompanying notes to financial statements

GREAT LAKES POWER LIMITED TRANSMISSION DIVISION
STATEMENT OF INCOME AND COMPREHENSIVE INCOME
Year ended December 31

thousands of CDN dollars	Notes		**2007**		2006
Revenues		**$**	**35,568**	$	34,686
Operating expenses					
Operating and administration			**4,652**		4,277
Depreciation			**6,122**		5,530
Maintenance			**1,242**		1,475
Taxes, other than income taxes			**493**		482
			23,059		22,922
Other income, net			**67**		179
			23,126		23,101
Expenses					
Interest	10		**7,397**		6,555
Loss on disposal of property, plant and equipment	8		**1,649**		1,436
Income taxes - current	11		**4,757**		5,057
Recovery of income taxes - future	11		**(2,174)**		(1,723)
			11,629		11,325
Net income and comprehensive income		**$**	**11,497**	$	11,776

See accompanying notes to financial statements

GREAT LAKES POWER LIMITED TRANSMISSION DIVISION
STATEMENT OF CASH FLOWS
Year ended December 31

thousands of CDN dollars	Notes	**2007**	2006
Operating activities			
Net Income		**$ 11,497**	$ 11,776
Items not affecting cash			
Depreciation		**6,122**	5,530
Non-cash interest expense	7,10	**37**	-
Future income taxes		**(2,174)**	(1,723)
Loss on disposal of property, plant and equipment	8	**1,649**	1,436
Net change in non-cash working capital and other	9	**(4,568)**	7,042
		12,563	24,061
Investing activities			
Due from related party		**4,781**	(1,995)
Proceeds on disposition of property, plant and equipment	6	**108**	250
Additions to property, plant and equipment		**(18,003)**	(19,339)
		(13,114)	(21,084)
Financing activities			
Deferred financing fees	7	**(998)**	-
		(998)	
(Decrease) increase in cash		**(1,549)**	2,977
Cash, beginning of year		**4,937**	1,960
Cash, end of year		**$ 3,388**	$ 4,937

See accompanying notes to financial statements

1. NATURE AND DESCRIPTION OF BUSINESS

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles on the basis that the Transmission Division (the "Division") of Great Lakes Power Limited ("GLPL") operates as a separate legal entity. The Division is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board (the "OEB"). These divisional financial statements do not include all of the assets, liabilities, revenues and expenses of GLPL. Consolidated financial statements of GLPL have been prepared for issuance to the shareholders and have been reported on by its auditors.

These financial statements have been derived from the consolidated financial statements and accounting records of GLPL using historical results of operations and historical basis of assets and liabilities of the Division. Management believes the assumptions underlying the financial statements are reasonable. However, the financial statements included herein may not necessarily reflect the Division's results of operations, financial position and cash flows in the future or what its results of operations, financial position and cash flows would have been had the Division been a stand-alone company during the years presented.

These financial statements include allocations of certain expenses and liabilities, including the items described below.

General Corporate Expenses

GLPL allocates some of its general corporate expenses for each fiscal year based on variable drivers depending on the nature of each expense. These general corporate expenses include accounting and administration, management salaries, planning and maintenance services and information technology. Administration costs such as accounting and management salaries are allocated equally across the divisions whereas information technology is allocated based on headcount. Total allocations amounted to $1,316 in 2007 (2006 – $1,286). These expenses have been included in operating and administrative expenses on the statement of income and comprehensive income. Management believes the cost of these services charged to the Division are a reasonable representation of the costs that would have been incurred if the Division had performed these functions as a stand-alone company.

Income taxes

The Division's income taxes were calculated on a separate tax return basis. However, GLPL was managing its tax position for the benefit of its business as a whole, and its tax strategies are not necessarily reflective of the tax strategies that the Division would have followed as a stand-alone company.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The following accounting policies have been applied in the preparation of these financial statements:

Property, plant and equipment

Property, plant and equipment are recorded at cost, including costs of acquisition incurred by the Division and its parent, less accumulated depreciation. The cost of the property, plant and equipment is depreciated over the estimated service lives of the assets as follows:

	Method	Rate
Buildings	Straight-line	40 years
Transmission stations, towers and related fixtures	Straight-line	25 to 40 years
Equipment	Straight-line	5 to 40 years

Construction work in progress is not depreciated until the assets are put into service.

Impairment of long-lived assets

The Division reviews long-lived assets for other than temporary impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. Should an asset be considered to be impaired, an impairment loss is recognized in an amount equal to the excess of the asset's carrying value over its fair value.

Deferred financing fees

Financing costs associated with the offering of the First mortgage bonds are capitalized, netted against the First mortgage bonds liability, and amortized over the term of the bonds using the effective interest method.

Capitalization of interest

Interest on funds used in construction is charged to construction work in progress at the prescribed rate of return applicable to the rate base.

Revenue recognition

The Division recognizes revenue on an accrual basis, when electricity is wheeled, at the regulated rate established by the OEB.

Income taxes

The Division uses the asset and liability method in accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities, and are measured using the enacted, or substantively enacted, tax rates and laws that will be in effect when the differences are expected to reverse, taking into account the organization of the Division's financial affairs and its impact on taxable income and tax losses.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, and disclosures of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. During the years presented, management has made a number of estimates and valuation assumptions including accruals, depreciation and those relevant to the defined benefit pension plan. Estimates are based on historical experience, current trends and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from those estimates.

Rate Regulation

On January 1, 2005, the Division adopted CICA Handbook Accounting Guideline 19, *Disclosure by Entities Subject to Rate Regulation*. The Division is regulated by the OEB. Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the financial statements as regulatory assets and liabilities. When the regulation provides assurance that incurred costs will be recovered in the future, the Division may defer these costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the future, the Division reports a regulatory liability. Also, if the regulation provides for lesser or greater planned revenue to be received or returned by the Division through future rates, the Division recognizes and reports a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities are subject to certain estimates and assumptions, including assumptions made in the interpretation of the relevant regulation.

3. CHANGES IN ACCOUNTING POLICIES

On January 1, 2007, the Division adopted the following new accounting standards for Canadian generally accepted accounting principles:

Handbook Section 1530, Comprehensive Income

This section establishes standards for reporting and presenting comprehensive income (loss), which is defined as the change in owners' equity from transactions and other events from non-owner sources. This standard requires certain gains and losses to be presented in other comprehensive income (loss) until it is considered appropriate to recognize into net income. Major components for this category include unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation amounts, net of hedging, arising from self-sustaining foreign operations, and changes in the fair value of the effective portion of cash flow hedging instruments. There was no impact on the adoption of this new standard on the Division's financial statements as at January 1, 2007.

Handbook Section 3251, Equity

The Division adopted Section 3251, Equity replacing Section 3250, Surplus. This section describes the presentation of equity and changes in equity for a reporting period as a result of the application of Section 1530, Comprehensive Income. There was no impact on the adoption of this new standard on the Division's financial statements as at January 1, 2007.

Handbook Section 3855, Financial Instruments – Recognition and Measurement

Under Section 3855, all financial instruments are classified as one of the following: held-for-trading, held-to-maturity investments, loans and receivables, other financial liabilities, or available-for-sale financial assets. Financial assets and liabilities held-for-trading are measured at fair value with gains and losses recognized in net income. Financial assets, held-to-maturity, loans and receivables and financial liabilities other than those held-for-trading, are measured at amortized cost using the effective interest rate method of amortization. Available-for-sale financial instruments are measured at fair value with unrealized gains and losses recognized in other comprehensive income. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading. For other financial instruments, transaction costs are capitalized on initial recognition.

The Division has implemented the following classifications:

a) Cash is designated as a financial asset held-for-trading and is measured at fair value through net income at each period end.

b) Accounts receivable and due from related parties are classified as loans and receivables. Accounts and other payables and due to related parties are classified as other financial liabilities. These accounts are measured at fair value at inception which, due to their short-term nature, approximates amortized cost.

c) After its initial fair value measurement, long-term debt is classified as other financial liabilities and is measured at amortized cost using the effective interest method.

There was no material impact on the adoption of this new standard on the Division's financial statements as at January 1, 2007.

4. FUTURE ACCOUNTING POLICY CHANGES

On December 1, 2006, the Accounting Standards Board issued three new accounting standards: Handbook Section 1535, Capital Disclosures, Handbook Section 3862, Financial Instruments – Disclosures, and Handbook Section 3863, Financial Instruments – Presentation. These new standards will be effective for the Division on January 1, 2008.

Section 1535 establishes standards for disclosing information about the Division's capital and how it is managed. The standard requires disclosures of the Division's objectives, policies and processes for managing capital, the quantitative data about what the Division regards as capital, whether the Division has complied with any capital requirements and if it has not complied, the consequences of such non-compliance.
The new sections 3862 and 3863 will replace Handbook Section 3861, Financial Instruments – Disclosure and Presentation by revising and enhancing disclosure requirements but carrying forward presentation requirements unchanged. They place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the Division manages those risks.

The Division does not expect the adoption of these new standards to have a material impact on the financial statements.

(in thousands of CDN dollars)

5. RELATED PARTY TRANSACTIONS

(a) The Division has provided advances to and received advances from entities under common control in the normal course of operations. The Division has also provided advances to and received advances from other divisions of GLPL. These advances are non-interest bearing, unsecured and due on demand.

(b) In the normal course of operations, Riskcorp Inc., a broker company affiliated with Brookfield Asset Management Inc., GLPL's ultimate parent, entered into transactions with GLPL to provide insurance. These transactions have been measured at exchange value. The total cost allocated to the Division in 2007 for these services was $116 (2006 – $117) and no amount remains outstanding at year end (2006 - $nil).

(c) As a result, the following balances are receivable (payable) at December 31:

		2007		2006
Due from related parties:				
Advances to other divisions of GLPL	**$**	**3,719**	$	8,500
Due to related parties:				
Advances from other divisions of GLPL	**$**	**(222)**	$	(5,892)
Advances from entities under common control		**(365)**		(281)
	$	**(587)**	$	(6,173)

6. PROPERTY, PLANT AND EQUIPMENT

						2007		2006
		Cost		**Accumulated Depreciation**		**Net Book Value**		Net Book Value
Land	**$**	**544**	**$**	**-**	**$**	**544**	$	544
Buildings		**14,772**		**3,988**		**10,784**		10,991
Transmission stations, towers and related fixtures		**249,296**		**55,917**		**193,379**		182,226
Construction work in progress		**5,605**		**-**		**5,605**		2,193
	$	**270,217**	**$**	**59,905**	**$**	**210,312**	$	195,954

Cost and accumulated depreciation as at December 31, 2006 were $249,771 and $53,817, respectively.

During 2007, the Division disposed of assets that had a net book value of $108 for net proceeds of $108.

Property, plant and equipment were comprehensively revalued to fair value in 1996. At December 31, 2007, the fair value adjustment and the related accumulated depreciation were $78,941 and $21,861, respectively (2006 - $78,941 and $19,888, respectively).

(in thousands of CDN dollars)

7. FIRST MORTGAGE BONDS

	2007	2006
Series 1 First Mortgage Bonds	**$ 384,000**	$ 384,000
Subordinated First Mortgage Bonds	**115,000**	115,000
	$ 499,000	$ 499,000

The Series 1 First Mortgage Bonds ("Series 1 Bonds") bear interest at the rate of 6.6%. Semi-annual payments of interest only are due and payable on June and December 16 each year until and including June 16, 2013. Equal blended semi-annual payments of principal and interest on the Series 1 Bonds will commence on December 16, 2013 and will continue until and including June 16, 2023. The Series 1 Bonds will not be fully amortized by their maturity date. The remaining principal balance of the Series 1 Bonds will be fully due on June 16, 2023.

The Subordinated First Mortgage Bonds bear interest at the rate of 7.8%, payable on June and December 16 each year, and are due on June 16, 2023.

The Series 1 First Mortgage Bonds and the Subordinated First Mortgage Bonds are both secured by a charge on generation and transmission present and future real property assets of GLPL. The fair market value of the First Mortgage Bonds is $553,852 (2006 - $576,262) based on current market prices for debt with similar terms.

The portion of the Series 1 Bonds has been allocated to the Division as follows:

	2007	2006
Series 1 Bonds	**$ 115,750**	$ 115,750
Less: Unamortized deferred financing fees	**961**	-
	$ 114,789	$ 115,750

Interest on the allocated Bonds is expensed in accordance with the interest rate prescribed by regulation. In 2007, the interest rate was 6.6% (2006 – 6.6%). The fair market value of the Series 1 Bonds that has been allocated to the Division is $125,187 (2006 - $130,338) based on current market prices for debt with similar terms. Amortization of deferred financing fees for the year related to the Division's long-term debt is included in interest expense and totalled $37 (2006 - $nil). See note 11.

8. EFFECT OF RATE REGULATION

The Division recorded the following regulatory assets and liability as at December 31:

	2007	2006
Regulatory assets:		
Deferred loss on disposal of transmission assets	**$ 3,299**	$ 4,948
Wholesale metering services rebates	**465**	-
Reorganization costs relating to the transfer of assets	**647**	-
Less: current portion	**(1,649)**	(1,649)
Long-term portion	**$ 2,762**	$ 3,299
Regulatory liability:		
Deferred rate impact accrual	**$ 2,391**	$ -

The Division operates in accordance with the regulations of the OEB. Regulatory assets and liabilities represent certain revenues earned or costs incurred in the current year or in prior years that have been or are expected to be recovered from customers upon approval from the OEB. In the absence of rate regulation, these balances would have been recorded as revenues or expenses in the statement of income and comprehensive income.

Deferred loss on disposal of transmission assets

As prescribed by regulatory order, gains or losses on disposal of assets are recorded as a regulatory asset or liability subject to approval by the OEB. For the year ended December 31, 2005, the Division incurred a loss on disposal of transmission assets of $8,246. This regulatory asset is recovered over a period of five years, which commenced on April 1, 2005, through rate increases. During 2007, the Division recovered $1,649 (2006 - $1,649) of the deferred loss. As the deferred loss on disposal of transmission assets has been approved by the OEB for recovery, there is no risk of non-collection of this balance.

Wholesale metering services rebates

As prescribed by regulatory order, the rebates related to metering services are recorded as a regulatory asset. The Division is responsible for paying the rebates and recording them in a regulatory asset deferral account. As wholesale metering services rebates have been approved by the OEB for recovery, there is no risk of non-collection of this balance. The Division will include its request to recover this amount in its next rate application filing to the OEB.

Reorganization costs relating to the transfer of assets

These reorganization costs were the result of the transfer of the Division's assets from GLPL to Great Lakes Power Transmission LP ("GLPTLP"), a subsidiary of Brookfield Infrastructure Partners LP, which is a newly formed partnership created by Brookfield Asset Management Inc. (note 14). Legislation through the Ontario Electricity Act requires the separation of transmission assets from generation assets, however, GLPL had an exemption to operate its transmission, distribution, and generation business within the same company until December 31, 2008. The costs associated with the transfer of the Division's assets were capitalized as regulatory assets as they are eligible for recovery through future rates, subject to OEB approval. The Division will include its request to recover this amount in its next rate application filing to the OEB.

Deferred rate impact accrual

The deferred rate impact accrual ("DRIA") was for revenues being recovered through the 2005 rate application filed with the OEB. On November 1, 2007, the OEB implemented a new uniform transmission rate as a result of the rate application filed by Hydro One Networks Inc. This resulted in the termination of the over recovery of the DRIA. At December 31, 2007, the DRIA balance of $2,391 is payable to the OEB. At December 31, 2006, the DRIA had a receivable balance of $317 and was included in accounts receivable.

(in thousands of CDN dollars)

9. STATEMENT OF CASH FLOWS

		2007		2006
Accounts receivable	$	312	$	2,083
Prepaid expenses and other		-		(48)
Reorganization costs relating to the transfer of assets		(647)		-
Wholesale metering services rebate		(465)		-
Accounts and other payables		2,834		(5,197)
Due to related parties		(5,586)		5,087
Regulatory liability		2,391		-
Taxes payable		(3,407)		5,117
	$	(4,568)	$	7,042

Capital asset additions totaling $6,466 have been excluded from the Statement of Cash Flows as they remain unpaid at year end. During 2007, capital asset additions totaling $3,881 have been included in the Statement of Cash Flows as they were accrued at December 31, 2006 and paid in 2007.

10. INTEREST AND FINANCING FEES

The net interest and financing fees recorded in the financial statements as at December 31 are comprised as follows:

		2007		2006
Interest expense incurred	$	7,660	$	7,659
Amortization of deferred financing fees		37		-
Capitalized interest		(300)		(1,104)
	$	7,397	$	6,555

11. INCOME TAXES

The provision for income taxes in the statement of income and comprehensive income represents an effective tax rate different than the Canadian statutory rate of 36.12% (2006 – 36.00%). The differences were as follows:

		2007		2006
Net income before income taxes	$	14,080	$	15,110
Computed income tax recovery at Canadian statutory rate		5,086		5,440
Increase resulting from:				
Impact of future rate change on future income tax liability		(2,607)		(2,007)
Other		104		(99)
Income tax provision	$	2,583	$	3,334
Future income tax liabilities				
CCA in excess of book depreciation	$	19,099	$	21,598
Other		238		(85)
	$	19,339	$	21,513

The Division's future income tax liability of $19,339 (2006 – $21,513) is comprised principally of temporary differences relating to the CCA in excess of book depreciation. At December 31, 2007, the Division did not have any unused capital losses (2006 – $nil).

12. FINANCIAL INSTRUMENTS

(a) Interest rate risk

The Division's long-term debt bears interest at a rate set periodically by the OEB. Consequently, there is cash flow exposure.

(b) Fair value

The carrying amounts in the balance sheet of accounts receivable and accounts and other payables approximate their fair values, reflecting their short maturities.
The fair value of the related party balances is not determinable by management due to the related party nature of these balances.

(c) Credit risk

Credit risk arises from the potential for a counterparty to default on its contractual obligations and is limited to those contracts where the Division would incur a loss in replacing the defaulted transaction. The Division's financial instruments that are potentially exposed to credit risks are accounts receivable. The Division actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

13. COMMITMENTS, CONTINGENCIES AND GUARANTEES

In the normal course of operations, the Division executes agreements that provide for indemnification and guarantees to third parties in transactions such as debt issuances. The nature of substantially all of the indemnification undertakings prevents the Division from making a reasonable estimate of the maximum potential amount the Division could be required to pay third parties as the agreements do not specify a maximum amount and the amounts are dependent upon the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time. Historically, the Division has not made significant payments under such indemnification agreements.

On behalf of GLPL, Brookfield Power Corporation obtained a letter of credit totaling $19,008 (2006 - $19,008) to cover nine months of interest payments on the First Mortgage Bonds. No amount has been drawn against this letter of credit.

In the normal course of operations, the Division has committed as at December 31, 2007 to spend approximately $6,466 (2006 - $5,500) on capital projects in future years.

The Division may, from time to time, be involved in legal proceedings, claims, and litigation that arise in the ordinary course of business which the Division believes would not reasonably be expected to have a material adverse effect on the financial condition of the Division.

There are no specified decommissioning costs relating to the Ontario transmission assets. The Division has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to optimum industry standards. Replacement of the assets occur in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which we would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

14. SUBSEQUENT EVENT

Effective March 12, 2008, GLPL transferred the Division’s operations to GLPTLP. GLPL will operate the GLPTLP transmission facilities pursuant to an Operation, Maintenance and Administration Agreement between GLPL and GLPTLP. On the same day, the financing agreement of the First Mortgage Bonds was amended to remove the security against the generation assets and to convert 31.25% of the principal amount of the Series 1 Bonds into Trans Senior Bonds having a principal of $120,000, the terms of which remain substantially unchanged. The Trans Senior Bonds are now secured by a charge on transmission present and future real property assets of GLPTLP. On behalf of GLPTLP, Brookfield Power Corporation, a company related through common control, obtained a letter of credit in the amount of $3,960 to cover six months of interest payments on the Trans Senior Bonds.

Financial Statements

GREAT LAKES POWER TRANSMISSION LIMITED PARTNERSHIP

December 31, 2008

Deloitte.

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Auditors' Report

To the Partners of
Great Lakes Power Transmission Limited Partnership

We have audited the balance sheet of Great Lakes Power Transmission Limited Partnership (the "Partnership") as at December 31, 2008 and the statements of partners' equity, income and comprehensive income and cash flows for the year then ended. These financial statements are the responsibility of the General Partner, Great Lakes Power Transmission Inc. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

Toronto, Canada
April 27, 2009

Great Lakes Power Transmission Limited Partnership
Balance Sheet
as at December 31, 2008

thousands of CDN dollars	*Notes*		**2008**		2007
Assets					
Current Assets					
Cash		**$**	**1,990**	$	3,388
Accounts receivable			**3,014**		3,200
Due from related parties			**-**		3,719
Prepaid expenses and other			**-**		157
Current portion of regulatory asset	*7*		**1,649**		1,649
			6,653		12,113
Regulatory asset	*7*		**4,044**		2,762
Property, plant and equipment, net	*5*		**212,330**		210,312
		$	**223,027**	$	225,187
Liabilities					
Current liabilities					
Accounts and other payables		**$**	**505**	$	10,578
Regulatory liability	*7*		**2,512**		2,391
Taxes payable			**-**		1,094
Due to related parties	*4*		**2,080**		587
			5,097		14,650
First mortgage bonds	*6*		**119,079**		114,789
Future income taxes	*10*		**-**		19,339
			124,176		148,778
Partners' equity			**98,851**		76,409
		$	**223,027**	$	225,187

The accompanying notes are an integral part of these financial statements

Great Lakes Power Transmission Limited Partnership

Statement of Partners' Equity

as at December 31, 2008

thousands of CDN dollars	*Notes*		Brookfield Infrastructure Holdings (Canada) Inc.		Great Lakes Power Transmission Inc.		**2008**		2007
Partners' equity, beginning of year		$	76,333	$	76	**$**	**76,409**	$	64,912
Allocation of net income			10,698		10		**10,708**		11,497
Allocation of contributed surplus adjustment	*12*		21,254		21		**21,275**		-
Distributions			(9,531)		(10)		**(9,541)**		-
Partners' equity, end of year		$	98,754	$	97	**$**	**98,851**	$	76,409

The accompanying notes are an integral part of these financial statements

Great Lakes Power Transmission Limited Partnership

Statement of Income and Comprehensive Income

for the year ending December 31, 2008

thousands of CDN dollars	*Notes*		**2008**		2007
Revenues		**$**	**35,074**	$	35,568
Expenses					
Operating and administration			**5,021**		4,652
Maintenance			**2,309**		1,242
Taxes, other than income taxes			**66**		493
			7,396		6,387
			27,678		29,181
Interest	*9*		**7,787**		7,397
Depreciation			**6,549**		6,122
Loss on disposal of property, plant and equipment	*5,7*		**1,749**		1,649
Other expenses/(income)			**28**		(67)
Net income before income taxes			**11,565**		14,080
Current tax provision	*10*		**754**		4,757
Future tax provision	*10*		**103**		(2,174)
Net income and comprehensive income		**$**	**10,708**	$	11,497

The accompanying notes are an integral part of these financial statements

Great Lakes Power Transmission Limited Partnership
Statement of Cash Flows
for the year ending December 31, 2008

thousands of CDN dollars	*Notes*	**2008**	2007
Operating Activities			
Net income		**$ 10,708**	$ 11,497
Items not affecting cash;			
Depreciation		**6,549**	6,122
Amortization of prepaid expenses		**178**	-
Non-cash interest expense		**40**	37
Future income taxes		**103**	(2,174)
Loss on disposal of property, plant and equipment		**1,749**	1,649
Net change in non-cash working capital and other	*8*	**(5,605)**	(4,568)
		13,722	12,563
Investing activities			
Receipt of amounts due from related parties		**3,718**	4,781
Proceeds on disposition of property, plant and equipment		**7**	108
Additions to property, plant and equipment		**(13,538)**	(18,003)
Additions to regulatory assets		**(16)**	-
		(9,829)	(13,114)
Financing activities			
Dividends paid		**(9,541)**	-
Deferred financing fees		**-**	(998)
Increase in borrowings		**4,250**	-
		(5,291)	(998)
Decrease in cash		**(1,398)**	(1,549)
Cash, beginning of year		**3,388**	4,937
Cash, end of year		**$ 1,990**	$ 3,388

The accompanying notes are an integral part of these financial statements

1. NATURE AND DESCRIPTION OF BUSINESS

Great Lakes Power Transmission Limited Partnership (the "Partnership") was formed on May 17, 2007 for the purpose of acquiring the assets and liabilities of the transmission division of Great Lakes Power Limited ("GLPL"). The Partnership completed this purchase on March 12, 2008 for total cash consideration of $92,500, which was paid directly to GLPL by Brookfield Infrastructure Partners LP ("BIP"), the ultimate parent of the Partnership. BIP then contributed these net assets directly to the Partnership.

Brookfield Infrastructure Holdings (Canada) Inc. is the limited partner and holds a 99.9% interest in the Partnership. Great Lakes Power Transmission Inc., the General Partner, holds a 0.1% limited interest in the Partnership and is responsible for management of the Partnership. Both the General and limited partners are wholly owned subsidiaries of BIP.

As both the Partnership and GLPL were owned and operated by the same ultimate parent at the time of the acquisition, this transaction constitutes a reorganization of entities under common control and has been accounted for using the continuity of influence method. Accordingly, these financial statements have been presented giving retroactive effect to this transaction using historical carrying costs of the assets and liabilities of the transmission division of GLPL for all periods presented. This treatment is described in further detail in note 2.

The Partnership is engaged in the transmission of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board (the "OEB").

2. BASIS OF PRESENTATION

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles. All amounts are reported in thousands of Canadian dollars, except as otherwise noted. These financial statements should be read in conjunction with the 2007 annual audited financial statements of Great Lakes Power Limited Transmission Division ("GLPLTD").

As required under the continuity of influence method these financial statements have been prepared as if the Partnership owned the assets and liabilities of GLPLTD in the comparative period. As the Partnership did not have any of its own operations prior to March 12, 2008 these financial statements effectively represent the operations of GLPLTD for the period January 1 to March 12, 2008 and the results of the Partnership for the period March 13 to December 31, 2008. Both GLPL and the Partnership remained under common control for the twelve month period ended December 31, 2008. The comparatives represent the audited financial statements of GLPLTD for the twelve month period ended December 31, 2007. The difference between the exchange value of the assets and liabilities transferred on sale and the proceeds has been treated as an increase to contributed surplus as of March 12, 2008 (see note 12).

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The following accounting policies have been applied in the preparation of these financial statements:

(a) *Property, plant and equipment*

Property, plant and equipment are recorded at cost, including costs of acquisition incurred by the Partnership, less accumulated depreciation. The cost of the property, plant and equipment is depreciated over the estimated service lives of the assets as follows:

	Method	Rate
Buildings	Straight-line	40 years
Transmission stations, towers and related fixtures	Straight-line	25 to 40 years
Equipment	Straight-line	5 to 40 years

Construction work in progress is not depreciated until the assets are put into service.

(b) *Impairment of long-lived assets*

The Partnership reviews long-lived assets for other than temporary impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. Should an asset be considered to be impaired, an impairment loss is recognized in an amount equal to the excess of the asset's carrying value over its fair value.

(c) *Deferred financing fees*

Financing costs associated with the offering of debt are capitalized, netted against the debt, and amortized over the term of the debt using the effective interest method.

(d) *Capitalization of interest*

Interest on funds used in construction is charged to construction work in progress at the prescribed rate of return applicable to the rate base.

(e) *Revenue recognition*

The Partnership recognizes revenue on an accrual basis, when electricity is wheeled, at the regulated rate established by the OEB.

(f) *Income taxes*

As of March 12, 2008 the date of the transfer of the transmission assets from GLPL, the Partnership recorded no income tax transactions, and balances previously recorded by GLPLTD have been adjusted against contributed surplus. This is because the Partnership is not subject to income taxation as a result of its formation as a limited partnership.

Prior to March 12, the Partnership used the asset and liability method in accounting for income taxes. Under this method, future income tax assets and liabilities were determined based on differences between the financial reporting and tax basis of assets and liabilities, and were measured using the enacted, or substantively enacted, tax rates and laws that would have been in effect when the differences are expected to reverse, taking into account the organization of the Partnership's financial affairs and its impact on taxable income and tax losses.

(g) *Use of estimates*

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets and liabilities, and disclosures of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. During the years presented, management has made a number of estimates and valuation assumptions including accruals and depreciation. Estimates are based on historical experience, current trends and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from those estimates.

(h) *Rate Regulation*

On January 1, 2005, the Partnership adopted CICA Handbook Accounting Guideline 19, *Disclosure by Entities Subject to Rate Regulation*. The Partnership is regulated by the OEB. Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the financial statements as regulatory assets and liabilities. When the regulation provides assurance that incurred costs will be recovered in the future, the Partnership may defer these costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the future, the Partnership reports a regulatory liability. Also, if the regulation provides for lesser or greater planned revenue to be received or returned by the Partnership through future rates, the Partnership recognizes and reports a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities are subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation.

4. RELATED PARTY TRANSACTIONS

(a) In the normal course of operations, Riskcorp Inc., an insurance broker related through common control, entered into transactions with GLPLTD and the Partnership to provide insurance. These transactions have been measured at exchange value. The total cost allocated to the Partnership in 2008 was $115 (2007 - $116) and no amount remains outstanding at year end (2007 $nil).

(b) In accordance with an OM&A agreement that exists between the Partnership and Great Lakes Power Limited ("GLPL"), the transmission assets are operated by GLPL, and all costs are passed on to the Partnership. GLPL is responsible for all operating, maintenance, administrative, and capital activity, the cost of which is tracked and billed to the Partnership with no mark-up.

(c) As a result, the following balances are receivable (payable) at December 31:

		2008		2007
Due from related parties				
Advances to entities under common control	$	-	$	3,719
Due to related parties				
Advances from entities under common control	$	-	$	(587)
Costs paid by GLPL on behalf of the Partnership		(2,080)		-
	$	**(2,080)**	**$**	**(587)**

5. PROPERTY, PLANT AND EQUIPMENT

			2008	2007
	Cost	**Accumulated Depreciation**	**Net Book Value**	Net Book Value
Land	**$ 544**	**$ -**	**$ 544**	$ 544
Buildings	**14,772**	**4,580**	**10,192**	10,784
Transmission stations, towers and related fixtures	**261,061**	**61,695**	**199,366**	193,379
Construction work in progress	**2,228**	**-**	**2,228**	5,605
	$ 278,605	**$ 66,275**	**$ 212,330**	$ 210,312

Cost and accumulated depreciation as at December 31, 2007 were $270,217 and $59,905, respectively.

During 2008, the Partnership disposed of assets that had a net book value of $107 for net proceeds of $7 (2007 - $108 and $108, respectively).

Property, plant and equipment were comprehensively revalued to fair value in 1996. At December 31, 2008, the fair value adjustment and the related accumulated depreciation were $78,941 and $23,834, respectively (2007 - $78,941 and $21,861, respectively).

6. TRANS SENIOR BONDS

On March 12, 2008, the financing agreement of the First Mortgage Bonds was amended to remove the security against the generation assets and to convert 31.25% of the principal amount of the Series 1 Bonds into Trans Senior Bonds having a principal of $120,000, the terms of which remain substantially unchanged. The Trans Senior Bonds are now secured by a charge on transmission present and future real property assets of the Partnership. On behalf of the Partnership, a company related through common control, Brookfield Renewable Power Inc. ("BRPI"), obtained a letter of credit in the amount of $3,960 to cover six months of interest payments on the Trans Senior Bonds.

The fair market value of the Trans Senior Bonds is $110,990 based on current market prices for debt with similar terms. Amortization of deferred financing fees for the year related to the Partnership's long-term debt is included in interest expense and totalled $40 (2007 - $37).

The Trans Senior Bonds ("the Bonds") bear interest at the rate of 6.6%. Semi-annual payments of interest only are due and payable on June and December 16 each year until and including June 16, 2013. Equal blended semi-annual payments of principal and interest on the Bonds will commence on December 16, 2013 and will continue until and including June 16, 2023. The Bonds will not be fully amortized by their maturity date. The remaining principal balance of the Bonds will be fully due on June 16, 2023.

	2008	**2007**
Trans Senior Bonds	**$ 120,000**	**$ -**
First Mortgage Bonds	**-**	**115,750**
Less: Unamortized deferred financing fees	**(921)**	**(961)**
	$ 119,079	**$114,789**

7. EFFECT OF RATE REGULATION

The Partnership recorded the following regulatory assets and liability as at December 31:

		2008		2007
Regulatory assets:				
Deferred loss on disposal of transmission assets	**$**	**1,649**	$	3,299
Wholesale metering services rebates		**465**		465
Reorganization costs relating to the transfer of assets		**3,562**		647
Other regulatory assets		**17**		-
Less: current portion		**(1,649)**		(1,649)
Long-term portion	**$**	**4,044**	$	2,762
Regulatory liability:				
Deferred rate impact accrual	**$**	**2,512**	$	2,391

The Partnership operates in accordance with the regulations of the OEB. Regulatory assets and liabilities represent certain revenues earned or costs incurred in the current year or in prior years that have been or are expected to be recovered from customers upon approval from the OEB. In the absence of rate regulation, these balances would have been recorded as revenues or expenses in the statement of income and comprehensive income.

Deferred loss on disposal of transmission assets

As prescribed by regulatory order, gains or losses on disposals of assets are recorded as a regulatory asset or liability subject to approval by the OEB. For the year ended December 31, 2005, GLPLTD incurred a loss on disposal of transmission assets of $8,246. This regulatory asset is recovered over a period of five years, which commenced on April 1, 2005, through rate increases. During 2008, the Partnership recovered $1,649 (2007 - $1,649) of the deferred loss. As the deferred loss on disposal of transmission assets has been approved by the OEB for recovery, there is no risk of non-collection of this balance.

Wholesale metering services rebates

As prescribed by regulatory order, the rebates related to metering services are recorded as a regulatory asset. The Partnership is responsible for paying the rebates and recording them in a regulatory asset deferral account. As wholesale metering services rebates have been approved by the OEB for recovery, there is no risk of non-collection of this balance. The Partnership will include its request to recover this amount in its next rate application filing to the OEB.

Reorganization costs relating to the transfer of assets

These reorganization costs were the result of the transfer of the Partnership's assets from GLPL to the Partnership. Legislation through the Ontario Electricity Act requires the separation of transmission assets from generation assets; however, GLPL had an exemption to operate its transmission, distribution, and generation business within the same company until December 31, 2008. The costs associated with the transfer of the Partnership's assets were capitalized as regulatory assets as they are eligible for recovery through future rates, subject to OEB approval.

The Partnership will include its request to recover this amount in its next rate application filing to the OEB.

Other regulatory assets

The Partnership incurred costs related to a study undertaken as a result of the settlement agreed upon in the last transmission rate application. As approved by the OEB, these costs have been deferred and will be recovered at a later date, and there is no risk of non-collection of this balance. The Partnership will include its request to recover this amount in its next rate application filing to the OEB.

Deferred rate impact accrual

The deferred rate impact accrual ("DRIA") was for revenues being recovered through the 2005 rate application filed with the OEB. On November 1, 2007, the OEB implemented a new uniform transmission rate as a result of the rate application filed by Hydro One Networks Inc. This resulted in the termination of the over recovery of the DRIA. At December 31, 2008, the DRIA balance of $2,512 is payable to the Ontario transmission rate-payers. At December 31, 2007, the DRIA had a payable balance of $2,391.

8. STATEMENT OF CASH FLOWS

	2008	2007
Accounts receivable	$ 165	$ 312
Reorganization costs relating to the transfer of assets	(2,915)	(647)
Wholesale metering services rebate	-	(465)
Due to related parties	1,493	(5,586)
Accounts and other payables	(5,208)	2,834
Regulatory liability	121	2,391
Taxes payable	739	(3,407)
	$ (5,605)	**$ (4,568)**

Capital asset additions totaling $1,602 have been excluded from the Statement of Cash Flows as they remain unpaid at year end. During 2008, capital asset additions totaling $6,466 have been included in the Statement of Cash Flows as they were accrued at December 31, 2007 and paid in 2008.

9. INTEREST AND FINANCING FEES

The net interest and financing fees recorded in the financial statements at December 31 are comprised as follows:

	2008	2007
Interest expense incurred	$ 8,045	$ 7,660
Amortization of deferred financing fees	40	37
Other interest	46	-
Capitalized interest	(344)	(300)
	$ 7,787	**$ 7,397**

10. INCOME TAXES

The provision for income taxes in the statement of income and comprehensive income represents the income taxes payable for the period from January 1, 2008 to March 12, 2008, while the ownership and operation of the transmission assets was the responsibility of GLPL. The provision for income taxes in the statement of income and comprehensive income represents an effective tax rate different than the Canadian statutory rate of 33.50% (2007 – 36.12%). The differences are as follows:

		Mar 12, 2008		2007
Net income before income taxes	**$**	**2,683**	$	14,080
Computed income tax expense at Canadian statutory rate		**899**		5,086
Decrease resulting from:				
Impact of future rate change on future income tax liability		**(42)**		(2,607)
Other		**-**		104
Income tax provision	**$**	**857**	$	2,583

		2008		2007
Future income tax liabilities				
CCA in excess of book depreciation	**$**	**-**	$	19,099
Other		**-**		240
	$	**-**	$	19,339

The Partnership does not record a future income tax liability as it is not subject to income taxation as a result of its formation as a limited partnership. The 2007 comparative of $19,339 is the future income tax recorded by GLPLTD.

11. PARTNERSHIP UNITS

The Partnership is authorized to issue an unlimited number of Class A and Class B partnership units, of which 19,898 Class A units and 1 Class B unit were issued and outstanding as at December 31, 2008. There has been no change in the number of units issued during 2008 and the value of these units is nominal.

12. CONTRIBUTED SURPLUS

As part of the purchase and sale agreement between GLPL and the Partnership (discussed in note 1) certain assets and liabilities were excluded from the transfer. As a result, the Partnership has recorded the following adjustments to remove these amounts and has credited them to contributed surplus:

	March 12, 2008
Taxes payable	$ 1,848
Future income tax liability	19,442
PST receivable	(500)
	$ 20,790

In addition a contribution of $485k was made by BIP and has been included in contributed surplus.

	March 12, 2008
Assets and liabilities not transferred to the Partnership	$ 20,790
Contribution of capital by Brookfield Infrastructure Partners LP	485
	$ 21,275

13. FUTURE ACCOUNTING POLICY CHANGES

Goodwill and Intangible Assets – Handbook Section 3064

In February 2008, the CICA issued Handbook Section 3064, Goodwill and Intangible Assets, replacing Handbook Sections 3062, Goodwill and Other Intangible Assets and 3450, Research and Development Costs. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangibles by profit-oriented enterprises. The new section will be applicable to the Partnership's financial statements beginning January 1, 2009. The Partnership is currently evaluating the impact of this pronouncement on its financial statements.

Rate Regulated Enterprises

During 2007, the Accounting Standards Board ("AcSB") issued an exposure draft proposing to remove all specific references to rate regulated accounting from the CICA Handbook. In August 2007, the AcSB decided to remove a temporary exemption in CICA Handbook Section 1100 "Generally Accepted Accounting Principles", retain existing references to rate regulated accounting in the CICA Handbook, amend CICA Handbook Section 3465 "Income Taxes" to require the recognition of future income tax liabilities and assets as well as a corresponding regulatory asset or liability, and retain existing requirements to disclose the effects of rate regulation per AcG-19. The new rules will apply retrospectively to annual financial statements relating to fiscal years beginning on or after January 1, 2009.

As explained in note 3, the Partnership is not subject to income taxation and as a result these changes are not expected to have an impact on the Partnership.

14. CAPITAL MANAGEMENT

On January 1, 2008, the Partnership adopted CICA Handbook Section 1535, Capital Disclosures. This section requires disclosure of the Partnership's objectives, policies and processes for managing capital, the quantitative data about what the Partnership regards as capital, whether any capital requirements have been met, and if not, the consequences of such non-compliance.

The Partnership's primary capital management objective is to ensure the sustainability of its capital to support continuing operations, meet its financial obligations, allow for growth opportunities and provide stable dividends to its partners. The Partnership manages its capital to maintain an investment grade credit rating while providing its ultimate parent with a prudent use of leverage to enhance returns and ensure access to incremental borrowings needed to fund new growth initiatives.

The Partnership manages its capital structure in accordance with changes in economic conditions. Generally, developments are funded with external borrowings. In order to adjust the capital structure, the Partnership may elect to adjust the dividend amount paid to its partners, increase or reduce the equity participation in new and existing operations, adjust the level of capital spending or issue new partnership units.

The Partnership manages its capital in order to maintain a debt to capitalization ratio below 75%. As at December 31, 2008, the ratio was 55% (2007 – 60%). The table below presents the detail of the Partnership's capitalization and the calculation of the ratio:

thousands of CDN dollars		**2008**		2007
Debt				
Trans Senior Bonds	**$**	**120,000**	$	115,750
		120,000		115,750
Partners' equity		**98,851**		76,409
Total capitalization	**$**	**218,851**	$	192,159
Debt to capitalization		**55%**		60%

The change in debt to capitalization ratio during the year ended December 31, 2008 is linked to the increase in the Partners' equity in relation to contributed surplus adjustments (see note 12).

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

On January 1, 2008, the Partnership adopted CICA Handbook Sections 3862 and 3863, Financial Instruments – Disclosures and Presentation. These sections replace section 3861 Financial Instruments – Disclosure and Presentation and place an increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how those risks are managed.

The Partnership classifies its financial assets and liabilities as outlined below:

Cash is designated as a financial asset held-for-trading and is measured at fair value through net income at each period end.

Accounts receivable as well as due from related parties are classified as loans and receivables, accounts and other payables, due to related parties, and Trans Senior Bonds are classified as other financial liabilities, and each are measured at fair value at inception and, except for certain related party transactions, are subsequently measured at amortized cost using the effective interest method.

The carrying value approximates fair value for the Partnership's financial assets and liabilities, with the exception of long-term debt.

The Partnership has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk. The Partnership's management is responsible for determining the acceptable level of risk.

Market Risk

Market risk is the risk that the fair value of future cash flows of financial assets or liabilities will fluctuate due to movements in market prices.

Interest Rates:
The Partnership's long-term debt is subject to a fixed interest rate of 6.6%, payable semi-annually on June 16 and December 16. As a result of having fixed rate debt, fluctuations in market interest rates are not expected to materially affect the Partnership's cash flows.

Credit Risk

Credit risk arises from the potential for a counterparty to default on its contractual obligations and is limited to those contracts where the Partnership would incur a loss in replacing the defaulted transaction. The Partnership's financial instruments that are potentially exposed to credit risks are accounts receivable. The Partnership actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and continually monitors these exposures.

The vast majority of accounts receivable transactions entered by the Partnership are with the Independent Electricity System Operator ("IESO"). The IESO operates the provincial transmission system, and is a reliable counterparty. The quality of the Partnership's counterparties mitigates the Partnership's exposure to credit risk.

Liquidity Risk

Liquidity risk is the risk the Partnership cannot meet a demand for cash or fund an obligation when due. Liquidity risk is mitigated by the Partnership's cash and cash equivalent balances and through the use and management of amounts due from related parties. The Partnership is subject to risk associated with debt financing, including the ability to refinance its debt at maturity. This risk is mitigated by the long-term duration of the Partnership's debt secured by high quality assets.

16. COMMITMENTS, CONTINGENCIES AND GUARANTEES

In the normal course of operations, the Partnership executes agreements that provide for indemnification and guarantees to third parties in transactions such as debt issuances. The nature of substantially all of the indemnification undertakings prevents the Partnership from making a reasonable estimate of the maximum potential amount the Partnership could be required to pay third parties as the agreements do not specify a maximum amount and the amounts are dependent upon the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time. Historically, the Partnership has not made significant payments under such indemnification agreements.

On behalf of the Partnership, BRPI obtained a letter of credit totalling $3,960 to cover six months of interest payments on the Trans Senior Bonds. No amount has been drawn against this letter of credit.

In the normal course of operations, the Partnership has committed as at December 31, 2008 to spend approximately $1,602 (2007 - $6,466) on capital projects in future years.

The Partnership may, from time to time, be involved in legal proceedings, claims, and litigation that arise in the ordinary course of business which the Partnership believes would not reasonably be expected to have a material adverse effect on the financial condition of the Partnership.

There are no specified decommissioning costs relating to the Ontario transmission assets. The Partnership has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to optimum industry standards. Replacement of the assets occurs in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which we would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

Exhibit 1, Tab 3, Schedule 2

Pro Forma Financial Statements (2009-2010)

PRO-FORMA FINANCIAL STATEMENTS – 2009 & 2010

GLPT's pro forma financial statements for 2009 and 2010 are provided in **Appendix "A"**.

APPENDIX "A"

Pro Forma Financial Statements for 2009 -2010

Pro-Forma Financial Statements

GREAT LAKES POWER TRANSMISSION LP

For the years ended December 31

GREAT LAKES POWER TRANSMISSION LP
PRO-FORMA BALANCE SHEET
As at December 31

thousands of CDN dollars		**2010**		**2009**
Assets				
Current assets				
Cash	$	851	$	644
Accounts receivable		3,000		2,877
Prepaid expenses and other		150		150
		4,001		3,671
Regulatory asset		25		871
Property, plant and equipment		224,396		215,087
	$	228,422	$	219,629
Liabilities and Capital Account				
Current liabilities				
Accounts and other payables	$	1,375	$	1,375
Regulatory liability		1,975		3,827
		3,350		5,202
First mortgage bonds		117,208		117,078
Intercompany loan		9,000		-
		129,558		122,280
Capital account		98,864		97,348
	$	228,422	$	219,629

GREAT LAKES POWER TRANSMISSION LP
PRO-FORMA STATEMENT OF PARTNERS' EQUITY
Years ended December 31

thousands of CDN dollars		**2010**		**2009**
Partners' equity, beginning of year	**$**	**97,348**	**$**	**98,851**
Allocation of net income		**12,515**		**6,997**
Distributions		**(11,000)**		**(8,500)**
Partners' equity, end of year	**$**	**98,864**	**$**	**97,348**

GREAT LAKES POWER TRANSMISSION LP
PRO-FORMA STATEMENT OF INCOME
Years ended December 31

thousands of CDN dollars	2010	2009
Revenues	$ 39,358	$ 31,958
Expenses		
Operating and administrative	8,488	6,498
Maintenance	2,811	1,685
Taxes, other than income taxes	125	108
	11,424	8,291
	27,934	23,667
Interest	7,982	8,099
Depreciation	7,444	6,974
Loss (gain) on disposal of property, plant and equipment	-	1,649
Other income, net	(7)	(52)
Net income before income taxes	12,515	6,997
Income taxes - current	-	-
Income taxes - future	-	-
Net income and comprehensive income	$ 12,515	$ 6,997

GREAT LAKES POWER TRANSMISSION LP
PRO-FORMA STATEMENT OF CASH FLOWS
Years ended December 31

thousands of CDN dollars	2010	2009
Operating activities		
Net income (loss)	$ 12,515	$ 6,997
Items not affecting cash		
Depreciation	7,444	6,974
Amortization of prepaid expenses	-	(150)
Non-cash interest expense	130	121
Loss (gain) on disposal of property, plant and equipment	-	1,649
Net change in non-cash working capital and other	(1,129)	3,415
	18,960	19,007
Investing activities		
Additions to property, plant and equipment	(16,753)	(9,731)
	(16,753)	(9,731)
Financing activities		
Distributions paid	(11,000)	(8,500)
Deferred financing fees	-	(2,122)
Increase in borrowings	9,000	-
	(2,000)	(10,622)
Increase (decrease) in cash	207	(1,346)
Cash, beginning of year	644	1,990
Cash, end of year	$ 851	$ 644

Exhibit 1, Tab 3, Schedule 3

Reconciliation

RECONCILIATION OF OM&A TO FINANCIAL STATEMENTS

GLPT has provided *Table 1-3-3 A* which reconciles the total operating, maintenance and administrative ("OM&A") expenses from GLPT's historical actual and pro-forma financial statements to the total OM&A expenses provided in Exhibit 4 of this application. The 'Total OM&A per Financial Statements' line in *Table 1-3-3 A* is equal to the 'Operating and administration' line plus the 'Maintenance' line in GLPT's Statement of Income and Comprehensive Income in GLPT's financial statements.

Table 1-3-3 A – Reconciliation of OM&A to Financial Statements

($000's)	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Total OM&A per Financial Statements	**$5,752.0**	**$5,894.0**	**$7,330.0**	**$8,183.0**	**$11,299.0**
Reconciling Items:					
Net revenue - merchandising & jobbing	42.6	(27.1)	(0.1)	-	-
Accrual adjustment	-	400.0	-	-	-
Donations	-	(45.0)	-	(60.0)	(60.0)
First Nations PILs Tax	(133.1)	(133.2)	(129.0)	(129.0)	(133.0)
Other (rounding)	(0.4)	0.8	1.0	0.1	(0.4)
Adjusted OM&A per Financial Statements	**$5,661.1**	**$6,089.6**	**$7,201.9**	**$7,994.1**	**$11,105.6**
Total OM&A per Table 4-2-1 A	**$5,661.1**	**$6,089.6**	**$7,201.9**	**$7,994.1**	**$11,105.6**

The reconciling items reflected in the table are described below:

Net revenue – merchandising & jobbing is the net of GLPT's merchandising and jobbing revenue and expenses. In GLPT's financial statements, they are included in OM&A. In this application, these costs and revenues are described in Other Revenue at Exhibit 3, Tab 1, Schedule 2.

Accrual adjustment is related to an adjustment arising from GLPT's audited financial statements in 2007. The amount in *Table 1-3-3 A* reflects a reduction made to GLPT's OM&A in the preparation of the 2007 audited financial statements, which arose as a result of an over-accrual of a prior period expense. If GLPT were to consider this adjustment in the 2007 OM&A in this application, the total OM&A would not be reflective of the actual operations of 2007. Because this adjustment was not related to actual 2007 operations, it was removed from GLPT's operating costs in Exhibit 4, Tab 1, Schedule 1, and throughout the application.

Donations are included in GLPT's OM&A per financial statements, but are not included in the OM&A GLPT is seeking in this application.

First Nations PILs Tax is related to GLPT's payments made in lieu of taxes to First Nations. In GLPT's financial statements, these costs are reflected in OM&A, however GLPT is seeking to recover these costs in Exhibit 4, Tab 3, Schedule 4 – property taxes.

Exhibit 1, Tab 3, Schedule 4

Rating Report

<u>RATING REPORT</u>

A copy of a Private Rating Report for Great Lakes Power Transmission LP, prepared by Dominion Bond Rating Service (DBRS) and dated June 8, 2009, is provided in **Appendix "A"**.

<u>APPENDIX "A"</u>

Private Rating Report for GLPT

Private Rating Report

Report Date:
June 8, 2009

Previous Report:
March 12, 2008

Insight beyond the rating.

Great Lakes Power Transmission LP

Analysts

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The Company

GLPT is a single purpose subsidiary of Brookfield Infrastructure Partners (BIP) established in 2008 to purchase the transmission assets of Great Lakes Power Limited (GLPL) and assume $120 million of GLPL's senior secured bonds associated with the assets.

Private Rating

Debt	Private Rating	Rating Action	Trend
Trans Senior Bonds	A	Confirmed	Stable

Rating Update

DBRS has confirmed the private rating on the $120 million of Trans Senior Bonds (the Bonds) of Great Lakes Power Transmission LP (GLPT or the Company) at "A" with a Stable trend. The rating confirmation reflects the strength of GLPT's regulated transmission assets and operations in northern Ontario, and the cost-of-service-based rate framework which provides relatively stable and predictable cash flow.

For the 12-month period ended on March 31, 2009, revenues and EBITDA were close to $35 million and $27 million, respectively. Substantial reinforcement and enhancement programs in recent years increased the rate base and extended asset life. Revenues and EBITDA are expected to remain reasonably stable in the medium term. After 2013, declines are likely as depreciation expense exceeds capital expenditures, thereby slowly reducing the rate base (and assuming no major capital programs). GLPT's capital structure is regulated, with a deemed equity component of 45%, which is favourable compared with its Canadian peers. The credit metrics are viewed as strong given the low level of business risk, with EBITDA-to-interest at 3.5 times, and cash flow-to-debt ratio at 15%. DBRS expects GLPT to manage its distributions in order to maintain its regulatory-approved capital structure.

Due to the regulated nature of GLPT's business, the rating would be affected by changes in regulation. Unfavourable developments in laws or regulations relevant to GLPT or negative results in future rate cases could have a material impact on the Company. DBRS believes this risk is low, however, given the minimal change in transmission-related regulations in Ontario since the breakup of generation, transmission and distribution functions of the government-owned utilities. The refinancing risk is sufficiently mitigated by the long life and low-risk nature of GLPT's transmission assets and operations.

Rating Considerations

Strengths

(1) Stable earnings from regulated rates
(2) Reliable and long-life assets with good operating history and recently completed system reinforcement and upgrades
(3) Six-month debt service reserve

Challenges

(1) Regulatory risk
(2) Refinancing risk with only partial amortization in later years and a balloon payment at maturity
(3) Approved ROEs sensitive to interest rates

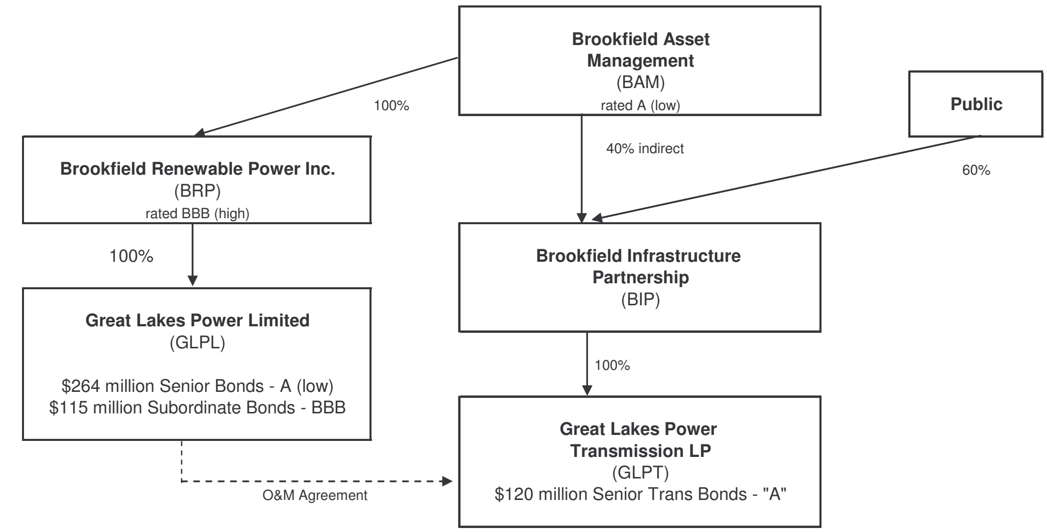
Summary Financial Information

	Years ended December 31				LTM ended March 31
	2005*	2006R*	2007*	2008	2009
Revenues	28.9	34.7	35.6	35.1	34.7
EBITDA	22.9	28.5	29.2	27.7	26.9
Operating cash flow	11.5	15.8	16.8	19.1	18.5
Cash flow/total debt	10%	14%	15%	16%	15%
Cash flow/capex	0.26x	0.81x	0.93x	1.41x	1.32x
EBITDA interest coverage	3.76x	3.72x	3.82x	3.56x	3.46x
Debt/EBITDA	5.06x	4.07x	3.97x	4.34x	4.46x
Debt service coverage	2.09x	2.43x	2.57x	2.84x	2.76x
Total debt in capital structure	68.5%	64.1%	60.2%	57.1%	57.5%

** Based on the statements of the transmission division of GLPL.*

Note: table may not add up due to rounding effects.

Simplified Organizational Chart



GLPT's Bonds have covenants and security similar to Great Lakes Power Limited (GLPL)'s Senior Bonds, including:

- Six-month debt service reserve in an account under the trustee's name for the benefit of the bondholders;
- Distribution test: trailing and forward-looking 12-month EBITDA-to-debt service ratio no lower than 1.5 times;
- Debt incurrence test: trailing 12-month EBITDA-to-pro forma interest no lower than 3.0 times; no rating change to the existing rating; a minimum rating of BBB; new bonds to have the same maturity date and amortize no sooner than existing bonds.

DBRS notes that, although the Trans Senior Bonds do not have a capex reserve requirement, the new feature is reflective of intensive capex program that was completed in the past several years and the generally low capex requirements going forward.

GLPT has a management, operations and maintenance agreement with GLPL under which GLPL will provide management, O&M, and planning and budgeting services for GLPT at arms-length.

Great Lakes Power Transmission LP

Report Date:
June 8, 2009

Rating Considerations Details

Strengths

(1) Regulated transmission in Ontario generally has low business risk, with relatively predictable revenues and cash flow. GLPT's transmission operation is regulated by the Ontario Energy Board (OEB) and under the cost-of-service ratemaking methodology. Rates are set to recover prudently-incurred costs, including O&M, depreciation, taxes, cost of debt and a return on equity.

The transmission assets have: (a) an approved rate base of almost $200 million; (b) a regulated capital structure of 55/45 debt-to-equity; and (c) an approved return on equity at 8.62% (3.8% above a government long-bond yield) and cost of debt at 6.6%. The revenue requirement is received on a monthly basis from the Independent Electricity System Operator (IESO), a creation of the Province of Ontario which receives its powers through provincial regulation and legislation. GLPT's revenue requirement is added to that of the other transmission owners in Ontario (with Hydro One Inc. having the dominant position). GLPT revenue requirements account for approximately 2.9% of the province's total.

For major capital expenditures (i.e., for lines longer than two kilometres), OEB's pre-approval is sought through a Leave to Construct, which grants the approval to proceed with capital projects, with an expected capital cost. If actual costs exceed expected amounts, OEB approval is required to include the overages in rate base, with "prudency" usually the key determinant in this process.

(2) GLPT and its predecessor has been providing transmission service in its territory since 1916. The assets have been upgraded, replaced or re-enforced in cycles similar to what the Company carried out in recent years. Although revenues are not explicitly tied to performance, GLPT has been achieving good operating performance, which helps the Company maintain good standing with the regulators.

(3) The Bonds will have a debt service reserve equal to six months of interest. This liquidity protection is considered adequate, given the stable and predicable nature of GLPT's business and limited capex going forward.

Challenges

(1) Regulatory uncertainties are the main risk of GLPT's business. This risk factor is intertwined with other key risk factors such as unexpected increases in capital program costs. To the extent that the OEB deems capital cost overruns to be imprudent, GLPT would not be able to recover that portion of costs in rate base. This risk is relatively muted for the next five to ten years as the Company has completed a round of intensive capital improvements. Capital expenditures going forward will be mainly for routine maintenance and reinforcement. Annual costs are expected to be a manageable level of approximately $10 million in the near- to medium-term and level off to less than $10 million after 2013. The sustaining or maintenance type of capital programs normally have limited scope or risk of construction work, if any, and has more certainty in regulatory approval of full cost recovery. In addition, the Company has generally had a positive relationship with the regulators and has not had any significant difficulty in obtaining approval of its rate cases, either through pre-arranged negotiated settlements or through other regulatory processes. GLPT significantly increased its ratebase from 2003 to 2007, with no major regulatory issues on capital cost recovery.

On a broader base, although any unfavourable change in the rate framework and process and the general regulatory environment for electric transmission in Ontario could present uncertainty to GLPT's business, no significant changes are expected.

(2) The Bonds will be amortized per a 25-year mortgage-style schedule (or $10 million equal annual payments after 2013) and will have a balloon payment (79% of original amount) due at maturity in 2023. The refinancing risk is mitigated by the long-lived, regulated and stable nature of GLPT's assets and operations. The Bonds outstanding at maturity are expected to be less than 60% of GLPT's then-current rate base and around 4.0 times projected EBITDA, which are viewed as financeable metrics, given the steady, low-risk cash flow stream of GLPT's regulated transmission business.

Great Lakes Power Transmission LP

Report Date:
June 8, 2009

(3) Regulatory-approved ROE levels are low and could continue to trend downwards if long-term interest rates decline. The after-tax ROE under the current rate order is 8.62%, reflecting a 380 basis point (bps) risk premium above long-term government bond yields.

Financial Profile

(CAD million)	For years ended December 31				LTM March 31
	2005*	2006R*	2007*	2008	2009
Transmission revenues	28.9	34.7	35.6	35.1	34.7
Operating costs	6.0	6.2	6.4	7.4	7.8
EBITDA	22.9	28.5	29.2	27.7	26.9
Depreciation	4.4	5.5	6.1	6.5	6.6
EBIT	18.4	22.9	23.1	21.1	20.3
Gross interest on senior debt	6.1	7.6	7.6	7.8	7.8
Capitalized interest	-	-	-	-	-
Earnings before tax	12.4	15.3	15.4	13.3	12.5
Current income tax	5.3	5.1	4.8	0.8	0.6
Future income tax	(0.0)	(1.7)	(2.2)	0.1	0.2
Net income (before extras)	7.0	11.9	12.8	12.5	11.7
Estimated operating cash flow	11.5	15.8	16.8	19.1	18.5
Interest on senior debt	6.1	7.6	7.6	7.8	7.8
Cash available for debt service and capex	17.5	23.4	24.4	26.9	26.3
Maintenance capital expenditures	*4.8*	*4.8*	*4.8*	*4.8*	*4.8*
Enhancement capital expenditure	39.3	14.5	13.2	8.7	9.2
Total capital expenditure	44.1	19.3	18.0	13.5	14.0
Free cash flow	(32.6)	(3.6)	(1.2)	5.6	4.5
YE principal outstanding	116	116	116	120	120
EBITDA interest coverage	3.76 x	3.72 x	3.82 x	3.56 x	3.46 x
EBITDA interest Coverage (after maintenance capex)	2.97 x	3.10 x	3.19 x	2.94 x	2.84 x
Debt service coverage ratio (before maintenance capex)	2.88 x	3.06 x	3.20 x	3.46 x	3.38 x
Debt service coverage ratio (after maintenance capex)	2.09 x	2.43 x	2.57 x	2.84 x	2.76 x
Cash flow/debt	10%	14%	15%	16%	15%
Debt/capital	69%	64%	60%	57%	57%
Est. Rate Base	140	196	197	197	200

** Based on the statements of the transmission division of GLPL.*
Note: Table may not add up due to rounding.

Summary

- EBITDA and earnings have remained relatively stable since completion of the reinforcement and upgrade program and the increase in rate base.
- Income tax was lower for 2008 due to the establishment of GLPT, a non-taxable limited partnership, at the time of the asset sale and transfer in March 2008.
- Enhancement capex has eased to more normalized levels in 2008.
- Key credit metrics continued to be strong, given the low level of business risk, and acceptable for the assigned "A" rating, with EBITDA-to-interest of 3.5x, cash flow-to-debt of 15%, and debt-to-capital of 60%.

Outlook

- The capital programs completed in 2005 have set up a very solid foundation for operations in the next ten to twenty years. Capital expenditures for the next few years, although slightly higher than the 20-year average, will be manageable and primarily maintenance related. DBRS expects the maintenance capex to be funded with internal cash flow.
- Revenues will be consistent with the rate base, staying above $30 million for the next few years and declining gradually over time, as depreciation exceeds capital spending and asset addition.

- The Bonds will begin to partially amortize in 2013 (25-year mortgage-style), reflecting the rate base and revenue profiles. DBRS expects GLPT to manage distribution levels in order to maintain the capital structure within regulatory approved levels.
- Liquidity is viewed as adequate, with stable regulated cash flows and limited capital expenditures. The $4 million debt service reserve provides further protection against unexpected cash flow shortfalls.

Description of Operations

- GLPT's assets are located along the eastern shore of Lake Superior, north of Sault Ste. Marie, Ontario.
- The assets consist of 14 transmission stations, 725 kilometres of high- and medium-voltage transmission lines, and related infrastructure, covering an area of 12,000 square kilometres in the Algoma region of Ontario.
- The asset network is interconnected with five industrial customers and two local distribution companies as well as to the rest of the Ontario power grid at Wawa and Mississagi, Ontario, east of Sault Ste. Marie.
- Based on instructions received from the IESO, GLPT switches and controls its transmission equipment remotely through a supervisory control and data acquisition (SCADA) centre located in the city of Sault Ste. Marie.
- Transmission in Ontario is regulated by the OEB, and rates are designed to recover allowed costs, including debt financing, and earn a specified rate of return on equity.
- Under current regulation, GLPT's transmission assets have:
  - An approved rate base of $197 million;
  - A regulated capital structure of 55/45 debt-to-equity;
  - An approved return on equity of 8.62% and debt interest rate of 6.6%.
- Transmission assets earn a guaranteed perpetual payment stream regardless of utilization.
- Maintenance capital expenditures, on a levelized basis, are expected to be less than $10 million annually for transmission.
- GLPT has a management, operations and maintenance agreement with GLPL under which GLPL will provide management, O&M, and planning and budgeting services for GLPT.

Summary Balance Sheet

(CAD millions)	Dec. 31		Mar. 31		Dec. 31		Mar. 31
Assets	2007	2008R*	2009	**Liabilities & Equity**	2007	2008R*	2009
Cash + equivalents	3.4	2.0	4.4	Accounts payable & accruals	10.6	0.3	2.3
Int. & accounts rec.	3.2	3.0	2.9	Due to related parties	0.6	2.1	1.1
Due from related parties	3.7	-	-	Others	3.5	4.1	5.0
Prepaid expenses & others	1.8	1.6	1.2	**Current liabilities**	14.7	6.5	8.3
Current Assets	12.1	6.7	8.5	Senior secured bonds	-	-	-
Due from related parties	-	-	-	Subordinate secured bonds	114.8	119.1	119.1
Regulatory asset	2.8	4.0	4.1	Future income tax liability	19.3	7.1	7.3
Net fixed assets	210.3	212.3	210.9	Capital account	76.4	90.3	88.7
Total	225.2	223.0	223.5	**Total**	225.2	223.0	223.5

*As shown in the Q1 2009 financial statements.

Note: table may not add up due to rounding effects.

Great Lakes Power Transmission LP

Report Date:
June 8, 2009

Private Rating

Debt	Rating	Rating Action	Trend
Trans Senior Bonds	A	Confirmed	Stable

Rating History

	Current	2008
Trans Senior Bonds	A	A

Note:
All figures are in Canadian dollars unless otherwise noted.

Exhibit 1, Tab 3, Schedule 5

BIP 2008 Annual Report

As filed with the Securities and Exchange Commission on April 30, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington D.C. 20549

FORM 20-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12(b) OR 12(g) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the fiscal year ended December 31, 2008

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☐ **SHELL COMPANY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number 001-33632

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.

(Exact name of Registrant as specified in its charter)

Bermuda

(Jurisdiction of incorporation or organization)

Cannon's Court
22 Victoria Street,
Hamilton, HM 12, Bermuda

(Address of principal executive offices)

Securities registered pursuant to Section 12(b) of the Act:

(Name, Telephone, E-mail and/or Facsimile number and Address of Company Contact Person)

Title of class	Name of each exchange on which registered
Limited Partnership Units	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

22,486,269 Limited Partnership Units as of April 24, 2009

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☐ **No** ☒

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.

Yes ☐ **No** ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ **No** ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer ☐ **Accelerated filer** ☐ **Non-accelerated filer** ☒

Indicate by check mark which basis of accounting the registrant has used to prepare the financial statements included in this filing:

☒ **U.S. GAAP** ☐ **International Financial Reporting Standards as issued by the International Accounting Standards Board** ☐ **Other**

If "Other" has been checked in response to the previous question indicate by check mark which financial statement item the registrant has elected to follow.

Item 17 ☐ **Item 18** ☐

If this is an annual report, indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐ **No** ☒

INTRODUCTION AND USE OF CERTAIN TERMS

Unless the context requires otherwise, when used in this annual report on Form 20-F, the terms "BIP", "we", "us" and "our" refer to Brookfield Infrastructure Partners L.P., Brookfield Infrastructure, the Holding Entities and the operating entities, each as defined below, taken together. In addition, unless the context suggests otherwise, references to:

- an "affiliate" of any person are to any other person that, directly or indirectly through one or more intermediaries, controls, is controlled by or is under common control with such person;
- "Brookfield" are to Brookfield Asset Management and any affiliate of Brookfield Asset Management, other than us;
- "Brookfield Asset Management" are to Brookfield Asset Management Inc.;
- "Brookfield Infrastructure" are to Brookfield Infrastructure L.P.;
- the "current operations" are to the businesses in which we hold an interest in as set out in Item 4.B "Business Overview";
- our "electricity transmission operations" refer to our interest in Transelec Chile S.A., or Transelec, our Chilean transmission operations, our investments in the Transmissoras Brasileiras de Energia companies, or TBE, our Brazilian transmission investments, which were transferred to us by Brookfield as described in Item 4.B "Business Overview—Current Operations—Electricity Transmission—Overview" and Great Lakes Power Transmission L.P., which holds our Ontario transmission operations as described in Item 4.B "Business Overview—Current Operations—Electricity Transmission—Overview";
- "Holding Entities" are to the subsidiaries of Brookfield Infrastructure, from time-to-time, through which it indirectly holds all of our interests in the operating entities;
- the "infrastructure division" are to the portion of Brookfield's infrastructure operations owned during the periods prior to November 27, 2007 that were contributed to us as part of the spin-off;
- the "Infrastructure General Partner" are to Brookfield Infrastructure General Partner Limited, which serves as the general partner of the Infrastructure GP LP;
- the "Infrastructure GP LP" are to Brookfield Infrastructure GP L.P., which serves as the general partner of Brookfield Infrastructure;
- "our limited partnership agreement" are to the amended and restated limited partnership agreement of our partnership;
- the "Manager" are to Brookfield Infrastructure Group Inc. and, unless the context otherwise requires, include any other affiliate of Brookfield that provides services to us pursuant to the Master Services Agreement or any other service agreement or arrangement;
- "our Managing General Partner" are to Brookfield Infrastructure Partners Limited, which serves as our partnership's general partner;
- "Master Services Agreement" are to the master management and administration agreement dated as of December 4, 2007, among the Service Recipients, Brookfield Infrastructure Group Inc. and certain other affiliates of Brookfield Asset Management who are party thereto;
- "operating entities" are to the entities which directly or indirectly hold our current operations and assets that we may acquire in the future, including any assets held through joint ventures, partnerships and consortium arrangements;
- "our partnership" are to Brookfield Infrastructure Partners L.P.;

- the “Redemption-Exchange Mechanism” are to the mechanism by which Brookfield may request redemption of its limited partnership interests in Brookfield Infrastructure in whole or in part in exchange for cash, subject to the right of our partnership to acquire such interests (in lieu of such redemption) in exchange for limited partnership units of our partnership, as more fully set forth in Item 10.B “Memorandum and Articles of Association—Description of Brookfield Infrastructure’s Limited Partnership Agreement—Redemption-Exchange Mechanism”;
- “Redemption-Exchange Unit” is a unit of Brookfield Infrastructure that has the rights of the Redemption-Exchange Mechanism. See Item 10.B “Memorandum and Articles of Association—Description of Brookfield Infrastructure’s Limited Partnership Agreement—Units”;
- “Service Recipients” are to our partnership, Brookfield Infrastructure and the Holding Entities;
- our “social infrastructure operations” are to our interest in the following Public Private Partnership or “PPP” projects: (i) Long Bay Forensic and Prison Hospitals, Australia, in which we hold a 50% interest; (ii) Peterborough Hospital, United Kingdom, in which we hold a 30% interest; and (iii) Royal Melbourne Showgrounds, Australia, in which we hold a 50% interest;
- “spin-off” are to the issuance of the special dividend by Brookfield Asset Management to its shareholders of 23,344,508 of our units on January 31, 2008;
- our “timber operations” are to our interest in Island Timberlands Limited Partnership, or Island Timberlands, our Canadian timber operations and our interest in Longview Timber Holdings, Corp., or Longview, our U.S. timber operations; and
- “our units” are to the limited partnership units in our partnership and references to “our unitholders” are to the holders of our units.

FORWARD-LOOKING STATEMENTS

This annual report on Form 20-F contains certain forward-looking statements. Forward-looking statements relate to expectations, beliefs, projections, future plans and strategies, anticipated events or trends and similar expressions concerning matters that are not historical facts. In some cases, you can identify forward-looking statements by terms such as "anticipate," "believe," "could," "estimate," "expect," "intend," "may," "plan," "potential," "should," "will" and "would" or the negative of those terms or other comparable terminology.

The forward-looking statements are based on our beliefs, assumptions and expectations of our future performance, taking into account all information currently available to us. These beliefs, assumptions and expectations can change as a result of many possible events or factors, not all of which are known to us or are within our control. If a change occurs, our business, financial condition, liquidity and results of operations may vary materially from those expressed in our forward looking statements. The following factors, among others, that could cause our actual results to vary from our forward looking statements:

- our partnership's limited separate operating history;
- our financial statements may not present our financial results in the most meaningful manner;
- our assets are or may become highly leveraged and we intend to incur indebtedness above the asset level;
- foreign currency risk and risk management activities;
- our partnership is not regulated as an investment company under the U.S. Investment Company Act;
- we are not subject to the same disclosure requirements as a U.S. domestic public company;
- we are exempt from certain requirements of Canadian securities laws;
- general economic conditions and government regulation;
- impact of recent global economic downturn;
- recent disruption in global credit and financial markets;
- exposure to uninsurable losses;
- contingent liabilities;
- labor disruptions and economically unfavorable collective bargaining agreements;
- the competitive market for acquisition opportunities;
- our ability to execute our growth strategy, including completion of acquisitions, and to achieve desired results from acquisitions;
- some of our current operations are held in the form of joint ventures or partnerships or through consortium arrangements;
- electricity transmission may require substantial capital expenditures;
- electricity transmission development projects may expose us to construction risks;
- electricity transmission clients may default on their obligations;
- changes in tolls or regulated rates for electricity transmission;
- potential adverse claims to lands used in our electricity transmission operations;
- weather conditions, industry practice and regulations associated with forestry may adversely affect our timber operations;
- the competitive business environment for our timber operations;

- aboriginal claims to lands may adversely affect our timber operations;
- Canadian export regulations applicable to timber;
- default by sub-contractors under our PPP contracts;
- change in government policy towards our social infrastructure operations;
- change in political attitudes towards PPP funding models of social infrastructure;
- operating cost overruns in relation to our PPP projects;
- higher than expected costs associated with our replacement or refurbishment obligations in connection with our PPP projects;
- exposure to construction risks associated with our PPP projects;
- changes in law requiring capital expenditures associated with our PPP projects;
- default by our public sector clients on their obligations under contractual arrangements associated with our PPP projects;
- Brookfield's influence over our partnership;
- the lack of an obligation of Brookfield to source acquisition opportunities for us;
- our dependence on Brookfield and its professionals;
- interests in our Managing General Partner may be transferred to a third party without unitholder consent;
- Brookfield may increase its ownership of our partnership;
- Brookfield does not owe our unitholders any fiduciary duties;
- conflicts of interest between our partnership and our unitholders, on the one hand, and Brookfield, on the other hand;
- our arrangements with Brookfield may contain terms that are less favorable than those which otherwise might have been obtained from unrelated parties;
- our Managing General Partner may be unable or unwilling to terminate the Master Services Agreement;
- the limited liability of, and our indemnification of, the Manager;
- changes in tax law and practice; and
- other factors described in this Form 20-F, including, but not limited to, those described under Item 3.D "Risk Factors" and elsewhere in this Form 20-F.

Except as required by applicable law, we undertake no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise. In light of these risks, uncertainties and assumptions, the events described by our forward-looking statements might not occur. We qualify any and all of our forward-looking statements by these cautionary factors. Please keep this cautionary note in mind as you read this Form 20-F.

PART I

ITEM 1. IDENTITY OF DIRECTORS, SENIOR MANAGEMENT AND ADVISERS

Not applicable.

ITEM 2. OFFER STATISTICS AND EXPECTED TIMETABLE

Not applicable.

ITEM 3. KEY INFORMATION

3.A SELECTED FINANCIAL DATA

Actual Basis

The following table presents financial data for Brookfield Infrastructure as of and for the periods indicated:

MILLIONS, UNAUDITED	For the Year Ended December 31, 2008	2007(1)	2006(1)
Income Statement Key Metrics			
Revenue	**$ 32.9**	$ 33.1	$30.7
Earnings (losses) from equity accounted investments	**25.2**	(7.8)	—
Dividend income	**14.3**	0.5	—
Interest expense	**(12.9)**	(6.9)	(5.8)
Net income	**28.0**	12.0	10.4

Balance Sheet Key Metrics	As of the Year Ended 2008	2007(1)
Total assets	**$1,174.3**	$1,157.9
Partnership capital	**899.9**	984.5
Corporate borrowings	**139.5**	—
Non-recourse borrowings	**97.6**	115.0

The following is non-GAAP financial information for Brookfield Infrastructure for the periods indicated:

MILLIONS, UNAUDITED	For the Year Ended December 31, 2008	2006	2005
Adjusted net operating income(1)	**$59.7**	$13.3	$15.1

(1) Adjusted net operating income is defined as net income adding back depreciation and amortization, deferred income taxes and a performance fee accrued, net of minority interest related to those items, which are either directly on the statement of income or are a component of the equity earnings of an underlying investee company. Adjusted net operating income is a measure of operating performance that is not calculated in accordance with U.S. GAAP. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Reconciliation of Non-GAAP Financial Measures" for a discussion of adjusted net operating income and its limitations as a measure of our operating performance. The following table presents a reconciliation of adjusted net operating income to net income:

MILLIONS, UNAUDITED	For the Year Ended December 31, 2008	2007	2006
Net income	**$ 28.0**	$12.0	$10.4
Add back or deduct the following:			
Depreciation, depletion and amortization	**54.3**	9.8	6.2
Deferred taxes	**(14.9)**	(8.4)	(1.5)
Performance fee	**(12.8)**	3.1	—
Unrealized loss on derivative instruments	**3.9**	—	—
Other non-cash items	**1.2**	(3.2)	—
Adjusted net operating income (ANOI)	**$ 59.7**	$13.3	$15.1

Pro Forma Basis

As our electricity transmission and timber operations were seeded into Brookfield Infrastructure on November 27, 2007, there are no meaningful GAAP financial comparatives. Accordingly, we also review our performance on a pro forma basis. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Reconciliation of Unaudited Pro Forma Financial Statements". The following table presents financial data for Brookfield Infrastructure on a pro forma basis as of and for the periods indicated:

	For the Year Ended December 31,		
MILLIONS, UNAUDITED	**2008**	**2007(1)**	**2006**
Income Statement Key Metrics			
Revenue	**$ 32.9**	$ 33.1	$ 30.7
Earnings (loss) from equity accounted investments	**25.9**	(9.5)	9.7
Dividend income	**14.3**	16.0	11.2
Interest expense	**(12.9)**	(12.5)	(11.3)
Net income	**27.9**	6.1	13.2

The following is non-GAAP financial information for Brookfield Infrastructure for the periods indicated:

	As of the Year Ended		
MILLIONS, UNAUDITED	**2008**	**2007**	**2006**
Adjusted net operating income(1)	**$ 63.3**	$ 52.2	$ 51.9

(1) Adjusted net operating income is defined as net income adding back depreciation and amortization, deferred income taxes and a performance fee accrued, net of minority interest related to those items, which are either directly on the statement of income or are a component of the equity earnings of an underlying investee company. Adjusted net operating income is a measure of operating performance that is not calculated in accordance with U.S. GAAP. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Reconciliation—Non-GAAP Financial Measures" for a discussion of adjusted net operating income and its limitations as a measure of our operating performance. The following table presents a reconciliation of adjusted net operating income to net income:

	For the Year Ended December 31,		
MILLIONS, UNAUDITED	**2008**	**2007**	**2006**
Net income	**$ 27.9**	$ 6.1	$13.2
Add back or deduct the following:			
Depreciation, depletion and amortization	**55.6**	47.7	28.7
Deferred taxes	**(15.6)**	(20.9)	(3.6)
Performance fee	**(12.8)**	3.1	15.0
Unrealized (gains) losses on derivative instruments	**6.9**	15.3	(1.4)
Other non-cash items	**1.3**	0.9	—
Adjusted net operating income (ANOI)	**$ 63.3**	$ 52.2	$51.9

3.B CAPITALIZATION AND INDEBTEDNESS

Not applicable.

3.C REASONS FOR THE OFFER AND USE OF PROCEEDS

Not applicable.

3.D RISK FACTORS

You should carefully consider the following factors in addition to the other information set forth in this Form 20-F. Additional risks and uncertainties that we do not presently know about or that we currently believe are immaterial may also adversely impact our business, financial condition, results of operations or the value of our unitholders' units. If any of the following risks actually occur, our business, financial condition and results of operations and the value of our unitholders' units would likely suffer.

Risks Relating to Us and Our Partnership

Our partnership is a recently formed partnership with limited separate operating history and the historical financial information included herein for periods prior to November 27, 2007 does not reflect the financial condition or operating results we would have achieved during the periods presented, and therefore may not be a reliable indicator of our future financial performance.

Our partnership was formed on May 21, 2007 and commenced its activities on November 27, 2007. Our limited operating history will make it difficult to assess our ability to operate profitably and make distributions to unitholders. Although most of our current operations have been under Brookfield's control prior to the formation of our partnership, their combined results have only recently been reported on a stand-alone basis and the historical financial statements included in this Form 20-F cover periods during which some of our current operations were not under Brookfield's control or management and, therefore, may not be indicative of our future financial condition or operating results. You should carefully consider the basis on which the historical financial information included herein was prepared and presented.

Our partnership's and Brookfield Infrastructure's financial statements may not present our partnership's financial results in the most meaningful manner.

Our partnership's sole material asset is its 60% limited partnership interest in Brookfield Infrastructure, which our partnership accounts for using equity accounting because our partnership does not control Brookfield Infrastructure; the general partner of which is controlled by Brookfield. Furthermore, as most of our current operations are accounted for using equity or cost accounting, Brookfield Infrastructure's financial statements do not include a detailed breakdown of the components of net income, cash flows or unitholders' equity for most of our current operations. The only operations that are currently consolidated into Brookfield Infrastructure's financial statements are our Ontario transmission operations. Although we provide certain income statement and balance sheet line items for our current operations on a segmented basis in a note to Brookfield Infrastructure's financial statements, such information does not include the level of detail and note discussion that would be provided if such operations were consolidated into our partnership's and Brookfield Infrastructure's financial statements. While separate audited financial statements for most of our current operations are included in this Form 20-F, our obligation to provide similar disclosure in the future will depend on the significance of each of the current operations at each year end relative to our overall assets and income. Accordingly, we may not continue to provide separate audited financial statements for each or any of our operations on an ongoing basis.

In addition, we do not expect to be able to provide investors with audited financial statements containing meaningful year-to-year comparisons of financial performance for several years because our partnership's results only reflect results for our current operations from and after the date we or, in some cases, Brookfield acquired them.

Our assets are or may become highly leveraged and we may incur indebtedness in addition to asset-level indebtedness under our new credit facility, which contains certain restrictive covenants, or otherwise.

Our operating entities have a significant degree of leverage on their assets, including acquisition-related leverage, which is not reflected in our partnership's historical financial statements. In addition, we may increase the leverage on our assets. Highly leveraged assets are inherently more sensitive to declines in revenues, increases in expenses and interest rates and adverse economic, market and industry developments. A leveraged company's income and net assets also tend to increase or decrease at a greater rate than would otherwise be the case if money had not been borrowed. As a result, the risk of loss associated with a leveraged company is generally greater than for companies with comparatively less debt. In addition, the use of indebtedness in connection with an acquisition may give rise to negative tax consequences to certain investors.

On a proportionate basis, the debt balance of all of our current operations was approximately $1,190 million as of December 31, 2008, with an annual debt service obligation of approximately $53 million. We may also incur indebtedness under one or more credit facilities, in addition to any asset-level indebtedness. On June 13, 2008, we entered into a $450 million senior secured credit facility which is available to fund acquisitions. For example, we may incur indebtedness under this credit facility in order to acquire an additional indirect interest in Longview in the event that Brookfield contributes its remaining interest in Longview to a timberlands focused partnership with institutional investors. We have made a commitment of up to $600 million to Brookfield to make such a purchase, subject to conditions, including a financing condition, described under Item 7.B "Related Party Transactions—Longview Purchase Agreement." Although we intend to complete any acquisition, including this indirect acquisition of Longview, with an appropriate mix of debt and equity financing for our capital structure, we may finance all or a portion of this or any other acquisition and other investments with debt.

The terms of our senior secured credit facility subjects us to financial and operating covenants which restrict our ability to engage in certain types of activities and make distributions in respect of equity. For example, the facility contains negative covenants that significantly restrict Brookfield Infrastructure including, among others, limitations on debt, liens, investments, mergers and operating activities, and restrictions from making any distributions on its equity unless immediately prior to, and after giving pro forma effect to, such distribution, no default has occurred and is continuing and Brookfield Infrastructure meets a minimum interest coverage ratio. If we fail to satisfy any debt service obligations under the facility or breach any financial or operating covenants thereunder, we will be prohibited from making any distributions until such breach is cured or the lenders could declare all advances outstanding under the senior secured credit facility to be immediately due and payable and could foreclose on our assets pledged as collateral.

We are subject to foreign currency risk and our risk management activities may adversely affect the performance of our operations.

Some of our current operations are in countries where the U.S. dollar is not the functional currency. These operations pay distributions in currencies other than the U.S. dollar which we must convert to U.S. dollars prior to making distributions and certain of our operations have revenues denominated in currencies different than our expense structure, thus exposing us to currency risk. Fluctuations in currency exchange rates could make it more expensive for our customers to purchase our services and consequently reduce the demand for our services. In addition, a significant depreciation in the value of such foreign currencies may have a material adverse effect on our results of operations and financial position.

When managing our exposure to such market risks, we may use forward contracts, options, swaps, caps, collars and floors or pursue other strategies or use other forms of derivative instruments. The success of any hedging or other derivative transactions that we enter into generally will depend on our ability to structure contracts that appropriately offset our risk position. As a result, while we may enter into such transactions in order to reduce our exposure to market risks, unanticipated market changes may result in poorer overall investment performance than if the transaction had not been executed. Such transactions may also limit the opportunity for gain if the value of a hedged position increases.

Our partnership is not, and does not intend to become, regulated as an investment company under the U.S. Investment Company Act (and similar legislation in other jurisdictions) and if our partnership was deemed an "investment company" under the U.S. Investment Company Act, applicable restrictions could make it impractical for us to operate as contemplated.

The U.S. Investment Company Act and the rules thereunder (and similar legislation in other jurisdictions) provide certain protections to investors and impose certain restrictions on companies that are registered as investment companies. Among other things, such rules limit or prohibit transactions with affiliates, impose limitations on the issuance of debt and equity securities and impose certain governance requirements. Our partnership has not been and does not intend to become regulated as an investment company and our partnership intends to conduct its activities so it will not be deemed to be an investment company under the U.S. Investment Company Act (and similar legislation in other jurisdictions). In order to ensure that we are not deemed to be an investment company, we may be required to materially restrict or limit the scope of our operations or plans, we will be limited in the types of acquisitions that we may make and we may need to modify our organizational structure or dispose of assets of which we would not otherwise dispose. Moreover, if anything were to happen which would potentially cause our partnership to be deemed an investment company under the U.S. Investment Company Act, it would be impractical for us to operate as intended. Agreements and arrangements between and among us and Brookfield would be impaired, the type and amount of acquisitions that we would be able to make as a principal would be limited and our business, financial condition and results of operations would be materially adversely affected. Accordingly, we would be required to take extraordinary steps to address the situation, such as the amendment or termination of the Master Services Agreement, restructuring our partnership and the Holding Entities, amendment of our limited partnership agreement or the termination of our partnership, any of which could materially adversely affect the value of our units. In addition, if our partnership were deemed to be an investment company under the U.S. Investment Company Act, it would be taxable as a corporation for U.S. federal income tax purposes, and such treatment could materially adversely affect the value of our units.

Our partnership is a "foreign private issuer" under U.S. securities laws and as a result is subject to disclosure obligations different from requirements applicable to U.S. domestic issuers listed on the NYSE.

Although our partnership is subject to the periodic reporting requirement of the U.S. Securities Exchange Act, as amended, or the Exchange Act, the periodic disclosure required of foreign private issuers under the Exchange Act is different from periodic disclosure required of U.S. domestic issuers. Therefore, there may be less publicly available information about our partnership than is regularly published by or about other public limited partnerships in the United States and our partnership is exempt from certain other sections of the Exchange Act that U.S. domestic issuers would otherwise be subject to, including the requirement to provide our unitholders with information statements or proxy statements that comply with the Exchange Act. In addition, insiders and large unitholders of our partnership are not obligated to file reports under Section 16 of the Exchange Act and certain of the governance rules imposed by the NYSE are inapplicable to our partnership.

Our partnership is an "SEC foreign issuer" under Canadian securities regulations and is exempt from certain requirements of Canadian securities laws.

Although our partnership is a reporting issuer in Canada, it is an "SEC foreign issuer" and is exempt from certain Canadian securities laws relating to continuous disclosure obligations and proxy solicitation if our partnership complies with certain reporting requirements applicable in the United States, provided that the relevant documents filed with the U.S. Securities and Exchange Commission, or the SEC, are filed in Canada and sent to our partnership's security holders in Canada to the extent and in the manner and within the time required by applicable U.S. requirements. Therefore, there may be less publicly available information in Canada about our partnership than would be available if we were a typical Canadian reporting issuer.

Risks Relating to Our Operations and the Infrastructure Industry

Risks Relating to Our Current Operations and Infrastructure Generally

All of our operating entities are subject to general economic conditions and government regulation.

All of our operating entities depend on the financial health of their customers who may be sensitive to the overall performance of the economy. Adverse local, regional or worldwide economic trends that affect each respective economy could have a material adverse effect on our financial condition and results of operations. Our financial condition and results of operations could also be affected by changes in economic or other government policies or other political or economic developments in each country or region, as well as regulatory changes or administrative practices over which we have no control such as: the regulatory environment related to our business operations and concession agreements; interest rates; currency fluctuations; exchange controls and restrictions; inflation; liquidity of domestic financial and capital markets; tax policies; and other political, social and economic developments that may occur in or affect the countries in which our operating entities operate or the countries in which the customers of our operating entities operate or both.

The recent unprecedented events in global financial markets have had a profound impact on the global economy and could have a material adverse effect on our business.

Many industries, including the industries in which we operate, are impacted by the recent unprecedented events in the global financial markets. Some of the key impacts of the current financial market turmoil include contraction in credit markets resulting in a widening of credit spreads, devaluations and high volatility in global equity, commodity and foreign exchange markets, and a general lack of market liquidity. A continued deterioration in the financial markets or other key measures of the global economy, including, but not limited to, new home construction, employment rates, business conditions, inflation, fuel and energy costs, lack of available credit, the state of the financial markets, interest rates and tax rates may adversely affect our growth and profitability. Specifically, the current global credit/liquidity crisis could materially impact the cost and availability of our financing and our overall liquidity; the volatility of commodity output prices and currency exchange markets could materially impact our revenues, profits and cash flow; volatile energy, commodity input and consumables prices and currency exchange rates could materially impact our production costs; and the devaluation and volatility of global stock markets could materially impact the valuation of our units. Any one of these factors could have a material adverse effect on our condition and results of operations.

Recent market events and conditions and the deterioration of general economic indicators have led to a loss of confidence in global credit and financial markets, restricted access to capital and credit, and increased counterparty risk. If this continues, our operations could be adversely impacted and the trading price of our units may be adversely affected.

Beginning in 2007, the U.S. credit markets began to experience and continue to experience serious disruption due in large part to a deterioration in residential property values, defaults and delinquencies in the residential mortgage market (particularly, sub-prime and non-prime mortgages) and a decline in the credit quality of mortgage backed securities. These conditions continued and worsened in 2008, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by the U.S. and foreign governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. In addition, general economic indicators have further deteriorated, resulting in declining consumer sentiment, increased unemployment and declining economic growth and uncertainty about corporate earnings. These unprecedented disruptions could, among other things, make it more difficult for us to obtain, or increase our cost of obtaining, capital and financing for our operations. Our access to additional capital may not be available on terms acceptable to us or at all. Failure to raise capital when needed or on reasonable terms may have a material adverse effect on our business, financial condition and results of operations. In addition, recent market events and conditions have significantly raised the risk of counterparty default. We are subject to counterparty risk and may be impacted in the event that a counterparty becomes insolvent. These factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. If such increased levels of volatility and market turmoil continue, our operations could be adversely impacted and the trading price of our units may be adversely affected.

We may be exposed to uninsurable losses.

The assets of infrastructure businesses are exposed to unplanned interruptions caused by significant catastrophic events such as floods, earthquakes, fires, major plant breakdowns, pipeline or electricity line ruptures or other disasters. Operational disruption, as well as supply disruption, could adversely affect the cash flows available from these assets. In addition, the cost of repairing or replacing damaged assets could be considerable. Repeated or prolonged interruption may result in a permanent loss of customers, substantial litigation or penalties or regulatory or contractual non-compliance. Moreover, any loss from such events may not be recoverable under relevant insurance policies.

Given the nature of the assets operated by our operating entities, we may be more exposed to risks in the insurance market that lead to limitations on coverage and/or increases in premium. For example, our timber operations are not insured against losses from fires and many components of our Chilean transmission operations are not insured against losses from earthquakes. Even if such insurance were available, the cost would be prohibitive. While not a risk borne directly by our partnership, the ability of the operating entities to obtain the required insurance coverage at a competitive price may have an impact on the returns generated by them and accordingly the returns received by our partnership.

The acquisition of our current operations may give rise to contingent liabilities and the integration of our current operations may not be successful.

Most of our current operations were recently acquired from third parties and have only been operated by us and Brookfield for a short period of time. We are subject to any contingent liabilities that are attached to our current operations, such as claims for failure to comply with government regulations or other past activities. Accordingly, there is risk regarding any undisclosed or unknown liabilities or issues concerning the current operations. The representations, warranties and indemnities of Brookfield to us in connection with our acquisition of the current operations are limited and for the most part do not protect us against these liabilities or guarantee the value of the current operations. Although the sellers of such operations made various representations to Brookfield in connection with the acquisitions, certain of the indemnification obligations are limited in duration and amount and may have already expired. In addition, even if we could make a claim against the seller of the interest for the amount that is required to be contributed, there can be no assurance that the seller would be willing or able to satisfy any claim that may be brought or that any claim would be successful. We also may not successfully integrate the business and operations of our current operations or realize any of the anticipated benefits of their acquisition and accordingly our results of operations and financial condition could be adversely affected.

Performance of our operating entities may be harmed by future labor disruptions and economically unfavorable collective bargaining agreements.

Several of our current operations have workforces that are unionized and, as a result, they are required to negotiate the wages, benefits and other terms with many of their employees collectively. If an operating entity were unable to negotiate acceptable contracts with any of its unions as existing agreements expire, it could experience a significant disruption of its operations, higher ongoing labor costs and restrictions of its ability to maximize the efficiency of its operations, which could have a material adverse effect on its operations and financial results.

Our operating entities may be exposed to higher levels of regulation than in other sectors and breaches of such regulations could expose our operating entities to claims for financial compensation and adverse regulatory consequences.

In many instances, ownership and operation of infrastructure assets involves an ongoing commitment to a governmental agency. The nature of these commitments exposes the owners of infrastructure assets to a higher level of regulatory control than typically imposed on other businesses. For example, our timber operations are subject to provincial, state and federal government regulations relating to forestry practices and the export of logs and our electricity transmission operations are subject to government regulation of their rates and revenues. The risk that a governmental agency will repeal, amend, enact or promulgate a new law or regulation or that a governmental authority will issue a new interpretation of the law or regulations, could affect our operating entities substantially.

In addition, our operating entities are subject to laws and regulations relating to pollution and the protection of the environment. They are also subject to laws and regulations governing health and safety matters, protecting both the public and their employees. Any breach of these obligations, or even incidents relating to the environment or health and safety that do not amount to a breach, could adversely affect the results of our operating entities and their reputations and expose them to claims for financial compensation or adverse regulatory consequences. There is also the risk that our operating entities do not have, or might not obtain, permits necessary for their operations. Permits or special rulings may be required on taxation, financial and regulatory related issues. Even though most permits and licences are obtained before the commencement of operations, many of these licences and permits have to be renewed or maintained over the life of the business.

We operate in a highly competitive market for acquisition opportunities.

Our acquisition strategy is dependent to a significant extent on the ability of Brookfield to identify acquisition opportunities that are suitable for us. We face competition for acquisitions primarily from investment funds, operating companies acting as strategic buyers, construction companies, commercial and investment banks and commercial finance companies. Many of these competitors are substantially larger and have considerably greater financial, technical and marketing resources than are available to us. Some of these competitors may also have higher risk tolerances or different risk assessments, which could allow them to consider a wider variety of acquisitions. Due to the capital intensive nature of infrastructure acquisitions, in order to finance acquisitions we will need to compete for equity capital from institutional investors and other equity providers, including Brookfield, and our ability to consummate acquisitions will be dependent on such capital continuing to be available. Increases in interest rates could also make it more difficult to consummate acquisitions because our competitors may have a lower cost of capital which may enable them to bid higher prices for assets. In addition, because of our affiliation with Brookfield, there is a higher risk that when we participate with Brookfield and others in joint ventures, partnerships and consortiums on acquisitions we may become subject to anti-trust or competition laws that we would not be subject to if we were acting alone. These factors may create competitive disadvantages for us with respect to acquisition opportunities.

We cannot assure you that the competitive pressures we face will not have a material adverse effect on our business, financial condition and results of operations or that Brookfield will be able to identify and make acquisitions on our behalf that are consistent with our objectives or that generate attractive returns for our unitholders. We may lose acquisition opportunities in the future if we do not match prices, structures and terms offered by competitors, if we are unable to access sources of equity or obtain indebtedness at attractive rates or if we become subject to anti-trust or competition laws. Alternatively, we may experience decreased rates of return and increased risks of loss if we match prices, structures and terms offered by competitors.

Future acquisitions may subject us to additional risks.

Future acquisitions will likely involve some or all of the following risks, which could materially and adversely affect our business, results of operations or financial condition: the difficulty of integrating the acquired operations and personnel into our current operations; potential disruption of our current operations; diversion of resources, including Brookfield’s time and attention; the difficulty of managing the growth of a larger organization; the risk of entering markets in which we have little experience; the risk of becoming involved in labor, commercial or regulatory disputes or litigation related to the new enterprise; and the risk of environmental or other liabilities associated with the acquired business.

Brookfield has structured some of our current operations as joint ventures, partnerships and consortium arrangements, and we will do so in the future, which will reduce Brookfield's and our control over our operations and may subject us to additional obligations.

Brookfield has structured some of our current operations as joint ventures, partnerships and consortium arrangements. An integral part of our strategy is to participate with institutional investors in Brookfield sponsored or co-sponsored consortiums for single asset acquisitions and as a partner in or alongside Brookfield sponsored or co-sponsored partnerships that target acquisitions that suit our profile. These arrangements are driven by the magnitude of capital required to complete acquisitions of infrastructure assets and other industrywide trends that we believe will continue. Such arrangements involve risks not present where a third party is not involved, including the possibility that partners or co-venturers might become bankrupt or otherwise fail to fund their share of required capital contributions. Additionally, partners or co-venturers might at any time have economic or other business interests or goals different from us and Brookfield.

Joint ventures, partnerships and consortium investments generally provide for a reduced level of control over an acquired company because governance rights are shared with others. Accordingly, decisions relating to the underlying operations, including decisions relating to the management and operation and the timing and nature of any exit, are often made by a majority vote of the investors or by separate agreements that are reached with respect to individual decisions. In addition, such operations may be subject to the risk that the company may make business, financial or management decisions with which we do not agree or the management of the company may take risks or otherwise act in a manner that does not serve our interests. Because we may not have the ability to exercise control over such operations, we may not be able to realize some or all of the benefits that we believe will be created from our and Brookfield's involvement. If any of the foregoing were to occur, our financial condition and results of operations could suffer as a result.

In addition, because some of our current operations are structured as joint ventures, partnerships or consortium arrangements, the sale or transfer of interests in some of our operations are subject to rights of first refusal or first offer, tag along rights or drag along rights and some agreements provide for buy-sell or similar arrangements. For example, our Chilean transmission operations are subject to a shareholders' agreement which allows for an en bloc sale of the assets without our consent and our Brazilian transmission investments are subject to put/call agreements with third parties. Such rights may be triggered at a time when we may not want them to be exercised and such rights may inhibit our ability to sell our interest in an entity within our desired time frame or on any other desired basis.

Risks Relating to Our Electricity Transmission Operations

Our electricity transmission operations may require substantial capital expenditures in the future.

In some of the jurisdictions in which we have electricity transmission operations, such as Brazil and Chile, certain maintenance capital expenditures may not be covered by the regulatory framework. If our electricity transmission operations in these jurisdictions require significant capital expenditures to maintain our asset base, we will not be able to cover such costs through the regulatory framework. In addition, we may be exposed to disallowance risk in other jurisdictions to the extent that capital expenditures and costs are not fully recovered through the regulatory framework.

Our electricity transmission operations may engage in development projects which may expose us to various risks associated with construction.

Our electricity transmission operations may engage in development projects. If such development projects enter the construction phase, we are likely to retain some risk that the project will not be completed within budget, within the agreed timeframe and to the agreed specifications. During the construction phase, the major risks include a delay in the projected completion of the project and a resultant delay in the commencement of cash flows, an increase in the capital needed to complete construction and the insolvency of the head contractor, a major subcontractor and/or key equipment supplier. Although frequently the main risks of any delay in completion of the construction or any "overrun" in the costs of construction will typically have been passed on by us contractually to a subcontractor, there is some risk that the anticipated returns of the relevant project may be adversely affected as a result. Unexpected increases in costs may also result in increased debt service costs and in funds being insufficient to complete construction. In addition, due to any of the aforementioned delays or cost overruns, regulatory changes or other external influences, we may decide to abandon construction or development of any given project resulting in a write-off of any cost recovery we may have received for costs to the point of abandonment. This would negatively impact our income and cash flow.

Clients of our electricity transmission operations may default on their obligations under the relevant contractual arrangements.

Some of our electricity transmission operations have customer contracts as well as concession agreements in place with public and private sector clients. On the public sector side this may include central government departments, local government bodies and quasi-government agencies. Since it cannot be assumed that a central government will in all cases assume liability for the obligation of quasi-government agencies or those central government departments will themselves not default on their obligations, the possibility of a default remains. Our electricity transmission operations also have contracts with private sector clients. There is an increased risk of default by private sector clients compared with public sector clients. For example, we have a single customer which represented approximately 71% of revenues of our Chilean transmission operations in 2008. As this accounts for a majority of its cash flow, our Chilean transmission operations could be materially adversely affected by any material change in the assets, financial condition or results of operations of that customer.

Our electricity transmission operations may be adversely affected by changes in tolls or regulated rates.

Some of our electricity transmission operations are regulated with respect to revenues and they recover their investment in transmission assets through tolls or regulated rates which are charged to third parties (including generating companies). In general, our electricity transmission operations are entitled to earn revenue that represents a rate of return on the regulated investment value of assets and to collect provisions for operating, maintenance and administrative costs. If any of the respective regulators in the jurisdictions in which we operate decide to change the tolls or rates we are allowed to charge or the amounts of the provisions we are allowed to collect, we may not be able to earn a rate of return on our businesses that we had planned or we may not be able to recover our initial investment cost.

The lands used in our electricity transmission operations may be subject to adverse claims.

Although we believe that we have valid rights to all easements, licences and rights of way necessary for our electricity transmission operations, not all of our easements, licences and rights of way are registered against the lands to which they relate and may not bind subsequent owners. In addition, our rights may be adversely affected by rights of governments or aboriginal groups.

Risks Relating to Our Timber Operations

The financial performance of our timber operations may be affected by economic recessions or downturns.

The vast majority of the products from our timber operations are sensitive to macro-economic conditions in North America and Japan and are thus susceptible to economic recessions or downturns in these markets. Decreases in the level of residential construction, repair and remodeling activity generally reduce demand for logs and wood products, resulting in lower revenues, profits and cash flows for lumber mills who are important customers to our timber operations. Depressed commodity prices in lumber, pulp or paper may also cause mill operators to temporarily or permanently shut down their mills if their product prices fall to a level where mill operation would be uneconomic. Moreover, these operators may be required to temporarily suspend operations at one or more of their mills to bring production in line with market demand or in response to market irregularities. Any of these circumstances could significantly reduce the prices that we realize for our timber as well as the volume of our timber that we may be able to sell. In addition to impacting our timber operations' sales, cash flows and earnings, weakness in the market prices of timber products will also have an effect on our ability to attract additional capital, the cost of that capital and the value of our timberland assets. Further, we may reduce near term harvest levels to preserve our inventory for periods of higher pricing, which would negatively impact the near term results and cashflow of our timber operations.

A variety of factors may limit or prevent harvesting by our timber operations.

Weather conditions, industry practices and federal, state and provincial laws and regulations associated with forestry practices, sale of logs and environmental matters, including wildlife and water resources, may limit or prevent harvesting, road building and other activities on the timberlands owned by our timber operations. In the case of restrictions arising from regulatory requirements, the size of the area subject to restriction will vary depending on the protected species at issue, the time of year and other factors. In addition, if regulations become more restrictive, the amount of the timberlands subject to harvest restrictions could increase. The timberlands owned by our timber operations may also suffer damage by fire, insect infestation, wind, disease, prolonged drought and other natural and man-made disasters. There can be no assurance that our timber operations will achieve harvest levels in the future necessary to maintain or increase revenues, earnings and cash flows. There can be no assurance that the forest management planning by our timber operations, including silviculture, will have the intended result of ensuring that their asset base appreciates over time.

Our timber operations operate in a highly competitive industry, subject to price fluctuations.

Timberland companies operate in a highly competitive business environment in which companies compete, to a large degree, on the basis of price and also on the basis of service and ability to provide a steady supply of products over the long-term. The prime competitors to our timber operations are governments, other large forestland owners and small private forestland owners. In addition, wood and paper products are subject to increasing competition from a variety of substitute products, including non-wood and engineered wood products and electronic media. The competitive position of our timber operations and the price realized for our products is also influenced by a number of other factors including: the ability to attract and maintain long-term customer relationships; the quality of our products; the health of the regional converting industry; the costs of timber production; the availability, quality and cost of labor; the cost of fuel; shipping and transportation costs; changes in global timber supply; technological advances that increase yield in other regions; and the price and availability of substitute wood and non-wood products.

Our ability to harvest timber may be adversely affected by aboriginal claims.

Aboriginal claims could adversely affect our ability to harvest timber in our Canadian (and to a lesser degree, U.S.) timber operations. Canadian courts have recognized that aboriginal peoples may possess rights at law in respect of land used or occupied by their ancestors where treaties have not been concluded to deal with these rights. In Canada, aboriginal groups have made claims in respect of land governed by Canadian authorities, which could affect a portion of our timber operations. Any settlements in respect of these claims could lower the volume of timber managed by our Canadian timber operations and could increase the cost to harvest timber on such lands.

Our Canadian timber operations are subject to federal restrictions which may require them to decrease their planned export of logs.

Currently, logs from most private timberlands in Canada are not subject to provincial export regulations, but are subject to federal export regulations. As a result, all export logs must be advertised for local consumption and may be exported only if there is a surplus of domestic supply as indicated by the absence of fair market value offers (based on current domestic prices) from domestic lumber mills. Accordingly, an increase in domestic demand could result in our Canadian timber operations being required to decrease their planned export of logs. The provincial government in British Columbia is currently reviewing its log export policy, and may recommend that the federal government impose a policy that may further restrict the export of logs from private lands in British Columbia. As export market pricing is generally at a premium to the domestic market pricing, any reduction in log exports could have an adverse effect on our Canadian timber operations.

Risks Relating to Our Public Private Partnership (or PPP) and Social Infrastructure Operations

We may be required to retain risks inherent in a PPP project and may be exposed to risks of default by our sub-contractors.

As described in further detail under Item 4.B "Business Overview—Current Operations—Social Infrastructure-Overview", contractual arrangements entered into by PPP project companies are generally structured to minimize the retention by the project company of risks inherent in the project by, among other things, passing these risks on under relevant sub-contracting arrangements. If the project company is required to replace a sub-contractor due to, for example, non-performance or other default, the project company will often bear the risk of any deductions that may accrue as a result of replacement and will bear the risk of any increased costs resulting from the replacement. Non-performance may also trigger a right for our public sector client to require us to replace a sub-contractor. In addition, the project company may be forced to retain certain residual risks where they are not assumed by the public sector client and cannot be passed on to sub-contractors.

Government policy towards our social infrastructure operations may change.

The policies of the relevant government entities in Australia and the UK, and other jurisdictions in which we may develop or acquire such assets, toward social infrastructure may change, which may cause a decrease in the use of PPP initiatives in those jurisdictions. If there is such a change in policy, the relevant government entity may seek to terminate the social infrastructure operation pursuant to the relevant project agreement. While termination should lead to compensation being paid to us, the compensation may not be sufficient to ensure that anticipated returns from the social infrastructure operation are realized.

Political attitudes towards PPP funding models of social infrastructure may change.

PPP funding of social infrastructure development has grown markedly in recent years worldwide, mainly in Europe, Australia and Canada. However, the PPP funding model is opposed by some political groups. If the PPP model of social infrastructure development were to decline worldwide due to increased political opposition, this would negatively affect our opportunities for growth in this area.

We may experience operating cost overruns in relation to a project.

In pricing our PPP projects, we will make allowances for certain direct operating costs of the project company, including operating insurances, management, accounting, and other professional services during the term. Any inadequacy in such projections will likely negatively impact upon our financial results.

We may experience higher than expected costs associated with Lifecycle Replacement or latent defects

Our project companies typically retain the obligation to undertake replacement and refurbishment of projects (frequently referred to as "Lifecycle Replacement") during the term as may be necessary to ensure the performance of the facilities to the contracted standards. Performance deductions resulting from a failure to undertake necessary Lifecycle Replacement are generally not eligible to be passed on to sub-contractors. In addition, project companies often bear the risk of latent defects after a specified number of years, prior to which this risk is borne by the construction contractor. Unanticipated costs of Lifecycle Replacement or the presence of latent defects could have a material adverse effect on our financial condition and financial results.

Our PPP project activities may include significant development activities, which may expose us to various risks associated with construction.

Our PPP project activities may include significant development activities. If such development activities enter the construction phase, we are likely to retain some risk that the project will not be completed within budget, within the agreed time frame and to the agreed specifications. During the construction phase, the major risks include a delay in the projected completion of the project and a resultant delay in the commencement of cash flows, an increase in the capital needed to complete construction and the insolvency of the head contractor, a major subcontractor and/or key equipment supplier. Although frequently the main risks of any delay in completion of the construction or any "overrun" in the costs of construction will typically have been passed on by us contractually to a sub-contractor, there is some risk that the anticipated returns of the relevant project may be adversely affected as a result. Unexpected increases in costs may also result in increased debt service costs and in funds being insufficient to complete construction. In addition, due to any of the aforementioned delays or cost overruns, regulatory changes or other external influences, we may decide to abandon construction or development of any given project resulting in a write-off of any cost recovery we may have received for costs to the point of abandonment. This would negatively impact our income and cash flow.

Changes in law requiring capital expenditures could have a material adverse effect on our operations.

Changes in law relating to the construction phase or the general performance of the services, in connection with a PPP project, are typically passed directly to the relevant sub-contractors. Where changes in law result in a requirement to make capital expenditures, however, our project company often shares this risk with the public sector client on a graduated scale, which could have a material adverse effect on our financial condition and financial results.

Our public sector clients may default on their obligations under the relevant contractual arrangements.

The concessions granted in our social infrastructure operations are granted by a variety of public sector clients, including central/state governments and statutory corporations. Although the creditworthiness and ability of each such body to enter into a project agreement (along with any related guarantees from higher government entities) has been considered on a case-by-case basis with the benefit of advice, the possibility of a default remains.

Risks Relating to Our Relationship with Brookfield

Brookfield exercises substantial influence over our partnership and we are highly dependent on the Manager.

Brookfield is the sole shareholder of our Managing General Partner. As a result of its ownership of our Managing General Partner, Brookfield is able to control the appointment and removal of our Managing General Partner's directors and, accordingly, exercise substantial influence over our partnership. In addition, our partnership holds its interest in the operating entities indirectly and will hold any future acquisitions indirectly through Brookfield Infrastructure, the general partner of which is controlled by Brookfield. As our partnership's only substantial asset is the limited partnership interests that it holds in Brookfield Infrastructure, our partnership does not have a right to participate directly in the management or activities of Brookfield Infrastructure or the Holding Entities, including with respect to the making of decisions.

Our partnership and Brookfield Infrastructure do not have any employees and depend on the management and administration services provided by the Manager. Brookfield personnel and support staff that provide services to us are not required to have as their primary responsibility the management and administration of our partnership or Brookfield Infrastructure or to act exclusively for either of us. Any failure to effectively manage our current operations or to implement our strategy could have a material adverse effect on our business, financial condition and results of operations.

Brookfield has no obligation to source acquisition opportunities for us and we may not have access to all infrastructure acquisitions that Brookfield identifies.

Our ability to grow depends on Brookfield's ability to identify and present us with acquisition opportunities. Brookfield has stated that we are its primary vehicle to own and operate certain infrastructure assets on a global basis. However, Brookfield has no obligation to source acquisition opportunities for us. In addition, Brookfield has not agreed to commit to us any minimum level of dedicated resources for the pursuit of infrastructure related acquisitions. There are a number of factors which could materially and adversely impact the extent to which suitable acquisition opportunities are made available from Brookfield, for example:

- there is no accepted industry standard for what constitutes an infrastructure asset. Brookfield may consider certain assets that have both real-estate related characteristics and infrastructure related characteristics to be real estate and not infrastructure;
- it is an integral part of Brookfield's (and our) strategy to pursue the acquisition of infrastructure assets through consortium arrangements with institutional investors, strategic partners or financial sponsors and to form partnerships to pursue such acquisitions on a specialized or global basis. Although Brookfield has agreed with us that it will not enter any such arrangements that are suitable for us without giving us an opportunity to participate in them, there is no minimum level of participation to which we will be entitled;
- the same professionals within Brookfield's organization that are involved in acquisitions that are suitable for us are responsible for the consortiums and partnerships referred to above, as well as having other responsibilities within Brookfield's broader asset management business. Limits on the availability of such individuals will likewise result in a limitation on the availability of acquisition opportunities for us;
- Brookfield will only recommend acquisition opportunities that it believes are suitable for us. Our focus is on assets where we believe that our operations-oriented approach can be deployed to create value. Accordingly, opportunities where Brookfield cannot play an active role in influencing the underlying operating company or managing the underlying assets may not be suitable for us, even though they may be attractive from a purely financial perspective. Legal, regulatory, tax and other commercial considerations will likewise be an important consideration in determining whether an opportunity is suitable and will limit our ability to participate in these more passive investments and may limit our ability to have more than 50% of our assets concentrated in a single jurisdiction; and
- in addition to structural limitations, the question of whether a particular acquisition is suitable is highly subjective and is dependent on a number of factors including our liquidity position at the time, the risk profile of the opportunity, its fit with the balance of our then current operations and other factors. If Brookfield determines that an opportunity is not suitable for us, it may still pursue such opportunity on its own behalf, or on behalf of a Brookfield sponsored partnership or consortium.

In making these determinations, Brookfield may be influenced by factors that result in a mis-alignment or conflict of interest. See Item 7.B "Related Party Transactions—Conflicts of Interest and Fiduciary Duties."

The departure of some or all of Brookfield's professionals could prevent us from achieving our objectives.

We depend on the diligence, skill and business contacts of Brookfield's professionals and the information and opportunities they generate during the normal course of their activities. Our future success will depend on the continued service of these individuals, who are not obligated to remain employed with Brookfield. Brookfield has experienced departures of key professionals in the past and may do so in the future, and we cannot predict the impact that any such departures will have on our ability to achieve our objectives. The departure of a significant number of Brookfield's professionals for any reason, or the failure to appoint qualified or effective successors in the event of such departures, could have a material adverse effect on our ability to achieve our objectives. Our limited partnership agreement and our Master Services Agreement do not require Brookfield to maintain the employment of any of its professionals or to cause any particular professionals to provide services to us or on our behalf.

The control of our Managing General Partner may be transferred to a third party without unitholder consent.

Our Managing General Partner may transfer its general partnership interest to a third party in a merger or consolidation or in a transfer of all or substantially all of its assets without the consent of our unitholders. Furthermore, at any time, the shareholder of our Managing General Partner may sell or transfer all or part of its shares in our Managing General Partner without the approval of our unitholders. If a new owner were to acquire ownership of our Managing General Partner and to appoint new directors or officers of its own choosing, it would be able to exercise substantial influence over our partnership's policies and procedures and exercise substantial influence over our management and the types of acquisitions that we make. Such changes could result in our partnership's capital being used to make acquisitions in which Brookfield has no involvement or in making acquisitions that are substantially different from our targeted acquisitions. Additionally, our partnership cannot predict with any certainty the effect that any transfer in the ownership of our Managing General Partner would have on the trading price of our units or our partnership's ability to raise capital or make investments in the future, because such matters would depend to a large extent on the identity of the new owner and the new owner's intentions with regard to our partnership. As a result, the future of our partnership would be uncertain and our partnership's financial condition and results of operations may suffer.

Brookfield may increase its ownership of our partnership and Brookfield Infrastructure relative to other unitholders.

Brookfield holds approximately 40% of the issued and outstanding interests in Brookfield Infrastructure through a 1% general partnership interest and a 39% limited partnership interest. The limited partnership interests held by Brookfield are redeemable for cash or exchangeable for our units in accordance with the Redemption-Exchange Mechanism, which could result in Brookfield eventually owning 39% of our issued and outstanding units. See Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Redemption-Exchange Mechanism." Brookfield also acquired 0.2% of our units in connection with the satisfaction of Canadian federal and U.S. "backup" withholding tax requirements upon the spin-off. Brookfield may also acquire additional units of Brookfield Infrastructure pursuant to an equity commitment provided by Brookfield. See Item 7.B "Related Party Transactions—Equity Commitment and Other Financing." Infrastructure GP LP may also reinvest incentive distributions in exchange for units of Brookfield Infrastructure. See Item 7.B "Related Party Transactions—Incentive Distributions." In addition, Brookfield has advised our partnership that it may from time-to-time reinvest distributions it receives from Brookfield Infrastructure in Brookfield Infrastructure's distribution reinvestment plan, with the result that Brookfield will receive additional units of Brookfield Infrastructure. Additional units of Brookfield Infrastructure acquired, directly or indirectly, by Brookfield are redeemable for cash or exchangeable for our units in accordance with the Redemption-Exchange Mechanism. See Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Redemption-Exchange Mechanism." Brookfield may also purchase additional units of our partnership in the market. Any of these events may result in Brookfield increasing its ownership of our partnership and Brookfield Infrastructure above 50%.

Brookfield does not owe our unitholders any fiduciary duties under the Master Services Agreement or our other arrangements with Brookfield.

The obligations of Brookfield under the Master Services Agreement and our other arrangements with them are contractual rather than fiduciary in nature. As a result, our Managing General Partner, which is an affiliate of Brookfield, in its capacity as our partnership's general partner, has sole authority and discretion to enforce the terms of such agreements and to consent to any waiver, modification or amendment of their provisions.

Our limited partnership agreement and Brookfield Infrastructure's limited partnership agreement contain various provisions that modify the fiduciary duties that might otherwise be owed to our partnership and our unitholders, including when such conflicts of interest arise. These modifications may be important to our unitholders because they restrict the remedies available for actions that might otherwise constitute a breach of fiduciary duty and permit our Managing General Partner and the Infrastructure General Partner to take into account the interests of third parties, including Brookfield, when resolving conflicts of interest. See Item 7.B "Related Party Transactions—Conflicts of Interest and Fiduciary Duties." It is possible that conflicts of interest may be resolved in a manner that is not in the best interests of our partnership or the best interests of our unitholders.

Our organizational and ownership structure may create significant conflicts of interest that may be resolved in a manner that is not in the best interests of our partnership or the best interests of our unitholders.

Our organizational and ownership structure involves a number of relationships that may give rise to conflicts of interest between our partnership and our unitholders, on the one hand, and Brookfield, on the other hand. In certain instances, the interests of Brookfield may differ from the interests of our partnership and our unitholders, including with respect to the types of acquisitions made, the timing and amount of distributions by our partnership, the reinvestment of returns generated by our operations, the use of leverage when making acquisitions and the appointment of outside advisors and service providers, including as a result of the reasons described under Item 7.B "Related Party Transactions."

Our arrangements with Brookfield were negotiated in the context of an affiliated relationship and may contain terms that are less favorable than those which otherwise might have been obtained from unrelated parties.

The terms of our arrangements with Brookfield were effectively determined by Brookfield in the context of the spin-off. While our Managing General Partner's independent directors are aware of the terms of these arrangements and have approved the arrangements on our behalf, they did not negotiate the terms. These terms, including terms relating to compensation, contractual or fiduciary duties, conflicts of interest and Brookfield's ability to engage in outside activities, including activities that compete with us, our activities and limitations on liability and indemnification, may be less favorable than otherwise might have resulted if the negotiations had involved unrelated parties. Under our limited partnership agreement, persons who acquire our units and their transferees will be deemed to have agreed that none of those arrangements constitutes a breach of any duty that may be owed to them under our limited partnership agreement or any duty stated or implied by law or equity.

Our Managing General Partner may be unable or unwilling to terminate the Master Services Agreement.

The Master Services Agreement provides that the Service Recipients may terminate the agreement only if the Manager defaults in the performance or observance of any material term, condition or covenant contained in the agreement in a manner that results in material harm to us and the default continues unremedied for a period of 30 days after written notice of the breach is given to the Manager; the Manager engages in any act of fraud, misappropriation of funds or embezzlement against any Service Recipient that results in material harm to us; the Manager is grossly negligent in the performance of its duties under the agreement and such negligence results in material harm to the Service Recipients; or upon the happening of certain events relating to the bankruptcy or insolvency of the Manager. Our Managing General Partner cannot terminate the agreement for any other reason, including if the Manager or Brookfield experiences a change of control, and there is no fixed term to the agreement. In addition, because our Managing General Partner is an affiliate of Brookfield, it may be unwilling to terminate the Master Services Agreement, even in the case of a default. If the Manager's performance does not meet the expectations of investors, and our Managing General Partner is unable or unwilling to terminate the Master Services Agreement, the market price of our units could suffer. Furthermore, the termination of the Master Services Agreement would terminate our partnership's rights under the Relationship Agreement and the licensing agreement. See Item 7.B "Related Party Transactions—Relationship Agreement" and Item 7.B "Related Party Transactions—Licensing Agreement."

The liability of the Manager is limited under our arrangements with it and we have agreed to indemnify the Manager against claims that it may face in connection with such arrangements, which may lead it to assume greater risks when making decisions relating to us than it otherwise would if acting solely for its own account.

Under the Master Services Agreement, the Manager has not assumed any responsibility other than to provide or arrange for the provision of the services described in the Master Services Agreement in good faith and will not be responsible for any action that our Managing General Partner takes in following or declining to follow its advice or recommendations. In addition, under our limited partnership agreement, the liability of the Managing General Partner and its affiliates, including the Manager, is limited to the fullest extent permitted by law to conduct involving bad faith, fraud or willful misconduct or, in the case of a criminal matter, action that was known to have been unlawful. The liability of the Manager under the Master Services Agreement is similarly limited, except that the Manager is also liable for liabilities arising from gross negligence. In addition, our partnership has agreed to indemnify the Manager to the fullest extent permitted by law from and against any claims, liabilities, losses, damages, costs or expenses incurred by an indemnified person or threatened in connection with our operations, investments and activities or in respect of or arising from the Master Services Agreement or the services provided by the Manager, except to the extent that the claims, liabilities, losses, damages, costs or expenses are determined to have resulted from the conduct in respect of which such persons have liability as described above. These protections may result in the Manager tolerating greater risks when making decisions than otherwise would be the case, including when determining whether to use leverage in connection with acquisitions. The indemnification arrangements to which the Manager is a party may also give rise to legal claims for indemnification that are adverse to our partnership and our unitholders.

Risks Relating to Our Units

Our unitholders do not have a right to vote on partnership matters or to take part in the management of our partnership.

Under our limited partnership agreement, our unitholders are not entitled to vote on matters relating to our partnership, such as acquisitions, dispositions or financing, or to participate in the management or control of our partnership. In particular, our unitholders do not have the right to remove our Managing General Partner, to cause our Managing General Partner to withdraw from our partnership, to cause a new general partner to be admitted to our partnership, to appoint new directors to our Managing General Partner's board of directors, to remove existing directors from our Managing General Partner's board of directors or to prevent a change of control of our Managing General Partner. In addition, except as prescribed by applicable laws, our unitholders' consent rights apply only with respect to certain amendments to our limited partnership agreement. As a result, unlike holders of common stock of a corporation, our unitholders are not able to influence the direction of our partnership, including its policies and procedures, or to cause a change in its management, even if they are unsatisfied with the performance of our partnership. Consequently, our unitholders may be deprived of an opportunity to receive a premium for their units in the future through a sale of our partnership and the trading price of our units may be adversely affected by the absence or a reduction of a takeover premium in the trading price.

Risks Relating to Taxation

General

Changes in tax law and practice may have a material adverse effect on our operations and, as a consequence, the value of our assets and the net amount of distributions payable to our unitholders.

Our structure, including the structure of the Holding Entities and the operating entities, is based on prevailing taxation law and practice in the local jurisdictions in which we operate. Any change in tax legislation (including in relation to taxation rates) and practice in these jurisdictions could adversely affect such company or entity, as well as the net amount of distributions payable to our unitholders. Furthermore, the manner in which we seek to structure acquisitions is dependent on the tax legislation and practice applicable at that time in the relevant jurisdiction. This may mean that we find it difficult to carry out acquisitions in a particular territory or in certain asset classes in any such territory for a period of time. Taxes and other constraints that would be applicable to us in such jurisdictions may not be applicable to local institutions or other parties and such parties may therefore have a significantly lower effective cost of capital and a corresponding competitive advantage in pursuing such acquisitions.

Our partnership's ability to make distributions depends on us receiving sufficient cash distributions from our underlying operations and we cannot assure our unit holders that our partnership will be able to make cash distributions to them in amounts that are sufficient to fund their tax liabilities.

We are subject to local taxes in each of the relevant territories and jurisdictions (such as Canada, the United States, the United Kingdom, Australia, Brazil and Chile) in which we have operations, including taxes on our income, profits or gains and withholding taxes. As a result, our partnership's cash available for distribution is reduced by such taxes and the post-tax return to investors is similarly reduced by such taxes. We intend that future acquisitions be assessed on a case-by-case basis and, where possible and commercially viable, structured so as to minimize any adverse tax consequences for us as a result of making such acquisitions.

Each of our unitholders will be required to include in their income its allocable share of our partnership's items of income, gain, loss, deduction and credit (including, so long as it is treated as a partnership for tax purposes, our partnership's allocable share of those items of Brookfield Infrastructure) for each of our taxable years ending with or within such unitholder's taxable year. See Item 10.E "Taxation." With respect to each of our unitholders, the cash distributed to a unitholder may not be sufficient to fund the payment of the full amount of such unitholder's tax liability in respect of its investment in our partnership because such unitholder's tax liability is dependent on their particular tax situation and we will make simplifying tax assumptions in determining the amount of the distribution. In addition, the actual amount and timing of distributions will always be subject to the discretion of our Managing General Partner's board of directors and we cannot assure our unitholders that our partnership will in fact make cash distributions as intended. See Item 8.A "Consolidated Statements and Other Financial Information." Even if our partnership is unable to distribute cash in an amount that is sufficient to fund our unitholders tax liabilities, each of our unitholders will still be required to pay income taxes on their share of our partnership's taxable income.

Our unitholders may be subject to taxes and tax filing obligations in jurisdictions in which they are not resident for tax purposes or are not otherwise subject to tax.

Because of our unitholders' holdings in our partnership, our unitholders may be subject to taxes and tax return filing obligations in jurisdictions other than the jurisdiction in which they are a resident for tax purposes or are not otherwise subject to tax. Although we will attempt, to the extent reasonably practicable, to structure our operations and investments so as to minimize income tax filing obligations by our unitholders in such jurisdictions, there may be circumstances in which we are unable to do so. Income or gains from our holdings may be subject to withholding or other taxes in jurisdictions outside our unitholders' jurisdiction of residence for tax purposes or in which they are not otherwise subject to tax. If any of our unitholders wish to claim the benefit of an applicable income tax treaty, such unitholders may be required to submit information to our partnership and/or the tax authorities in such jurisdictions.

Our unitholders may be exposed to transfer pricing risks.

To the extent that our partnership, Brookfield Infrastructure, the Holding Entities or the operating entities enter into transactions or arrangements with parties with whom they do not deal at arm's length, including Brookfield, the relevant tax authorities may seek to adjust the quantum or nature of the amounts received or paid by such entities if they consider that the terms and conditions of such transactions or arrangements differ from those that would have been made between persons dealing at arm's length. This could result in more tax being paid by such entities and therefore the return to investors could be reduced.

Our Managing General Partner and the Infrastructure GP LP believe that the base management fee and any other amount that is paid to the Manager will be commensurate with the value of the services being provided by the Manager and are comparable to the fees or other amounts that would be agreed to in an arm's length arrangement. The Managing General Partner and the Infrastructure GP LP therefore do not anticipate that the amounts of income (or loss) allocated to our unitholders will be adjusted. However, no assurance can be given in this regard.

If the relevant tax authority were to assert that an adjustment should be made under the transfer pricing rules to an amount (most likely, an expense) that is relevant to the computation of the income of Brookfield Infrastructure or our partnership, such assertion could result in adjustments to amounts of income (or loss) allocated to our unitholders by our partnership for tax purposes. In addition, our unitholders may also be liable for transfer pricing penalties in respect of transfer pricing adjustments unless reasonable efforts were made to determine, and use, arm's length transfer prices. Generally, reasonable efforts in this regard are only considered to be made if contemporaneous documentation has been prepared in respect of such transactions or arrangements that support the transfer pricing methodology. Our Managing General Partner and Infrastructure GP LP advise that satisfactory contemporaneous documentation for these purposes has been and will be prepared in respect of all transactions or arrangements with Brookfield, and in particular with respect to the Master Services Agreement. Accordingly, our Managing General Partner and the Infrastructure General Partner do not anticipate that the amounts of income (or loss) allocated to our unitholders for tax purposes will be required to be adjusted or that our unitholders, our partnership, or Brookfield Infrastructure will be subject to transfer pricing penalties described above. However, no assurance can be given in this regard.

United States

If either our partnership or Brookfield Infrastructure were to be treated as a corporation for U.S. federal income tax purposes, the value of our units may be adversely affected.

The value of our units will depend in part on our partnership and Brookfield Infrastructure being treated as partnerships for U.S. federal income tax purposes. Our partnership and Brookfield Infrastructure have each made an election to be treated as a partnership for U.S. federal income tax purposes. However, in order for our partnership to be considered a partnership for U.S. federal income tax purposes, under present law, 90% or more of our partnership's gross income for every taxable year must consist of qualifying income, as defined in Section 7704 of the U.S. Internal Revenue Code of 1986, as amended, or the U.S. Internal Revenue Code, and the partnership must not be required to register, if it were a U.S. corporation, as an investment company under the U.S. Investment Company Act and related rules. Although we intend to manage our affairs so that our partnership would not need to be registered as an investment company if it were a U.S. corporation and so that it will meet the 90% test described above in each taxable year, our partnership may not meet these requirements or current law may change so as to cause, in either event, our partnership to be treated as a corporation for U.S. federal income tax purposes. If our partnership were treated as a corporation for U.S. federal income tax purposes, (i) the deemed conversion to corporate status would generally result in recognition of gain (but not loss) to U.S. unitholders; (ii) our partnership would likely be subject to U.S. corporate income tax and branch profits tax with respect to income, if any, that is effectively connected to a U.S. trade or business; (iii) distributions to our U.S. unitholders would be taxable as dividends to the extent of our partnership's earnings and profits; (iv) dividends, interest, and certain other passive income our partnership receives from U.S. entities would, in most instances, be subject to U.S. withholding tax at a rate of 30% (although certain non-U.S. holders of our units nevertheless may be entitled to certain treaty benefits in respect of their allocable share of such income), and U.S. unitholders (other than certain U.S. corporate unitholders who own 10% or more of our units) would not be allowed a tax credit with respect to any such tax withheld; (v) the "portfolio interest" exemption would not apply to interest income of our partnership derived from entities bearing certain relationships to our partnership (although certain non-U.S. holders of our units nevertheless may be entitled to certain treaty benefits in respect of their allocable share of such income) and (vi) our partnership could be classified as a "passive foreign investment company" (as defined in the U.S. Internal Revenue Code), and such classification would have adverse tax consequences to U.S. unitholders with respect to distributions and gain recognized on the sale of our units. In addition to the foregoing consequences, if our partnership were treated as a corporation for U.S. federal income tax purposes, and, as of the time of conversion from partnership status to corporate status, the value of our partnership's U.S. assets equaled or exceeded sixty percent of the value of our partnership's total assets, some or all of the net income recognized by our partnership subsequent to such conversion would be subject to U.S. corporate income tax. It is not expected that our partnership's U.S. assets will at any time equal or exceed such thresholds. If Brookfield Infrastructure were to be treated as a corporation for U.S. federal income tax purposes, consequences similar to those described above would apply.

Neither our partnership nor Brookfield Infrastructure has requested, and they do not plan to request, a ruling from the IRS on their tax status for U.S. federal income tax purposes or as to any other matter affecting us.

A non-U.S. person who holds more than 5% of our units very likely will be subject to special rules under the Foreign Investment Real Property Tax Act of 1980, which may have a material adverse effect on the return to such person from an investment in our units.

A non-U.S. person who holds more than 5% of our units very likely will be subject to special rules under the Foreign Investment Real Property Tax Act of 1980, or FIRPTA. For purposes of determining whether a non-U.S. person holds more than 5% of our units, special attribution rules apply. The application of the FIRPTA rules to a non-U.S. person who holds (or is deemed to hold) more than 5% of our units could have a material adverse effect on such non-U.S. person. Accordingly, our partnership does not believe that it is generally advisable for a non-U.S. person to own more than 5% of our units. If any of our unitholders is a non-U.S. person and owns or anticipates owning more than 5% of our units, such person should consult their tax advisors. See Item 10.E "Taxation—United States Tax Considerations—Consequences to Non-U.S. Holders of Our Units."

We may be subject to U.S. "backup" withholding tax or other U.S. withholding taxes if our unitholders fail to comply with U.S. tax reporting rules or if the IRS or other applicable state and local taxing authorities do not accept our withholding methodology, and such excess withholding tax cost will be an expense borne by our partnership, and, therefore, all of our unitholders on a pro rata basis.

We may become subject to U.S. "backup" withholding tax at the applicable rate (currently 28%) or other U.S. withholding taxes (potentially as high as 30%) if our U.S. and non-U.S. unitholders fails to timely provide our partnership (or the clearing agent or other intermediary) with an IRS Form W-9 or IRS Form W-8, as the case may be, or if the withholding methodology we use is not accepted by the IRS or applicable state and local taxing authorities. See Item 10.E "Taxation—United States Tax Considerations—Administrative Matters—Backup and Other Administrative Withholding Issues." Accordingly, it is important that each of our unitholders timely provides our partnership (or the clearing agent or other intermediary) with an IRS Form W-9 or IRS Form W-8, as applicable. To the extent that any unitholder fails to timely provide the applicable forms (or such form is not properly completed), or should the IRS or other applicable state and local taxing authorities not accept our withholding methodology, our partnership may treat such U.S. "backup" withholding taxes or other U.S. withholding taxes as an expense, which will be borne by all unitholders on a pro rata basis. As a result, our unitholders that fully comply with their U.S. tax reporting obligations may bear a share of such burden created by other unitholders that do not comply with the U.S. tax reporting rules.

Tax-exempt entities face unique U.S. tax issues from owning our units that may result in adverse U.S. tax consequences to them.

Our partnership and Brookfield Infrastructure are not prohibited from incurring indebtedness, and at times either or both may do so. If any such indebtedness were used to acquire property by our partnership or by Brookfield Infrastructure, such property generally would constitute "debt-financed property," and any income or gain realized on such property and allocated to a tax-exempt entity generally would constitute "unrelated business taxable income" to such tax-exempt entity. In addition, even if such indebtedness were not used either by our partnership or by Brookfield Infrastructure to acquire property but were instead used to fund distributions to our unitholders, if a tax-exempt U.S. unitholder used such proceeds to make an investment outside our partnership, the IRS could assert that such investment constitutes "debt-financed property" to such unitholder with the consequences noted above. A tax-exempt entity is subject to U.S. federal income tax at regular graduated rates on the net amount of its unrelated business taxable income. In addition, a tax-exempt entity is required to file a U.S. federal income tax return for any taxable year that the tax-exempt entity derives gross income characterized as unrelated business taxable income in excess of $1,000. The potential for having income characterized as unrelated business taxable income may make our units an unsuitable investment for a tax-exempt entity.

There may be limitations on the deductibility of our partnership's interest expense.

For so long as our partnership is treated as a partnership for U.S. federal income tax purposes, each of our unitholders that is a U.S. person (or otherwise taxable in the United States) generally will be taxed on their share of our partnership's net taxable income. However, U.S. federal income tax law may limit the deductibility of such a unitholder's share of our partnership's interest expense. In addition, deductions for such a unitholder's share of our partnership's interest expense may be limited or disallowed for U.S. state and local tax purposes. Therefore, any such unitholders may be taxed on amounts in excess of such unitholder's share of the net income of our partnership. This could adversely impact the value of our units if our partnership was to incur (either directly or indirectly) a significant amount of indebtedness. See Item 10.E "Taxation—United States Tax Considerations—Consequences to U.S. Holders—Holding of Our Units."

Non-U.S. persons face unique U.S. tax issues from owning our units that may result in adverse tax consequences to them.

Our partnership believes that it is not engaged in a U.S. trade or business for U.S. federal income tax purposes, and intends to use commercially reasonable efforts to structure its activities to avoid generating income treated as effectively connected with a U.S. trade or business, including effectively connected income attributable to the sale of a "United States Real Property Interest," as defined in the U.S. Internal Revenue Code. Accordingly our partnership's non-U.S. unitholders will generally not be subject to U.S. federal income tax on interest, dividends and gains derived from non-U.S. sources. It is possible, however, that the IRS could disagree or that the U.S. federal tax laws and Treasury regulations could change and our partnership could be deemed to be engaged in a U.S. trade or business, which would have a material adverse effect on non-U.S. unitholders. If, contrary to our partnership's expectations, our partnership is considered to be engaged in a U.S. trade or business or realizes gain from the sale or other disposition of a United States Real Property Interest, non-U.S. unitholders would be required to file U.S. federal income tax returns and would be subject to U.S. federal income tax at the regular graduated rates, which our partnership may be required to withhold.

To meet U.S. federal income tax and other objectives, our partnership and Brookfield Infrastructure will invest through foreign and domestic Holding Entities that are treated as corporations for U.S. federal income tax purposes, and such Holding Entities may be subject to corporate income tax.

To meet U.S. federal income tax and other objectives, our partnership and Brookfield Infrastructure will invest through foreign and domestic Holding Entities that are treated as corporations for U.S. federal income tax purposes, and such Holding Entities may be subject to corporate income tax. Consequently, items of income, gain, loss, deduction and credit realized in the first instance by our operating entities will not flow, for U.S. federal income tax purposes, directly to Brookfield Infrastructure, our partnership, or our unitholders, and any such items may be subject to a corporate income tax, in the United States and other jurisdictions, at the level of the Holding Entities. Any such additional taxes may adversely affect our ability to operate solely to maximize our cash flow.

Certain of our Holding Entities or operating entities may be, or may be acquired through, an entity classified as a "passive foreign investment company" for U.S. federal income tax purposes.

With the exception of our social infrastructure operations, based on our analysis of our operating entities and Holding Entities, as well as our expectations regarding future operations, we do not believe that any operating entities are or are likely to become a "passive foreign investment company" for U.S. federal income tax purposes. However, we may in the future acquire certain investments or operating entities through one or more Holding Entities which may be treated as corporations for U.S. federal income tax purposes, and such future Holding Entities or other companies in which we acquire an interest may be or become treated as passive foreign investment companies. U.S. unitholders face unique U.S. tax issues from indirectly owing interests in a passive foreign investment company that may result in adverse U.S. tax consequences to them. See Item 10.E "Taxation—United States Tax Considerations—Consequences to U.S. Holders—Passive Foreign Investment Companies."

Tax gain or loss on disposition of our units could be more or less than expected.

If our unitholders sell their units and are taxable in the United States, they will recognize a gain or loss for U.S. federal income tax purposes equal to the difference between the amount realized and the adjusted tax basis in those units. Prior distributions to our unitholders in excess of the total net taxable income allocated to them, which decreased the tax basis in their units, will in effect become taxable income to them for U.S. federal income tax purposes if the units are sold at a price greater than their tax basis in those units, even if the price is less than the original cost. A portion of the amount realized, whether or not representing gain, may be ordinary income to out unitholders.

Our structure involves complex provisions of U.S. federal income tax law for which no clear precedent or authority may be available. Our structure also is subject to potential legislative, judicial or administrative change and differing interpretations, possibly on a retroactive basis.

The U.S. federal income tax treatment of our unitholders depends in some instances on determinations of fact and interpretations of complex provisions of U.S. federal income tax law for which no clear precedent or authority may be available. Our unitholders should be aware that the U.S. federal income tax rules, particularly those applicable to partnerships, are constantly under review (including currently) by the Congressional tax-writing committees and other persons involved in the legislative process, the IRS, the U.S. Treasury Department and the courts, frequently resulting in revised interpretations of established concepts, statutory changes, revisions to regulations and other modifications and interpretations, any of which could adversely affect the value of our units and be effective on a retroactive basis. For example, changes to the U.S. federal tax laws and interpretations thereof could adversely affect the U.S. federal income tax treatment of publicly traded partnerships, including changes that make it more difficult or impossible for our partnership (and Brookfield Infrastructure) to meet the "qualifying income" exception to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation and changes that reduce the net amount of distributions available to our unitholders. Such changes could also affect or cause us to change the way we conduct our activities, affect the tax considerations of an investment in our partnership, change the character or treatment of portions of our partnership's income (including changes that recharacterize certain allocations as potentially non-deductible fees) and adversely affect an investment in our units.

Our partnership's organizational documents and agreements permit our Managing General Partner to modify our limited partnership agreement from time-to-time, without the consent of our unitholders, to address certain changes in U.S. federal income tax regulations, legislation or interpretation. In some circumstances, such revisions could have a material adverse impact on some or all of our unitholders.

The IRS may not agree with certain assumptions and conventions that we use in attempting to comply with applicable U.S. federal income tax laws or that we use to report income, gain, loss, deduction and credit to our unitholders.

Our partnership will apply certain assumptions and conventions in an attempt to comply with applicable rules and to report income, gain, deduction, loss and credit to our unitholders in a manner that reflects such unitholders' beneficial ownership of partnership items, taking into account variation in ownership interests during each taxable year because of trading activity. Because our partnership cannot match transferors and transferees of our units, our partnership will adopt depreciation, amortization and other tax accounting conventions that may not conform with all aspects of existing Treasury regulations. In order to maintain the fungibility of all of our units at all times, we seek to achieve the uniformity of U.S. tax treatment for all purchasers of our units which are acquired at the same time and price (irrespective of the identity of the particular seller of the units or the time when the units are issued by our partnership) through the application of certain accounting principles that we believe are reasonable for our partnership. A successful IRS challenge to any of the foregoing assumptions or conventions could adversely affect the amount of tax benefits available to our unitholders and could require that items of income, gain, deductions, loss or credit, including interest deductions, be adjusted, reallocated or disallowed in a manner that adversely affects our unitholders. It also could affect the timing of these tax benefits or the amount of gain on the sale of our units and could have a negative impact on the value of our units or result in audits of and adjustments to our unitholders' tax returns.

Our unitholders may be subject to state, local and non-U.S. taxes and return filing requirements as a result of holding our units.

Our unitholders may be subject to state, local and non-U.S. taxes, including unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which either our partnership or Brookfield Infrastructure does business or owns property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders may be required to file income tax returns and pay income taxes in some or all of these jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each of our unitholders to file all U.S. federal, state, local and non-U.S. tax returns that may be required of such unitholder.

Our partnership may not be able to furnish to each of our unitholders specific tax information within 90 days after the close of each calendar year, which means that our unitholders who are U.S. taxpayers should anticipate the need to file annually a request for an extension of the due date of their income tax return.

It may require longer than 90 days after the end of our partnership's fiscal year to obtain the requisite information from all lower-tier entities so that Schedule K-1s may be prepared for our partnership. For this reason, our unitholders who are U.S. taxpayers should anticipate the need to file annually with the IRS (and certain states) a request for an extension past April 15 or the otherwise applicable due date of their income tax return for the taxable year. See Item 10.E "Taxation—United States Tax Considerations—Administrative Matters—Information Returns."

The sale or exchange of 50% or more of our units will result in the termination of our partnership for U.S. federal income tax purposes.

Our partnership will be considered to have been terminated for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of our units within a 12-month period. A termination of our partnership would, among other things, result in the closing of our taxable year for U.S. federal income tax purposes for all our unitholders and could result in possible acceleration of income to certain of our unitholders and certain other consequences that may adversely affect the value of our units. See Item 10.E "Taxation—United States Tax Considerations—Administrative Matters—Constructive Termination."

Canada

Tax proposals may deny the deductibility of losses arising from our unitholders' units in our partnership in computing their income for Canadian federal income tax purposes.

On October 31, 2003, the Department of Finance released for public comment tax proposals, or the REOP Proposals, regarding the deductibility of interest and other expenses for purposes of the Income Tax Act (Canada), or the Tax Act. Under the REOP Proposals, a taxpayer would be considered to have a loss from a source that is a business or property for a taxation year only if, in that year, it is reasonable to assume that the taxpayer will realize a cumulative profit (excluding capital gains or losses) from the business or property during the period that the business is carried on or that the property is held. In general, these proposals may deny the deduction of losses arising from our unitholders' units in our partnership in computing their income for Canadian federal income tax purposes in a particular taxation year, if, in the year the loss is claimed, it is not reasonable to expect that an overall cumulative profit would be earned from the investment in our partnership for the period in which our unitholders held and can reasonably be expected to hold the investment. Our Managing General Partner and the Infrastructure General Partner do not anticipate that the activities of our partnership and Brookfield Infrastructure will, in and of themselves, generate losses. However, investors may incur expenses in connection with an acquisition of units in our partnership that could result in a loss that would be affected by the REOP Proposals. The REOP Proposals have been the subject of a number of submissions to the Minister of Finance (Canada). As part of the 2005 federal budget, the Minister of Finance (Canada) announced that an alternative proposal to reflect the REOP Proposals would be released for comment at an early opportunity. No such alternative proposal has been released to date. There can be no assurance that such alternative proposal will not adversely affect our unitholders or that it may not differ significantly from the REOP Proposals described above and in Item 10.E "Taxation—Canadian Federal Income Tax Considerations."

If the non-Canadian subsidiaries in which Brookfield Infrastructure directly invests earn income that is foreign accrual property income our unitholders may be required to include amounts allocated from our partnership in computing their income for Canadian federal income tax purposes even though there may be no corresponding cash distribution.

Each of the non-Canadian subsidiaries in which Brookfield Infrastructure will directly invest is expected to be a "controlled foreign affiliate", as defined in the Tax Act, of Brookfield Infrastructure. If any of such non-Canadian subsidiaries earns income that is "foreign accrual property income", or FAPI, as defined in the Tax Act, in a taxation year, Brookfield Infrastructure's proportionate share of such FAPI must be included in computing the income of Brookfield Infrastructure for Canadian federal income tax purposes for the fiscal period of Brookfield Infrastructure in which the taxation year of such controlled foreign affiliate that earned the FAPI ends, whether or not Brookfield Infrastructure actually receives a distribution of such income. Our partnership will include its share of such FAPI of Brookfield Infrastructure in computing its income for Canadian federal income tax purposes and our unitholders will be required to include their proportionate share of such FAPI allocated from our partnership in computing their income for Canadian federal income tax purposes. As a result, our unitholders may be required to include amounts in their income even though they have not and may not receive an actual cash distribution of such amount.

If any of the non-Canadian subsidiaries in which Brookfield Infrastructure directly invests were not considered to be a controlled foreign affiliate of Brookfield Infrastructure or is a tracked interest, the interest in the non-Canadian subsidiary would be subject to the proposals regarding the taxation of investments in foreign investment entities, unless another exemption is available.

Each of the non-Canadian subsidiaries in which Brookfield Infrastructure will directly invest is expected to be a controlled foreign affiliate and not a tracked interest of Brookfield Infrastructure. On that basis, Brookfield Infrastructure's interest in such non-Canadian subsidiaries will be exempt from the legislative proposals regarding the taxation of investments in foreign investment entities or the FIE Proposals. However, if any of such non-Canadian subsidiaries becomes a tracked interest or ceases to be a controlled foreign affiliate of Brookfield Infrastructure or if interests in subsequently acquired non-Canadian subsidiaries are tracked interests or such subsequently acquired non-Canadian subsidiaries are not controlled foreign affiliates of Brookfield Infrastructure, Brookfield Infrastructure's interest in such non-Canadian subsidiary would be subject to the FIE Proposals, unless another exemption from the FIE Proposals is available. If the FIE Proposals were to apply, the income tax consequences of an investment in our partnership could be materially different in certain respects from those described in Item 10.E "Taxation—Canadian Federal Income Tax Considerations," and our unitholders may be required to include amounts in their income even though they have not and may not receive an actual cash distribution of such amount.

Unitholders who are not resident in Canada may be subject to Canadian federal income tax with respect to any Canadian source business income earned by our partnership or Brookfield Infrastructure if our partnership or Brookfield Infrastructure were considered to carry on business in Canada.

If our partnership or Brookfield Infrastructure were considered to carry on a business in Canada for purposes of the Tax Act, unitholders who are not resident in Canada or deemed to be resident in Canada for purposes of the Tax Act, or non-Canadian limited partners, would be subject to Canadian federal income tax on their proportionate share of any Canadian source business income earned or considered to be earned by our partnership, subject to the potential application of the safe harbour rule in section 115.2 of the Tax Act and any relief that may be provided by any relevant income tax treaty or convention.

Our Managing General Partner and the Infrastructure General Partner intend to manage the affairs of our partnership and Brookfield Infrastructure, to the extent possible, so that they do not carry on business in Canada and are not considered or deemed to carry on business in Canada for purposes of the Tax Act. Nevertheless, because the determination of whether our partnership or Brookfield Infrastructure is carrying on business and, if so, whether that business is carried on in Canada, is a question of fact that is dependent upon the surrounding circumstances, the CRA might contend successfully that either or both of our partnership and Brookfield Infrastructure carries on business in Canada for purposes of the Tax Act.

If our partnership or Brookfield Infrastructure is considered to carry on business in Canada or is deemed to carry on business in Canada for the purposes of the Tax Act, non-Canadian limited partners that are corporations would be required to file a Canadian federal income tax return for each of the taxation years in which they were a non-Canadian limited partner regardless of whether relief from Canadian taxation is available under an applicable income tax treaty or convention. Non-Canadian limited partners who are individuals would only be required to file a Canadian federal income tax return for any taxation year in which they are allocated income from our partnership from carrying on business in Canada that is not exempt from Canadian taxation under the terms of an applicable income tax treaty or convention. However, for 2009 and subsequent years non-Canadian limited partners will not be required to file a Canadian federal income tax return in respect of a disposition of taxable Canadian property by our Partnership or Brookfield Infrastructure if the deposition is an "excluded disposition" (as discussed below).

Non-Canadian limited partners may be subject to Canadian federal income tax on capital gains realized by our partnership or Brookfield Infrastructure on dispositions of "taxable Canadian property".

A non-Canadian limited partner will be subject to Canadian federal income tax on its proportionate share of capital gains realized by our partnership or Brookfield Infrastructure on the disposition of "taxable Canadian property" as defined in the Tax Act (which includes, but is not limited to, property that is used or held in a business carried on in Canada, shares of corporations resident in Canada that are not listed on a designated stock exchange, and listed shares where the number of shares owned exceeds prescribed amounts) other than "treaty protected property" as defined in the Tax Act. Property of our partnership and Brookfield Infrastructure generally will be treaty-protected property to a non-Canadian limited partner if the gain from the disposition of the property would, because of an applicable income tax treaty or convention, be exempt from tax under the Tax Act. Our Managing General Partner and the Infrastructure General Partner advise that our partnership and Brookfield Infrastructure are not expected to realize capital gains or losses from dispositions of taxable Canadian property. However, no assurance can be given in this regard. For 2009 and subsequent years non-Canadian limited partners will not be required to file a Canadian federal income tax return in respect of a disposition of taxable Canadian property by our partnership or Brookfield Infrastructure if the disposition is an "excluded disposition" for the purposes of the Tax Act. However, non-Canadian limited partners that are corporations will still be required to file a Canadian federal income tax return in respect of a disposition if tax would otherwise be payable under Part I of the Tax Act by the non-Canadian limited partner in respect of the disposition but is not because of a tax treaty. In general, an "excluded disposition" is a disposition of property by a taxpayer in a taxation year where (a) the taxpayer is a non-resident of Canada at the time of the disposition; (b) no tax is payable by the taxpayer under Part I of the Tax Act for the taxation year; (c) the taxpayer is not liable to pay any amounts under the Tax Act in respect of any previous taxation year (other than certain amounts for which CRA holds adequate security);

and (d) each taxable Canadian property disposed of by the taxpayer in the taxation year is either (i) "excluded property" as defined in subsection 116(6) of the Tax Act or (ii) is property in respect of the disposition of which a certificate under subsection 116(2),(4) or (5.2) has been issued by CRA. Non-Canadian limited partners should consult their own tax advisors with respect to the requirements to file a Canadian federal income tax return in respect of a disposition of taxable Canadian property by our partnership or Brookfield Infrastructure after 2008.

Non-Canadian limited partners may be subject to Canadian federal income tax on capital gains realized on the disposition of our units if our units are taxable Canadian property.

Any capital gain arising from the disposition or deemed disposition of our units by a non-Canadian limited partner will be subject to taxation in Canada, if, at the time of the disposition or deemed disposition, the units are taxable Canadian property, unless the units are treaty-protected property to such non-Canadian limited partner. In general, our units will be taxable Canadian property at the time of disposition or deemed disposition if, at any time within the 60-month period ending at the time of disposition or deemed disposition, the fair market value of all of the properties of our partnership that were taxable Canadian property, certain types of resource properties, income interests in trusts resident in Canada or interests in or options in respect thereof, was greater than 50% of the fair market value of all of its properties. Since our partnership's assets will consist principally of units of Brookfield Infrastructure, our units would generally be taxable Canadian property if the units of Brookfield Infrastructure held by us were considered to be used or held by us in a business carried on in Canada or if applying the greater than 50% test to Brookfield Infrastructure, its units were taxable Canadian property at any time during the relevant 60-month period. Units of our partnership will be treaty protected property if the gain on the disposition of the units is exempt from tax under the Tax Act under the terms of an applicable income tax treaty or convention. Our Managing General Partner advises that our units are not expected to be taxable Canadian property but no assurance can be given in this regard. See Item 10.E "Taxation—Canadian Federal Income Tax Considerations—Taxation of Non-Canadian Limited Partners." Prior to 2009, if our units constitute taxable Canadian property, non-Canadian limited partners will be required to file a Canadian federal income tax return for any taxation year in which the non-Canadian limited partner disposes of our units even if any gain arising therefrom is exempt from Canadian federal income tax under an applicable income tax treaty or convention. For 2009 and subsequent years, if our units constitute taxable Canadian property, non-Canadian limited partners will not be required to file a Canadian federal income tax return in respect of a disposition of our units if the disposition is an excluded disposition (as discussed above). If our units constitute taxable Canadian property, non-Canadian limited partners should consult their own tax advisors with respect to the requirement to file a Canadian federal income tax return in respect of a disposition of our units after 2008.

Non-Canadian limited partners may be subject to Canadian federal reporting and withholding tax requirements on the disposition of taxable Canadian property.

Non-Canadian limited partners who dispose of taxable Canadian property, other than "excluded property" as defined in the Tax Act (or who are considered to have disposed of such property on the disposition of such property by our partnership or Brookfield Infrastructure), are obligated to comply with the procedures set out in section 116 of the Tax Act and obtain a certificate thereunder. In order to obtain such certificate, the non-Canadian limited partner is required to report certain particulars relating to the transaction to the CRA either prior to the transaction or not later than 10 days after the disposition occurs. Our Managing General Partner advises that our units are not expected to be taxable Canadian property and our Managing General Partner and the Infrastructure General Partner advise that our partnership and Brookfield Infrastructure are not expected to dispose of property that is taxable Canadian property but no assurance can be given in these regards.

Payments of dividends or interest (other than interest exempt from Canadian federal withholding tax) by residents of Canada to Brookfield Infrastructure will be subject to Canadian federal withholding tax and we may be unable to apply a reduced rate taking into account the residency or entitlement to relief under an applicable income tax treaty or convention of our unitholders.

Our partnership and Brookfield Infrastructure will be deemed to be a non-resident person in respect of certain amounts paid or credited to them by a person resident or deemed to be resident in Canada, including dividends or interest. Dividends or interest (other than interest exempt from Canadian federal withholding tax) paid by a person resident or deemed to be resident in Canada to Brookfield Infrastructure will be subject to withholding tax under Part XIII of the Tax Act at the rate of 25%. However, CRA's administrative practice in similar circumstances is to permit the rate of Canadian federal withholding tax applicable to such payments to be computed by looking through the partnership and taking into account the residency of the partners (including partners who are resident in Canada) and any reduced rates of Canadian federal withholding tax that any non-Canadian limited partners may be entitled to under an applicable income tax treaty or convention provided that the residency status and entitlement to treaty benefits can be established. In determining the rate of Canadian federal withholding tax applicable to amounts paid by the Holding Entities to Brookfield Infrastructure, we expect the Holding Entities to look-through Brookfield Infrastructure and our partnership to the residency of the partners of our partnership (including partners who are residents of Canada) and to take into account any reduced rates of Canadian federal withholding tax that non-Canadian limited partners may be entitled to under an applicable income tax treaty or convention in order to determine the appropriate amount of Canadian federal withholding tax to withhold from dividends or interest paid to Brookfield Infrastructure. However, there can be no assurance that CRA would apply its administrative practice in this context. If CRA's administrative practice is not applied and the Holding Entities withhold Canadian federal withholding tax from applicable payments on a look-through basis, the Holding Entities may be liable for additional amounts of Canadian federal withholding tax plus any associated interest and penalties. Pursuant to recent amendments made by the "Fifth Protocol" to the Canada-U.S. Tax Treaty, a Canadian resident payer may be required to look-through fiscally transparent partnerships such as our partnership and Brookfield Infrastructure to the residency of limited partners of our partnership who are entitled to relief under that treaty and take into account reduced rates of Canadian federal withholding tax that such limited partners may be entitled to under that treaty.

While we expect the Holding Entities to look-through our partnership and Brookfield Infrastructure in determining the rate of Canadian federal withholding tax applicable to amounts paid by the Holding Entities to Brookfield Infrastructure, we may be unable to accurately or timely determine the residency of our unitholders for purposes of establishing the extent to which Canadian federal withholding taxes apply or whether reduced rates of withholding apply to some or all of our unitholders. In such a case, we will withhold Canadian federal withholding tax from all payments made to Brookfield Infrastructure that are subject to Canadian federal withholding tax at the rate of 25%. Canadian resident unitholders will be entitled to claim a credit for such taxes against their Canadian federal income tax liability but non-Canadian limited partners will need to take certain steps to receive a refund or credit in respect of any such Canadian federal withholding taxes withheld equal to the difference between the withholding tax at a rate of 25% and the withholding tax at the reduced rate they are entitled to under an applicable income tax treaty or convention. See Item 10.E "Taxation—Canadian Federal Income Tax Considerations" for further detail. Investors should consult their own tax advisors concerning all aspects of Canadian federal withholding taxes.

We may not be able to provide unitholders with specific information required to file their Canadian federal income tax returns by the time such tax returns are due.

We may not be able to provide unitholders with specific information required to file their Canadian federal income tax returns by the time such tax returns are due. In such cases, our unitholders who are required to file Canadian federal income tax returns will be required to estimate the income or loss arising in respect of their investment in our partnership for the relevant year. This could result in liability for additional taxes, interest and possibly penalties if the actual amount of income allocable from the investment in our partnership for such year turns out to be higher.

Our units may or may not continue to be "qualified investments" under the Tax Act for registered plans.

Units of our partnership should be "qualified investments" under the Tax Act for trusts governed by registered retirement savings plans, deferred profit sharing plans, registered retirement income funds, registered education savings plans, registered disability savings plans, and commencing 2009, tax-free savings accounts, collectively registered plans, provided that our units are listed on a designated stock exchange (which would include the NYSE). In certain limited circumstances Units of our partnership might not be a qualified investment. Unitholders should consult their own tax advisors for advice with respect to whether our units would be a prohibited investment for their tax-free savings account. There can also be no assurance that tax laws relating to qualified investments will not be changed. Taxes may be imposed in respect of the acquisition or holding of non-qualified investments by registered plans and certain other taxpayers.

The Canadian federal income tax consequences to our unitholders could be materially different in certain respects from those described in this Form 20-F if our partnership or Brookfield Infrastructure is a "specified investment flow-through" partnership.

Under the SIFT Rules, certain income and gains earned by a "specified investment flow-through" partnership, or SIFT Partnership, will be subject to income tax at a rate similar to a corporation and allocations of such income and gains to its partners will be taxed as a dividend from a taxable Canadian corporation. In particular, a SIFT Partnership will be required to pay a tax on the total of its income from businesses carried on in Canada, income from "non-portfolio properties" as defined in the SIFT Rules (other than taxable dividends), and taxable capital gains from dispositions of non-portfolio properties. "Non-portfolio properties" include, among other things, equity interests or debt of corporations, trusts or partnerships that are resident in Canada, and of non-resident persons or partnerships the principal source of income of which is one or any combination of sources in Canada, that are held by the SIFT Partnership and have a fair market value that is greater than 10% of the equity value of such entity, or that have, together with debt or equity that the SIFT Partnership holds of entities affiliated with such entity, an aggregate fair market value that is greater than 50% of the equity value of the SIFT Partnership. The tax rate applied to the above mentioned sources of income and gains is set at a rate equal to the federal corporate tax rate, plus an amount on account of provincial tax.

Under the SIFT Rules, our partnership and Brookfield Infrastructure could each be a SIFT Partnership if it is a "Canadian resident partnership". However, Brookfield Infrastructure would not be a SIFT Partnership if our partnership is a SIFT Partnership, whether or not Brookfield Infrastructure is a Canadian resident partnership. Our partnership and Brookfield Infrastructure will be a "Canadian resident partnership" if the central management and control of these partnerships is located in Canada. This determination is a question of fact and is expected to depend on where our Managing General Partner and the Infrastructure General Partner are located and exercise central management and control of the respective partnerships. Our Managing General Partner and the Infrastructure General Partner advise that they will each take appropriate steps so that the central management and control of these entities is not located in Canada such that the SIFT Rules should not apply to our partnership and Brookfield Infrastructure at any relevant time. However, no assurance can be given in this regard. If our partnership or Brookfield Infrastructure are SIFT Partnerships under the SIFT Rules, the Canadian income tax consequences to our unitholders could be materially different in certain respects from those described in Item 10.E "Taxation—Canadian Federal Income Tax Considerations." In addition, even if the SIFT Rules do not apply to our partnership or to Brookfield Infrastructure at any relevant time, there can be no assurance that the SIFT Rules will not be revised or amended in the future such that the SIFT Rules will apply.

ITEM 4. INFORMATION ON THE COMPANY

4.A HISTORY AND DEVELOPMENT OF BIP

Our partnership, Brookfield Infrastructure Partners L.P., is a Bermuda exempted limited partnership that was established on May 21, 2007 under the provisions of the Exempted Partnership Act, 1992 of Bermuda and the Limited Partnership Act, 1883 of Bermuda. Our registered office is Cannon's Court, 22 Victoria Street, Hamilton HM 12, Bermuda. Our head office is 7 Reid Street, 4th Floor, Hamilton HM 11, Bermuda and our telephone number at that address is +1 441 296-4480.

Our partnership and its related entities were established by Brookfield Asset Management as its primary vehicle to own and operate certain infrastructure assets on a global basis. Brookfield was a promoter of the spinoff within the meaning of applicable Canadian securities legislation for its role in founding and organizing our partnership. We focus on high quality, long-life assets that generate stable cash flows, require relatively minimal maintenance capital expenditures and, by virtue of barriers to entry or other characteristics, tend to appreciate in value over time. Our current operations consist of electricity transmission systems, timberlands and social infrastructure projects, but we intend to seek acquisition opportunities in other sectors with similar attributes and in which we can deploy our operations-oriented approach to create value. Our Manager is an affiliate of Brookfield. Our sole material asset is a 60% limited partnership interest in Brookfield Infrastructure, a limited partnership through which we indirectly hold all of our current operations. Brookfield holds the remaining 40% interest in Brookfield Infrastructure through a 1% general partnership interest and a 39% limited partnership interest. Brookfield's 1% general partnership interest in Brookfield Infrastructure also entitles it to receive incentive distributions from Brookfield Infrastructure. The economic interests in Brookfield Infrastructure noted above do not reflect the exercise of the equity commitment referred to in this Form 20-F or interests to be acquired under Brookfield Infrastructure's distribution reinvestment plan.

All of the interests in our partnership, from its formation until the completion of the spin-off on January 31, 2008, were held by Brookfield and its subsidiaries. Prior to the spin-off, Brookfield effected a reorganization so that our electricity transmission and timber operations were held by the Holding Entities, the common shares of which are wholly-owned by Brookfield Infrastructure. Prior to the spin-off, Brookfield held an approximate 60% limited partnership interest in Brookfield Infrastructure and one or more wholly-owned subsidiaries of Brookfield held the remaining 40% interest in Brookfield Infrastructure through a 1% general partnership interest and an approximate 39% limited partnership interest. In order to complete the spin-off, Brookfield transferred the approximate 60% limited partnership interest in Brookfield Infrastructure that it held to our partnership in consideration for our units. These units were then distributed by Brookfield on January 31, 2008 to holders of record of its Class A limited voting shares and Class B limited voting shares as a special dividend. The remaining limited partnership interest in Brookfield Infrastructure held by one or more wholly-owned subsidiaries of Brookfield is subject to the Redemption-Exchange Mechanism.

Brookfield had acquired the following interests in our electricity transmission and timber operations prior to the spin-off: (i) a 50% interest in Island Timberlands, our Canadian timber operations, in May 2005; (ii) a 27.8% interest in Transelec, our Chilean transmission operations, in June 2006; (iii) 7%-18% interests in TBE, a group of five related transmission investments in Brazil, in 2006; (iv) a 100% interest in Great Lakes Power Transmission L.P., our Ontario transmission operations, in 1982; and (v) a 100% interest in Longview, our U.S. timber operations, on April 20, 2007. Upon completion of the spin-off and certain follow-on transactions, Brookfield transferred to us certain interests in these assets. Brookfield retained an interest in each of Transelec, Island Timberlands and Longview, and therefore the infrastructure division's ownership interests in these operations is different than the current ownership interests of Brookfield Infrastructure. Brookfield acquired its interests in our social infrastructure operations through its acquisition of Brookfield Multiplex (formerly Multiplex Limited) in October 2007.

Our current operations include interests in electricity transmission assets held directly and through consortiums in Chile, Brazil and Canada, comprised of:

- a 17.8% interest in Transelec which owns approximately 8,200 kilometers, or km, of transmission lines in Chile that serve 98% of the population of the country which include 100% of Chile's 500 kV transmission lines, the highest voltage lines in the country, and approximately 45% and 95% of the 200kV and 154 kV lines in Chile, respectively;
- ownership of 7% to 18% interests in a group of five related transmission investments comprising over 2,100 km of transmission lines in Brazil, with one transmission line located in the south and the remaining four lines located in the northeast. Four of the lines are rated 500 kV or higher and one line is rated at 230 kV. The transmission lines began service between 2002 and 2005; and
- a 100% interest in Great Lakes Power Transmission L.P. which owns approximately 550 km of 44 kV to 230 kV transmission lines in Canada that comprise an important component of Ontario's

transmission system that connects generation in Northern Ontario to electricity demand in Southern Ontario. Our Ontario operations were transferred by Brookfield to us on March 12, 2008 following receipt of required regulatory approvals.

On September 23, 2008, we exercised our option to sell our interests in TBE to a Brazilian state-owned utility. See Item 4.B "Business Overview—Current Operations—Electricity Transmission" for further detail.

Our current operations also include interests in timberlands held in partnership with Brookfield and other consortium members in the coastal region of British Columbia, Canada and the Pacific Northwest region of the United States, comprised of:

- a 37.5% interest in Island Timberlands which owns approximately 634,000 acres of freehold timberlands located principally on Vancouver Island with an estimated merchantable inventory of 58.0 million cubic meters, or m^3, primarily comprised of high value Douglas-fir, Hemlock and Cedar with a long-run sustainable yield of 1.8 million m^3, and approximately 33,163 acres of higher and better use properties, or HBU lands, which are properties that we believe will have greater value if used for a purpose other than as timberlands, such as real estate development or conservation; and
- a 30% interest in Longview (7% of which is held through the Brookfield Global Timber Fund) which owns approximately 655,000 acres of freehold timberlands in Oregon and Washington with an estimated merchantable inventory of 42.1 million m^3, primarily comprised of high value Douglas-fir and Hemlock with a long-run sustainable yield of 2.6 million m^3.

In addition, we have the ability to acquire an additional indirect interest in Longview in the event that Brookfield contributes its remaining interest in Longview to a timberlands focused partnership with institutional investors. We have agreed that we will participate in any such partnership through a commitment of up to $600 million provided that: (i) third party institutional investors commit at least $400 million; (ii) the transfer of Longview is at a price equal to the appraised value of the timberlands and real estate plus working capital, and (iii) the transaction is completed within 18 months. Our agreement is also subject to a financing condition in our favor.

Our social infrastructure operations were acquired from an affiliate of Brookfield following the spin-off on the dates indicated below. These assets are comprised of the following PPP interests:

- a 50% interest in Long Bay Forensic and Prison Hospitals located in Sydney, Australia comprised of a 135-bed forensic hospital, 85-bed prison hospital and administration building, acquired on December 5, 2008;
- a 30% interest in Peterborough Hospital located in Peterborough, United Kingdom comprised of a 612-bed acute hospital, 102- bed mental health unit and an integrated care center, acquired on December 5, 2008; and
- a 50% interest in Royal Melbourne Showgrounds located in Melbourne, Australia consisting of a special purpose exhibition facility on a 19 ha site comprising office complexes, open air arenas and large scale tension structures, acquired on February 3, 2009.

About Brookfield

Brookfield is a global asset management company focused on property, power and other infrastructure assets with approximately $80 billion of assets under management and more than 400 investment professionals and 14,000 operating employees around the world. Brookfield's strategy, which is part of our strategy as well, is to combine best-in-class operating platforms and best-in-class transaction execution capabilities to acquire and invest in targeted assets and actively manage them in order to achieve superior returns.

4.B BUSINESS OVERVIEW

Our Partnership

Our partnership and its related entities were established by Brookfield Asset Management as its primary vehicle to own and operate certain infrastructure assets on a global basis. We focus on high quality, long-life assets that generate stable cash flows, require relatively minimal maintenance capital expenditures and, by virtue of barriers to entry or other characteristics, tend to appreciate in value over time. Our current operations consist principally of the ownership and operation of electricity transmission systems, timberlands and social infrastructure, but we intend to seek acquisition opportunities in other sectors with similar attributes and in which we can deploy our operations oriented approach to create value. Our Manager is an affiliate of Brookfield. Our sole material asset is a 60% limited partnership interest in Brookfield Infrastructure, a limited partnership through which we indirectly hold all of our current operations.

Current Operations

Electricity Transmission

Overview

Electricity transmission assets provide the critical link for the high-voltage transmission of electricity from generators to consumers of electricity. Electricity transmission is a natural monopoly and is generally provided by a single supplier, with revenues regulated either on a cost plus basis or under long-term concessions. Both of these revenue mechanisms provide secure cash flow streams that, in many instances, are not subject to volume or utilization risk. Due to their combination of high capital costs and low variable costs, electricity transmission systems generally have very high operating margins. Since the cost of electricity transmission is typically a minor component of an end user's electricity bill, regulators in many jurisdictions are sanctioning pricing regimes that encourage capital investment to ensure reliability and support economic growth rather than focusing on lowering transmission rates.

Our current electricity transmission assets are held directly and through consortiums in Chile, Brazil and Canada.

Location	Description	Our Interest
Chile	approximately 8,200 km of transmission lines that serve 98% of the population of the country which include 100% of Chile's 500 kV transmission lines, the highest voltage lines in the country, and approximately 45% and 95% of the 200 kV and 154 kV lines in Chile, respectively	17.8%(1)
Brazil	over 2,100 km of transmission lines, with one transmission line located in the south and the remaining four lines located in the northeast. Four of the lines are rated 500 kV or higher and one line is rated at 230 kV. The transmission lines began service between 2002 and 2005	7% to 18%(2)
Canada	approximately 550 km of 44 kV to 230 kV transmission lines that comprise an important component of Ontario's transmission system that connects generators in Northern Ontario to electricity demand in Southern Ontario	100%(3)

(1) Percentage includes the increase in ownership resulting from the April 4, 2008 purchase price adjustment which was made upon finalization of the previous transmission industry rate proceeding.

(2) Our Brazilian transmission investments are comprised of interests in a group of five related transmission operations owned with four other industry partners, with ownership in each asset ranging from 7% to 18%. On September 23, 2008, we exercised our option to sell our interests in TBE to a Brazilian state-owned utility. See below for further detail.

(3) Our Ontario transmission operations were transferred by Brookfield to us on March 12, 2008 following receipt of required regulatory approvals.

Our Chilean operations were acquired by Brookfield on June 30, 2006 from Hydro Quebec International Inc. and International Finance Corporation by a consortium of buyers led by Brookfield. As part of the stock purchase agreement between the parties, the buyers agreed to pay a purchase price adjustment of $160 million that was determined on April 4, 2008 following the final resolution of the previous transmission industry rate proceeding. In conjunction with our disproportionate funding of this purchase price adjustment, our ownership in Transelec increased from 10.7% to 17.8%.

Brookfield acquired our Brazilian transmission investments in July 2006. These investments were transferred to us in November 2007. Our Brazilian transmission investments are comprised of interests in a group of five related transmission operations owned with four other industry partners with ownership ranging from 7% to 18%. On September 23, 2008, we exercised our option to sell our interests in TBE to a Brazilian state-owned utility. Closing of the transaction is expected in the second quarter of 2009, subject to the receipt of regulatory and other approvals. After-tax proceeds from the sale are expected to be approximately $274 million, of which $68 million has already been received from realized hedge gains.

Our Ontario transmission operations were transferred to us on March 12, 2008 upon receipt of approval by the Ontario Energy Board, or OEB.

Revenue Framework

The revenue framework for our transmission operations is a combination of regulated sales, concessions and long-term contracts with large customers.

In Chile, which has a long tradition of supportive regulatory frameworks for utility assets, regulated revenues are determined every four years based on a 10% annuity return on replacement cost of the existing transmission system for high voltage transmission (500 kV or above) plus annual payments that provide for recovery of operational, maintenance and administrative costs. Between rate reviews, both revenue components are adjusted on a semi-annual basis by a multi-component inflation index that is designed to approximate the changes in underlying costs drivers. The replacement, operational, maintenance and administration costs, the indexation formula and the asset life of the transmission system are determined every four years in a transmission study performed by an independent consultant, subject to final approval by the experts' panel, which is the arbitrator for the electricity industry in Chile. Once revenue has been calculated, it is allocated to market participants as a fixed charge; thus our Chilean high voltage transmission operations do not have volume risk. For lower voltage transmission lines the framework for regulatory revenues is similar to that for high voltage transmission lines; however, the 10% annuity return is assessed on the demand adapted system, which factors in projected usage of the system over a forecast period in determining replacement cost. Since our regulated Chilean operations earn a 10% annuity return on replacement cost, we effectively earn a real pre-tax 10% return on capital investments. In addition, the 10% return rate framework is provided for by Chilean law which would require legislative action to revise.

Approximately 60% of our revenues in Chile are derived from a number of long-term transmission contracts, primarily with power generators. These contracts have a pricing framework that is similar to the regulatory framework; however, we believe these contracts have greater certainty than our regulated revenues since all of the material drivers such as the regulated asset base and the indexation formula are stipulated in the contracts rather than periodically determined. The largest of these contracts expires in 2016. Following the expiration of these contracts, a majority of this contracted revenue will convert to the regulatory framework; the balance remaining contractual. We believe that the risks of default or non-renewal on similar terms for these contracts is relatively low because transmission is an essential operating expense that must be paid by generators in order for them to sell the power output of their generating assets. In particular, our largest single customer's power generation portfolio is comprised principally of hydroelectric facilities, which we believe have a minimal risk of shut down for economic reasons.

For both the regulated and contracted revenues of our Chilean operations, we earn a return on replacement cost that is comprised of Chilean pesos and U.S. dollars. As a result, even though our revenues are converted into Chilean pesos and billed to customers on a monthly basis, we economically have a combination of Chilean peso and U.S. dollar revenue.

Pursuant to Chilean law, for our high voltage transmission lines we have the exclusive ability to invest in any approved upgrades to our trunk transmission asset base at rates determined in accordance with the Chilean regulatory framework described above. Expansions to the transmission system are put out to competitive bid, under which the qualified bidder with the lowest fixed price 20-year toll is awarded the project. Due to our scale within Chile and our intimate knowledge of the transmission system and permitting landscape, we believe that we are well positioned to compete for expansion projects. For our lower voltage transmission lines, we have the discretion to invest in upgrades and expansions of our system, as well as the responsibility to invest sufficient capital to maintain reliability without having to obtain regulatory approval to obtain reimbursement.

In Brazil, the federal electricity regulator, Agência Nacional de Energía Eléctrica regulates expansion of the transmission system through the award of long-term concessions. Concessionaires are remunerated based on Annual Permitted Revenues, or APR, that is adjusted annually to account for changes in Brazilian inflation. APR is independent of load, volume or utilization of the transmission lines. Extraordinary revisions to APR are permissible due to changes in taxes, regulatory charges, required investments and other items that alter the economic-financial equilibrium of the concession in the view of the regulator. APR is subject to pre-specified penalties due to transmission line unavailability. In order to facilitate the financing of new projects, transmission concession revenues are front end loaded and have a single step down provision which reduces the capacity component of APR by 50% beginning in year 16 of transmission following commencement of operations for the remaining term of the 30-year concession.

Our Brazilian transmission investees generate their revenues in reis under five separate 30-year concession agreements. The average remaining life of our concessions is 26 years. Under the capacity component of revenues for each respective concession will be reduced by 50% beginning in 2017 through 2020, as provided under the concession agreements.

Our Brazilian transmission investments are subject to put/call agreements with third parties whereby we have the right to sell and the third parties have the right to buy our investments at a price that will yield a real, compounded annual return equal to 14.8% paid in Brazilian reis, including all distributions received to that date. On September 23, 2008, we exercised our option to sell our interests in TBE to a Brazilian state-owned utility. After-tax proceeds from the sale are expected to be approximately $274 million, of which $68 million has already been received from realized hedge gains. Closing is expected in the second quarter of 2009, subject to the receipt of regulatory and other approvals.

Although it is a high quality transmission asset, Brookfield Infrastructure's investment in TBE is passive.

In Ontario, transmission revenues are based on periodic rate cases in which the OEB determines allowed revenue that provides for recovery of our operating and financing costs plus an after-tax return on equity.

Currently, we are allowed to earn an 8.61% return on the equity, which is deemed to be 45% of our rate base. In Ontario, regulated rate base is equal to the historic cost of the system assets plus any capital expenditures less depreciation and other deductibles. The regulatory framework in Ontario does not provide for any inflationary adjustments. Once our revenue requirement has been determined, the OEB establishes tariffs. All transmission tariffs are combined into one pool and allocated to system users throughout the province. Our operating revenues do not fluctuate with usage of our system but do fluctuate based on provincial electric loads which are measured by the Independent Electricity System Operator. We expect our next rate review will occur in 2009 for implementation in 2010.

The principal means to grow our Ontario operations is to invest capital in excess of depreciation. Brookfield recently completed the construction of an $80 million upgrade to the system in Northern Ontario which increased adjusted net operating income. In the near term, we expect that our capital expenditures will exceed depreciation by approximately $15 million. Over the longer term, there are a number of potential electricity transmission projects in Ontario under development. If any of these projects come to fruition, we expect that we will have an opportunity to further grow our regulated rate base and corresponding earnings.

Key Highlights of our Electricity Transmission Operations

We believe that our transmission operations have a number of favorable characteristics that position us well for continued strong and growing cash flows as follows:

- ***Stable revenues with inflationary growth.*** Due to our regulatory frameworks and contracts, combined with the essential nature of our service, our transmission systems have a very secure competitive position. All three systems generate stable revenue with no material volume risk and, in many instances, have automatic inflation escalators. Revenues for all three of our transmission operations are spread across a large user base, or have high quality credit investors, mitigating credit risk.
- ***Constructive regulatory regimes.*** Our Chilean and Brazilian systems are subject to favorable regulatory regimes. Our Chilean system's 10% return on replacement cost is stipulated in Chilean law. Thus, a change of law would be required to reduce this return. Furthermore, since it is a return on total assets, the risk that a regulator reduces rates based upon actual capital structure deployed is reduced. For our Brazilian system, rates are established in the concession agreement. The only factor that causes rates to fluctuate during the concession period is the cumulative change in Brazilian inflation.
- ***Strong free cash flow generation.*** Since the Chilean regulatory and contractual frameworks are based on replacement cost and the Brazilian revenues are based on stipulated contractual amounts, we are not required to invest at our level of depreciation to prevent a decline in revenues in those countries. Since both systems are in good physical condition, maintenance capital expenditures are at relatively low levels. As a result of high profit margins combined with low maintenance capital expenditures, our transmission operations generate strong cash flow.
- ***Expansion opportunities.*** Our Chilean and Ontario systems have significant revenue generating capital investment opportunities. Both Chile and Canada have economic generation that is many miles away from customers. Upgrades and expansions of the electricity transmission system will be required to connect this economic generation to load centers to satisfy increased electricity demand resulting from economic growth. In addition, our Chilean operations are also well positioned to pursue opportunities to expand their subtransmission lines to augment their existing network.

Timber

Overview

Timber is a vital component of the global economy. In North America, timber is generally harvested for one of three types of end users: (1) lumber mills (which use saw logs to produce lumber), (2) pulp mills (which use pulpwood as a major source of fiber for use in the paper and containerboard industries) and (3) other wood products such as boards, structural and non-structural panels, moldings, etc. In addition, timber by-products are being increasingly viewed as a source of fuel or feed stock for biomass energy and ethanol production.

The use of timber in new home construction results in exposure to general economic and housing construction cycles. However, use in the much less cyclical repair and renovation and general construction markets as well as diversification across export markets provides mitigation to economic cycles. In addition, timber can either be harvested and sold in attractive price environments or "warehoused on the stump" for later harvest if and when prices recover. This ability to delay harvest and increase the value of timber inventory allows timberland owners to maximize the long-term value of timberlands by matching harvest opportunities to market conditions. Furthermore, this ability to warehouse timber has historically moderated timber supply and pricing, resulting in the volatility of timber prices being less than the volatility of prices for finished forest products such as oriented strand board, framing lumber, pulp, newsprint and fine papers.

Our current timberlands assets are held in partnership with Brookfield and other consortium members and are located in the coastal region of British Columbia, Canada and the Pacific Northwest region of the United States.

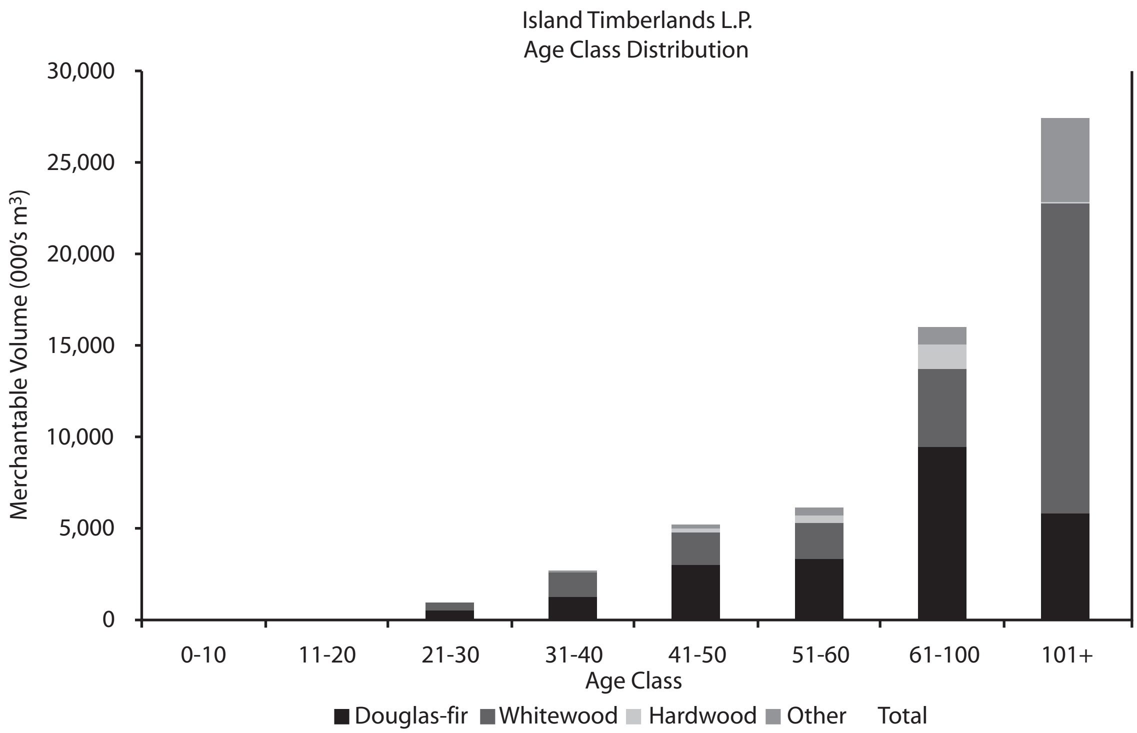
Location	Description	Our Ownership Percentage
Coastal British Columbia, Canada	approximately 634,000 acres of freehold timberlands located principally on Vancouver Island with an estimated merchantable inventory of 58.0 million m^3, primarily comprised of high value Douglas-fir, Hemlock and Cedar with a long-run sustainable yield of 1.8 million m^3 and approximately 33,163 acres of HBU lands	37.5%
Oregon and Washington, United States	approximately 655,000 acres of freehold timberlands in Oregon and Washington with an estimated merchantable inventory of 37.5 million m^3, primarily comprised of high value Douglas-fir and Hemlock with a long-run sustainable yield of 2.6 million m^3	30%

In addition, we have the ability to acquire an additional indirect interest in Longview in the event that Brookfield contributes its remaining interest in Longview to a timberlands focused partnership with institutional investors. We have agreed that we will participate in any such partnership through a commitment of up to $600 million provided that: (i) third party institutional investors commit at least $400 million; (ii) the transfer of Longview is at a price equal to the appraised value of the timberlands and real estate plus working capital, and (iii) the transaction is completed within 18 months. Our agreement is also subject to a financing condition in our favour.

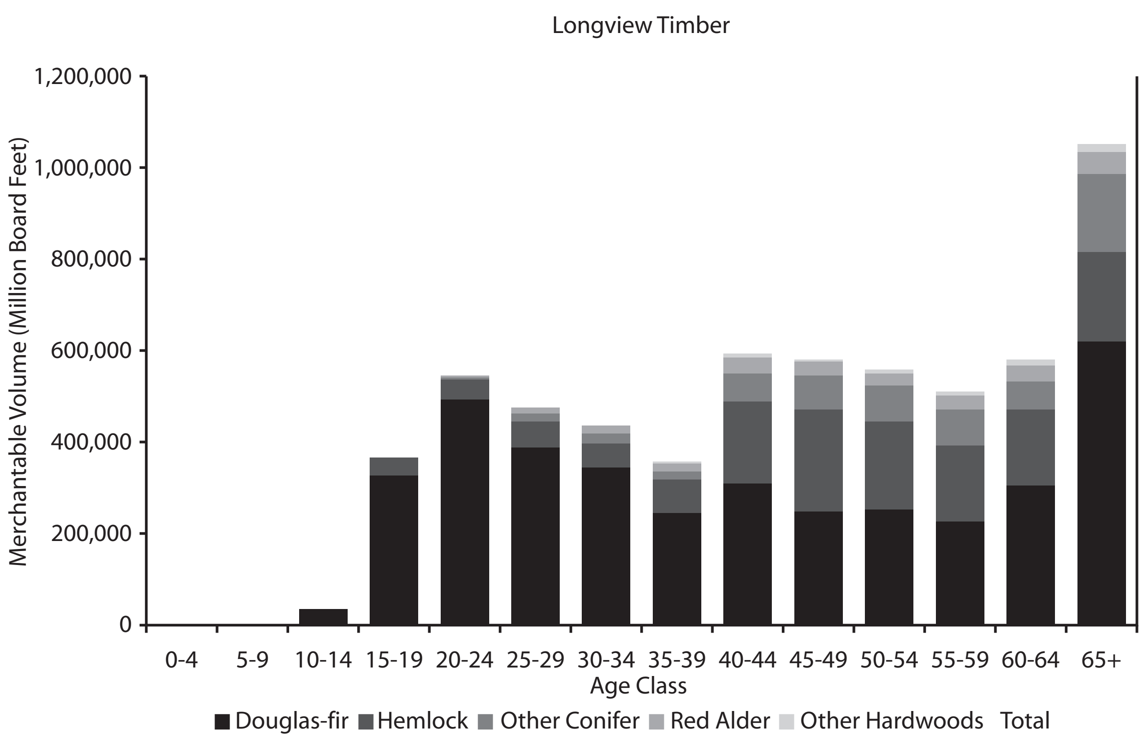
Our Canadian operations were acquired by Brookfield on May 30, 2005. Of our U.S. operations, 588,000 acres were acquired by Brookfield on April 20, 2007, and an additional 67,661 acres were acquired in November 2008.

These timberlands have a combined merchantable inventory of over 95 million m^3 with 55% of this inventory in Douglas-fir, 31% in Whitewoods and the remainder composed of Cedar, Alder, Cypress and other species. These timberlands are heavily weighted to merchantable timber which offers strong, high value near term harvest opportunities.

Merchantable volume by species and age class—Canada (000s m³)



Merchantable volume by species and age class—United States (000s mmbf)



Revenue Framework

The revenue framework for our timber business is a combination of log sales and, to a lesser degree, the sale of HBU lands. Our timber operations have very few long-term sales agreements, accounting for less than 10% of the value of annual log sales, with all logs sold at market prices and payments received in advance of delivery.

Our primary markets are the Pacific Northwest region of the United States and Japan and, for our Canadian operations, the coastal region of British Columbia. Secondary markets include South Korea, China and other Asian markets. The preference of Japanese customers for large, high value primary growth Douglas-fir logs, for which no substitute exists, is a key driver in establishing export market demand.

Some of our timber operations, particularly those located in Canada, are located in regions where the land may be better served as a residential or commercial development. We estimate that approximately 33,163 acres of our lands are HBU lands that, as market conditions develop, could be opportunistically developed and sold for greater value if used for a purpose other than timberlands, such as real estate development or conservation, without materially impacting our sustainable harvest levels.

Key Highlights of our Timber Operations

We believe that our timber operations have a number of favorable characteristics that position us well for strong and growing cash flows as follows:

- ***Scarce, high value, premium asset.*** Our timberlands are primarily comprised of softwood such as Douglas-fir and Hemlock that is generally preferred over hardwood for construction lumber and plywood because of its strength and flexibility. Our timberlands include significant volumes of finegrained Douglas-fir, which is considered a premium product and is in strong demand in the Asian export markets because of its aesthetic appeal and structural properties.
- ***Market access and location.*** The coastal location of our Canadian timberlands provides access to the western U.S. and Asian markets, and our U.S. timberlands also have ready access to the Asian marketplace through the port of Longview. This access to multiple markets provides us flexibility to react quickly to changes in market conditions.
- ***Favorable long-term industry dynamics.*** Sawmill modernization and construction has resulted in over three billion board feet of additional lumber manufacturing capacity in the Pacific Northwest in the last five years. We also expect our timberlands to benefit from increasing scarcity in global timber supplies. This increasing scarcity is expected to result from a number of factors including the Western Canadian mountain pine beetle infestation which has had a significant impact on the supply of Canadian timber from the interior of British Columbia and Alberta, newly implemented Russian log export restrictions, continued withdrawals of North American timberlands for conservation and alternative uses and competition for wood fibre for use in bio fuels.
- ***Diversified product mix in highly productive climate.*** Our timberlands are diversified by species mix, age distribution, geographic location and customer type. As a result, we are well-positioned to serve the Canadian, U.S. and Asian timber markets. Species and age diversification allows us to offer over 200 different log sort grades, enabling us to meet the needs of a large customer base. Also, due to the climate of our coastal location, we have among the most productive timberlands in North America with an overall average annual growth rate on unmanaged natural stands of 3.68 m^3 per acre, more than three times the average annual growth rate of timberlands located in the northeastern part of North America.
- ***High margin business with sustainable cash flows.*** Our timber operations generate strong profit margins due to our low fixed cost structure and strategic harvesting decisions designed to enhance margins. In addition, our timberlands require minimal amounts of maintenance capital. This low capital intensity, together with high operating margins, allows our timberlands to produce sustainable cash flows that generally will capture inflationary price increases.

However, despite these characteristics which we believe will position us well in the medium to long-term, we expect that the continued softness in the U.S. housing market, exacerbated by the extreme dislocations in the mortgage financing market, will result in continued reduction in demand from sawmills that produce lumber for the housing market, putting downward pressure on log prices.

Social Infrastructure

Overview

Social infrastructure includes assets such as hospitals, convention centers, court houses, schools and police stations. The Public Private Partnership or PPP model (also referred to as the Private Finance Initiative or PFI model) has been developed by governments to facilitate private sector participation in the development, operation and financing of such infrastructure assets. Under a typical social infrastructure PPP, a government entity grants a long-term concession to a private sector participant, often referred to as the "concessionaire", who designs, constructs and operates an asset for the duration of the concession contract. Typically the concession contracts are structured such that the concessionaire does not take any volume or patronage risk. There may, however, be reductions in the amount payable to the concessionaire to the extent it does not meet the performance or availability requirements specified in the contract. The concessionaire will often hedge this risk by entering into long term service contracts with subcontractors who commit to similar performance or availability standards and agree to pay damages to the concessionaire in the event that such standards are not achieved.

The PPP market continues to grow rapidly as governments continue to recognize the benefits of delivering social infrastructure services in conjunction with the private sector. According to industry sources, from 1994 to 2005, the private sector has invested approximately $260 billion in infrastructure based PPPs globally, primarily in Europe, Australia and Canada. Industry sources also estimate that in 2007, $70 billion was invested in infrastructure assets by the private sector worldwide through the PPP model, an increase of approximately 40% on the previous year. We believe that this market will grow substantially as governments worldwide continue to adopt this model as a means of funding critical social infrastructure projects in an era of substantial governmental budgetary constraints.

Our current social infrastructure operations are based on the PPP model and were originally developed and held by Brookfield Multiplex (formerly Multiplex Limited), which Brookfield acquired in late 2007. We believe that we will benefit from Brookfield's experience in designing, building and maintaining social infrastructure assets developed under the PPP model. This experience was initially gained through the design and construction of such projects, followed by expansion into facilities management roles and, more recently, in the capacity of an equity investor. Our social infrastructure operations consist of interests in the following concessions: (i) a 30% interest in Peterborough Hospital located in the United Kingdom and acquired from Brookfield Multiplex on December 5, 2008, (ii) a 50% interest in Long Bay Forensic and Prison Hospitals, located in Australia and acquired from Brookfield Multiplex on December 5, 2008; and, (iii) a 50% interest in Royal Melbourne Showgrounds located in Australia and acquired from Brookfield Multiplex on February 3, 2009, for aggregate consideration of approximately $15.3 million.

Asset	Location	Description	Our Ownership Percentage	Concession Details
Peterborough Hospital	Peterborough, United Kingdom	A 612-bed acute hospital, 102-bed mental health unit and an integrated care centre	30%	34 year concession with 3 UK National Health Trusts
Long Bay Forensic and Prison Hospitals	Sydney, Australia	A 135-bed forensic hospital, 85-bed prison hospital and administration building	50%	26 year concession with State Government of New South Wales
Royal Melbourne Showgrounds	Melbourne, Australia	A special purpose exhibition facility on a 19ha site comprising office complexes, open air arenas and large scale tension structures	50%	23 year concession with State Government of Victoria

As described in greater detail above, our social infrastructure operations consist of assets that were constructed by Brookfield Multiplex, a wholly-owned subsidiary of Brookfield. As shown in the table below, facilities management obligations have been sub-contracted to Brookfield Multiplex Services Pty Limited, Brookfield Europe Services Limited, both wholly-owned subsidiaries of Brookfield, and Honeywell Limited. The facilities managers are responsible for meeting the performance and availability requirements and bear the associated operational risk. In the case of Long Bay and Showgrounds, the facilities manager subcontractors are also responsible for maintaining the physical condition of the asset through ongoing capital expenditure programs.

	Royal Melbourne Showgrounds	Long Bay Forensic and Prison Hospitals	Peterborough Hospital
Design and Construct subcontractor:	Brookfield Multiplex Constructions Pty Limited	Brookfield Multiplex Constructions Pty Limited	Brookfield Europe Constructions Limited
Facilities Manager subcontractor:	Brookfield Multiplex Services Pty Limited	Honeywell Limited	Brookfield Europe Services Limited

Revenue Framework

Revenue for our current social infrastructure operations is received through an availability-based payment arrangement set out in the relevant contract. Once a project is operational, we are required to operate and maintain the project to documented performance and availability standards. The applicable government body makes service payments which are dependent on us providing for the availability of the facilities and meeting the standard of service obligations under the contract. We take no patronage risk under the contract structure. We in turn make payments to the facilities manager subcontractor subject to any abatement it may suffer in the event that the performance standards are not met. This structure is designed to substantially shelter us as the project company from operational risk.

Key Highlights of our Social Infrastructure Operations

We believe our social infrastructure operations have a number of attractive attributes, including:

- ***Secure and stable revenues.*** Due to the long-term contractual arrangements with local governments our social infrastructure operations have very secure and stable revenues. The contracts range between 23 years and 34 years. Revenues are availability based with no volume or patronage risk.
- ***Strong free cash flow.*** Since all major operational and maintenance risks are typically passed on to subcontractors through long term service contracts, our social infrastructure operations' cash flow is stable and predictable for the duration of the concession contract We believe that our PPP contracts are backed by strong counterparties and in most cases come with additional security such as letters of credit or corporate guarantees.
- ***Growth opportunities.*** PPP investments remain a growth market with billions of dollars in projects expected to be tendered globally in 2009, according to industry sources.

While our current social infrastructure operations are small relative to our electricity transmission and timber operations, we believe that we can build this platform into a meaningful business unit. We believe we have a competitive advantage in the social infrastructure industry as a result of Brookfield's track record of developing, constructing, managing and, most recently, investing in these types of facilities in Australia and the United Kingdom.

Our Growth Strategy

Our vision is to be a leading owner and operator of high quality infrastructure assets. We seek to grow by deploying our operations-oriented approach to enhance value and by leveraging our relationship with Brookfield to pursue acquisitions. To execute our strategy, we seek to:

- incorporate our technical insight into the evaluation and execution of acquisitions;

- maintain a disciplined approach to acquisitions;
- actively manage our assets to improve operating performance; and
- employ a hands-on approach to key value drivers such as capital investments, development projects, follow-on acquisitions and financings.

We believe that our relationship with Brookfield provides us with competitive advantages in comparison with a stand-alone infrastructure company in the following respects:

- ***Ability to leverage Brookfield's transaction structuring expertise.*** With its extensive background in the real estate, power generation and other hard asset industries, Brookfield has in depth experience acquiring and financing different classes of hard assets.
- ***Ability to pursue acquisitions of businesses that own infrastructure assets together with other assets that have a riskier cash flow profile.*** Such transactions may not be appropriate for us on a stand-alone basis. Brookfield has the skills and capital to acquire such companies and separate the infrastructure assets from the non-infrastructure assets. A good example of this is the acquisition of Longview, which had both a timber business and an integrated converting business that increased the overall risk profile of the company. Brookfield separated these two businesses and contributed an interest in the timber operations to us while retaining and restructuring the more volatile converting business. We believe that we will have an opportunity to acquire infrastructure assets through similar transactions in the future.
- ***Ability to acquire assets developed by Brookfield through its operating platforms.*** Brookfield is well positioned to identify development opportunities. For example, Brookfield is actively pursuing greenfield development projects in the electricity transmission sector, and we expect that, if and when these development projects come to fruition, we will have an opportunity to acquire an interest in them from Brookfield.
- ***Ability to participate alongside Brookfield and in or alongside Brookfield sponsored consortiums and partnerships.*** Our acquisition strategy focuses on large scale transactions, for which we believe there is less competition and where Brookfield has sufficient influence or control so that our operations-oriented approach can be deployed to create value. Due to similar asset characteristics and capital requirements, we believe that the infrastructure industry will evolve like the real estate industry in which assets are commonly owned through consortiums and partnerships of institutional equity investors and owner/operators such as ourselves. Accordingly, an integral part of our strategy is to participate with institutional investors in Brookfield sponsored or co-sponsored consortiums for single asset acquisitions and as a partner in or alongside Brookfield sponsored or co-sponsored partnerships that target acquisitions that suit our profile. Brookfield has a strong track record of leading such consortiums and partnerships and actively managing underlying assets to improve performance.

Brookfield has agreed that it will not sponsor such arrangements that are suitable for us in the infrastructure sector unless we are given an opportunity to participate. See Item 7.B "Related Party Transactions—Relationship Agreement".

Since Brookfield has large, well established operations in real estate and renewable power which is separate from us, Brookfield will not be obligated to provide us with any opportunities in these sectors. In addition, since Brookfield has granted an affiliate the right to act as the exclusive vehicle for Brookfield's timberland acquisitions in Eastern Canada and the Northeastern U.S., we will not be entitled to participate in timberland acquisitions in those geographic regions.

Employees

Our partnership does not employ any of the individuals who carry out the management and activities of our partnership. The personnel that carry out these activities are employees of Brookfield, and their services are provided to our partnership or for our benefit under our Master Services Agreement. For a discussion of the individuals from Brookfield's management team that are expected to be involved in our infrastructure business, see Item 6.A "Directors and Senior Management—Our Management".

Intellectual Property

Our partnership, as licensee, has entered into a licensing agreement with Brookfield pursuant to which Brookfield has granted us a non-exclusive, royalty-free license to use the name "Brookfield" and the Brookfield logo in connection with marketing activities. Other than under this limited license, we do not have a legal right to the "Brookfield" name and the Brookfield logo. Brookfield may terminate the licensing agreement immediately upon termination of our Master Services Agreement and it may be terminated in the circumstances described under Item 7.B "Related Party Transactions—Licensing Agreement".

Properties

Our partnership's principal office is at 7 Reid Street, 4th Floor, Hamilton HM 11, Bermuda and its registered office is Cannon's Court, 22 Victoria Street, Hamilton HM12, Bermuda. Our partnership does not directly own any real property.

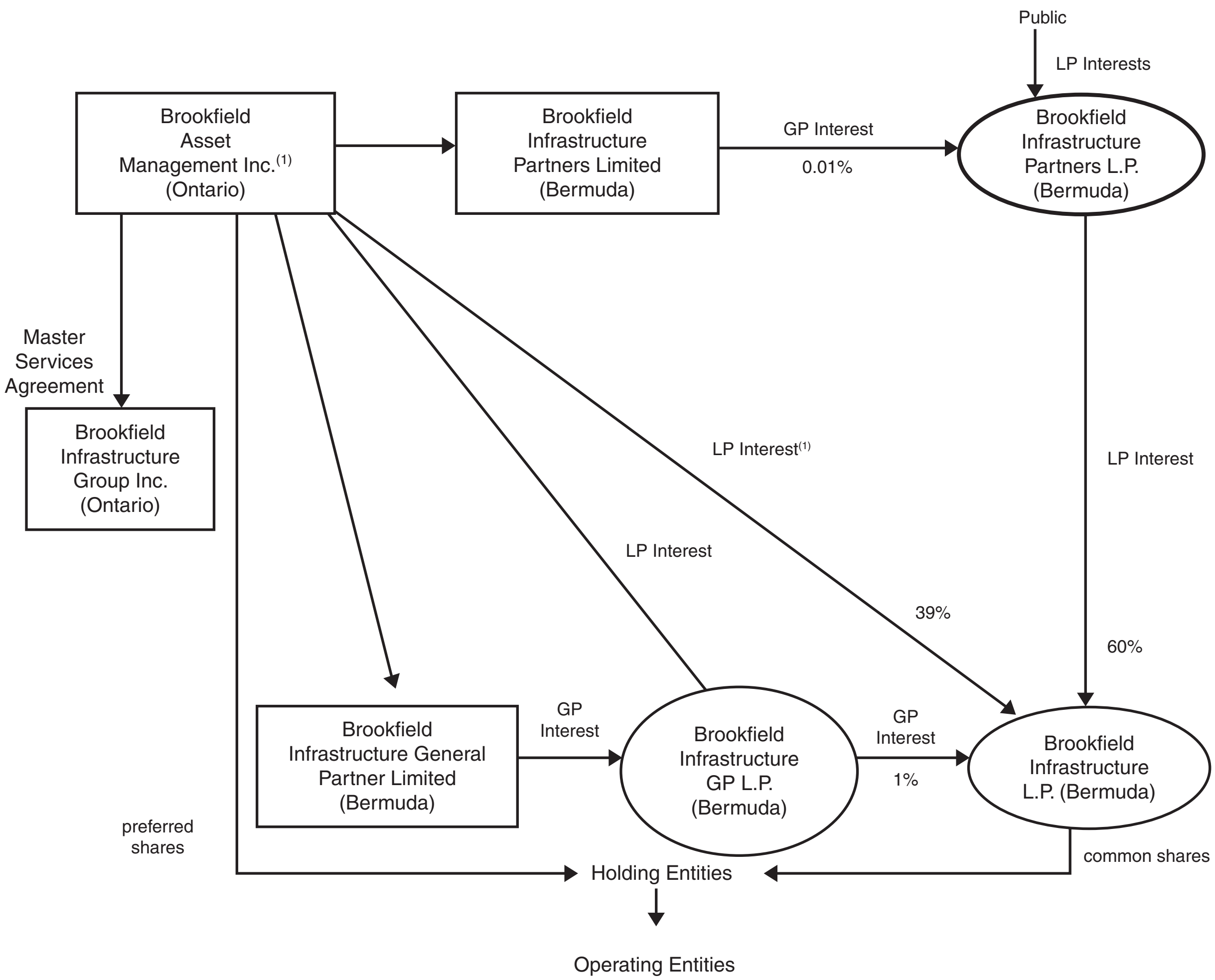
Governmental, Legal and Arbitration Proceedings

Our partnership may be named as a party in various claims and legal proceedings which arise in the ordinary course of business. Our partnership has not been in the previous 12 months and is not currently subject to any material governmental, legal or arbitration proceedings which may have or have had a significant impact on our partnership's financial position or profitability nor is our partnership aware of such proceedings that are pending or threatened.

4.C ORGANIZATIONAL STRUCTURE

Organizational Chart

The chart below presents a simplified summary of our ownership and organizational structure. Please note that on this chart all interests are 100% unless otherwise indicated and "GP Interest" denotes a general partnership interest and "LP Interest" denotes a limited partnership interest. This chart should be read in conjunction with the explanation of our ownership and organizational structure below and the information included under Item 4.B "Business Overview," Item 6.C "Board Practices" and Item 7.B "Related Party Transactions."



(1) Brookfield's limited partnership interest in Brookfield Infrastructure is redeemable for cash or exchangeable for our units in accordance with the Redemption-Exchange Mechanism, which could result in Brookfield Asset Management eventually owning approximately 39% of our issued and outstanding units. See Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Redemption-Exchange Mechanism."

Our Partnership

Our partnership, Brookfield Infrastructure Partners L.P., is a Bermuda exempted limited partnership that was established on May 21, 2007. Our partnership's head office is 7 Reid Street, 4th Floor, Hamilton HM 11, Bermuda, and our registered office is Cannon's Court, 22 Victoria Street, Hamilton HM 12, Bermuda. Our partnership and its related entities were established by Brookfield as its primary vehicle to own and operate certain infrastructure assets on a global basis.

Our partnership's sole material asset is its approximate 60% limited partnership interest in Brookfield Infrastructure. Our partnership anticipates that the only distributions that it will receive in respect of our partnership's limited partnership interests in Brookfield Infrastructure will consist of amounts that are intended to assist our partnership in making distributions to our unitholders in accordance with our partnership's distribution policy and to allow our partnership to pay expenses as they become due. The declaration and payment of cash distributions by our partnership is at the discretion of our Managing General Partner which is not required to make such distributions and our partnership cannot assure you that it will make such distributions as intended.

Our Manager and Brookfield

The Service Recipients have engaged the Manager, an affiliate of Brookfield, to provide them with management and administration services pursuant to the Master Services Agreement.

Our Managing General Partner

Our Managing General Partner serves as our partnership's general partner and has sole authority for the management and control of our partnership which is exercised exclusively by its board of directors in Bermuda. Because our partnership's only interest in Brookfield Infrastructure consists of limited partnership interests in Brookfield Infrastructure, which by law do not entitle the holders thereof to participate in partnership decisions, our Managing General Partner's directors are not entitled to participate in the management or activities of Brookfield Infrastructure or the Holding Entities, including with respect to any acquisition decisions that they may make.

Brookfield Infrastructure and Holding Entities

Our partnership indirectly holds its interests in operating entities through the Holding Entities. Brookfield Infrastructure owns all of the common shares of the Holding Entities. Brookfield has provided an aggregate of $20 million of working capital to the Holding Entities through a subscription for preferred shares of such Holding Entities. These preferred shares are entitled to receive a cumulative preferential dividend equal to 6% of their redemption value as and when declared by the board of directors of the applicable Holding Entity and are redeemable at the option of the Holding Entity, subject to certain limitations, at any time after the tenth anniversary of their issuance. The preferred shares are not entitled to vote, except as required by law.

Infrastructure GP LP and Infrastructure General Partner

The Infrastructure GP LP serves as the general partner of Brookfield Infrastructure and has sole authority for the management and control of Brookfield Infrastructure. The general partner of Infrastructure GP LP is the Infrastructure General Partner, a corporation owned indirectly by Brookfield Asset Management. Infrastructure GP LP is entitled to receive incentive distributions from Brookfield Infrastructure as a result of its ownership of the general partnership interests of Brookfield Infrastructure. See Item 7.B "Related Party Transactions—Incentive Distributions."

See also the information contained in this Form 20-F under Item 3.D "Risk Factors—Risk Relating to Us and Our Partnership," Item 3.D "Risk Factors—Risk Relating to our Relationship with Brookfield," Item 6.A "Directors and Senior Management," Item 7.B "Related Party Transactions," Item 10.B "Memorandum and

Articles of Association—Description of Our Units and Our Limited Partnership," Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement" and Item 7.A "Major Shareholders."

4.D PROPERTY, PLANTS AND EQUIPMENT

Our partnership's principal office is at 7 Reid Street, 4th Floor, Hamilton HM 11, Bermuda and its registered office is Cannon's Court, 22 Victoria Street, Hamilton HM12, Bermuda. Our partnership does not directly own any real property.

See also the information contained in this Form 20-F under Item 3.D "Risk Factors—Risks Relating to Our Operations and the Infrastructure Industry—Risks Relating to Our Electricity Transmission Operations—Our electricity transmission operations may require substantial capital expenditures in the future," "—Our electricity transmission operations may engage in development projects which may expose us to various risks associated with construction," "—Risks Relating to Our Timber Operations—A variety of factors may limit or prevent harvesting by our timber operations," "—Risks Relating to Our Public Private Partnership (or PPP) and Social Infrastructure Operations—We may experience operating cost overruns in relation to a project," "—We may experience higher than expected cost associated with Lifecycle Replacement or latent defects," "—Our PPP project activities may include significant development activities, which may expose us to various risks associated with construction," "—Changes in law requiring capital expenditures could have a material adverse effect on our operations," and Item 5 "Operating and Financial Review and Prospects."

ITEM 4E. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 5. OPERATING AND FINANCIAL REVIEW AND PROSPECTS

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

This management discussion and analysis ("MD&A") should be read in conjunction with the remainder of the information contained in this Form 20-F. Additional information, is available on the Partnership's web site at www.brookfieldinfrastructure.com, on SEDAR's *website at www.sedar.com* and on EDGAR's web site at *www.edgar.com.*

Business Overview

Brookfield Infrastructure Partners L.P. (the "Partnership") was established by Brookfield Asset Management Inc. ("Brookfield") as its primary vehicle to own and operate certain infrastructure assets on a global basis. The Partnership, through its related entities, operates high quality, long-life assets that generate stable cash flows, require relatively minimal maintenance capital expenditures and, by virtue of barriers to entry and other characteristics, tend to appreciate in value over time. Its current business consists of the ownership and operation of premier electricity transmission systems, timberlands and social infrastructure in North and South America, the United Kingdom and Australia, and it seeks acquisition opportunities in other infrastructure sectors with similar attributes.

Our vision is to be a leading owner and operator of high quality infrastructure assets that produces an attractive risk-adjusted total return for our unit holders. We will seek to leverage Brookfield's best-in-class operating platforms to invest in targeted assets and actively manage them to extract additional value following acquisition close. Due to similar asset characteristics and capital requirements, we believe that the infrastructure industry will evolve like the real estate industry in which assets are commonly owned through consortiums and partnerships of institutional equity investors and owner/operators such as ourselves. Accordingly, an integral part of our strategy is to participate with institutional investors in Brookfield sponsored consortiums for single asset acquisitions and as a partner in or alongside Brookfield sponsored partnerships that target acquisitions that suit our profile. We will focus on consortiums and partnerships where Brookfield has sufficient influence or control to deploy our operations oriented approach. Brookfield has a strong track record of leading such transactions and actively managing underlying assets to improve performance.

Basis of Presentation

The Partnership's sole material asset is its 60% limited partnership interest in Brookfield Infrastructure L.P. ("Brookfield Infrastructure"), which is accounted for using the equity method. As a result, we believe the financial statements of Brookfield Infrastructure are more relevant than the Partnership's because they present the financial position and results of our underlying operations in greater detail. Brookfield and its affiliates own the remaining 40% of Brookfield Infrastructure, which through a redemption exchange mechanism can be converted into an equivalent interest in the Partnership.

Upon formation of Brookfield Infrastructure on November 27, 2007, Brookfield Infrastructure's ownership interests in its underlying operations were as follows: 10.7% of Transelec Chile S.A. ("Transelec" or our "Chilean transmission operations"), 37.5% of Island Timberlands Limited Partnership ("Island Timberlands" or our "Canadian timber operations"), 30% of Longview Timber Holdings Corp. ("Longview" or our "U.S. timber operations") and 7-18% of Transmissoras Brasileiras de Energia ("TBE").

On March 12, 2008, Brookfield Infrastructure acquired 100% of the transmission division of Great Lakes Power Limited (our "Ontario transmission operations") from Brookfield. Since our Ontario transmission operations remained under common control by Brookfield following the transfer to Brookfield Infrastructure, its results of operations are included in our historical results from January 1, 2006.

On April 4, 2008, Brookfield Infrastructure acquired an additional 7.1% interest in Transelec, bringing its ownership interest to 17.8%.

On November 4, 2008, Longview Timber Holdings Corp. ("Longview"), in which Brookfield Infrastructure holds a 30% interest, completed the add-on acquisition of a 67,661 acre tree farm in Washington State for $163 million. Concurrently, Longview repaid its outstanding bridge loan whose principal amount was approximately $250 million. In order to fund these amounts, Longview issued $70 million of long-term debt and financed the balance with new equity. Brookfield Infrastructure invested approximately $103 million directly and indirectly (through the Brookfield Global Timber Fund) into Longview in order to maintain its interest at the 30% level.

On December 5, 2008, Brookfield Infrastructure completed the acquisition of Brookfield Multiplex's interest in two social infrastructure Public Private Partnerships ("PPP")—the Peterborough Hospital in the United Kingdom and the Long Bay Forensic and Prison Hospitals in Australia for a total investment of approximately $12.3 million. On February 3, 2009, subsequent to year end, Brookfield Infrastructure completed the acquisition of Brookfield Multiplex's interest in an additional PPP Project—the Royal Melbourne Showgrounds in Australia—for an investment of approximately $3.0 million.

The unaudited results that are presented in this MD&A reflect the financial position and results of our current operations for the year ended December 31, 2008.

We will also present our results on a pro forma basis to reflect the following transactions as if they occurred on January 1, 2006:

- Brookfield Infrastructure's increased investment in Transelec, which increased our ownership to approximately 17.8%;

- The seeding of the assets into Brookfield Infrastructure on November 27, 2007; and
- The spin-off of Brookfield Infrastructure from Brookfield and related transactions including entry into the master services agreement with Brookfield (the "Master Services Agreement"), and any related corporate general and administrative expenses as well as financing fees.

For each of its business segments, this MD&A discusses Brookfield Infrastructure's proportionate share of results for its consolidated operations and equity accounted investments in order to demonstrate the impact of key value drivers of each of these segments on Brookfield Infrastructure's overall performance. Consistent with how the business is managed, the segments are electricity transmission and timber. Each of these platforms have their own management teams responsible for their operations and investments. Certain items, such as corporate administration costs, are not included in this segmented financial information. All figures are provided in U.S. dollars, unless otherwise noted.

Performance Targets and Key Measures

Our objective is to earn a total return of 11% to 15% per annum from the infrastructure assets that we acquire, including our current operations, when measured over the long term. This return will be generated from our initial adjusted net operating income plus growth in adjusted net operating income and asset values. We endeavor to manage our operations to generate increasing adjusted net operating income per unit over a very long period of time. If we are successful in doing so, we will be able to increase distributions to unitholders. Furthermore, the increase in our adjusted net operating income should result in capital appreciation of our operations. Thus, our key performance measure is the growth of adjusted net operating income per unit. We also measure our cash return on equity, which demonstrates how effectively we deploy the capital which has been entrusted to us by our unitholders. However, we recognize that a certain amount of the capital appreciation of our operations may not be reflected in our financial results for many years, if ever, until a realization event, which typically takes the form of gains on a direct or indirect disposition of the assets.

Based on the foregoing, our intention is to provide unitholders with an attractive total return on their investment, consisting of both cash distributions as well as increased unit value.

Although these are our long-term objectives, we cannot assure you that we will achieve them in any particular reporting period or year. Furthermore, we intend to pursue acquisitions that we believe are attractive on a long-term cash flow or total return basis, but may not be accretive on a short-term cash flow basis. Such acquisitions may adversely impact our adjusted net operating income per unit on a near-term basis following the acquisition.

Overview of Performance

In this section we review our performance and our financial position for the year ended December 31, 2008. As the operating assets were seeded into Brookfield Infrastructure on November 27, 2007, there are no meaningful GAAP financial comparatives. Accordingly, we also review our performance on a pro forma basis. Further details on our operations and financial position are contained within the review of Operating Platforms.

To measure performance, we focus on net income as well as adjusted net operating income or ANOI. We define adjusted net operating income as net income excluding the impact of depreciation, depletion and amortization, deferred taxes and other items as detailed in the reconciliation shown under the Reconciliation Of Non-GAAP Financial Measures section of this MD&A. Adjusted net operating income is a measure of operating performance that is not calculated in accordance with, and does not have any standardized meaning prescribed by, U.S. generally accepted accounting principles ("GAAP"). Adjusted net operating income is therefore unlikely to be comparable to similar measures presented by other issuers. Adjusted net operating income has limitations as an analytical tool. See the Reconciliation Of Non-GAAP Financial Measures section for a more fulsome discussion including a reconciliation to the most directly comparable GAAP measure.

Results of Operations

The following table summarizes the financial results of Brookfield Infrastructure.

MILLIONS, UNAUDITED	As at and for the Years Ended December 31 2008	2007[(1),(2)]	2006[(1)]
Income Statement Key Metrics			
Revenue	**$ 32.9**	$ 33.1	$30.7
Earnings (losses) from equity accounted investments	**25.2**	(7.8)	—
Dividend income	**14.3**	0.5	—
Interest expense	**(12.9)**	(6.9)	(5.8)
Net income	**28.0**	12.0	10.4
Adjusted net operating income (ANOI)	**59.7**[(2)]	13.3	15.1
Balance Sheet Key Metrics			
Total assets	**$1,174.3**	$1,157.9	
Partnership capital[(3)]	**899.9**	984.5	
Corporate borrowings	**139.5**	—	
Non-recourse borrowings	**97.6**	115.0	

(1) Brookfield Infrastructure was formed on November 27, 2007, accordingly, results for 2007 reflect only one month of Brookfield Infrastructure activity. In addition, results for 2007 and 2006 reflect the historical results of our Ontario transmission operations.

(2) Certain prior period amounts have been reclassified to conform to the current period's presentation.

(3) Includes redeemable partnership units as they can be converted to an equivalent interest in partnership units through a redemption exchange mechanism.

Due to our levels of ownership and control, Brookfield Infrastructure's financial statements reflect a mix of consolidation accounting (Ontario transmission operations), equity accounting (Transelec, Island Timberlands, Longview, PPP) and cost accounting (TBE).

For the year ended December 31, 2008, we recorded net income of $28.0 million compared to $12.0 million for the same period of 2007. Brookfield Infrastructure was formed on November 27, 2007, accordingly, results for 2007 reflect only one month of Brookfield Infrastructure activity. In addition, since it remained under common control by Brookfield following its transfer to Brookfield Infrastructure, results reflect the historical results of our Ontario transmission operations for the full year in 2007 and 2006. Under GAAP, the historical results transfer to Brookfield Infrastructure as a result of this continuity of interest. In addition, 2008 results reflect Brookfield Infrastructure's increased 17.8% ownership of Transelec beginning April 4, 2008.

As at December 31, 2008, Brookfield Infrastructure had $1,174.3 million in assets and $899.9 million in Partnership capital. Corporate borrowings were $139.5 million at year end. Brookfield Infrastructure's credit facility was drawn in the fourth quarter of 2008 to fund the additional investment in Longview, the acquisition of the PPP assets and for general working capital purposes. The amount will be repaid with the proceeds from the previously announced TBE divestiture, expected to be received in the second quarter of 2009. Please refer to the Overview of Performance—Business Development—Electricity Transmission section of this MD&A for further information regarding the TBE divestiture. In addition, our consolidated balance sheet at December 31, 2008 reflects $97.6 million in non-recourse borrowings at our Ontario transmission operations.

The following table presents both net income and adjusted net operating income by segment:

MILLIONS, UNAUDITED	For the Year Ended December 31, 2008	2007(1)	2006(1)
Net income (loss) by segment			
Electricity transmission	**$ 39.9**	$ 9.8	$10.4
Timber	**6.7**	(6.2)	—
Corporate	**(18.6)**	8.4	—
Net income	**$ 28.0**	$12.0	$10.4
Adjusted net operating income by segment			
Electricity transmission	**$ 64.0**	$17.4	$15.1
Timber	**12.8**	(4.1)	—
Corporate	**(17.1)**	—	—
Adjusted net operating income (ANOI)	**$ 59.7**(2)	$13.3	$15.1

(1) Brookfield Infrastructure was formed on November 27, 2007, accordingly, results for 2007 reflect only one month of Brookfield Infrastructure activity. In addition, 2007 and 2006 results reflect a full year of the historical results of our Ontario transmission operations.

(2) Certain prior period amounts have been reclassified to conform to the current period's presentation.

Pro Forma Results of Operations

As the operating assets were seeded into Brookfield Infrastructure on November 27, 2007, there are no meaningful GAAP financial comparatives. Accordingly, we also review our performance on a pro forma basis. The Reconciliation of Unaudited Pro Forma Financial Information section of this MD&A contains additional information regarding this pro forma presentation.

The following table summarizes the financial results of Brookfield Infrastructure for the year on a pro forma basis to reflect the following transactions as if they occurred on January 1, 2006:

- Brookfield Infrastructure's increased investment in Transelec, which increased our ownership to approximately 17.8%;
- The seeding of the assets into Brookfield Infrastructure on November 27, 2007; and
- The spin-off of Brookfield Infrastructure from Brookfield and related transactions including entry into the Master Services Agreement, and any related corporate general and administrative expenses as well as financing fees.

MILLIONS, UNAUDITED	For the Year Ended December 31, 2008	2007(1)	2006
Income Statement Key Metrics			
Revenue	**$ 32.9**	$ 33.1	$ 30.7
Earnings (loss) from equity accounted investments	**25.9**	(9.5)	9.7
Dividend income	**14.3**	16.0	11.2
Interest expense	**(12.9)**	(12.5)	(11.3)
Net income	**27.9**	6.1	13.2
Adjusted net operating income (ANOI)	**$ 63.3**	$ 52.2	$ 51.9

(1) Certain prior period amounts have been reclassified to conform to the current period's presentation.

For the year ended December 31, 2008, we recorded pro forma net income of $27.9 million compared to income of $6.1 million and $13.2 million for 2007 and 2006 respectively. The increase is primarily driven by strong performance from our transmission segment and non-recurring revenue of $8.5 million as a result of retroactive application of the 2006 trunk transaction study at our Chilean transmission operations.

The following table presents both pro forma net income and adjusted net operating income by segment:

	For the Year Ended December 31,		
MILLIONS, UNAUDITED	**2008**	**2007**[(1)]	**2006**
Net Income (loss) by segment			
Electricity transmission	**$ 40.7**	$ 27.4	$ 31.2
Timber	**6.7**	(10.6)	(0.1)
Corporate	**(19.5)**	(10.7)	(17.9)
Net income	**$ 27.9**	$ 6.1	$ 13.2
Adjusted net operating income by segment			
Electricity transmission	**$ 68.4**	$ 54.2	$ 43.3
Timber	**12.8**	15.9	26.5
Corporate	**(17.9)**	(17.9)	(17.9)
Adjusted net operating income (ANOI)	**$ 63.3**	$ 52.2	$ 51.9

(1) Certain prior period amounts have been reclassified to conform to the current period's presentation.

Changes in net income and adjusted net operating income for each segment, as presented above, are discussed in the Operating Platforms section of this supplemental information, which follows. Corporate expenditures are comparable with the prior years, with the exception that 2007 corporate expenditures impacting net income includes the benefit of a $8.4 million income tax recovery which arose on the formation of Brookfield Infrastructure.

Operating Platforms

In this section, we review the operating results of our two principal operating platforms, Electricity Transmission and Timber.

Electricity Transmission Operations

Our transmission segment generates stable revenue that is governed by regulated frameworks and long-term contracts. Accordingly, we expect this segment to produce consistent revenue and margins that should increase with inflation and other factors such as operational improvements. We also expect to achieve continued growth in revenues and income as we earn a return on the investment of additional capital into our existing operations.

The following table presents our electricity transmission segment's proportionate share of financial results. As it is accounted for on a cost basis, TBE's results are reflected as dividend income.

	For the Year Ended December 31,		
MILLIONS, UNAUDITED	**2008**	**2007**(1)	**2006**(1)
Revenue	**$ 86.4**	$35.5	$30.7
Costs attributed to revenues	**(15.8)**	(6.4)	(5.1)
Dividend income	**14.3**	0.5	—
Net operating income	**84.9**	29.6	25.6
Other income (expense)	**1.6**	0.3	(0.3)
Interest expense(2)	**(21.1)**	(8.0)	(5.8)
Cash taxes	**(1.4)**	(4.5)	(4.4)
Adjusted net operating income (ANOI)	**64.0**(2)	17.4	15.1
Depreciation and amortization	**(17.6)**	(8.0)	(6.2)
Unrealized gains (losses) on derivative instruments	**(2.9)**	1.5	—
Deferred taxes and other items	**(3.6)**	(1.1)	1.5
Net income	**$ 39.9**	$ 9.8	$10.4

(1) Brookfield Infrastructure was formed on November 27, 2007, accordingly, results for 2007 reflect only one month of Brookfield Infrastructure activity. In addition, 2007 and 2006 results reflect the historical results of our Ontario transmission operations.

(2) Excludes non-cash components of interest expense which are included in the line item deferred taxes and other items.

On a proportionate basis, our transmission operations earned $84.9 million of net operating income, $64.0 million of adjusted net operating income and $39.9 million of net income for the year ended December 31, 2008. Results for 2007 and 2006 are not comparable as they reflect only one month of Brookfield Infrastructure activity as Brookfield Infrastructure was formed on November 27, 2007. In addition, results reflect the historical results of our Ontario transmission operations.

The following table presents the transmission segment's pro forma proportionate share of financial results.

	For the Year Ended December 31,		
MILLIONS, UNAUDITED	**2008**	**2007**(2)	**2006**
Revenue	**$ 93.0**	$ 78.1	$ 70.1
Costs attributed to revenues	**(16.5)**	(13.3)	(13.7)
Dividend income	**14.3**	16.0	11.2
Net operating income	**90.8**	80.8	67.6
Other income (expenses)	**1.6**	0.9	3.0
Interest expense(1)	**(22.6)**	(23.0)	(22.6)
Cash taxes	**(1.4)**	(4.5)	(4.7)
Adjusted net operating income (ANOI)	**68.4**	54.2	43.3
Depreciation and amortization	**(18.9)**	(17.8)	(15.6)
Unrealized gains (losses) on derivative instruments	**(6.6)**	(15.0)	—
Deferred taxes and other items	**(2.2)**	6.0	3.5
Net income	**$ 40.7**	$ 27.4	$ 31.2

(1) Excludes non-cash components of interest expense which are included in the line item deferred taxes and other items.

(2) Certain prior period amounts have been reclassified to conform to the current period's presentation.

On a pro forma proportionate basis, our transmission businesses recorded strong results. For the year ended December 31, 2008 Transelec's net operating income and ANOI were $50.9 million and $37.3 million, respectively, compared with $37.5 million and $22.3 million for the prior year. Transelec's results reflected non-recurring revenues of $8.5 million as a result of retroactive application of the 2006 trunk transmission study. Adjusting for non-recurring revenue, Transelec's ANOI increased 29% relative to the prior year primarily as a result of the rate increases provided for in the 2006 trunk transmission study, the benefit of growth capital expenditures and indexation of revenues resulting from inflation and foreign exchange movements. After adjusting for non-recurring revenues, operating margins at our Chilean transmission operations were 82% which are in line with historical levels.

For the year ended December 31, 2008, Ontario transmission's net operating income and ANOI were $25.6 million and $16.8 million, respectively, compared with $27.3 million and $15.9 million from the prior year. Revenues from our Ontario transmission operations were essentially flat compared with the prior year. Operating and maintenance expenses increased relative to the prior year due to personnel costs associated with the establishment of Ontario transmission as an independent operation for which we intend to apply for cost recovery in our upcoming rate case. This increase in costs contributed to the decline in net operating income. This decline was more than offset by lower cash taxes in 2008, resulting in an increase in ANOI.

Dividends received from our TBE investment in 2008 were $14.3 million for the year compared to $16.0 million in 2007. Dividends from TBE are paid on a periodic basis.

Non-cash expenses are primarily comprised of depreciation and amortization which reflect application of purchase accounting in our Chilean transmission operations, as well as non-cash inflation indexations on our Chilean peso denominated debt. Depreciation and amortization amounted to $18.9 million in 2008, up from $17.8 million in 2007 related to incremental depreciation booked in conjunction with the expansion of our regulated asset base.

Overall our transmission businesses recorded stronger operating results in 2007 compared to 2006 primarily as a result of higher investment income from our Brazilian transmission investment and higher margins earned at our Chilean transmission operations. Operating margins at our Chilean transmission operations increased to 83% for 2007, in comparison with 78% in 2006, when margins were impacted by acquisition integration costs and higher maintenance expenses. Net income decreased $3.8 million in 2007 compared to 2006 as the strong operating results were offset by unrealized losses on derivative instruments.

Our transmission operations have a combination of regulatory and contractual frameworks, some of which are indexed. For our transmission operations with revenue indexation, increases in revenue are primarily a result of inflation, changes in foreign exchange rates and growth capital expenditures. For our remaining operations, revenue increases are primarily attributable to growth capital expenditures. Growth and maintenance capital expenditures are discussed in the Capital Expenditures section of this MD&A. The following table breaks down our proportionate share of revenue by these categories:

	For the Year Ended December 31,		
MILLIONS, UNAUDITED	**2008**	**2007**	**2006**
Contractual revenue with indexation	**$27.3**	$25.4	$23.0
Regulated revenue with indexation	**30.2**	15.4	14.7
	57.5	40.8	37.7
Other transmission revenue	**35.5**	37.3	32.4
	$93.0	$78.1	$70.1

For the year, adjusting for non-recurring revenues of $8.5 million, our proportionate share of revenues with indexation increased by $8.2 million or 20% in 2008 compared with 2007. Of the total, $4.3 million was due to the ongoing benefit from the increased replacement cost provided in the 2006 trunk transmission study, $2.9 million was attributable to inflation indexation and $1.0 million was attributable to growth capital expenditures.

Revenues with indexation increased by 8% in 2007 compared to 2006. This was primarily driven by Chilean inflation which was higher in 2007 compared to 2006, thus contributing approximately $2.5 million to the increase and also due to growth capital expenditures which contributed approximately $0.5 million to the increase.

Business Development—Electricity Transmission

As previously disclosed, Brookfield Infrastructure has exercised an option to sell its minority interests in TBE. The primary purchaser of TBE will be CEMIG, the electric utility for the state of Minas Gerais in Brazil. Closing is expected to occur in the second quarter of 2009, subject to receipt of regulatory and other approvals. Concurrent with the exercise of the put option, Brookfield Infrastructure entered into a foreign exchange hedge to lock in projected proceeds in U.S. dollars. Brookfield Infrastructure expects to receive after tax proceeds from the sale of approximately $274 million, of which $27 million was received from realized hedge gains in 2008 and an additional $41 million was received from realized hedge gains in January of 2009. The proceeds will be used to repay corporate borrowings, fund growth capital investments and acquisitions as well as for general corporate working capital purposes. In 2008, Transelec's growth capital expenditures were $71 million which was lower than expected primarily due to a number of budgeted projects that were deferred. As a result of the deferral of certain projects and approximately $190 million of new projects that were booked during the year, Transelec's capital expenditure backlog (projects that have been awarded to Transelec for which expenditures have not yet been made) was approximately $240 million at the end of 2008 compared with $120 million at the end of the prior year. Furthermore, as we enter 2009, we are experiencing an increase in opportunities to build transmission lines for unregulated customers such as generators and copper mines as they seek to deploy their capital more efficiently in the current difficult economic environment. As Transelec enters the second year of its five-year plan to invest $1 billion in growth capital expenditures on a 100% basis, of which Brookfield Infrastructure's share is approximately $180 million, we remain optimistic that this objective can be achieved. We will continue to look for opportunities to grow this business and have adjusted our investment hurdle rates to reflect the current environment.

In order to partially finance its growth plan, Transelec has executed a capital expenditure credit facility of approximately $130 million. The objective is to draw the facility to fund capital expenditures and to refinance the facility over time through the issuance of long-term debt.

In 2008, Transelec implemented a long-term hedge program in order to substantially convert Transelec to a U.S. dollar asset with minimal ongoing exposure to the Chilean peso. The program was comprised of matched maturity cross-currency interest rate swaps which converted Transelec's U.S. dollar debt into inflation indexed Chilean peso debt and foreign exchange swaps to convert the residual Chilean peso equity investment into U.S. dollars. This program was completed in August 2008, prior to the recent significant devaluation of the Chilean peso. Although the hedge program was designed to limit the impact of foreign exchange on U.S. dollar denominated adjusted net operating income, foreign exchange movements will continue to impact the various components of ANOI. Going forward, for example, we expect the recent devaluation of the Chilean peso would decrease Transelec's net operating income, principally due to the impact of foreign exchange on revenue indexation offset to a degree by its impact on operating costs. Interest expense would also decrease due to the recent foreign currency devaluation. Additionally, fair market value gains on the foreign exchange swaps would be included in other income. Notwithstanding the hedge program, a modest impact on ANOI due to foreign exchange movement is expected to remain because of imperfections of the hedge program.

Timber Operations

Our timber operations consist of high quality timberlands located in the coastal region of British Columbia, Canada and the Pacific Northwest region of the U.S. These operations are predominantly comprised of premium species and are expected to provide attractive risk adjusted returns on capital employed over the long term.

The following table presents our timber segment's proportionate share of financial results.

MILLIONS, UNAUDITED	For the Year Ended December 31, 2008	2007[(1)]	2006[(1)]
Revenue	**$124.8**	$ 6.1	$—
Cost attributed to revenues	**(81.8)**	(5.6)	—
Net operating income	**43.0**	0.5	—
Other expense	**(0.5)**	(1.9)	—
Interest expense	**(29.0)**	(2.7)	—
Cash taxes	**(0.7)**	—	—
Adjusted net operating income (ANOI)	**12.8**	(4.1)	—
Depreciation, depletion and amortization	**(36.7)**	(1.8)	—
Performance fee	**12.8**	(3.1)	—
Deferred taxes and other items	**17.8**	2.8	—
Net income (loss)	**$ 6.7**	$(6.2)	$—

(1) Brookfield Infrastructure was formed on November 27, 2007, accordingly, results for 2007 reflect only one month of Brookfield Infrastructure activity.

On a proportionate basis, our timber operations generated $43.0 million of net operating income, $12.8 million of adjusted net operating income and a net income of $6.7 million for the year ended December 31, 2008. Results for 2007 are not comparable as the results reflect only one month of Brookfield Infrastructure activity as Brookfield Infrastructure was formed on November 27, 2007. Similarly, 2006 results are not comparable.

The following table presents our timber segment's pro forma proportionate share of financial results.

MILLIONS, UNAUDITED	For the Year Ended December 31, 2008	2007[(1)]	2006
Revenue	**$124.8**	$131.4	$131.9
Cost attributed to revenues	**(81.8)**	(79.6)	(77.1)
Net operating income	**43.0**	51.8	54.8
Other income (expense)	**(0.5)**	(5.0)	1.9
Interest expense	**(29.0)**	(30.9)	(30.2)
Cash taxes	**(0.7)**	—	—
Adjusted net operating income (ANOI)	**12.8**	15.9	26.5
Depreciation, depletion and amortization	**(36.7)**	(29.9)	(13.3)
Performance fee	**12.8**	(3.1)	(15.0)
Deferred taxes and other items	**17.8**	6.5	1.7
Net income (loss)	**$ 6.7**	$ (10.6)	$ (0.1)

(1) Certain prior period amounts have been reclassified to conform to the current period's presentation.

In our timber operations for the year ended December 31, 2008, net operating income and ANOI were $43.0 million and $12.8 million, respectively, on a pro forma basis compared to $51.8 million and $15.9 million respectively, in the prior year.

Harvest and sales volumes at our Canadian timber operations decreased 7% and 13%, respectively, versus 2007. Sales volumes in 2008 were in line with harvest levels, while in 2007, sales volumes exceeded harvest levels due to significantly more logs purchased for resale in 2007. In 2008 we reduced sales of second growth Douglas-fir as markets for this product are highly dependant on new home construction in the U.S., which remains severely depressed. To mitigate the impact of weak North American markets, we have remained focused on increasing the percentage of appearance grade products in our mix which we export to Asian markets and continue to yield higher margins, net of transportation costs. Export volumes represented 29% of shipments in 2008, compared to 27% in 2007. Costs per unit increased 6% compared to 2007 primarily as a result of product mix and to a lesser extent higher fuel costs. As a result of the foregoing, our operating margins declined to 26% for the year versus 31% in the prior year.

At our U.S. timber operations, harvest and sales volumes increased 6% and 12%, respectively, in 2008 over the prior year despite difficult market conditions. The increase is primarily due to weather conditions which had less of an impact on 2008 operations compared with 2007. Operations on the additional 68,000 acres of timberlands acquired in November 2008 also contributed to the increase, although to a lesser degree. Please see the Business Development—Timber section of this MD&A for further information regarding this acquisition. We have continued to maximize our proportion of export quality timber from our harvest to take advantage of the significantly better prices available in the off-shore markets. The volume exported increased to 24% of total shipments in 2008, up sharply from 16% in 2007. As a result of this focus on export opportunities, we mitigated the decline in our average selling price for Douglas-fir which was 7% less than 2007, while domestic prices declined by approximately 14%. Costs per unit increased 1% compared to 2007, principally due to higher costs associated with storm damage clean up in early 2008 and the impact of higher fuel costs. Overall margins decreased to 34% in 2008 from 42% in 2007 principally due to the decline in average selling price.

Our timber operations recorded weaker results in 2007 compared to 2006, experiencing a decline in net operating income and ANOI on a year over year basis. The decline in net operating income was primarily due to softness in the U.S. housing market which impacted the results of our U.S. timber business, offset by improved performance in our Canadian timber operations. The decline in ANOI on a year over year basis was due to the decrease in net operating income as well as the decrease in investment and other income which was a result of non-recurring charges of approximately $6.5 million incurred in our U.S. timber operations associated with the sale of Longview and other transactions.

For the year ended December 31, 2008, 2007 and 2006, depreciation, depletion and amortization was $36.7 million, $29.9 million, and $13.3 million, respectively. The increase in depreciation and depletion is predominantly due to the step up in the carrying value of the Longview assets which increased depreciation beginning in April 2007.

The following table summarizes our proportionate share of operating metrics for our timber operations:

	Year Ended December 31, 2008				**Year Ended December 31, 2007**				**Year Ended December 31, 2006**			
UNAUDITED	**Harvest (000s m^3)**	**Sales (000s m^3)**	**Revenue/ m^3**	**Revenue ($ millions)**	**Harvest (000s m^3)**	**Sales (000s m^3)**	**Revenue/ m^3**	**Revenue ($ millions)**	**Harvest (000s m^3)**	**Sales (000s m^3)**	**Revenue/ m^3**	**Revenue ($ millions)**
Douglas-fir	**773**	**793**	**$ 88.3**	**$ 70.0**	828	841	$ 91.6	$ 77.1	827	823	$101.3	$ 83.4
Whitewood	**403**	**419**	**59.6**	**25.0**	463	489	65.4	32.0	393	393	71.2	28.0
Other species	**246**	**233**	**109.4**	**25.5**	150	149	130.9	19.5	149	149	121.5	18.1
	1,422	**1,445**	**$ 83.4**	**$120.5**	1,441	1,479	$ 86.9	$128.6	1,369	1,365	$ 94.9	$129.5
HBU and other sales				**4.3**				2.8				2.4
Total				**$124.8**				$131.4				$131.9

In 2008, sales volumes of Douglas-fir and Whitewood declined by 6% and 14%, respectively, versus 2007 due to the difficult market conditions in the structural lumber market. Sales volumes of other species increased significantly as a result of better relative market conditions for pulp logs and cedar through the first nine months of the year.

The average realized price for Douglas-fir decreased by 4% compared to the prior year as declines in prices of products sold to the domestic market were offset by a higher percentage of high value appearance and export grade products sold to off-shore markets. The average selling price of Whitewood decreased by 9% over 2007 reflecting challenging North American market conditions. The significant change in the average realized price for other species is mostly attributable to a change in the mix of products included in that category.

Our share of higher and better use ("HBU") land and other sales were $4.3 million for the year as compared to $2.8 million for 2007 and $2.4 million in 2006.

Business Development—Timber

In the fourth quarter of 2008, Longview completed the add-on acquisition of a 68,000 acre tree farm in Washington State for $163 million. The property is in close proximity to Longview's existing asset base and will benefit from efficiencies associated with integration into Longview's operations. Concurrently, Longview repaid its outstanding bridge loan whose principal amount was approximately $250 million. In order to fund these amounts, Longview issued $70 million long-term debt and financed the balance with new equity. Brookfield Infrastructure invested $103 million directly and indirectly into Longview in order to maintain its interest at the 30% level.

Outlook—Timber

We believe operating results for the timber segment will meaningfully improve over the long term, however, the timing of the recovery is highly dependant on the recovery in U.S. new home construction.

Although it is difficult to predict the timing and impact of variances in these factors, we believe that we will achieve increases in adjusted net operating income and net income from this segment of our business for the following reasons:

- Increased harvest levels
  - Production levels in 2008 at our Canadian operations were 12% below planned levels, due to unfavorable market and weather conditions. The long-run sustainable yield is estimated to be approximately 0.7 million m^3 on a proportionate basis. We expect to achieve an elevated harvest level at our Canadian operations of approximately 0.9 million m^3 on a proportionate basis for a period of 10 years before returning to the long-run sustainable yield level.
  - As a result of a substantial surplus of merchantable standing inventory at our U.S. operations, we expect to increase harvest levels to approximately 0.9 million m^3 on a proportionate basis and sustain this higher level for a period of 10 years before returning to a long-run sustainable yield of approximately 0.8 million m^3.
  - In order to capture the full value of this inventory, this increase in harvest will be staged in as market conditions improve. We currently do not anticipate operating at the higher harvest plan before 2010.
- Increased margins

  As our product mix evolves over time to a greater percentage of second growth harvest relative to primary growth harvest in our Canadian operations, we expect our margins to increase due to the lower harvesting costs of this product.

In the near term, we expect that the softness in the U.S. housing market, exacerbated by extreme dislocations in the mortgage financing market, will result in continued reduction in demand from sawmills that produce structural lumber for the housing market, putting downward pressure on sawlog prices. Over the mid-to-long term, we expect that our timber operations will be positively impacted by a number of fundamental factors affecting the supply of timber in the markets that we serve:

- the mountain pine beetle infestation, which is having a significant impact on the supply of timber from the interior of British Columbia, Alberta and the U.S. Inland;

- Russian timber supply to the Asian markets, which is expected to be constrained as a result of log export restrictions that are being phased in by Russia; and
- timberlands that are continuing to be withdrawn for conservation and alternate uses.

Business Developments—PPP Projects

In the fourth quarter we completed the acquisition of two equity interests in PPP projects—Long Bay Forensic and Prison Hospitals in Australia and Peterborough Hospital in the United Kingdom—from Brookfield Multiplex for approximately $12 million. A third equity interest—Royal Melbourne Showgrounds in Australia—closed subsequent to year end for an additional investment of approximately $3 million. We believe that based on current trends, the PPP market is positioned to experience significant growth as governments continue to realize the benefits of delivering social infrastructure in conjunction with the private sector, and these transactions allow Brookfield infrastructure to establish a platform to participate in the PPP space.

Both the Long Bay and Peterborough projects were in their construction phase in the fourth quarter, accordingly, no cash flow was received from these investments. Long Bay Forensic and Prison Hospitals completed construction in the first quarter of 2009 and we expect to begin to receive cash flows from this investment in 2009. Peterborough Hospital is expected to be completed in late 2011 and no cash flows are expected from this project until that time. We have a commitment to fund our share of the additional equity investment in the project totaling approximately £8 million. We have entered into foreign currency contracts to hedge this amount to the equivalent of approximately $12 million. Royal Melbourne Showgrounds will begin to contribute cash flow in the first quarter of 2009.

Corporate Expenses

The following table presents the components of corporate expenses for the year ended December 31, 2008:

MILLIONS, UNAUDITED	**Year Ended December 31, 2008**
General and administrative costs	**$ 7.0**
Base management fee[(1)]	**7.8**
Financing costs[(2)]	**4.4**
	$19.2

(1) Pursuant to the Master Service Agreement on a gross basis.

(2) Financing costs include dividends paid on the preferred shares, interest expense and standby fees from the committed credit facility and the non-cash amortization of financing costs, less ancillary interest earned on cash balances. Non-cash amortization of financing costs was $1.3 million for the year ended December 31, 2008.

We estimate that our general and administrative costs related to Brookfield Infrastructure will be approximately $7 million to $8 million per annum on a going-forward basis. Prospectively, any base fees and/or performance fees paid by our operations to Brookfield will be netted against the base fees and/or incentive distributions payable to Brookfield under the Master Services Agreement and other arrangements in order to avoid double payment of fees.

Capital Expenditures

MILLIONS, UNAUDITED	Years Ended December 31 2008	2007	2006
Maintenance capital expenditures by segment			
Electricity Transmission	**$ 7.5**	$ 7.5	$ 6.6
Timber	**5.2**	4.0	7.3
	$12.7	$11.5	$13.9
Growth capital expenditures by segment			
Electricity Transmission	**$14.6**	$20.6	$16.6
Timber	**—**	—	—
	$14.6	$20.6	$16.6

Maintenance capital expenditures are expenditures that are required to maintain the current revenue generating capability of our asset base; these expenditures do not increase our revenues. Growth capital investments are investments on which we expect to earn additional revenues; as these investments are typically discretionary, we invest this capital if we believe we can earn attractive risk-adjusted returns.

Included in the transmission segment's growth capital expenditures is $12.6 million (2007—$7.3 million: 2006—$0.5 million) representing our share of growth capital investments at Transelec, comprised of regulated and contracted transmission projects which should result in additional adjusted net operating income.

Corporate Initiatives

We have implemented a unit repurchase program because we believe that, from time to time, the market price of the Partnership's limited partnership units ("Units") may be a more compelling investment opportunity than other investments under consideration. Under the unit repurchase program, the Partnership is authorized to repurchase up to $25 million of its Units, subject to a regulatory limit of 1,167,043 Units in the aggregate. Repurchases pursuant to this unit repurchase program will be made through the facilities of the New York Stock Exchange ("NYSE"). Repurchases were authorized to commence on November 10, 2008 and will terminate on November 9, 2009, or earlier should the Partnership complete its repurchases prior to such date. Repurchases occur subject to prevailing market conditions and are funded from available cash. Repurchases also are subject to compliance with applicable United States federal securities laws, including Rule 10b-18 under the United States Securities Exchange Act of 1934, as amended, as well as applicable Canadian securities laws. All Units acquired by the Partnership under this program will be cancelled. We will also purchase and cancel a number of limited partnership units of Brookfield Infrastructure held by the Partnership corresponding to the number of Units repurchased under the program.

At December 31, 2008, 180,602 Units had been repurchased and cancelled under this program at an average price of $11.05 per unit.

Capital Resources and Liquidity

The nature of our asset base and the quality of associated cash flows enable us to maintain a stable and low cost capitalization. We attempt to maintain sufficient financial liquidity at all times so that we are able to participate in attractive opportunities as they arise, better withstand sudden adverse changes in economic circumstances, and maintain a relatively high distribution of our adjusted net operating income to unitholders.

Our principal sources of liquidity are cash flow from our operations, undrawn credit and equity facilities and access to public and private capital markets. We also structure the ownership of our assets to enhance our ability to monetize them to provide additional liquidity if necessary.

Brookfield Infrastructure's total estimated liquidity as at December 31, 2008 was as follows:

MILLIONS, UNAUDITED	**As at December 31, 2008**
Cash	**$ 8**
Availability under committed credit facility	**311**
Proceeds from the sale of TBE[(1)]	**247**
Total estimated liquidity	**$566**

(1) Estimated proceeds (see Operating Platforms—Business Development—Electricity Transmission).

At December 31, 2008, we had approximately $8 million of cash for working capital purposes. In June 2008, Brookfield Infrastructure closed a $450 million senior secured revolving credit facility, of which $135 million is available for working capital including acquisitions and $315 million is available for acquisitions. Prior to drawing on the facility we must satisfy a number of customary conditions including compliance with certain financial ratios. At December 31, 2008, $139 million was drawn on this facility and $311 million was available to fund growth capital investments and acquisitions as well as for general corporate working capital purposes. During the year, we announced our plan to sell our interests in TBE which, once completed, is expected to generate approximately $274 million in after tax proceeds of which $27 million has already been received from a realized hedge gain. In January 2009, subsequent to year end an additional $41 million was received from a realized hedge gain.

In addition, Brookfield has provided Brookfield Infrastructure with an equity commitment in the amount of $200 million. The equity commitment may be called by our Partnership and/or Brookfield Infrastructure in exchange for the issuance of a number of units of our Partnership or of Brookfield Infrastructure, as the case may be, to Brookfield, corresponding to the amount of the equity commitment called divided by the five day, volume-weighted average trading price for our Partnership's Units.

Our equity strategy is to issue equity in conjunction with future acquisitions; we may also issue an amount of equity opportunistically to enhance our liquidity to pursue future acquisitions.

We finance our assets principally at the operating entity level through the use of long-term debt that has recourse only to the underlying operations. In addition, Brookfield Infrastructure's operations endeavor to maintain investment grade or crossover ratings.

We also strive to ladder our principal repayments over a number of years. Scheduled principal repayments as at December 31, 2008 on a proportionate basis on Brookfield Infrastructure's borrowings over the next five years are as follows:

MILLIONS, UNAUDITED	**Average Term (years)**	**2009**	**2010**	**2011**	**2012**	**2013**	**Beyond**	**Total**
Electricity Transmission[(1)]	10.8	$—	$—	$ 82.8	$—	$ 26.7	$235.0	$ 344.5
Timber[(1)]	9.1	—	—	—	—	127.1	347.8	474.9
Social Infrastructure	19.5	—	—	—	—	—	231.5	231.5
Corporate borrowings	2.5	—	—	139.5	—	—	—	139.5
Total	10.8	$—	$—	$222.3	$—	$153.8	$814.3	$1,190.4

(1) Represents non-recourse debt to Brookfield Infrastructure as the holders have recourse only to the underlying operations.

As illustrated in the schedule above, the proportionate share of debt associated with Brookfield Infrastructure as at December 31, 2008 was $1,190.4 million. Furthermore, the debt has a long-term average term of 10.8 years with no significant debt maturities until 2011. The debt to capitalization ratio for Brookfield Infrastructure as at December 31, 2008 was 57%.

The following table summarizes our proportionate share of debt on a segment basis:

	Year Ended December 31, 2008			Year Ended December 31, 2007			Year Ended December 31, 2006		
MILLIONS, UNAUDITED	Proportionate Average Debt	Average cash interest rate	Cash interest	Proportionate Average Debt	Average cash interest rate	Cash interest	Proportionate Average Debt	Average cash interest rate	Cash interest
Electricity transmission[(1)]	**$366.6**	**6.2%**	**$22.6**	$390.8	5.9%	$23.0	$335.1	6.7%	$22.6
Timber[(1)]	**510.6**	**5.7%**	**29.0**	513.8	6.0%	30.9	513.8	5.9%	30.2
Corporate borrowings	**17.5**	**5.7%**	**1.0**	—	—	—	—	—	—
Total	**$894.7**	**5.9%**	**$52.6**	$904.6	5.9%	$53.9	$848.9	6.2%	$52.8

(1) Represents non-recourse debt to Brookfield Infrastructure as the holders have recourse only to the underlying operations.

(2) The above table excludes debt associated with the two social infrastructure projects acquired in December 2008 as all associated interest is capitalized because these projects are under construction.

Senior Secured Credit Facility

In June 2008, Brookfield Infrastructure closed a senior secured revolving credit facility with Citibank, N.A., Credit Suisse, Toronto Branch, HSBC Bank USA, N.A., Toronto Branch, Royal Bank of Canada and the The Royal Bank of Scotland for $450 million. The facility includes two tranches, tranche A in maximum principal amount of $135 million for general working capital including acquisitions and tranche B in a maximum principal amount of $315 million for acquisitions. The facility is available on a revolving basis for 1 year unless extended in accordance with the terms of the credit agreement. All amounts outstanding under this facility will be repayable in full in June 2011. All obligations of Brookfield Infrastructure under the facility are guaranteed by certain subsidiaries of Brookfield Infrastructure and are secured by our partnership's limited partnership interests in Brookfield Infrastructure and all of the assets of Brookfield Infrastructure and the guarantors. Loans under the facility accrue interest at a floating rate based on LIBOR plus 2.75%, increasing, in the case of loans under tranche B which are at any time outstanding for a period longer than 6 months, by 0.50% on each 6 month anniversary of the date of advance of such loans. We are required to pay an unused commitment fee for each tranche under the facility equal to 35% of the applicable margin per annum.

The senior credit facility restricts Brookfield Infrastructure from making any distributions on its equity unless immediately prior to, and after giving pro forma effect to, such distribution, no default has occurred and is continuing and (1) Brookfield Infrastructure meets a minimum interest coverage ratio of 2.5 to 1 in the first fiscal year, 2.75 to 1 in the second year or 3 to 1 in the third year; a maximum debt to cash flow ratio of 5.5 to 1 in the first year or 5 to 1 thereafter; and maintains minimum liquidity of $25 million or (2) the distribution is funded with proceeds of certain permitted capital raising or sales of assets.

Financial Risk Management

Our business is impacted by changes in currency rates, interest rates and other financial exposures. As a general policy, we endeavour to maintain balanced positions where practical or economical to do so, although unmatched positions may be taken from time-to-time on a closely monitored basis. Our principal financial risks are foreign currency and interest rate fluctuations.

We prefer to hedge financial risks with offsetting items such as debt denominated in local currencies that match the profile of the operations being financed. We also make selective use of financial instruments, known as derivatives, to hedge financial positions from time-to-time when natural hedges are not available or when derivatives are more cost effective. The use of derivatives will be governed by carefully prescribed policies. We evaluate and monitor the credit risk of derivative financial instruments, and we minimize credit risk through collateral and other mitigation techniques.

Foreign Currency

A number of our operations are conducted in currencies other than the U.S. dollar. Our policy is to hedge foreign currency denominated book values and/or cash flows where economical to do so, using foreign currency denominated debt as well as financial contracts. It is not, however, always possible or economically feasible to hedge certain exposures with the result that a portion of our cash flows and equity is exposed to foreign currency fluctuations. We may also enter into financial contracts to further hedge assets recognizing that in some cases changes to the value of these contracts may be reflected in net income even though the offsetting impact on the value of the assets being hedged may not. We have economic currency exposure to Chilean pesos, Brazilian reis, British Pound, Australian dollars and Canadian dollars.

Interest Rate

We believe that the value of the vast majority of our assets will vary in part with changes in long-term interest rates due to the nature of their revenue streams. Accordingly, we endeavour to finance these assets with long-term fixed rate borrowings. We intend to match fund floating rate assets with floating rate debt and will otherwise minimize the use of floating rate liabilities other than in carefully monitored circumstances that are intended to lower our overall cost of capital on an appropriate risk adjusted basis.

Quantitative and Qualitative Disclosures about Market Risks

We are exposed to market risks in our underlying operations, namely our Canadian and U.S. timber and Chilean transmission operations, principally resulting from changes in interest rates and currency exchange rates.

Interest Rate and Inflation Risk

Interest rate risk related to our Chilean transmission and U.S. timber operations exists principally with respect to its indebtedness with variable rates. Furthermore, our Chilean transmission operations is subject to inflation risk as 59% of its debt portfolio is denominated in Unidad de Fomento, or UF, which is an inflation indexed Chilean peso monetary unit that is set daily, in advance, on the basis of the prior month’s inflation rate. However, we believe this is offset by the nature of our revenues which, both contractually and in the regulatory framework, are in large part indexed to Chilean inflation.

We also have financial assets that are sensitive to interest rate changes. These assets include short-term Chilean peso, or CLP, and U.S. dollar denominated time deposits totaling $130.3 million as at December 31, 2008 that earn interest at the market prevailing rate at the time an investment contract is executed.

The following table summarizes our interest earning assets and debt obligations that are sensitive to changes in interest rates as well as Chilean inflation at December 31, 2008 on a proportionate basis. For debt obligations, the table presents principal cash flows by expected (contractual) maturity dates.

December 31, 2008	**Expected Maturity Dates**						
MILLIONS	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**
Interest rate sensitivity:							
Current assets[(1)]	$23.1	$—	$ 126.9	$—	$ 26.6	$ —	$ 176.6
Long-term assets	—	—	—	—	—	—	—
Current liabilities	—	—	—	—	—	—	—
Long-term debt	(0.4)	(0.4)	(200.9)	(0.8)	(49.6)	(132.3)	(384.4)
Net floating rate position	22.7	(0.4)	(74.0)	(0.8)	(23.0)	(132.3)	(207.8)
Chilean inflation sensitivity:							
Long-term debt[(2)]	$ (0.4)	$(0.4)	$ (82.8)	$(0.8)	$(23.0)	$(132.3)	$(239.7)

(1) Current assets includes short term money market instruments (time deposits etc.) used primarily for cash management purposes.

(2) Long-term debt contains our Chilean transmission operations' debt that is denominated in UF.

We primarily manage interest rate risk through the issuance of fixed rate debt.

Foreign Currency Risk

Our principal foreign exchange risks involve changes in the value of the CLP versus the U.S. dollar, and to a lesser extent, changes in the Canadian dollar, Australian dollar and British pound versus the U.S. dollar.

Although our Chilean transmission operations' revenues are billed in CLP, from an economic perspective, they are a combination of CLP and U.S. dollar amounts that are converted to CLP prior to invoicing. These revenues are calculated based upon a return on the replacement cost of our Chilean transmission system, which is comprised of components denominated in U.S. dollars as well as CLP. Based on existing long term contracts and the current regulated transmission rate proceedings, we estimate that our revenues are 67% CLP and 33% U.S. dollar. Factoring in our CLP debt financings and cross currency interest rate swaps, we estimate that our Chilean transmission operations' adjusted net operating income is 70% U.S. dollar and 30% CLP.

Our Canadian timber operations' output is sold into both international and local markets. We view the international timber market as a market that is denominated in U.S. dollars, whereas the local market is denominated in Canadian dollars. Our local timber sales off-set roughly half of our operating and maintenance costs, which are largely Canadian dollar based. Our Canadian timber operations' project debt financing is U.S. dollar based. Currently our Canadian timber operations do not have any material hedges in place to convert their remaining Canadian dollar operating and maintenance expense exposure to U.S. dollars, although they are considering entering into a combination of short and mid term currency swaps to manage this exposure.

Our Chilean transmission operations have a portfolio of financial contracts to hedge their currency risk. The table below summarizes our outstanding financial contracts on a proportionate basis. The $465 million cross currency interest rate swap that matures in 2011, which converts U.S. dollar debt in our Chilean transmission operations to UF debt, is factored in to the analysis above.

Our PPP projects receive concession payments denominated in local currencies. At December 31, 2008 we had two equity interests in PPP projects—Longbay Forensic and Prison Hospitals in Australia and Peterborough Hospital in the United Kingdom. Currently we do not have any material hedges in place to convert our Australian dollar denominated concession payments to U.S. dollars, although we are considering entering into a combination of short and mid term currency swaps to manage this exposure. The Peterborough Hospital in the

United Kingdom is in the construction phase until late 2011 and no cash flows are expected from this project until that time. We have a commitment to fund our share of the remaining construction costs of the project totaling approximately £8 million. We have entered foreign currency contracts to effectively hedge this amount to the equivalent of approximately $12 million.

The table below presents on a proportionate basis information about our debt and derivatives that are denominated in CLP and UF and presents this information on a U.S. dollar equivalent basis. For UF-denominated debt obligations, the table presents principal cash flows, by expected maturity dates. For foreign currency forward exchange and swap contracts, the table presents the notional amounts by expected maturity dates.

December 31, 2008	**Expected Maturity Dates**						
US$ MILLIONS	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**
Assets							
USD	$14.6	$—	$126.9	$—	$ 26.6	$ —	$ 168.1
CLP	8.5	—	—	—	—	—	8.5
UF	—	—	—	—	—	—	—
Liabilities							
USD	—	—	(82.5)	—	(26.6)	—	(109.1)
CLP	—	—	(35.5)	—	—	—	(35.5)
UF	(0.4)	(0.4)	(82.8)	(0.8)	(23.0)	(132.3)	(239.7)
Net exposure							
USD	14.6	—	44.4	—	—	—	59.0
CLP	8.5	—	(35.5)	—	—	—	(27.0)
UF	$ (0.4)	$(0.4)	$ (82.8)	$(0.8)	$(23.0)	$(132.3)	$(239.7)

We will evaluate strategies or instruments to manage our foreign exchange risks on a portfolio basis.

Commodity Risk

Our principal commodity risk is the price of timber and to a lesser extent metals, primarily aluminum. All of our Canadian and U.S. timber operations' log sales are at market prices.

Approximately 90% of our Chilean transmission operation's revenues are adjusted on a semi-annual basis by a multi-factor inflation index that is designed to approximate changes in prices of the underlying components of the replacement cost of our transmission system. See Item 4.B "Business Overview". Due to the construction of the system, metals such as aluminum are a material percentage of replacement cost. Thus, changes in the price of these metals will impact the revenues of our Chilean transmission operations.

We do not currently use any strategies or instruments to manage commodity risks in our Canadian timber and Chilean transmission operations.

Contractual Obligations

Pursuant to the Master Service Agreement, on a quarterly basis, we pay a base management fee to the Manager equal to 0.3125% (1.25% annually) of the market value of our partnership. Based on the market value of our partnership as of December 31, 2008, this fee is estimated to be approximately $6.7 million per annum.

Related Party Transactions

We have entered into a number of related party transactions with Brookfield. See Item 7.B—"Related Party Transactions."

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In particular, critical accounting policies and estimates utilized in the normal course of preparing the partnership's financial statements require the determination of future cash flows utilized in assessing net recoverable amounts and net realizable values; depreciation and amortization; value of goodwill and intangible assets; ability to utilize tax losses; the determination of the primary beneficiary of variable interest entities; effectiveness of financial hedges for accounting purposes; and fair values for disclosure purposes.

In making estimates, management relies on external information and observable conditions where possible, supplemented by internal analysis as required. These estimates have been applied in a manner consistent with that in a prior year and there are no known trends, commitments, events or uncertainties that we believe will materially affect the methodology or assumptions utilized in this report. The estimates are impacted by, among other things, movements in interest rates, foreign exchange and other factors, some of which are highly uncertain. The interrelated nature of these factors prevents us from quantifying the overall impact of these movements on the partnership's financial statements in a meaningful way.

Brookfield Infrastructure's main critical accounting policy is investment valuation. Brookfield Infrastructure recognizes an impairment charge when a decline in the fair value of its investments below the carrying value is judged to be other-than-temporary. Brookfield Infrastructure considers various factors in determining whether to recognize an impairment charge, including the length of time and extent to which the fair value has been less than Brookfield Infrastructure's cost basis, the financial condition and near-term prospects of the investee, and Brookfield Infrastructure's intent and ability to hold the investment for a period of time sufficient to allow for any anticipated recovery in market value.

The following is a discussion of the critical accounting estimates of the companies in which we hold interests:

- ***Timberland Carrying Value.*** Timberlands are carried at cost less accumulated depletion. Site preparation and planting costs are capitalized as reforestation. Reforestation is transferred to a merchantable timber classification after 30 years. Depletion of the timberlands is based on the volume of timber estimated to be available over the harvest cycle. The process of estimating sustainable harvest is complex, requiring significant estimation in the evaluation of timber stand volumes based on the development of yield curves derived from data on timber species, timber stand age and growing site indexes gathered from a physical sampling of the timberland resource base. Although every reasonable effort is made to ensure that the sustainable harvest determination represents the most accurate assessment possible, subjective decisions and variances in sampling data from the actual timberland resource base make this determination generally less precise than other estimates used in the preparation of the financial statements. Changes in the determination of sustainable harvest could result in corresponding changes in the provision for depletion of the private timberland asset. Rates of depletion are revised for material changes to growth and harvest assumptions and are adjusted for any significant acquisition or disposition of timber.

- ***Island Timberlands Performance Fee.*** Accrual of the expense relating to the Island Timberlands performance fee (proportionate share of $13.1 million accrual reversal in 2008, $3.0 million expense in 2007) is determined based upon the internal rate of return of the business which includes estimates of the fair market value of Island Timberland's timber business determined utilizing a discounted cash flow approach. Based on this analysis, the timber business is estimated to be valued at approximately $313.1 million as at December 31, 2008 ($333.8 million as at December 31, 2007) on a proportionate basis. Below, we have outlined the material assumptions that underlie the estimated valuation as well as a sensitivity analysis for each material assumption (all numbers presented on a proportionate basis):

- ***Timber growth and depletion over the next 10 years.*** Studies have shown that a base level cut of about 1,843,000 cubic meters per year is sustainable over the long term, with an additional 547,000 cubic meters available for a 10 year period, primarily due to the existence of a surplus of mature timber. If sustainable harvest rates decreased/increased by 10%, the value of the timber assets would decrease/increase to $265.2 million and $349.5 million respectively in 2008 ($300.0 million and $371.3 million, respectively in 2007).
- ***Log prices.*** The estimated valuation assumes that log prices will remain unchanged for the next few years and then gradually increase. If log prices decreased/increased by 10%, the value of the timber assets would decrease/increase to $223.0 million and $403.6 million, respectively in 2008 ($249.4 million and $418.1 million, respectively in 2007).
- ***A discount rate of 6.9% was used in the appraisal.*** If the discount rate increased/decreased by 10%, the value of the timber assets would decrease/increase to $346.5 million and $284.5 million, respectively in 2008 ($367.5 million and $303.8 million, respectively in 2007).

The HBU lands are estimated to be valued at approximately $77.3 million ($112.1 million as at December 31, 2007) on a proportionate basis. Below, we have outlined the two material assumptions that underlie the estimated valuation of the HBU land as well as a sensitivity analysis for each material assumption:

- ***Lot selling prices.*** The estimated valuation assumes lot selling prices based on market averages in the region. If lot selling prices decreased/increased by 10%, the value of the HBU land would decrease/increase to $68.3 million and $86.3 million respectively in 2008 ($97.5 million and $127.1 million, respectively in 2007).
- ***Discount rate.*** A discount rate of 15.3% was used in the appraisal. If the discount rate increased/decreased by 10%, the value of the HBU land would decrease/increase to $85.5 million and $70.5 million, respectively in 2008 ($127.9 million and $99.8 million, respectively in 2007).

Goodwill. Impairment testing for goodwill is performed on an annual basis by the underlying investments. The first part of the test is a comparison of the fair value of the reporting unit to its carrying amount, including goodwill. If the fair value is less than the carrying value, then the second part of the test is required to measure the amount of potential goodwill impairment. The second step of the goodwill impairment test, used to measure the amount of impairment loss, compares the implied fair value of reporting unit goodwill (that shall be determined in the same manner as the amount of goodwill recognized in a business combination) with the carrying amount of that goodwill. If the carrying value of the reporting unit goodwill exceeds the implied fair value of that goodwill, then we would recognize an impairment loss in the amount of the difference, which would be recorded as a charge to income. The fair value of the reporting unit is determined using discounted cash flow models. In order to estimate future cash flows, we must make assumptions about future events that are highly uncertain at the time of estimation. For example, we make assumptions and estimates about future interest rates, exchange rates, electricity transmission rate increases, cost trends, including expected operating and maintenance costs and taxes. The number of years included in determining discounted cash flow, in our opinion, is estimable because the number is closely associated with the useful lives of our transmission lines and other tangible assets. These useful lives are determinable based on historical experience and electricity transmission regulatory framework. The discount rate used in the analysis may fluctuate as economic conditions change. Therefore, the likelihood of a change in estimate in any given period may be relatively high.

- ***Intangible Assets.*** Intangible assets that are not subject to amortization (e.g. rights-of-way) are tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that the assets might be impaired. The impairment test consists of a comparison of the fair value of an intangible asset with its carrying amount. If the carrying amount of an intangible asset exceeds its fair value, an impairment loss is recognized in an amount equal to that excess. Fair value of the indefinite useful life intangible assets may be assessed by reference to the market prices and if such information is not available we apply discounted cash flow models that are subject to the same inherent limitations and uncertainties as those described above related to the estimations of the fair value of our reporting unit.

- ***Derivatives.*** Transelec has certain financial derivative and embedded derivative instruments that are recorded at fair value, with changes in fair value recognized in earnings under the U.S. Financial Accounting Standards Board Statement of Financial Accounting Standard No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, except for certain instruments that qualify and are effective hedges of the foreign exchange risk exposure in the net investment of our transmission assets for which the changes in fair value are recognized in other comprehensive income. In establishing the fair value of such instruments, Transelec makes assumptions based on available market data and pricing models, which may change from time to time. Calculation of fair values of financial and embedded derivatives is done using models that are based primarily on discounted future cash flows and which use various inputs. Those inputs include estimated forward exchange rates, interest rates, inflation indices, prices of metals, and others. These inputs become more difficult to predict and the estimates are less precise, the further in the future these estimates are made. As a result, fair values are highly dependent upon the assumptions being used.

Reconciliation of Non-GAAP Financial Measures

To measure performance, we focus on net income as well as adjusted net operating income. We define adjusted net operating income or ANOI as net income excluding the impact of depreciation, depletion and amortization, deferred taxes and other items as shown in the reconciliation below. Adjusted net operating income is a measure of operating performance that is not calculated in accordance with, and does not have any standardized meaning prescribed by GAAP. Adjusted net operating income is therefore unlikely to be comparable to similar measures presented by other issuers. Adjusted net operating income has limitations as an analytical tool.

- Adjusted net operating income does not include depreciation and amortization expense; because we own capital assets with finite lives, depreciation and amortization expense recognizes the fact that we must maintain or replace our asset base in order to preserve our revenue generating capability;
- Adjusted net operating income does not include deferred income taxes, which may become payable if we own our assets for a long period of time; and
- Adjusted net operating income does not include performance fees accrued relating to our Canadian timber operations, which will be required to be paid in cash and which type of fee we expect to accrue in the future.

Because of these limitations, adjusted net operating income should not be considered as the sole measure of our performance and should not be considered in isolation from, or as a substitute for, analysis of our results as reported under GAAP. We compensate for these limitations by relying on our GAAP results and using adjusted net operating income only supplementally. However, adjusted net operating income is a key measure that management uses to evaluate the performance of our operations and forms the basis for our Partnership's distribution policy.

When viewed with our GAAP results, we believe that adjusted net operating income provides a more complete understanding of factors and trends affecting our underlying operations. Adjusted net operating income allows our management to evaluate our businesses on the basis of cash return on net capital deployed by removing the effect of non-cash and other items. We add back depreciation and amortization to remove the implication that our assets decline in value over time since we believe that the value of most or our assets will typically increase over time provided we make all necessary maintenance expenditures.

We add back depletion because we endeavor to manage our timberlands on a sustainable basis over the long term. Furthermore, changes in asset values typically do not decline on a predetermined schedule, as suggested by accounting depreciation or depletion, but instead will inevitably vary upwards and downwards based on a number of market and other conditions that cannot be determined in advance. We add back deferred income taxes because we do not believe this item reflects the present value of the actual cash tax obligations we will be required to pay, particularly if our operations are held for a long period of time. Finally, we add back a performance fee payable to Brookfield by Island Timberlands. This performance fee was calculated based upon a percentage of the increased appraised value of the timber and HBU land assets held by our Canadian timber operations over a threshold level. We believe it is appropriate to measure our performance excluding the impact of this accrual as we expect that over time the financial impact of this fee will be more than offset by increased income associated with the increased appraised value of these assets, which benefit is not reflected in the period in which the related fee accrues. In addition, as a result of our fee netting mechanism which is designed to eliminate any duplication of fees, any performance fees will reduce future incentive distributions that may otherwise be made to Brookfield by Brookfield Infrastructure. As this credit is reflected as a reduction in distributions to Brookfield, it would not be reflected in adjusted net operating income without adding back the performance fee.

The following table reconciles adjusted net operating income to the most directly comparable GAAP measure, which is net income. In doing so, we add back to net income the amounts recorded in respect of depreciation, depletion and amortization, deferred taxes and certain other items as well as the minority interest related to those items such that, similar to net income, adjusted net operating income reflects Brookfield Infrastructure's ownership interest. We urge you to review the GAAP financial measures in the supplemental financial information contained herein, and to not rely on any single financial measure to evaluate Brookfield Infrastructure.

	Years Ended December 31		
MILLIONS, UNAUDITED	**2008**	**2007**	**2006**
Net income	**$ 28.0**	$12.0	$10.4
Add back or deduct the following:			
Depreciation, depletion and amortization	**54.3**	9.8	6.2
Deferred taxes	**(14.9)**	(8.4)	(1.5)
Performance fee	**(12.8)**	3.1	—
Unrealized (gains) losses on derivative instruments	**3.9**	—	—
Other non-cash items	**1.2**	(3.2)	—
Adjusted net operating income (ANOI)	**$ 59.7**	$13.3	$15.1

On a pro forma basis, the following table reconciles net income to adjusted net operating income.

	Years Ended December 31		
MILLIONS, UNAUDITED	**2008**	**2007**	**2006**
Net income	**$ 27.9**	$ 6.1	$13.2
Add back or deduct the following:			
Depreciation, depletion and amortization	**55.6**	47.7	28.7
Deferred taxes	**(15.6)**	(20.9)	(3.6)
Performance fee	**(12.8)**	3.1	15.0
Unrealized (gains) losses on derivative instruments	**6.9**	15.3	(1.4)
Other non-cash items	**1.3**	0.9	—
Adjusted net operating income (ANOI)	**$ 63.3**	$ 52.2	$51.9

The difference between net income and adjusted net operating income is primarily attributable to depreciation and depletion expense which reflects purchase accounting adjustments for Transelec and Longview associated with their respective acquisitions, deferred taxes due to the step up in tax basis associated with those acquisitions, as well as non-cash expenses in Transelec, primarily relating to non-cash inflation indexations on its Chilean peso denominated debt.

Reconciliation of Unaudited Pro Forma Financial Statements

The unaudited pro forma statements of operations of Brookfield Infrastructure for the years ended December 31, 2008, 2007 and 2006, present Brookfield Infrastructure's results of operations, in each case adjusted to give effect to:

- the transfer to Brookfield Infrastructure of a 10.7% ownership interest in Transelec (which was acquired by Brookfield on June 30, 2006) and a 37.5% interest in Island Timberlands (which was acquired by Brookfield on May 30, 2005);
- the additional equity investment in Transelec to fund an adjustment to the original purchase price of Transelec due to an increase in the regulated asset value of our Chilean transmission operations, which resulted in an increase in Brookfield Infrastructure's ownership interest in Transelec from 10.7% to 17.8%;
- the transfer to Brookfield Infrastructure of a 30% interest in Longview Fibre Company's timberland operations (which was acquired by Brookfield on April 20, 2007) reflecting adjustments to Longview Fibre Company's historical financial statements for the sale by Longview Fibre Company of eight converting facilities and all of its manufacturing operations prior to Brookfield Infrastructure's acquisition of its interest in our U.S. timber operations;
- the transfer to Brookfield Infrastructure of interests ranging from 7% to 18% in five separate, but related, Brazilian electricity transmission investments, which are collectively referred to as TBE; and
- the spin-off and related transactions including entry into our Master Services Agreement and the issuance by the Holding Entities of preferred shares to Brookfield;

in each case, as if these transactions were completed on January 1, 2006.

The pro forma financial statements have been prepared based upon currently available information and assumptions deemed appropriate by management. The pro forma financial statements are provided for information purposes only and may not be indicative of the results that would have occurred if the spin-off and the other transactions had been effected on the dates indicated. The unaudited consolidated pro forma financial information also does not project the results of operations or financial position for any future period or date.

The unaudited consolidated pro forma financial information should be read together with the remainder of the information contained in this MD&A and our historical financial statements and related notes included elsewhere in this Form 20-F.

All financial data in these pro forma financial statements is presented in U.S. dollars and, unless otherwise indicated, has been prepared in accordance with GAAP.

Pro Forma Statement of Operations

For the Year Ended December 31, 2008 *US$ MILLIONS (UNAUDITED)*	Historical Financials	Acquisition of Additional Interest in Transelec1(a)	Corporate Expenses1(e)	Pro Forma
Revenues	$ 32.9	$—	$—	$ 32.9
Cost of revenues (exclusive of depreciation expense)	(2.6)	—	—	(2.6)
Selling, general and administrative expenses	(18.7)	—	(0.8)	(19.5)
Other income	0.9	—	—	0.9
Depreciation expense	(7.7)	—	—	(7.7)
Interest expense	(12.9)	—	—	(12.9)
Earnings from equity accounted investments	25.2	0.7	—	25.9
Dividend income	14.3	—	—	14.3
Net income before taxes	31.4	0.7	(0.8)	31.3
Income tax expense	(3.4)	—	—	(3.4)
Net income	$ 28.0	$ 0.7	$(0.8)	$ 27.9

For the Year Ended December 31, 2007 *US$ MILLIONS (UNAUDITED)*	Historical Financials	Transfer of Interests1(b)	Acquisition of TBE1(c)	Acquisition of Additional Interest in Transelec1(a)	Acquisition of Longview1(d)	Corporate Expenses1(e)	Pro Forma
Revenues	$33.1	$—	$ —	$ —	$—	$ —	$ 33.1
Cost of revenues (exclusive of depreciation expense)	(1.1)	—	—	—	—	—	(1.1)
Selling, general and administrative expenses	(4.4)	—	—	—	—	(14.8)	(19.2)
Other expense	(0.4)	—	—	—	—	—	(0.4)
Depreciation expense	(7.2)	—	—	—	—	—	(7.2)
Interest expense	(6.9)	—	—	—	—	(4.9)	(11.8)
Earnings (losses) from equity accounted investments	(7.8)	3.3	—	0.2	(5.2)	—	(9.5)
Dividend income	0.5	—	15.5	—	—	—	16.0
Net income before taxes	5.8	3.3	15.5	0.2	(5.2)	(19.7)	(0.1)
Income tax expense	6.2	—	—	—	—	—	6.2
Net income	$12.0	$ 3.3	$15.5	$ 0.2	$(5.2)	$(19.7)	$ 6.1

For the Year Ended December 31, 2006 *US$ MILLIONS (UNAUDITED)*	Historical Financials	Transfer of Interests1(b)	Acquisition of Longview1(d)	Acquisition of TBE1(c)	Acquisition of Additional Interest in Transelec1(a)	Corporate Expenses1(e)	Pro Forma
Revenues	$30.7	$—	$ —	$ —	$—	$ —	$ 30.7
Cost of revenues (exclusive of depreciation expense)	(1.3)	—	—	—	—	—	(1.3)
Selling, general and administrative expenses	(3.8)	—	—	—	—	(14.8)	(18.6)
Other income	(0.3)	—	—	—	—	—	(0.3)
Depreciation expense	(6.2)	—	—	—	—	—	(6.2)
Interest expense	(5.8)	—	—	—	—	(4.9)	(10.7)
Earnings (losses) from equity accounted investments	—	(5.0)	9.3	—	7.0	—	11.3
Dividend income	—	—	—	11.2	—	—	11.2
Net income before taxes	13.3	(5.0)	9.3	11.2	7.0	(19.7)	16.1
Income tax expense	(2.9)	—	—	—	—	—	(2.9)
Net income	$10.4	$(5.0)	$ 9.3	$11.2	$ 7.0	$(19.7)	$ 13.2

Notes to the Pro Forma Financial Statements

1. Pro Forma Adjustments

Brookfield Infrastructure's pro forma financial statements adjust Brookfield Infrastructure's financial statements to give effect to the matters discussed in these notes. The pro forma financial statements do not reflect the impact of potential cost savings and other synergies or incremental costs of the acquisitions.

The following adjustments were made to Brookfield Infrastructure's statements of operations for the years ended December 31, 2008, 2007 and 2006, in each case as if the applicable transaction had occurred on January 1, 2006.

a) Acquisition of Additional Interest in Transelec

Reflects the additional investment in Transelec, which increased Brookfield Infrastructure's ownership interest in Transelec from 10.7% to 17.8%. This transaction contributed to incremental equity earnings of $0.7 million, $0.2 million and $7.0 million for the years ended December 31, 2008, 2007 and 2006, respectively.

b) Transfer of Interests

Reflects the transfer of interest of Transelec, Island Timberlands, and Longview into Brookfield Infrastructure. Based upon Brookfield Infrastructure's level of control, Brookfield Infrastructure's interests in such entities is accounted for under the equity method of accounting. This resulted in the following adjustments to equity earnings:

	2007	2006
Equity earnings (losses) adjustment:		
Transelec	$ 1.1	$ 3.1
Island Timberlands	11.6	(8.1)
Longview	(9.4)	—
	$ 3.3	$(5.0)

c) Acquisition of TBE

Reflects an adjustment for dividends on the cost accounted investment in TBE, as if the investment had occurred on January 1, 2006. The net impact of this adjustment results in investment income of $15.5 million and $11.2 million for the years ended December 31, 2007, and 2006, respectively.

d) Acquisition of Longview

Brookfield acquired Longview Fibre Company, a timber and sawmill manufacturing company, on April 20, 2007 for $2,312.4 million. On May 31, 2007, Longview Fibre Company sold its manufacturing operation to a separate affiliate of Brookfield. The net result of this transaction is the inclusion of the Brookfield Infrastructure's 30% share of net income of Longview, using the equity method of accounting, as if its sole operations were the timber operations, as of January 1, 2006 resulting in equity losses of $5.2 million and earnings of $8.8 million for the years ended December 31, 2007 and 2006, respectively.

e) Corporate expenses

Reflects the following:

- Charges relating to the management fee paid by Brookfield Infrastructure to the Manager for Services rendered under the Master Services Agreement, based on an annual management base fee of 1.25% of the market value of our partnership. This results in an adjustment to selling, general and administrative expenses of $0.8 million for the year ended December 31, 2008, and $7.8 million for the years ended December 31, 2007 and 2006.

- Corporate expenses incurred by the partnership. Charges of $7.0 million were recorded for the years ended December 31, 2007 and 2006 to be comparable with the December 31, 2008 period.
- Interest expenses on the partnership's credit facility that was drawn upon in December 31, 2008. Charges of $4.9 million were adjusted for in interest expense for the years ended December 31, 2007 and 2006 for comparable with the December 31, 2008 period.
- Dividends paid on the $20 million of preferred shares issued to Brookfield Infrastructure by each Holding entity. This results in an adjustment to interest expense of $1.2 million for each year ended December 31, 2007 and 2006.

2. Adjusted Net Operating Income—Pro Forma

Adjusted net operating income is defined as net income adding back depreciation, depletion and amortization, deferred income taxes and other items which are either directly on the statement of income or are a component of the equity earnings of an underlying operating entity. Adjusted net operating income is a measure of operating performance that is not calculated in accordance with U.S. GAAP. Please see the Reconciliation of Non-GAAP Financial Measures section of this MD&A for a discussion of the limitations of adjusted net operating income as a measure of our operating performance. Below is a reconciliation of pro forma net income to pro forma adjusted net operating income for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31		
US$ MILLIONS, UNAUDITED	**2008**	**2007**	**2006**
Net income	**$ 27.9**	$ 6.1	$ 13.2
Add back or deduct non-cash and other components of net income:			
Depreciation and amortization	**55.6**	47.8	28.7
Deferred taxes and other	**(20.2)**	(1.7)	(5.0)
Performance fees	**—**	—	15.0
Adjusted net operating income	**$ 63.3**	$ 52.2	$ 51.9
Net Income by segment:			
Electricity transmission	**40.7**	27.4	31.2
Timber	**6.7**	(10.6)	(0.1)
Corporate	**(19.5)**	(10.7)	(17.9)
Total	**$ 27.9**	6.1	13.2
Adjusted net operating income by segment:			
Electricity transmission	**$ 68.4**	$ 54.2	$ 43.3
Timber	**12.8**	15.9	26.5
Corporate	**(17.9)**	(17.9)	(17.9)
Total	**$ 63.3**	$ 52.2	$ 51.9

Electricity Transmission

US$ MILLIONS, UNAUDITED	Years Ended December 31 2008	2007	2006
Revenue	**$ 93.0**	$ 78.1	$ 70.1
Costs attributed to revenues	**(16.5)**	(13.3)	(13.7)
Dividend income	**14.3**	16.0	11.2
Net operating income	**90.8**	80.8	67.6
Other income	**1.6**	0.9	3.0
Interest expense	**(22.6)**	(23.0)	(22.6)
Cash taxes	**(1.4)**	(4.5)	(4.7)
Adjusted net operating income (ANOI)	**68.4**	54.2	43.3
Depreciation and amortization	**(18.9)**	(17.8)	(15.6)
Deferred taxes and other	**(8.8)**	(9.0)	3.5
Net income	**$ 40.7**	$ 27.4	$ 31.2

Timber

US$ MILLIONS, UNAUDITED	Years Ended December 31 2008	2007	2006
Revenue	**$124.8**	$131.4	$131.9
Costs attributed to revenues	**(81.8)**	(79.6)	(77.1)
Net operating income	**43.0**	51.8	54.8
Investment and other income (expense)	**(0.5)**	(5.0)	1.9
Interest expense	**(29.0)**	(30.9)	(30.2)
Cash taxes	**(0.7)**	—	—
Adjusted net operating income (ANOI)	**12.8**	15.9	26.5
Depreciation and amortization	**(36.7)**	(29.9)	(13.3)
Performance fees	**—**	—	(15.0)
Deferred taxes and other	**30.6**	3.4	1.7
Net Income (loss)	**$ 6.7**	$ (10.6)	$ (0.1)

ITEM 6. DIRECTORS AND SENIOR MANAGEMENT

6.A DIRECTORS AND SENIOR MANAGEMENT

Board of Directors of our Managing General Partner

As required by law, our limited partnership agreement provides for the management and control of our partnership by a general partner rather than a board of directors and officers. Our Managing General Partner serves as our partnership's general partner and has a board of directors. Our Managing General Partner has no executive officers. Our Managing General Partner has sole responsibility and authority for the central management and control of our partnership, which is exercised through its board of directors in Bermuda.

The following table presents certain information concerning the current board of directors of our Managing General Partner:

Name and Municipality of Residence[(1)]	Age	Position	Principal Occupation
Derek Pannell Toronto, Canada	62	Chairman	Managing Partner, Brookfield Asset Management
Alex Erskine Devonshire, Bermuda	45	Director	Partner, Appleby, an international law firm
Jonathan Hagger Tunbridge Wells, England	60	Director	Chief Financial Officer, Grosvenor Estate and Investment Organization
Arthur Jacobson, Jr.[(3,4)] Mamaroneck, New York	45	Director	Managing Member, Martinart Partners, L.L.C., a restaurant
Anne Schaumburg[(2)] Short Hills, New Jersey	59	Director	Director, NRG Energy, Inc.
Danesh Varma[(2,3,4)] Kingston-Upon-Thames, England	58	Director	Chief Financial Officer, African-Aura Resources Limited, a mining company
James Wallace[(2,3,4)] Sudbury, Ontario	62	Director	President, Pioneer Construction Inc., a construction company

(1) The business address for each of the directors is Cannon's Court, 22 Victoria Street, Hamilton, HM 12, Bermuda.

(2) Member of the audit committee. Danesh Varma is the chairman of the audit committee.

(3) Member of the nominating and governance committee. James Wallace is the Chairman of the nominating and governance committee.

(4) Member of the compensation committee. James Wallace is the Chairman of the compensation committee.

Set forth below is biographical information for our Managing General Partner's current directors.

Derek Pannell. Derek is a Managing Partner of Brookfield Asset Management. Prior to this he was the Chief Executive Officer of Noranda Inc. and Falconbridge Limited from June 2002 to October 2006. He also served as the President and Chief Operating Officer for Noranda Inc. between September 2001 and June 2002. Derek is a metallurgical engineer with over 37 years of experience in the mining and metals industry. He is former Chair of the Mining Association of Canada and board member of the International Council on Mining and Metals. Derek serves on the boards of Teck Cominco Limited, Agrium Inc. and Major Drilling Group International Inc. Derek is a professional engineer registered in Quebec and Peru and is an Associate of the Royal School of Mines and a Fellow of the Canadian Academy of Engineers. Derek holds a Bachelor of Science degree from Imperial College in London, England.

Alex Erskine. Alex is a Partner and the Local Team Leader of the Funds and Investment Services team at Appleby. He practices in the areas of corporate and commercial law, specializing in advising on structuring and operating investment vehicles including mutual funds, hedge funds, unit trusts, partnerships, and close ended funds. Alex joined Appleby in 1999. Prior to joining Appleby he was Deputy Legal and Compliance Director of the Asset Management Division of UBS AG. Alex was educated in Ghana and England and studied law at the University College of Wales, Aberystwyth graduating in 1986 with an L.L.B.Hons. He was called to the Bar of England and Wales in 1996, the Bermuda Bar in 2006 and the British Virgin Islands Bar in 2007.

Jonathan Hagger. Jonathan is the Chief Financial Officer of Grosvenor Estate, the investment holding organization of the Duke of Westminster, which includes the worldwide real estate operations of the Grosvenor Group. Prior to his current position, Mr. Hagger was Group Finance Director of Grosvenor Group for 15 years until 2006. Prior to that, Mr. Hagger held a number of senior Board positions in the insurance industry. Mr. Hagger is a Fellow of both the Institute of Chartered Accountants in England and Wales and the Association of Corporate Treasurers, and serves on several non-profit Boards.

Arthur Jacobson, Jr. Arthur is a former Managing Director of Spear, Leeds Kellogg Specialists LLC (a division of Goldman Sachs Group Inc.) from 2001 to 2004. He was partner of Benjamin Jacobson and Sons, LLC from 1987 to 2001. He was also a specialist on the NYSE for 16 years, from 1988 to 2004. Prior to that he was an account executive at Drexel Burnham Lambert Inc. from 1985 to 1987. Arthur holds a degree in business administration from the University of Southern California.

Anne Schaumburg. Anne has been a member of the board of directors of NRG Energy, Inc., a power generation company listed on NYSE, since 2005. From 1984 until her retirement in 2002, Anne was with the Global Energy Group of Credit Suisse First Boston, where she last served as Managing Director. From 1979 to 1984, she was with the Utilities Group at Dean Witter Financial Services Group, where she last served as Managing Director. From 1971 to 1978, Anne was at First Boston Corporation in the Public Utilities Group. Anne is a graduate of the City University of New York.

Danesh Varma. Danesh is the Chief Financial Officer of African-Aura Resources Limited. He joined African-Aura Resources Limited in 2007 and was Chief Financial Officer of Minco PLC from 2006 to 2007. From 1999 to 2005, Danesh was a director at Dundee B Corp. Ltd. Prior to that, Danesh held a number of senior positions in the banking, corporate finance and accounting fields. Danesh holds a degree from Delhi University and is a Chartered Accountant.

James Wallace. James is the President of Pioneer Construction Inc. James is currently serving on the Boards of the following public corporations: Xstrata Canada Limited and Northstar Aerospace (Canada) Inc. He previously held positions on the boards of Falconbridge Limited, Noranda Income Fund, Osprey Media Income Fund, Rio Algom Ltd., and CTV as well as a number of other private companies in which he has ownership interests. James holds a Bachelor of Science from Laurentian University and a Masters of Business Administration from the University of Windsor. James is a Certified Management Accountant and holds a CFA designation.

Our Management

Our Managing General Partner does not have any employees. Instead, members of Brookfield's senior management and other individuals from Brookfield's global affiliates are drawn upon to fulfill the Manager's obligations to provide us with management services under our Master Services Agreement. Brookfield currently has approximately 14,000 employees including 400 investment professionals around the world. The following table presents certain information concerning the core senior management team that is principally responsible for our operations and their positions with the Manager:

Name	Age	Years of Experience	Years at Brookfield	Current Position with the Manager
Jeffrey Blidner	61	33	8	Chair
Samuel Pollock	42	20	15	Chief Executive Officer
John Stinebaugh	42	20	4	Chief Financial Officer

Each of the members of this team has substantial deal origination and execution expertise, having put together numerous consortiums, partnerships and joint ventures for large complex transactions. Members of this team have also been integral in building and developing Brookfield's electricity transmission and timber platforms. Set forth below is biographical information for Messrs. Blidner, Pollock, and Stinebaugh.

Jeffrey Blidner. Jeff is a Senior Managing Partner of Brookfield Asset Management with responsibility for strategic planning. Jeff is also the Chairman of the Manager. Jeff led the $2.5 billion acquisition of Transelec, as well as Brookfield's recently completed $7 billion acquisition of the Multiplex Group, an Australian-based global property, construction, and development company. Jeff is also the Chairman of the Board of Transelec. Prior to joining Brookfield in 2000, Jeff was a senior partner at Goodman & Carr LLP, a Toronto-based law firm. Jeff's practice focused on merchant banking transactions, public offerings, mergers and acquisitions, management buy-outs, restructurings and private equity transactions. Jeff received his LLB from Osgoode Hall Law School and was called to the Bar in Ontario as a Gold Medalist in 1974.

Samuel Pollock. Sam is a Senior Managing Partner of Brookfield Asset Management and Chief Executive Officer of the Manager. Sam has been responsible for the expansion of Brookfield's infrastructure operating platform. Under Sam's leadership, Brookfield has built its timber platform over the past five years from a modest operation of 400,000 acres under management in 2002 to the fifth largest in North America with more than 2.5 million acres under management. Sam has also acted as Brookfield's Chief Investment Officer, leading privatizations such as the $9 billion privatization of Trizec Properties Inc. and the $2 billion acquisition of O&Y Canada. Sam is a Chartered Accountant and holds a business degree from Queen's University.

John Stinebaugh. John is a Managing Partner of Brookfield Asset Management and Chief Financial Officer of the Manager. He is responsible for business development for Brookfield's utility infrastructure business, focusing on acquisitions of utility infrastructure assets in North America and other jurisdictions. John co-led the $2.5 billion acquisition of Transelec. Prior to that, John was with Credit Suisse Securities (U.S.A.) LLC. He worked in the energy group with responsibility for mergers and acquisitions and leveraged financings. During his tenure at Brookfield Asset Management and Credit Suisse, John worked on announced acquisitions and divestitures of energy infrastructure companies in excess of $15 billion. John received his Chartered Financial Analyst designation in 1995 and graduated with a degree in economics from Harvard University.

See also information contained in this Form 20-F under Item 6.C "Board Practices," Item 3.D "Risk Factors—Risks Relating to our Relationship with Brookfield," Item 6.A "Directors and Senior Management" and Item 7.B "Related Party Transactions."

Our Master Services Agreement

The Service Recipients have entered into a Master Services Agreement pursuant to which Brookfield Infrastructure Group Inc. and certain other affiliates of Brookfield Asset Management who are party thereto have agreed to provide or arrange for other service providers to provide management and administration services to our partnership and the other Service Recipients. The operating entities are not a party to the Master Services Agreement.

The following is a summary of certain provisions of our Master Services Agreement and is qualified in its entirety by reference to all of the provisions of the agreement. Because this description is only a summary of the Master Services Agreement, it does not necessarily contain all of the information that you may find useful. We therefore urge you to review the Master Services Agreement in its entirety. Copies of the Master Services Agreement are available electronically on the website of the Securities and Exchange Commission at *www.sec.gov* and on our SEDAR profile at *www.sedar.com* and are made available to our unitholders as described under Item 10.C "Material Contracts" and Item 10.H "Documents on display."

Appointment of the Manager and Services Rendered

Under our Master Services Agreement, the Service Recipients have appointed the Manager, as the service provider, to provide or arrange for the provision by an appropriate service provider of the following services:

- causing or supervising the carrying out of all day-to-day management, secretarial, accounting, banking, treasury, administrative, liaison, representative, regulatory and reporting functions and obligations;
- establishing and maintaining or supervising the establishment and maintenance of books and records;
- identifying, evaluating and recommending to the Holding Entities acquisitions or dispositions from time-to-time and, where requested to do so, assisting in negotiating the terms of such acquisitions or dispositions;

- recommending and, where requested to do so, assisting in the raising of funds whether by way of debt, equity or otherwise, including the preparation, review or distribution of any prospectus or offering memorandum in respect thereof and assisting with communications support in connection therewith;
- recommending to the Holding Entities suitable candidates to serve on the boards of directors or their equivalents of the operating entities;
- making recommendations with respect to the exercise of any voting rights to which the Holding Entities are entitled in respect of the operating entities;
- making recommendations with respect to the payment of dividends by the Holding Entities or any other distributions by the Service Recipients, including distributions by our partnership to our unitholders;
- monitoring and/or oversight of the applicable Service Recipient's accountants, legal counsel and other accounting, financial or legal advisors and technical, commercial, marketing and other independent experts, and managing litigation in which a Service Recipient is sued or commencing litigation after consulting with, and subject to the approval of, the relevant board of directors or its equivalent;
- attending to all matters necessary for any reorganization, bankruptcy proceedings, dissolution or winding up of a Service Recipient, subject to approval by the relevant board of directors or its equivalent;
- supervising the timely calculation and payment of taxes payable, and the filing of all tax returns due, by each Service Recipient;
- causing the Service Recipients' annual consolidated financial statements and quarterly interim financial statements to be: (i) prepared in accordance with generally accepted accounting principles or other applicable accounting principles for review and audit at least to such extent and with such frequency as may be required by law or regulation; and (ii) submitted to the relevant board of directors or its equivalent for its prior approval;
- making recommendations in relation to and effecting the entry into insurance of each Service Recipient's assets, together with other insurances against other risks, including directors and officers insurance as the relevant service provider and the relevant board of directors or its equivalent may from time to time agree;
- arranging for individuals to carry out the functions of principal executive, accounting and financial officers for our partnership only for purposes of applicable securities laws;
- providing individuals to act as senior officers of Holding Entities as agreed from time-to-time, subject to the approval of the relevant board of directors or its equivalent;
- advising the Service Recipients regarding the maintenance of compliance with applicable laws and other obligations; and
- providing all such other services as may from time-to-time be agreed with the Service Recipients that are reasonably related to the Service Recipient's day-to-day operations.

The Manager's activities are subject to the supervision of the board of directors of our Managing General Partner and of each of the other Service Recipients or their equivalent, as applicable.

Management Fee

Pursuant to the Master Services Agreement, on a quarterly basis, we pay a base management fee, referred to as the Base Management Fee, to the Manager equal to 0.3125% (1.25% annually) of the market value of our partnership. For purposes of calculating the Base Management Fee, the market value of our partnership is equal to the volume weighted average of the closing prices of our partnership's units on the NYSE (or other exchange or market where our partnership's units are principally traded) for each of the last five trading days of the applicable quarter multiplied by the number of issued and outstanding units of our partnership on the last of those days (assuming full conversion of Brookfield's interest in Brookfield Infrastructure into units of our partnership), plus the amount of net third-party debt with recourse to our partnership, Brookfield Infrastructure and any Holding Entity.

To the extent that under any other arrangement we are obligated to pay a base management fee (directly or indirectly through an equivalent arrangement) to the Manager (or any affiliate) on a portion of our capital that is comparable to the Base Management Fee, the Base Management Fee payable for each quarter in respect thereof will be reduced on a dollar for dollar basis by our proportionate share of the comparable base management fee (or equivalent amount) under such other arrangement for that quarter. The Base Management Fee will not be reduced by the amount of any incentive distribution payable by any Service Recipient or operating entity to the Manager (or any other affiliate) (for which there is a separate credit mechanism under Brookfield Infrastructure's limited partnership agreement), or any other fees that are payable by any operating entity to Brookfield for financial advisory, operations and maintenance, development, operations management and other services. See Item 7.B "Related Party Transactions—Other Services" and Item 7.B "Related Party Transactions—Incentive Distributions."

Reimbursement of Expenses and Certain Taxes

We also reimburse the Manager for any out-of-pocket fees, costs and expenses incurred in the provision of the management and administration services. However, the Service Recipients are not required to reimburse the Manager for the salaries and other remuneration of its management, personnel or support staff who carry out any services or functions for such Service Recipients or overhead for such persons.

The relevant Service Recipient is required to pay the Manager all other out-of-pocket fees, costs and expenses incurred in connection with the provision of the services including those of any third party and to reimburse the Manager for any such fees, costs and expenses. Such out-of-pocket fees, costs and expenses include, among other things, (i) fees, costs and expenses relating to any debt or equity financing; (ii) out-of-pocket fees, costs and expenses incurred in connection with the general administration of any Service Recipient; (iii) taxes, licenses and other statutory fees or penalties levied against or in respect of a Service Recipient; (iv) amounts owed under indemnification, contribution or similar arrangements; (v) fees, costs and expenses relating to our financial reporting, regulatory filings and investor relations and the fees, costs and expenses of agents, advisors and other persons who provide services to or on behalf of a Service Recipient; and (vi) any other fees, costs and expenses incurred by the Manager that are reasonably necessary for the performance by the Manager of its duties and functions under the Master Services Agreement.

In addition, the Service Recipients are required to pay all fees, expenses and costs incurred in connection with the investigation, acquisition, holding or disposal of any acquisition that is made or that is proposed to be made by us. Where the acquisition or proposed acquisition involves a joint acquisition that is made alongside one or more other persons, the Manager will be required to allocate such fees, costs and expenses in proportion to the notional amount of the acquisition made (or that would have been made in the case of an unconsummated acquisition) among all joint investors. Such additional fees, expenses and costs represent out-of-pocket costs associated with investment activities that are undertaken pursuant to the Master Services Agreement.

The Service Recipients are also required to pay or reimburse the Manager for all sales, use, value added, withholding or other taxes or customs duties or other governmental charges levied or imposed by reason of the Master Services Agreement or any agreement it contemplates, other than income taxes, corporation taxes, capital taxes or other similar taxes payable by the Manager, which are personal to the Manager.

Termination

The Master Services Agreement has no fixed term. However, the Service Recipients may terminate the Master Services Agreement upon 30 days' prior written notice of termination from our Managing General Partner to the Manager if any of the following occurs:

- the Manager defaults in the performance or observance of any material term, condition or covenant contained in the agreement in a manner that results in material harm to the Service Recipients and the default continues unremedied for a period of 30 days after written notice of the breach is given to the Manager;
- the Manager engages in any act of fraud, misappropriation of funds or embezzlement against any Service Recipient that results in material harm to the Service Recipients;
- the Manager is grossly negligent in the performance of its duties under the agreement and such negligence results in material harm to the Service Recipients; or
- certain events relating to the bankruptcy or insolvency of the Manager.

The Service Recipients have no right to terminate for any other reason, including if the Manager or Brookfield experiences a change of control. The Managing General Partner may only terminate the Master Services Agreement on behalf of our partnership with the prior unanimous approval of the Managing General Partner's independent directors.

Our Master Services Agreement expressly provides that the agreement may not be terminated by our Managing General Partner due solely to the poor performance or the under performance of any of our operations.

The Manager may terminate the Master Services Agreement upon 30 days' prior written notice of termination to our Managing General Partner if any Service Recipient defaults in the performance or observance of any material term, condition or covenant contained in the agreement in a manner that results in material harm and the default continues unremedied for a period of 30 days after written notice of the breach is given to the Service Recipient. The Manager may also terminate the Master Services Agreement upon the occurrence of certain events relating to the bankruptcy or insolvency of our partnership.

If the Master Services Agreement is terminated, the licensing agreement, the Relationship Agreement and any of Brookfield's obligations under the Relationship Agreement would also terminate. See Item 7.B "Related Party Transactions—Relationship Agreement" and Item 3.D "Risk Factors—Risks Relating to Our Relationship with Brookfield."

Indemnification and Limitations on Liability

Under the Master Services Agreement, the Manager has not assumed and will not assume any responsibility other than to provide or arrange for the provision of the services called for thereunder in good faith and will not be responsible for any action that the Service Recipients take in following or declining to follow the advice or recommendations of the Manager. The maximum amount of the aggregate liability of the Manager or any of its affiliates, or of any director, officer, employee, contractor, agent, advisor or other representative of the Manager or any of its affiliates, will be equal to the Base Management Fee previously paid by the Service Recipients in the two most recent calendar years pursuant to the Master Services Agreement. The Service Recipients have also agreed to indemnify each of the Manager, Brookfield and their affiliates, directors, officers, agents, members, partners, shareholders and employees to the fullest extent permitted by law from and against any claims, liabilities, losses, damages, costs or expenses (including legal fees) incurred by an indemnified person or threatened in connection with our respective businesses, investments and activities or in respect of or arising from the Master Services Agreement or the services provided by the Manager, except to the extent that the claims, liabilities, losses, damages, costs or expenses are determined to have resulted from the indemnified person's bad faith, fraud or willful misconduct, or in the case of a criminal matter, action that the indemnified person knew to have been unlawful. In addition, under the Master Services Agreement, the indemnified persons will not be liable to the Service Recipients to the fullest extent permitted by law, except for conduct that involved bad faith, fraud, willful misconduct, gross negligence or in the case of a criminal matter, action that the indemnified person knew to have been unlawful.

Outside Activities

Our Master Services Agreement does not prohibit the Manager or its affiliates from pursuing other business activities or providing services to third parties that compete directly or indirectly with us. For a description of related aspects of the relationship between Brookfield and the Service Recipients, see Item 7.B "Related Party Transactions—Relationship Agreement."

6.B COMPENSATION

Our Managing General Partner pays each of its directors $50,000 per year for serving on its board of directors and various board committees. The Managing General Partner pays the chairperson of the board of directors $100,000 per year for serving as chairperson of its board of directors.

Our Managing General Partner does not have any employees. Our partnership has entered into a Master Services Agreement with the Manager pursuant to which the Manager and certain other affiliates of Brookfield provide or arrange for other service providers to provide day-to-day management and administrative services for our partnership, Brookfield Infrastructure and the Holding Entities. The fees payable under the Master Service Agreement are set forth under Item 6.A "Directors and Senior Management—Our Master Services Agreement—Management Fee." In addition, Brookfield is entitled to receive incentive distributions from Brookfield Infrastructure described under Item 7.B "Related Party Transactions—Incentive Distributions."

Pursuant to the Master Service Agreement, members of Brookfield's senior management and other individuals from Brookfield's global affiliates are drawn upon to fulfill obligations under the Master Service Agreement. However, these individuals, including the Brookfield employees identified in the table under Item 6.A "Directors and Senior Management—Our Management," are not compensated by our partnership or our Managing General Partner. Instead, they will continue to be compensated by Brookfield. These individuals are not directors or officers of the partnership or our Managing General Partner.

6.C BOARD PRACTICES

Board Structure, Practices and Committees

The structure, practices and committees of our Managing General Partner's board of directors, including matters relating to the size, independence and composition of the board of directors, the election and removal of directors, requirements relating to board action and the powers delegated to board committees, are governed by our Managing General Partner's Bye-laws. Our Managing General Partner's board of directors is responsible for exercising the management, control, power and authority of the Managing General Partner except as required by applicable law or the Bye-laws of the Managing General Partner. Our corporate governance practices are not materially different than those required of domestic companies under the NYSE's listing standards. The following is a summary of certain provisions of those Bye-laws that affect our partnership's governance.

Size, Independence and Composition of the Board of Directors

Our Managing General Partner's board of directors is currently set at seven directors. The board may consist of between three and eleven directors or such other number of directors as may be determined from time-to-time by a resolution of our Managing General Partner's shareholders and subject to its bye-laws. At least three directors and at least a majority of the directors holding office must be independent of our Managing General Partner, Brookfield and its affiliates, as determined by the full board of directors using the standards for independence established by the NYSE.

If the death, resignation or removal of an independent director results in the board of directors consisting of less than a majority of independent directors, the vacancy must be filled promptly. Pending the filling of such vacancy, the board of directors may temporarily consist of less than a majority of independent directors and those directors who do not meet the standards for independence may continue to hold office. In addition, our Managing General Partner's Bye-laws prohibit 50% or more of the board of directors (or the independent directors as a group) from being citizens or residents of any one of Canada, the United Kingdom or the United States, and require that all board meetings be held in Bermuda.

Election and Removal of Directors

Our Managing General Partner's board of directors was appointed by its shareholders and each of its current directors will serve until the earlier of his or her death, resignation or removal from office. Vacancies on the board of directors may be filled and additional directors may be added by a resolution of our Managing General Partner's shareholders or a vote of the directors then in office. A director may be removed from office by a resolution duly passed by our Managing General Partner's shareholders or, if the director has been absent without leave from three consecutive meetings of the board of directors, by a written resolution requesting resignation signed by all other directors then holding office. A director will be automatically removed from the board of directors if he or she becomes bankrupt, insolvent or suspends payments to his or her creditors or becomes prohibited by law from acting as a director.

Action by the Board of Directors

Our Managing General Partner's board of directors may take action in a duly convened meeting at which a quorum is present or by a written resolution signed by all directors then holding office. Our Managing General Partners' board of directors holds a minimum of four meetings per year. When action is to be taken at a meeting of the board of directors, the affirmative vote of a majority of the votes cast is required for any action to be taken.

Transactions Requiring Approval by Independent Directors

Our Managing General Partner's independent directors have approved a conflicts policy which addresses the approval and other requirements for transactions in which there is greater potential for a conflict of interest to arise. These transactions include:

- the dissolution of our partnership;
- any material amendment to the Master Services Agreement, the equity commitment, our limited partnership agreement or Brookfield Infrastructure's limited partnership agreement;
- any material service agreement or other arrangement pursuant to which Brookfield will be paid a fee, or other consideration other than any agreement or arrangement contemplated by the Master Services Agreement;
- any calls by Brookfield Infrastructure or our partnership on the equity commitment provided by Brookfield as described under Item 7.B "Related Party Transactions—Equity Commitment and Other Financing";
- acquisitions by us from, and dispositions by us to, Brookfield or any of it affiliates;
- any other material transaction involving us and Brookfield or an affiliate of Brookfield; and
- termination of, or any determinations regarding indemnification under, the Master Services Agreement.

Our conflicts policy requires the transactions described above to be approved by a majority of our Managing General Partner's independent directors. Pursuant to our conflicts policy, independent directors may grant approvals for any of the transactions described above in the form of general guidelines, policies or procedures in which case no further special approval will be required in connection with a particular transaction or matter permitted thereby. See Item 7.B "Related Party Transactions—Conflicts of Interest and Fiduciary Duties."

Transactions in which a director has an Interest

A director who directly or indirectly has an interest in a contract, transaction or arrangement with our Managing General Partner, our partnership or certain of our affiliates is required to disclose the nature of his or her interest to the full board of directors. Such disclosure may generally take the form of a general notice given to the board of directors to the effect that the director has an interest in a specified company or firm and is to be regarded as interested in any contract, transaction or arrangement which may after the date of the notice be made with that company or firm or its affiliates. A director may participate in any meeting called to discuss or any vote called to approve the transaction in which the director has an interest and any transaction approved by the board of directors will not be void or voidable solely because the director was present at or participates in the meeting in which the approval was given provided that the board of directors or a board committee authorizes the transaction in good faith after the director's interest has been disclosed or the transaction is fair to our Managing General Partner and our partnership at the time it is approved.

Audit Committee

Our Managing General Partner's board of directors is required to establish and maintain at all times an audit committee that operates pursuant to a written charter. The audit committee is required to consist solely of independent directors and each member must be financially literate and there will be at least one member designated as an audit committee financial expert. 50% or more of the audit committee may not be directors who are citizens or residents of any one of Canada, the United Kingdom or the United States.

The audit committee is responsible for assisting and advising our Managing General Partner's board of directors with matters relating to:

- our accounting and financial reporting processes;
- the integrity and audits of our financial statements;
- our compliance with legal and regulatory requirements; and
- the qualifications, performance and independence of our independent accountants.

The audit committee is also responsible for engaging our independent accountants, reviewing the plans and results of each audit engagement with our independent accountants, approving professional services provided by our independent accountants, considering the range of audit and non-audit fees charged by our independent accountants and reviewing the adequacy of our internal accounting controls. All meetings of the audit committee will be held in Bermuda. The audit committee charter is available on our website at www.brookfieldinfrastructure.com/aboutus/governance and is available upon written request from our Corporate Secretary, at Cannon's Court, 22 Victoria Street, Hamilton HM 12, Bermuda.

Nominating and Governance Committee

Our Managing General Partner's board of directors is required to establish and maintain at all times a nominating and governance committee that operates pursuant to a written charter. The nominating and governance committee is required to consist entirely of independent directors and 50% or more of the nominating and corporate governance committee may not be directors who are citizens or residents of any one of Canada, the United Kingdom or the United States.

The nominating and governance committee is responsible for approving the appointment by the sitting directors of a person to the office of director and for recommending a slate of nominees for election as directors by our Managing General Partner's shareholders. The nominating and governance committee is also responsible for assisting and advising our Managing General Partner's board of directors with respect to matters relating to the general operation of the board of directors, our partnership's governance, the governance of our Managing General Partner and the performance of its board of directors and individual directors. All meetings of the nominating and governance committee will be held in Bermuda. The nominating and governance committee charter is available on our website at www.brookfieldinfrastructure.com/aboutus/governance and is available upon written request from our Corporate Secretary, at Cannon's Court, 22 Victoria Street, Hamilton HM 12, Bermuda.

Compensation Committee

Our Managing General Partner's board of directors is required to establish and maintain at all times a compensation committee that operates pursuant to a written charter. The compensation committee is required to consist solely of independent directors. 50% or more of the compensation committee may not be directors who are citizens or residents of any one of Canada, the United Kingdom or the United States.

The compensation committee is responsible for reviewing and making recommendations to the board of directors of the Managing General Partner concerning the remuneration of directors and committee members and supervising any changes in the fees to be paid pursuant to the Master Services Agreement. All meetings of the compensation committee will be held in Bermuda. The compensation committee charter is available on our website at www.brookfieldinfrastructure.com/aboutus/governance and is available upon written request from our Corporate Secretary, at Cannon's Court, 22 Victoria Street, Hamilton HM 12, Bermuda.

Indemnification and Limitations on Liability

Our Limited Partnership Agreement

Bermuda law permits the partnership agreement of a limited partnership, such as our partnership, to provide for the indemnification of a partner, the officers and directors of a partner and any other person against any and all claims and demands whatsoever, except to the extent that the indemnification may be held by the courts of Bermuda to be contrary to public policy or to the extent that Bermuda law prohibits indemnification against personal liability that may be imposed under specific provisions of Bermuda law. Bermuda law also permits a partnership to pay or reimburse an indemnified person's expenses in advance of a final disposition of a proceeding for which indemnification is sought. See Item 10.B "Memorandum and Articles of Association—Description of Our Units and Our Limited Partnership Agreement—Indemnification; Limitations on Liability" for a description of the indemnification arrangements in place under our limited partnership agreement.

Our Managing General Partner's Bye-laws

Bermuda law permits the Bye-laws of an exempted company, such as our Managing General Partner, to provide for the indemnification of its officers, directors and shareholders and any other person designated by the company against any and all claims and demands whatsoever, except to the extent that the indemnification may be held by the courts of Bermuda to be contrary to public policy or to the extent that Bermuda law prohibits indemnification against personal liability that may be imposed under specific provisions of Bermuda law. Bermuda company law also permits an exempted company to pay or reimburse an indemnified person's expenses in advance of a final disposition of a proceeding for which indemnification is sought.

Under our Managing General Partner's Bye-laws, our Managing General Partner is required to indemnify, to the fullest extent permitted by law, its affiliates, directors, officers, resident representative, shareholders and employees, any person who serves on a governing body of Brookfield Infrastructure or any of its subsidiaries and certain others against any and all losses, claims, damages, liabilities, costs or expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all claims, demands, actions, suits or proceedings, incurred by an indemnified person in connection with our partnership's investments and activities or in respect of or arising from their holding such positions, except to the extent that the claims, liabilities, losses, damages, costs or expenses are determined to have resulted from the indemnified person's bad faith, fraud or willful misconduct, or in the case of a criminal matter, action that the indemnified person knew to have been unlawful. In addition, under our Managing General Partner's Bye-laws, (i) the liability of such persons has been limited to the fullest extent permitted by law and except to the extent that their conduct involves bad faith, fraud or willful misconduct, or in the case of a criminal matter, action that the indemnified person knew to have been unlawful; and (ii) any matter that is approved by the independent directors will not constitute a breach of any duties stated or implied by law or equity, including fiduciary duties. Our Managing General Partner's Bye-laws require it to advance funds to pay the expenses of an indemnified person in connection with a matter in which indemnification may be sought until it is determined that the indemnified person is not entitled to indemnification.

Insurance

Our partnership has obtained insurance coverage under which the directors of our Managing General Partner are insured, subject to the limits of the policy, against certain losses arising from claims made against such directors by reason of any acts or omissions covered under the policy in their respective capacities as directors of our Managing General Partner, including certain liabilities under securities laws.

Canadian Insider Reporting

Our partnership is not subject to Canadian insider reporting requirements due to its status as a "SEC Foreign Issuer" under Canadian securities laws. However, our partnership does not rely on the exemption that is available to it from the insider reporting requirements of Canadian securities laws. In addition to meeting the minimum legal standards, our partnership treats all entities related to our partnership over which Brookfield Asset Management or our partnership exercise control (individually or when combined) that have an equity value in excess of $200 million (approximately 20% of the value of Brookfield Infrastructure) as being "major subsidiaries". This includes Brookfield Infrastructure, all the Holding Entities and the following current operations: Island Timberlands (and its general partner), Transelec and Longview.

Governance of Brookfield Infrastructure

The board of directors of the Infrastructure General Partner is identical to the board of directors of our Managing General Partner and has substantially similar governance arrangements as our partnership. However, the Infrastructure General Partner's Bye-laws allow for alternate directors. A director of the Infrastructure General Partner may by written notice to the secretary of the Infrastructure General Partner appoint any person, including another director, who meets any minimum standards that are required by applicable law to serve as an alternate director to attend and vote in the director's place at any meeting of the Infrastructure General Partner's board of directors at which the director is not personally present and to perform any duties and functions and exercise any rights that the director could perform or exercise personally. Any alternate director appointed may not be a citizen or resident of Canada, the United Kingdom or the United States if such residency would cause 50% or more of the board of directors (or the independent directors as a group) to consist of directors who are citizens or residents of any one of Canada, the United Kingdom or the United States.

6.D EMPLOYEES

Our partnership does not employ any of the individuals who carry out the management and activities of our partnership. The personnel that carry out these activities are employees of Brookfield, and their services are provided to our partnership or for our benefit under our Master Services Agreement. For a discussion of the individuals from Brookfield's management team that are expected to be involved in our infrastructure business, see Item 6.A "Directors and Senior Management—Our Management."

6.E SHARE OWNERSHIP

Each of our directors and officers of the Managing General Partner own less than one percent of our units.

ITEM 7. MAJOR SHAREHOLDERS AND RELATED PARTY TRANSACTIONS

7.A MAJOR SHAREHOLDERS

The following table presents information regarding the beneficial ownership of our limited partnership units by each entity that we know beneficially owns more than 5% of our partnership's units, as at December 31, 2008.

	Units Outstanding	
Name and Address	Units Owned	Percentage(1)
Brookfield Asset Management Inc. Suite 300, Brookfield Place, 181 Bay Street Toronto, Ontario M5J 2T3	15.2 million(2)	39.7%(2)
BAM Investments Corp. Suite 300, Brookfield Place, 181 Bay Street Toronto, Ontario M5J 2T3	2.2 million	5.7%
Partners Limited Suite 300, Brookfield Place, 181 Bay Street Toronto, Ontario M5J 2T3	17.4 million(3)	45.4%(3)
Morgan Stanley Investment Management Inc. (U.S.) 522 Fifth Avenue, New York, NY 10036	4.6 million	12.0%

(1) Assumes that all of the Redemption—Exchange Units of Brookfield Infrastructure are exchanged for our units pursuant to the Redemption Exchange Mechanism described at Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Redemption Exchange Mechanism."

(2) Brookfield will be deemed to be the beneficial owner of 15,161,573 our units constituting approximately 39.7% of the issued and outstanding units, assuming that all of the Redemption—Exchange Units of Brookfield Infrastructure are exchanged for our units pursuant to the Redemption Exchange Mechanism described at Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Redemption Exchange Mechanism." This includes 48,829 units, constituting approximately 0.2% of the issued and outstanding units, beneficially held by Brookfield.

(3) Partners Limited will be deemed to be the beneficial owner of 17,400,517 of our units, constituting approximately 45.4% of the issued and outstanding units, assuming that all of the Redemption-Exchange Units of Brookfield Infrastructure are exchanged for our units pursuant to the Redemption-Exchange Mechanism described at Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Redemption Exchange Mechanism." Partners may be deemed to have the power (together with each of Brookfield and BAM Investments Corp.) to vote or direct the vote of the units beneficially owned by it or to dispose of such units other than 20,295 of our units constituting approximately 0.09% with respect to which it has sole voting and investment power.

See also the information contained in this Form 20-F under Item 3.D "Risk Factors—Risks Relating to our Relationship with Brookfield," Item 6.C "Board Practices," Item 6.A "Directors and Senior Management" and Item 7.B "Related Party Transactions."

7.B RELATED PARTY TRANSACTIONS

We are an affiliate of Brookfield. We have entered into a number of agreements and arrangements with Brookfield in order to enable us to be established as a separate entity and pursue our vision of being a leading owner and operator of high quality infrastructure assets. While we believe that this ongoing relationship with Brookfield provides us with a strong competitive advantage as well as access to opportunities that would otherwise not be available to us, we operate very differently from an independent, stand-alone entity. We describe below these relationships as well as potential conflicts of interest (and the methods for resolving them) and other material considerations arising from our relationship with Brookfield.

See also the information contained in this Form 20-F under Item 3.D “Risk Factors—Risks Relating to our Relationship with Brookfield,” Item 6.C “Board Practices,” Item 6.A “Directors and Senior Management” and Item 7.A “Major Shareholders.”

Relationship Agreement

Our partnership, Brookfield Infrastructure, the Holding Entities, the Manager and Brookfield have entered into an agreement, referred to as the Relationship Agreement, that governs aspects of the relationship among them. Pursuant to the Relationship Agreement, Brookfield has agreed that we serve as the primary (though not exclusive) vehicle through which Brookfield makes future infrastructure related acquisitions that are suitable for our strategy and objectives. Our acquisition strategy focuses on large scale transactions, for which we believe there is less competition and where Brookfield has sufficient influence or control so that our operations-oriented approach can be deployed to create value. Due to similar asset characteristics and capital requirements we believe that the infrastructure industry will evolve like the real estate industry in which assets are commonly owned through consortiums and partnerships of institutional equity investors and owner/operators such as ourselves. Accordingly, an integral part of our strategy is to participate with institutional investors in Brookfield sponsored or co-sponsored consortiums for single asset acquisitions and as a partner in or alongside Brookfield sponsored or co-sponsored partnerships that target acquisitions that suit our profile. Brookfield has a strong track record of leading such consortiums and partnerships and actively managing underlying assets to improve performance. Brookfield agreed that it will not sponsor such arrangements that are suitable for us in the infrastructure sector unless we are given an opportunity to participate.

Brookfield’s commitment to us and our ability to take advantage of opportunities is subject to a number of inherent limitations such as our financial capacity, the suitability of the acquisition in terms of the underlying asset characteristics and its fit with our strategy, limitations arising from the tax and regulatory regimes that govern our affairs and certain other restrictions. See Item 3.D “Risk Factors—Risks Relating to Our Relationship with Brookfield.” Under the terms of the Relationship Agreement, our partnership, Brookfield Infrastructure and the Holding Entities acknowledge and agree that, subject to providing us the opportunity to participate on the basis described above, Brookfield (including its directors, officers, agents, members, partners, shareholders and employees) is able to pursue other business activities and provide services to third parties that compete directly or indirectly with us. In addition, Brookfield has established or advised, and may continue to establish or advise, other entities that rely on the diligence, skill and business contacts of Brookfield’s professionals and the information and acquisition opportunities they generate during the normal course of their activities. Our partnership, Brookfield Infrastructure and the Holding Entities acknowledge and agree that some of these entities may have objectives that overlap with our objectives or may acquire infrastructure assets or businesses that could be considered appropriate acquisitions for us, and that Brookfield may have greater financial incentives to assist those other entities over us. Due to the foregoing, we expect to compete from time-to-time with other affiliates of Brookfield or other third parties for access to the benefits that we expect to realize from Brookfield’s involvement in our business.

Since Brookfield has large, well established operations in the real estate and renewable power businesses that will remain separate from us, Brookfield is not obligated to provide us with any opportunities in these sectors, and we do not anticipate pursuing acquisitions in these areas. In addition, since Brookfield has granted an affiliate the right to act as the exclusive vehicle for Brookfield’s timberland acquisitions in Eastern Canada and the Northeastern U.S., we are not entitled to participate in timberland acquisitions in those geographic regions. In the event of the termination of the Master Services Agreement, the Relationship Agreement would also terminate, including Brookfield’s commitments to provide us with acquisition opportunities, as described above.

Pursuant to the Relationship Agreement, Brookfield has also agreed to use reasonable efforts to ensure that any voting rights with respect to any operating entity (other than TBE, our Brazilian transmission investments) that are held by entities over which it has control are voted:

- in favour of the election of a director (or its equivalent) approved by the entity through which our interest in the relevant entity is held; and

- in accordance with the direction of the entity through which our interest in the relevant entity is held with respect to the approval or rejection of the following matters relating to the operating entity, as applicable: (i) any sale of all or substantially all of its assets, (ii) any merger, amalgamation, consolidation, business combination or other material corporate transaction, except in connection with any internal reorganization that does not result in a change of control, (iii) any plan or proposal for a complete or partial liquidation or dissolution, or any reorganization or any case, proceeding or action seeking relief under any existing laws or future laws relating to bankruptcy or insolvency, (iv) any issuance of shares, units or other securities, including debt securities, or (v) any commitment or agreement to do any of the foregoing.

For these purposes, the relevant entity may maintain, from time-to-time, an approved slate of nominees or provide direction with respect to the approval or rejection of any matter in the form of general guidelines, policies or procedures in which case no further approval or direction will be required. Any such general guidelines, policies or procedures may be modified by the relevant entity in its discretion.

Under the Relationship Agreement, our partnership, Brookfield Infrastructure and the Holding Entities have agreed that none of Brookfield or the Manager, nor any director, officer, agent, member, partner, shareholder or employee of Brookfield or the Manager, will be liable to us for any claims, liabilities, losses, damages, costs or expenses (including legal fees) arising in connection with the business, investments and activities in respect of or arising from the Relationship Agreement. The maximum amount of the aggregate liability of Brookfield, or any of its affiliates, or of any director, officer, employee, contractor, agent, advisor or other representative of Brookfield, will be equal to the amounts previously paid in the two most recent calendar years by the Service Recipients pursuant to the Master Services Agreement.

Services Provided under Our Master Services Agreement

The Service Recipients have entered into the Master Services Agreement pursuant to which Brookfield Infrastructure Group Inc. and certain other affiliates of Brookfield Asset Management who are party thereto agreed to provide or arrange for other service providers to provide management and administration services to our partnership and the other Service Recipients. In exchange, the Manager is entitled to a Base Management Fee. For a description of our Master Services Agreement, see Item 6.A “Directors and Senior Management—Our Master Services Agreement.”

Other Services

Brookfield may provide to the operating entities services which are outside the scope of the Master Services Agreement under arrangements that are on market terms and conditions and pursuant to which Brookfield will receive fees. The services provided under these arrangements include financial advisory, operations and maintenance, development, operations management and other services. Pursuant to our conflict of interest guidelines, those arrangements may require prior approval by a majority of the independent directors, which may be granted in the form of general guidelines, policies or procedures. See “—Conflicts of Interest and Fiduciary Duties.”

Longview Purchase Agreement

We have entered into an agreement with Brookfield that provides for us to acquire an additional indirect interest in Longview in the event that Brookfield contributes its remaining interest in Longview to a timberlands focused partnership with institutional investors. The agreement provides that we will participate in any such partnership through a commitment of up to $600 million provided that (i) third party institutional investors commit at least $400 million; (ii) the transfer of Longview is at a price equal to the appraised value of the timberlands and real estate plus working capital; and (iii) the transaction is completed within 18 months. Our agreement is also subject to our ability to obtain financing. The agreement also includes other conditions, representations and warranties and covenants that are customary for an agreement of this nature. Pursuant to this agreement, we have also acknowledged that, we will be subject to typical market terms as a partner, including with respect to capital commitments, applicable fees and carried interest.

Equity Commitment and Other Financing

Concurrent with the closing of the spin-off, Brookfield provided to our partnership and Brookfield Infrastructure an equity commitment in the amount of $200 million. The equity commitment may be called by our partnership and/or Brookfield Infrastructure in exchange for the issuance of a number of units of our partnership or Brookfield Infrastructure, as the case may be, to Brookfield, corresponding to the amount of the equity commitment called divided by the volume weighted average of the trading price for our units on the principal stock exchange on which our units are listed for the five days immediately preceding the date of the call. The equity commitment is available to be called for a three year duration following closing of the spin-off. The equity commitment is available in minimum amounts of $10 million and the amount available under the equity commitment will be reduced permanently by the amount so called. Before funds may be called on the equity commitment a number of conditions precedent must be met, including that Brookfield continues to control the Infrastructure GP LP and has the ability to elect a majority of the board of directors of the Infrastructure General Partner.

The units of Brookfield Infrastructure to be issued under the equity commitment will become subject to the Redemption-Exchange Mechanism and may therefore result in Brookfield acquiring additional units of our partnership. See Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Redemption-Exchange Mechanism."

If the equity commitment were called in full by Brookfield Infrastructure, Brookfield's ownership of Brookfield Infrastructure would increase from approximately 40% to approximately 51% or, if the equity commitment were called in full by our partnership, Brookfield's ownership of our outstanding limited partnership units would increase from approximately 6% to approximately 31%, in each case assuming that our units' market price is equal to our pro forma book value per unit. However, since capital calls under the equity commitment will be at the five day volume weighted average price of our units, the capital calls will not be economically dilutive to our existing unit holders.

The rationale for the equity commitment is to provide our partnership and Brookfield Infrastructure with access to equity capital on an as needed basis and to maximize our flexibility. Brookfield Infrastructure has also established a credit facility with a syndicate of banks. We intend to use the liquidity provided by the equity commitment and credit facility for working capital purposes, and we may use the proceeds from the equity commitment to fund growth capital investments and acquisitions. Furthermore, Brookfield has informed us that it will also consider providing bridge financing to us for the purposes of funding acquisitions. The determination of which of these sources of funding Brookfield Infrastructure will access in any particular situation will be a matter of optimizing needs and opportunities at that time.

Preferred Shares

Brookfield has provided an aggregate of $20 million of working capital to our Holding Entities through a subscription for preferred shares of such Holding Entities. The preferred shares are entitled to receive a cumulative preferential dividend equal to 6% of their redemption value as and when declared by the board of directors of the applicable Holding Entity and are redeemable at the option of the Holding Entity, subject to certain limitations, at any time after the tenth anniversary of their issuance. The preferred shares are not entitled to vote, except as required by law.

Redemption-Exchange Mechanism

At any time after two years from the date of closing of the spin-off, one or more wholly-owned subsidiaries of Brookfield that hold Redemption-Exchange Units (as hereinafter defined) will have the right to require

Brookfield Infrastructure to redeem all or a portion of the Redemption-Exchange Units, subject to our partnership's right of first refusal, for cash in an amount equal to the market value of one of our units multiplied by the number of units to be redeemed (subject to certain adjustments). See Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Redemption-Exchange Mechanism." Taken together, the effect of the redemption right and the right of first refusal is that one or more wholly-owned subsidiaries of Brookfield will receive our units, or the value of such units, at the election of our partnership. Should our partnership determine not to exercise its right of first refusal, cash required to fund a redemption of limited partnership interests of Brookfield Infrastructure held by whollyowned subsidiaries of Brookfield will likely be financed by a public offering of our units.

Registration Rights Agreement

Our partnership has entered into a registration rights agreement with Brookfield pursuant to which our partnership has agreed that, upon the request of Brookfield, our partnership will file one or more registration statements to register for sale under the United States Securities Act of 1933, as amended, any of our partnership's units held by Brookfield (including our units acquired pursuant to the Redemption-Exchange Mechanism). In the registration rights agreement we have agreed to pay expenses in connection with such registration and sales and have indemnified Brookfield for material misstatements or omissions in the registration statement.

Incentive Distributions

Infrastructure GP LP is entitled to receive incentive distributions from Brookfield Infrastructure as a result of its ownership of the general partnership interest in Brookfield Infrastructure. The incentive distributions are to be calculated in increments based on the amount by which quarterly distributions on the limited partnership units of Brookfield Infrastructure exceed specified target levels as set forth in Brookfield Infrastructure's limited partnership agreement. See Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Distributions."

The Infrastructure GP LP may, at its sole discretion, elect to reinvest incentive distributions in exchange for Redemption-Exchange Units.

To the extent that any Holding Entity or any operating entity pays to Brookfield any comparable performance or incentive distribution, the amount of any future incentive distributions will be reduced in an equitable manner to avoid duplication of distributions.

For example, in conjunction with the consortium arrangements in respect of our Canadian timber operations and our Chilean transmission operations, we pay to Brookfield our pro-rata share of base management fees paid by each of the respective consortiums and, in the case of our Canadian timber operations, our pro-rata share of performance fees. Pursuant to the Master Services Agreement, the base management fees paid pursuant to the consortium arrangements are creditable against the management fee payable under the Master Services Agreement and, in the case of the performance fees paid pursuant to the consortium arrangements in respect of the Canadian timber operations, such performance fees reduce incentive distributions to which Brookfield would otherwise be entitled from Brookfield Infrastructure pursuant to Brookfield Infrastructure's limited partnership agreement. See Item 6.A "Directors and Senior Management—Our Master Services Agreement."

In addition, operations, maintenance and corporate services will continue to be provided to the Ontario transmission operations by Brookfield on an outsourced—cost recovery basis, with such costs being recoverable under the regulated revenue requirement of this operation. Other services may also be provided to us under arrangements that are on market terms and conditions, such as participation in Brookfield's group insurance and purchase programs, as described under "—Other Services."

General Partner Distributions

Pursuant to our limited partnership agreement, the Managing General Partner is entitled to receive a general partner distribution equal to 0.01% of the total distributions of our partnership. See Item 10.B “Memorandum and Articles of Association—Description of Our Units and Our Limited Partnership Agreement.”

Pursuant to the limited partnership agreement of Brookfield Infrastructure, Infrastructure GP LP is entitled to receive a general partner distribution from Brookfield Infrastructure equal to a share of the total distributions of Brookfield Infrastructure in proportion to the Infrastructure GP LP’s percentage interest in Brookfield Infrastructure which, immediately following the spin-off, was equal to 1% of the total distributions of Brookfield Infrastructure. See Item 10.B “Memorandum and Articles of Association—Description of Brookfield Infrastructure’s Limited Partnership Agreement—Distributions.” In addition, it is entitled to receive the incentive distributions described above under “—Incentive Distribution.”

Distribution Reinvestment Plan

Brookfield Infrastructure has a distribution reinvestment plan. Brookfield has advised our partnership that it may from time-to-time reinvest distributions it receives from Brookfield Infrastructure in Brookfield Infrastructure’s distribution reinvestment plan. In addition, subject to regulatory approval and U.S. securities law registration requirements, our partnership intends to adopt a distribution reinvestment plan. While our partnership has not yet adopted a distribution reinvestment plan, the following is a summary description of the principal terms of the plan our partnership intends to adopt.

Pursuant to the distribution reinvestment plan, holders of our units in certain jurisdictions will be able to elect to have all distributions paid on our units held by them automatically reinvested in additional units in accordance with the terms of the distribution reinvestment plan. Distributions to be reinvested in our units under the distribution reinvestment plan will be reduced by the amount of any applicable withholding tax.

Distributions due to plan participants will be paid to the plan agent, for the benefit of the plan participants and, if a plan participant has elected to have his or her distributions automatically reinvested, applied, on behalf of such plan participant, to the purchase of additional units. Such purchases will be made either (a) on the stock exchange on which our units are listed on the date the relevant distribution is paid by our partnership or (b) from our partnership on the distribution date at a price per unit calculated by reference to the volume weighted average of the trading price for our units on a stock exchange on which our units are listed for the five trading days immediately preceding the date the relevant distribution is paid by our partnership.

The units so purchased will be allocated on a pro rata basis to plan participants. The plan agent will furnish to each plan participant a report of the units purchased for the distribution reinvestment plan participant’s account in respect of each distribution and the cumulative total purchased for that account. While our partnership will not issue fractional units, a plan participant’s pro rata entitlement to units purchased under the distribution reinvestment plan may include a fraction of a unit and such fractional units shall accumulate. A cash adjustment for any fractional units will be paid by the plan agent upon the withdrawal from or termination by a plan participant of his or her participation in the distribution reinvestment plan or upon termination of the distribution reinvestment plan at price per unit calculated by reference to the volume weighted average of the trading price for our units on a stock exchange on which our units are listed for the five trading days immediately preceding such withdrawal or termination. No certificates representing units issued or purchased pursuant to the distribution reinvestment plan will be issued, other than upon a plan participant’s termination of participation in the distribution reinvestment plan. The automatic reinvestment of distributions under the distribution reinvestment plan will not relieve participants of any income tax obligations applicable to such distributions.

If our units are thinly traded, purchases in the market under the distribution reinvestment plan may significantly affect the market price. Depending on market conditions, direct reinvestment of cash distributions by unitholders in the market may be more, or less, advantageous than the reinvestment arrangements under the distribution reinvestment plan. No brokerage commissions will be payable in connection with the purchase of our units under the distribution reinvestment plan and all administrative costs will be borne by our partnership.

Unitholders will be able to terminate their participation in the distribution reinvestment plan by providing, or by causing to be provided, at least 10 business days' prior written notice to our partnership. Such notice, if actually received by our partnership no later than 10 business days prior to a record date, will have effect in respect of the distribution to be made as of such date. Thereafter, distributions to such unitholders will be in cash. Our partnership will be able to terminate the distribution reinvestment plan, in its sole discretion, upon not less than 30 days' notice to the plan participants and the plan agent. Our partnership will also be able to amend, modify or suspend the distribution reinvestment plan at any time in its sole discretion, provided that it gives notice of that amendment, modification or suspension to our unitholders, which notice may be given by our partnership issuing a press release or by publishing an advertisement containing a summary description of the amendment in at least one major daily newspaper of general and regular paid circulation in Canada and the United States or in any other manner our partnership determines to be appropriate.

Brookfield Infrastructure will have a corresponding distribution reinvestment plan in respect of distributions made to our partnership and Brookfield. Brookfield Infrastructure's distribution reinvestment plan may be implemented prior to our partnership adopting its distribution reinvestment plan. Our partnership does not intend to reinvest distributions it receives from Brookfield Infrastructure in Brookfield Infrastructure's distribution reinvestment plan except to the extent that holders of our units elect to reinvest distributions pursuant to our distribution reinvestment plan. Brookfield has advised our partnership that it may from time-to-time reinvest distributions it receives from Brookfield Infrastructure pursuant to Brookfield Infrastructure's distribution reinvestment plan. The units of Brookfield Infrastructure to be issued to Brookfield under the distribution reinvestment plan will become subject to the Redemption-Exchange Mechanism and may therefore result in Brookfield acquiring additional units of our partnership. See Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Redemption-Exchange Mechanism."

Indemnification Arrangements

Subject to certain limitations, Brookfield and its directors, officers, agents, members, partners, shareholders and employees generally benefit from indemnification provisions and limitations on liability that are included in our limited partnership agreement, our Managing General Partner's Bye-laws, Brookfield Infrastructure's limited partnership agreement, our Master Services Agreement and other arrangements with Brookfield. See Item 6.A "Directors and Senior Management—Our Master Services Agreement," Item 10.B "Memorandum and Articles of Association—Description of Our Units and Our Limited Partnership Agreement—Indemnification; Limitations of Liability" and Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement—Indemnification; Limitations of Liability."

Licensing Agreement

Our partnership and Brookfield Infrastructure have each entered into a licensing agreement with Brookfield pursuant to which Brookfield has granted a non-exclusive, royalty-free license to use the name "Brookfield" and the Brookfield logo. Other than under this limited license, we do not have a legal right to the "Brookfield" name and the Brookfield logo in the United States and Canada.

We will be permitted to terminate the licensing agreement upon 30 days' prior written notice if Brookfield defaults in the performance of any material term, condition or agreement contained in the agreement and the default continues for a period of 30 days after written notice of termination of the breach is given to Brookfield.

Brookfield may terminate the licensing agreement effective immediately upon termination of our Master Services Agreement or with respect to any licensee upon 30 days' prior written notice of termination if any of the following occurs:

- the licensee defaults in the performance of any material term, condition or agreement contained in the agreement and the default continues for a period of 30 days after written notice of termination of the breach is given to the licensee;
- the licensee assigns, sublicenses, pledges, mortgages or otherwise encumbers the intellectual property rights granted to it pursuant to the licensing agreement;
- certain events relating to a bankruptcy or insolvency of the licensee; or
- the licensee ceases to be an affiliate of Brookfield.

A termination of the licensing agreement with respect to one or more licensee will not affect the validity or enforceability of the agreement with respect to any other licensees.

Conflicts of Interest and Fiduciary Duties

Our organizational and ownership structure and strategy involve a number of relationships that may give rise to conflicts of interest between our partnership and our unitholders, on the one hand, and Brookfield, on the other hand. In particular, conflicts of interest could arise, among other reasons, because:

- in originating and recommending acquisition opportunities, Brookfield has significant discretion to determine the suitability of opportunities for us and to allocate such opportunities to us or to itself or third parties;
- because of the scale of typical infrastructure acquisitions and because our strategy includes completing acquisitions through consortium or partnership arrangements with pension funds and other financial sponsors, we will likely make co-investments with Brookfield and Brookfield sponsored funds or Brookfield sponsored or co-sponsored consortiums and partnerships, which typically will require that Brookfield owe fiduciary duties to the other partners or consortium members that it does not owe to us;
- there may be circumstances where Brookfield will determine that an acquisition opportunity is not suitable for us because of limits arising due to regulatory or tax considerations or limits on our financial capacity or because of the immaturity of the target assets or the fit with our acquisition strategy and Brookfield is entitled to pursue the acquisition on its own behalf rather than offering us the opportunity to make the acquisition and, as a result, Brookfield may initially or ultimately make the acquisition;
- where Brookfield has made an acquisition, it may transfer it to us at a later date after the assets have been developed or we have obtained sufficient financing;
- our relationship with Brookfield involves a number of arrangements pursuant to which Brookfield provides various services and access to financing arrangements and acquisition opportunities, and circumstances may arise in which these arrangements will need to be amended or new arrangements will need to be entered into;
- our arrangements with Brookfield were negotiated in the context of the spin-off, which may have resulted in those arrangements containing terms that are less favorable than those which otherwise might have been obtained from unrelated parties;
- under Brookfield Infrastructure's limited partnership agreement and the agreements governing the operating entities, Brookfield is generally entitled to share in the returns generated by our operations, which could create an incentive for it to assume greater risks when making decisions than they otherwise would in the absence of such arrangements;

- Brookfield is permitted to pursue other business activities and provide services to third parties that compete directly with our business and activities without providing us with an opportunity to participate, which could result in the allocation of Brookfield's resources, personnel and acquisition opportunities to others who compete with us;
- Brookfield does not owe our partnership or our unitholders any fiduciary duties, which may limit our recourse against it; and
- the liability of Brookfield is limited under our arrangements with them, and we have agreed to indemnify Brookfield against claims, liabilities, losses, damages, costs or expenses which they may face in connection with those arrangements, which may lead them to assume greater risks when making decisions than they otherwise would if such decisions were being made solely for their own account, or may give rise to legal claims for indemnification that are adverse to the interests of our unitholders.

With respect to transactions in which there is greater potential for a conflict of interest to arise, our Managing General Partner may be required to seek the prior approval of a majority of the independent directors pursuant to conflict of interest guidelines that have been approved by a majority of the independent directors. These transactions include (i) the dissolution of our partnership; (ii) any material amendment to the Master Services Agreement, the equity commitment, our limited partnership agreement or Brookfield Infrastructure's limited partnership agreement; (iii) any material service agreement or other arrangement pursuant to which Brookfield will be paid a fee, or other consideration other than any agreement or arrangement contemplated by the Master Services Agreement; (iv) any calls by Brookfield Infrastructure or our partnership on the equity commitment; (v) acquisitions by us from, and dispositions by us to, Brookfield or any of its affiliates; (vi) any other transaction involving Brookfield or an affiliate of Brookfield and (vii) termination of, or any determinations regarding indemnification under, the Master Services Agreement. Pursuant to our conflicts policy, independent directors may grant prior approvals for any of these transactions in the form of general guidelines, policies or procedures in which case no further special approval will be required in connection with a particular transaction or matter permitted thereby. In certain circumstances, these transactions may be related party transactions for the purposes of, and subject to certain requirements of, Multilateral Instrument 61-101, or MI 61-101, which in some situations requires minority shareholder approval and/or valuation for transactions with related parties. An exemption from such requirements is available when the fair market value of the transaction is not more than 25% of the market capitalization of the issuer. Our partnership has been granted exemptive relief from the requirements of MI 61-101 that, subject to certain conditions, would permit it to be exempt from the minority approval and valuation requirements for transactions that would have a value of less than 25% of our partnership's market capitalization if Brookfield's indirect equity interest in our partnership was included in the calculation of our partnership's market capitalization. As a result, the 25% threshold above which the minority approval and valuation requirements would apply would be increased to include the approximately 40% indirect interest in our partnership held by Brookfield.

We maintain a conflicts policy to assist in the resolution of these potential or actual conflicts which states that conflicts be resolved based on the principles of transparency, independent validation and approvals. The policy recognizes the benefit to us of our relationship with Brookfield and our intent to pursue a strategy that seeks to maximize the benefits from this relationship. The policy also recognizes that the principal areas of potential application of the policy on an ongoing basis will be in connection with our acquisitions and our participation in Brookfield led consortia and partnership arrangements, together with any management or service arrangements entered into in connection therewith or the ongoing operations of the underlying operating entities.

In general, the policy provides that acquisitions that are carried out jointly by us and Brookfield, or in the context of a Brookfield led or co-led consortium or partnership be carried out on the basis that the consideration paid by us be no more, on a per share or proportionate basis, than the consideration paid by Brookfield or other participants, as applicable. The policy also provides that any fees or carried interest payable in respect of our proportionate investment, or in respect of an acquisition made solely by us, must be credited in the manner contemplated by our Master Services Agreement and Brookfield Infrastructure's limited partnership agreement, where applicable, or that such fees or carried interest must either have been negotiated with another arm's length participant or otherwise demonstrated to be on market terms. The policy further provides that if the acquisition involves the purchase by us of an asset from Brookfield, or the participation in a transaction involving the purchase by us and Brookfield of different assets, that a fairness opinion or, in some circumstances, a valuation or appraisal by a qualified expert be obtained. These requirements provided for in the conflicts policy are in addition to any disclosure, approval and valuation requirements that may arise under applicable law.

Our limited partnership agreement and the limited partnership agreement of Brookfield Infrastructure contain various provisions that modify the fiduciary duties that might otherwise be owed to us and our unitholders. These duties include the duties of care and loyalty. The duty of loyalty, in the absence of provisions in the limited partnership agreements of our partnership and Brookfield Infrastructure to the contrary, would generally prohibit the Managing General Partner and Infrastructure General Partner from taking any action or engaging in any transaction as to which it has a conflict of interest. The limited partnership agreements of our partnership and Brookfield Infrastructure each prohibit the limited partners from advancing claims that otherwise might raise issues as to compliance with fiduciary duties or applicable law. For example, the agreements provide that our Managing General Partner, the Infrastructure General Partner and their affiliates will not have any obligation under the limited partnership agreements of our partnership or Brookfield Infrastructure, or as a result of any duties stated or implied by law or equity, including fiduciary duties, to present business or investment opportunities to our partnership, Brookfield Infrastructure, any Holding Entity or any other holding vehicle established by our partnership. They also allow affiliates of the Managing General Partner and Infrastructure General Partner to engage in activities that may compete with us or our activities. In addition, the agreements permit our Managing General Partner and the Infrastructure General Partner to take into account the interests of third parties, including Brookfield, when resolving conflicts of interest.

These modifications to the fiduciary duties are detrimental to our unitholders because they restrict the remedies available for actions that might otherwise constitute a breach of fiduciary duty and permit conflicts of interest to be resolved in a manner that is not always in the best interests of our partnership or the best interests of our unitholders. We believe it is necessary to modify the fiduciary duties that might otherwise be owed to us and our unitholders, as described above, due to our organizational and ownership structure and the potential conflicts of interest created thereby. Without modifying those duties, the ability of our Managing General Partner and the Infrastructure General Partner to attract and retain experienced and capable directors and to take actions that we believe will be necessary for the carrying out of our business would be unduly limited due to their concern about potential liability.

7.C INTEREST OF EXPERTS AND COUNSEL

Not applicable.

ITEM 8. FINANCIAL INFORMATION

8.A CONSOLIDATED STATEMENTS AND OTHER FINANCIAL INFORMATION

Please see Item 18 below for additional information required to be disclosed under this Item.

8.B SIGNIFICANT CHANGES

Please see Item 3 "Key Information," Item 4 "Information on the Company," Item 5 "Operating and Financial Review and Prospects" for additional information.

ITEM 9. THE OFFER AND LISTING

9.A LISTING DETAILS

The following table sets forth the high and low prices for our units on the NYSE for the periods indicated since the date of listing on January 31, 2008:

	High	Low
January 31, 2008 to March 31, 2008	$21.60	$14.60
April 1, 2008 to June 30, 2008	$21.00	$16.95
July 1, 2008 to September 30, 2008	$19.81	$15.00
October 1, 2008 to October 31, 2008	$16.55	$ 9.47
November 1, 2008 to November 30, 2008	$16.17	$ 9.82
December 1, 2008 to December 31, 2008	$12.20	$10.22
January 1, 2009 to January 31, 2009	$15.00	$11.30
February 1, 2009 to February 28, 2009	$14.30	$11.23
March 1, 2009 to March 31, 2009	$14.31	$ 7.15
April 1, 2009 to April 24, 2009	$14.01	$11.51

9.B PLAN OF DISTRIBUTION

Not applicable.

9.C MARKET

Our units are listed on the NYSE under the symbol “BIP”.

9.D SELLING SHAREHOLDERS

Not applicable.

9.E DILUTION

Not applicable.

9.F EXPENSES OF THE ISSUE

Not applicable.

ITEM 10. ADDITIONAL INFORMATION

10.A SHARE CAPITAL

Not applicable.

10.B MEMORANDUM AND ARTICLES OF ASSOCIATION

DESCRIPTION OF OUR UNITS AND OUR LIMITED PARTNERSHIP AGREEMENT

The following is a description of the material terms of our units and our limited partnership agreement, as amended, and is qualified in its entirety by reference to all of the provisions of our limited partnership agreement. Because this description is only a summary of the terms of our units and our limited partnership agreement, it does not contain all of the information that you may find useful. For more complete information, you should read the limited partnership agreement which is available electronically on the website of the Securities and Exchange Commission at *www.sec.gov* and our SEDAR profile at *www.sedar.com* and will be made available to our holders as described under Item 10.C “Material Contracts” and Item 10.H “Documents on display.”

See also the information contained in this Form 20-F under Item 3.D "Risk Factors—Risk Relating to Our Relationship with Brookfield," Item 6.C "Board Practices," Item 6.A "Directors and Senior Management" and Item 7.B "Related Party Transactions."

Formation and Duration

Our partnership is a Bermuda exempted limited partnership registered under the Limited Partnership Act 1883 and the Exempted Partnerships Act 1992. Our partnership has a perpetual existence and will continue as a limited liability partnership unless our partnership is terminated or dissolved in accordance with our limited partnership agreement. Our partnership interests consist of our units, which represent limited partnership interests in our partnership, and any additional partnership interests representing limited partnership interests that we may issue in the future as described below under "—Issuance of Additional Partnership Interests." In this description, references to "holders of our partnership interests" and our "unitholders" are to our limited partners and references to our limited partners include holders of our units.

Nature and Purpose

Under our limited partnership agreement, the purpose of our partnership is to: acquire and hold interests in Brookfield Infrastructure and, subject to the approval of the Managing General Partner, any other subsidiary of our partnership; engage in any activity related to the capitalization and financing of our partnership's interests in such entities; and engage in any other activity that is incidental to or in furtherance of the foregoing and that is approved by our Managing General Partner and that lawfully may be conducted by a limited partnership organized under the Limited Partnership Act 1883 and our limited partnership agreement.

Our Units

Our units are limited partnership interests in our partnership. Holders of our units are not entitled to the withdrawal or return of capital contributions in respect of our units, except to the extent, if any, that distributions are made to such holders pursuant to our limited partnership agreement or upon the liquidation of our partnership as described below under "—Liquidation and Distribution of Proceeds" or as otherwise required by applicable law. Except to the extent expressly provided in our limited partnership agreement, a holder of our units does not have priority over any other holder of our units, either as to the return of capital contributions or as to profits, losses or distributions. Holders of our units will not be granted any preemptive or other similar right to acquire additional interests in our partnership. In addition, holders of our units do not have any right to have their units redeemed by our partnership.

Issuance of Additional Partnership Interests

Our Managing General Partner has broad rights to cause our partnership to issue additional partnership interests and may cause our partnership to issue additional partnership interests (including new classes of partnership interests and options, rights, warrants and appreciation rights relating to such interests) for any partnership purpose, at any time and on such terms and conditions as it may determine without the approval of any limited partners. Any additional partnership interests may be issued in one or more classes, or one or more series of classes, with such designations, preferences, rights, powers and duties (which may be senior to existing classes and series of partnership interests) as may be determined by our Managing General Partner in its sole discretion, all without approval of our limited partners.

Investments in Brookfield Infrastructure

If and to the extent that our partnership raises funds by way of the issuance of equity or debt securities, or otherwise, pursuant to a public offering, private placement or otherwise, an amount equal to the proceeds will be invested in Brookfield Infrastructure.

Capital Contributions

Brookfield and the Managing General Partner each contributed $1 to the capital of our partnership in order to form our partnership. Thereafter, Brookfield contributed to our partnership limited partnership interests of Brookfield Infrastructure in exchange for Redemption-Exchange Units and our units, the latter of which was distributed by Brookfield Asset Management in the spin off.

Distributions

Distributions to partners of our partnership will be made only as determined by the Managing General Partner in its sole discretion. However, the Managing General Partner will not be permitted to cause our partnership to make a distribution if it does not have sufficient cash on hand to make the distribution, the distribution would render it insolvent or if, in the opinion of the Managing General Partner, the distribution would leave it with insufficient funds to meet any future contingent obligations.

Any distributions from our partnership will be made to the limited partners as to 99.99% and to the Managing General Partner as to 0.01%. Each limited partner will receive a pro rata share of distributions made to all limited partners in accordance with the proportion of all outstanding units held by that limited partner. See Item 8.A "Consolidated Statements and Other Financial Information."

Allocations of Income and Losses

Net income and net loss for U.S. federal income tax purposes will be allocated for each taxable year among our partners using a monthly, quarterly or other permissible convention pro rata on a per unit basis, except to the extent otherwise required by law or pursuant to tax elections made by our partnership. The source and character of items of income and loss so allocated to a partner of our partnership will be the same source and character as the income earned or loss incurred by our partnership.

The income for Canadian federal income tax purposes of our partnership for a given fiscal year of our partnership will be allocated to each partner in an amount calculated by multiplying such income by a fraction, the numerator of which is the sum of the distributions received by such partner with respect to such fiscal year and the denominator of which is the aggregate amount of the distributions made by our partnership to partners with respect to such fiscal year. Generally, the source and character of items of income so allocated to a partner with respect to a fiscal year of our partnership will be the same source and character as the distributions received by such partner with respect to such fiscal year.

If, with respect to a given fiscal year, no distribution is made by our partnership or our partnership has a loss for Canadian federal income tax purposes, one quarter of the income, or loss, as the case may be, for Canadian federal income tax purposes of our partnership for such fiscal year, will be allocated to the partners of record at the end of each calendar quarter ending in such fiscal year pro rata to their respective percentage interests in our partnership, which in the case of the Managing General Partner shall mean 0.01%, and in the case of all limited partners of our partnership shall mean in the aggregate 99.99%, which aggregate percentage interest shall be allocated among the limited partners in the proportion that the number of limited partnership units held at each such date by a limited partner is of the total number of limited partnership units issued and outstanding at each such date. Generally, the source and character of such income or losses so allocated to a partner at the end of each calendar quarter will be the same source and character as the income or loss earned or incurred by our partnership in such calendar quarter.

Limited Liability

Assuming that a limited partner does not participate in the control or management of our partnership or conduct the affairs of, sign or execute documents for or otherwise bind our partnership within the meaning of the Limited Partnership Act 1883 and otherwise acts in conformity with the provisions of our limited partnership agreement, such partner's liability under the Limited Partnership Act 1883 and our limited partnership agreement will be limited to the amount of capital such partner is obligated to contribute to our partnership for its limited partner interest plus its share of any undistributed profits and assets, except as described below.

If it were determined, however, that a limited partner was participating in the control or management of our partnership or conducting the affairs of, signing or executing documents for or otherwise binding our partnership (or purporting to do any of the foregoing) within the meaning of the Limited Partnership Act 1883 or the Exempted Partnerships Act 1992, such limited partner would be liable as if it were a general partner of our partnership in respect of all debts of our partnership incurred while that limited partner was so acting or purporting to act. Neither our limited partnership agreement nor the Limited Partnership Act 1883 specifically provides for legal recourse against our Managing General Partner if a limited partner were to lose limited liability through any fault of our Managing General Partner. While this does not mean that a limited partner could not seek legal recourse, we are not aware of any precedent for such a claim in Bermuda case law.

No Management or Control

Our partnership's limited partners, in their capacities as such, may not take part in the management or control of the activities and affairs of our partnership and do not have any right or authority to act for or to bind our partnership or to take part or interfere in the conduct or management of our partnership. Limited partners are not entitled to vote on matters relating to our partnership, although holders of units are entitled to consent to certain matters as described under "—Amendment of Our Limited Partnership Agreement," "—Opinion of Counsel and Limited Partner Approval," "—Merger, Sale or Other Disposition of Assets," and "—Withdrawal of Our Managing General Partner" which may be effected only with the consent of the holders of the percentages of our outstanding units specified below. Each unit shall entitle the holder thereof to one vote for the purposes of any approvals of holders of units.

Meetings

Our Managing General Partner may call special meetings of partners at a time and place outside of Canada determined by our Managing General Partner on a date not less than 10 days nor more than 60 days after the mailing of notice of the meeting. The limited partners do not have the ability to call a special meeting. Only holders of record on the date set by our Managing General Partner (which may not be less than 10 days nor more than 60 days, before the meeting) are entitled to notice of any meeting.

Written consents may be solicited only by or on behalf of our Managing General Partner. Any such consent solicitation may specify that any written consents must be returned to our partnership within the time period, which may not be less than 20 days, specified by our Managing General Partner.

For purposes of determining holders of partnership interests entitled to provide consents to any action described above, our Managing General Partner may set a record date, which may be not less than 10 nor more than 60 days before the date by which record holders are requested in writing by our Managing General Partner to provide such consents. Only those holders of partnership interests on the record date established by our Managing General Partner will be entitled to provide consents with respect to matters as to which a consent right applies.

Amendment of Our Limited Partnership Agreement

Amendments to our limited partnership agreement may be proposed only by or with the consent of our Managing General Partner. To adopt a proposed amendment, other than the amendments that do not require limited partner approval discussed below, our Managing General Partner must seek approval of a majority of our outstanding units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, except that any amendment that would have a material adverse effect on the rights or preferences of any class of partnership interests in relation to other classes of partnership interests may be approved by at least a majority of the type or class of partnership interests so affected, or
- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by our partnership to our Managing General Partner or any of its affiliates without the consent of our Managing General Partner, which may be given or withheld in its sole discretion.

The provision of our limited partnership agreement preventing the amendments having the effects described directly above can be amended upon the approval of the holders of at least 90% of the outstanding units.

No Limited Partner Approval

Subject to applicable law, our Managing General Partner may generally make amendments to our limited partnership agreement without the approval of any limited partner to reflect:

- a change in the name of our partnership, the location of our partnership's registered office, or our partnership's registered agent,
- the admission, substitution or withdrawal of partners in accordance with our limited partnership agreement,
- a change that our Managing General Partner determines is necessary or appropriate for our partnership to qualify or to continue our partnership's qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any jurisdiction or to ensure that our partnership will not be treated as an association taxable as a corporation or otherwise taxed as an entity for tax purposes,
- an amendment that our Managing General Partner determines to be necessary or appropriate to address certain changes in tax regulations, legislation or interpretation,
- an amendment that is necessary, in the opinion of our counsel, to prevent our partnership or our Managing General Partner or its directors, officers, agents or trustees, from having a material risk of being in any manner being subjected to the provisions of the U.S. Investment Company Act or similar legislation in other jurisdictions,
- an amendment that our Managing General Partner determines in its sole discretion to be necessary or appropriate for the creation, authorization or issuance of any class or series of partnership interests or options, rights, warrants or appreciation rights relating to partnership securities,
- any amendment expressly permitted in our limited partnership agreement to be made by our Managing General Partner acting alone,
- an amendment effected, necessitated or contemplated by an agreement of merger, consolidation or other combination agreement that has been approved under the terms of our limited partnership agreement,
- any amendment that in the sole discretion of our Managing General Partner is necessary or appropriate to reflect and account for the formation by our partnership of, or its investment in, any corporation, partnership, joint venture, limited liability company or other entity, as otherwise permitted by our limited partnership agreement,
- a change in our partnership's fiscal year and related changes, or
- any other amendments substantially similar to any of the matters described directly above.

In addition, our Managing General Partner may make amendments to our limited partnership agreement without the approval of any limited partner if those amendments, in the discretion of our Managing General Partner:

- do not adversely affect our partnership's limited partners considered as a whole (including any particular class of partnership interests as compared to other classes of partnership interests) in any material respect,
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any governmental agency or judicial authority,
- are necessary or appropriate to facilitate the trading of our units or to comply with any rule, regulation, guideline or requirement of any securities exchange on which our units are or will be listed for trading,
- are necessary or appropriate for any action taken by our Managing General Partner relating to splits or combinations of units under the provisions of our limited partnership agreement, or
- are required to effect the intent expressed in this Form 20-F or the intent of the provisions of our limited partnership agreement or are otherwise contemplated by our limited partnership agreement.

Opinion of Counsel and Limited Partner Approval

Our Managing General Partner will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners if one of the amendments described above under "—No Limited Partner Approval" should occur. No other amendments to our limited partnership agreement (other than an amendment pursuant to a merger, sale or other disposition of assets effected in accordance with the provisions described under "—Merger, Sale or Other Disposition of Assets") will become effective without the approval of holders of at least 90% of our units, unless our partnership obtains an opinion of counsel to the effect that the amendment will not cause our partnership to be treated as an association taxable as a corporation or otherwise taxable as an entity for tax purposes (provided that for U.S. tax purposes our Managing General Partner has not made the election described below under "—Election to be Treated as a Corporation") or affect the limited liability under the Limited Partnership Act of 1883 of any of our partnership's limited partners.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of partnership interests in relation to other classes of partnership interests will also require the approval of the holders of at least a majority of the outstanding partnership interests of the class so affected.

In addition, any amendment that reduces the voting percentage required to take any action must be approved by the affirmative vote of limited partners whose aggregate outstanding voting units constitute not less than the voting requirement sought to be reduced.

Merger, Sale or Other Disposition of Assets

Any merger, consolidation or other combination of our partnership requires the prior approval of our Managing General Partner who has no duty or obligation to provide any such approval. Our limited partnership agreement generally prohibits our Managing General Partner, without the prior approval of the holders of a majority of our units, from causing our partnership to, among other things, sell, exchange or otherwise dispose of all or substantially all of our partnership's assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination, or approving on our partnership's behalf the sale, exchange or other disposition of all or substantially all of the assets of our partnership's subsidiaries. However, our Managing General Partner in its sole discretion may mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our partnership's assets (including for the benefit of persons other than our partnership or our partnership's subsidiaries) without that approval. Our Managing General Partner may also sell all or substantially all of our partnership's assets under any forced sale of any or all of our partnership's assets pursuant to the foreclosure or other realization upon those encumbrances without that approval.

If conditions specified in our limited partnership agreement are satisfied, our Managing General Partner may convert or merge our partnership into, or convey some or all of our partnership's assets to, a newly formed entity if the sole purpose of that merger or conveyance is to effect a mere change in our partnership's legal form into another limited liability entity. Holders of partnership interests are not entitled to dissenters' rights of appraisal under our limited partnership agreement or the Limited Partnership Act 1883 or the Exempted Partnerships Act 1992 in the event of a merger or consolidation, a sale of substantially all of our assets or any other transaction or event.

Election to be Treated as a Corporation

If our Managing General Partner determines that it is no longer in our partnership's best interests to continue as a partnership for U.S. federal income tax purposes, our Managing General Partner may elect to treat our partnership as an association or as a publicly traded partnership taxable as a corporation for U.S. federal (and applicable state) income tax purposes.

Termination and Dissolution

Our partnership will terminate upon the earlier to occur of (i) the date on which all of our partnership's assets have been disposed of or otherwise realized by our partnership and the proceeds of such disposals or realizations have been distributed to partners, (ii) the service of notice by our Managing General Partner, with the special approval of a majority of its independent directors, that in its opinion the coming into force of any law, regulation or binding authority has or will render illegal or impracticable the continuation of our partnership, and (iii) at the election of our Managing General Partner, if our partnership, as determined by the Managing General Partner, is required to register as an "investment company" under the U.S. Investment Company Act or similar legislation in other jurisdictions.

Our partnership will be dissolved upon the withdrawal of our Managing General Partner as the general partner of our partnership (unless Brookfield becomes the general partner as described in the following sentence or the withdrawal is effected in compliance with the provisions of our limited partnership agreement that are described below under "—Withdrawal of Our Managing General Partner") or the entry by a court of competent jurisdiction of a decree of judicial dissolution of our partnership or an order to wind up or liquidate our Managing General Partner. Our partnership will be reconstituted and continue without dissolution if within 30 days of the date of dissolution (and so long as a notice of dissolution has not been filed with the Bermuda Monetary Authority), Brookfield executes a transfer deed pursuant to which it becomes the general partner and assumes the rights and undertakes the obligations of the general partner and our partnership receives an opinion of counsel that the admission of Brookfield as general partner will not result in the loss of the limited liability of any limited partner.

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our partnership is continued as a new limited partnership, the liquidator authorized to wind up our partnership's affairs will, acting with all of the powers of our Managing General Partner that the liquidator deems necessary or appropriate in its judgment, liquidate our partnership's assets and apply the proceeds of the liquidation first, to discharge our partnership's liabilities as provided in our limited partnership agreement and by law and thereafter to the partners pro rata according to the percentages of their respective partnership interests as of a record date selected by the liquidator. The liquidator may defer liquidation of our partnership's assets for a reasonable period of time or distribute assets to partners in kind if it determines that an immediate sale or distribution of all or some of our partnership's assets would be impractical or would cause undue loss to the partners.

Withdrawal of Our Managing General Partner

Our Managing General Partner may withdraw as Managing General Partner without first obtaining approval of our unitholders by giving 90 days' advance notice, and that withdrawal will not constitute a violation of our limited partnership agreement.

Upon the withdrawal of our Managing General Partner, the holders of a majority of the voting power of our outstanding units may select a successor to that withdrawing Managing General Partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability, tax matters and the U.S. Investment Company Act (and similar legislation in other jurisdictions) cannot be obtained, our partnership will be dissolved, wound up and liquidated. See "—Termination and Dissolution" above.

In the event of withdrawal of a general partner where that withdrawal violates our limited partnership agreement, a successor general partner will have the option to purchase the general partnership interest of the departing general partner for a cash payment equal to its fair market value. Under all other circumstances where a general partner withdraws, the departing general partner will have the option to require the successor general partner to purchase the general partnership interest of the departing general partner for a cash payment equal to its fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached within 30 days of the general partner's departure, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. If the departing general partner and the successor general partner cannot agree upon an expert within 45 days of the general partner's departure, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partnership interests will automatically convert into units pursuant to a valuation of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

Transfer of the General Partnership Interest

Our Managing General Partner may transfer all or any part of its general partnership interests without first obtaining approval of any unitholder. As a condition of this transfer, the transferee must assume the rights and duties of the Managing General Partner to whose interest that transferee has succeeded, agree to be bound by the provisions of our limited partnership agreement and furnish an opinion of counsel regarding limited liability, tax matters, and the U.S. Investment Company Act (and similar legislation in other jurisdictions). Any transfer of the general partnership interest is subject to prior notice to and approval of the relevant Bermuda regulatory authorities. At any time, the members of our Managing General Partner may sell or transfer all or part of their shares in our Managing General Partner without the approval of the unitholders.

Partnership Name

If our Managing General Partner ceases to be the general partner of our partnership and our new general partner is not an affiliate of Brookfield, our partnership will be required by our limited partnership agreement to change the name of our partnership to a name that does not include "Brookfield" and which could not be capable of confusion in any way with such name. Our limited partnership agreement explicitly provides that this obligation shall be enforceable and waivable by our Managing General Partner notwithstanding that it may have ceased to be the general partner of our partnership.

Transactions with Interested Parties

Our Managing General Partner, the Manager and their respective partners, members, shareholders, directors, officers, employees and shareholders, which we refer to as "interested parties," may become limited partners or beneficially interested in limited partners and may hold, dispose of or otherwise deal with our units with the same rights they would have if our Managing General Partner was not a party to our limited partnership agreement. An interested party will not be liable to account either to other interested parties or to our partnership, our partnership's partners or any other persons for any profits or benefits made or derived by or in connection with any such transaction.

Our limited partnership agreement permits an interested party to sell investments to, purchase assets from, vest assets in and enter into any contract, arrangement or transaction with our partnership, Brookfield Infrastructure, any of the Holding Entities, any operating entity or any other holding vehicle established by our partnership and may be interested in any such contract, transaction or arrangement and shall not be liable to account either to our partnership, Brookfield Infrastructure, any of the Holding Entities, any operating entity or any other holding vehicle established by our partnership or any other person in respect of any such contract, transaction or arrangement, or any benefits or profits made or derived therefrom, by virtue only of the relationship between the parties concerned, subject to any approval requirements that are contained in our conflicts policy. See Item 7.B "Related Party Transactions—Conflicts of Interest and Fiduciary Duties."

Outside Activities of Our Managing General Partner; Conflicts of Interest

Under our limited partnership agreement, our Managing General Partner is required to maintain as its sole activity the role of general partner of our partnership. Our Managing General Partner is not permitted to engage in any activity or incur any debts or liabilities except in connection with or incidental to its performance as general partner or acquiring, owning or disposing of debt or equity securities of Brookfield Infrastructure, a Holding Entity or any other holding vehicle established by our partnership.

Our limited partnership agreement provides that each person who is entitled to be indemnified by our partnership (other than our Managing General Partner), as described below under "—Indemnification; Limitation on Liability," has the right to engage in businesses of every type and description and other activities for profit, and to engage in and possess interests in business ventures of any and every type or description, irrespective of whether (i) such activities are similar to our affairs or activities or (ii) such affairs and activities directly compete with, or disfavor or exclude, our Managing General Partner, our partnership, Brookfield Infrastructure, any Holding Entity, any operating entity or any other holding vehicle established by our partnership. Such business interests, activities and engagements will be deemed not to constitute a breach of our limited partnership agreement or any duties stated or implied by law or equity, including fiduciary duties, owed to any of our Managing General Partner, our partnership, Brookfield Infrastructure, any Holding Entity, any operating entity and any other holding vehicle established by our partnership (or any of their respective investors), and shall be deemed not to be a breach of our Managing General Partner's fiduciary duties or any other obligation of any type whatsoever of our Managing General Partner. None of our Managing General Partner, our partnership, Brookfield Infrastructure, any Holding Entity, any operating entity, any other holding vehicle established by our partnership or any other person shall have any rights by virtue of our limited partnership agreement or the partnership relationship established thereby or otherwise in any business ventures of any person who is entitled to be indemnified by our partnership as described below under "—Indemnification; Limitation on Liability."

Our Managing General Partner and the other indemnified persons described in the preceding paragraph do not have any obligation under our limited partnership agreement or as a result of any duties stated or implied by law or equity, including fiduciary duties, to present business or investment opportunities to our partnership, Brookfield Infrastructure, any Holding Entity, any operating entity or any other holding vehicle established by our partnership. These provisions will not affect any obligation of an indemnified person to present business or investment opportunities to our partnership, Brookfield Infrastructure, any Holding Entity, any operating entity or any other holding vehicle established by our partnership pursuant to a separate written agreement between such persons.

Any conflicts of interest and potential conflicts of interest that are approved by a majority of our Managing General Partner's independent directors from time-to-time will be deemed approved by all partners. Pursuant to our conflicts policy, independent directors may grant approvals for any of the transactions described above in the form of general guidelines, policies or procedures in which case no further special approval will be required in connection with a particular transaction or matter permitted thereby. See Item 7.B "Related Party Transactions—Conflicts of Interest and Fiduciary Duties."

Indemnification; Limitations on Liability

Under our limited partnership agreement, our partnership is required to indemnify to the fullest extent permitted by law our Managing General Partner, our Manager and any of their respective affiliates (and their respective officers, directors, agents, shareholders, partners, members and employees), any person who serves on a governing body of Brookfield Infrastructure, a Holding Entity, operating entity or any other holding vehicle established by our partnership and any other person designated by our Managing General Partner as an indemnified person, in each case, against all losses, claims, damages, liabilities, costs or expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all claims, demands, actions, suits or proceedings, incurred by an indemnified person in connection with our investments and activities or by reason of their holding such positions, except to the extent that the claims, liabilities, losses, damages, costs or expenses are determined to have resulted from the indemnified person's bad faith, fraud or willful misconduct, or in the case of a criminal matter, action that the indemnified person knew to have been unlawful. In addition, under our limited partnership agreement, (i) the liability of such persons has been limited to the fullest extent permitted by law, except to the extent that their conduct involves bad faith, fraud or willful misconduct, or in the case of a criminal matter, action that the indemnified person knew to have been unlawful and (ii) any matter that is approved by the independent directors of our Managing General Partner will not constitute a breach of our limited partnership agreement or any duties stated or implied by law or equity, including fiduciary duties. Our limited partnership agreement requires us to advance funds to pay the expenses of an indemnified person in connection with a matter in which indemnification may be sought until it is determined that the indemnified person is not entitled to indemnification.

Accounts, Reports and Other Information

Under our limited partnership agreement, our partnership is required to prepare financial statements in accordance with U.S. GAAP. Our partnership's financial statements must be made publicly available together with a statement of the accounting policies used in their preparation, such information as may be required by applicable laws and regulations and such information as our Managing General Partner deems appropriate. Our partnership's annual financial statements must be audited by an independent accountant firm of international standing and made publicly available within such period of time as is required to comply with applicable laws and regulations, including any rules of any applicable securities exchange. Our partnership's quarterly financial statements may be unaudited and are made available publicly as and within the time period required by applicable laws and regulations.

The Managing General Partner is also required to use commercially reasonable efforts to prepare and send to the limited partners of our partnership on an annual basis, additional information regarding our partnership, including Schedule K-1 (or equivalent) and information related to the passive foreign investment company status of any non-U.S. corporation that we control and, where reasonably possible, any other non-U.S. corporation in which we hold an interest. The Managing General Partner will, where reasonably possible, prepare and send information required by the non-U.S. limited partners of our partnership for U.S. federal income tax reporting purposes, including information related to investments in "U.S. real property interests," as that term is defined in Section 897 of the U.S. Internal Revenue Code. The Managing General Partner will also, where reasonably possible and applicable, prepare and send information required by limited partners of our partnership for Canadian federal income tax purposes.

Governing Law; Submission to Jurisdiction

Our limited partnership agreement is governed by and will be construed in accordance with the laws of Bermuda. Under our limited partnership agreement, each of our partnership's partners (other than governmental entities prohibited from submitting to the jurisdiction of a particular jurisdiction) will submit to the non-exclusive jurisdiction of any court in Bermuda in any dispute, suit, action or proceeding arising out of or relating to our limited partnership agreement. Each partner waives, to the fullest extent permitted by law, any immunity from jurisdiction of any such court or from any legal process therein and further waives, to the fullest extent permitted by law, any claim of inconvenient forum, improper venue or that any such court does not have jurisdiction over the partner. Any final judgment against a partner in any proceedings brought in a court in Bermuda will be conclusive and binding upon the partner and may be enforced in the courts of any other jurisdiction of which the partner is or may be subject, by suit upon such judgment. The foregoing submission to jurisdiction and waivers will survive the dissolution, liquidation, winding up and termination of our partnership.

Transfers of Units

We are not required to recognize any transfer of our units until certificates, if any, evidencing such units are surrendered for registration of transfer. Each person to whom a unit is transferred (including any nominee holder or an agent or representative acquiring such unit for the account of another person) will be admitted to our partnership as a partner with respect to the unit so transferred subject to and in accordance with the terms of our limited partnership agreement. Any transfer of a unit will not entitle the transferee to share in the profits and losses of our partnership, to receive distributions, to receive allocations of income, gain, loss, deduction or credit or any similar item or to any other rights to which the transferor was entitled until the transferee becomes a partner and a party to our partnership's limited partnership agreement.

By accepting a unit for transfer in accordance with our limited partnership agreement, each transferee will be deemed to have:

- executed our limited partnership agreement and become bound by the terms thereof;
- granted an irrevocable power of attorney to our Managing General Partner and any officer thereof to act as such partner's agent and attorney-in-fact to execute, swear to, acknowledge, deliver, file and record in the appropriate public offices all (i) all agreements, certificates, documents and other instruments relating to the existence or qualification of our partnership as an exempted limited partnership (or a partnership in which the limited partners have limited liability) in Bermuda and in all jurisdictions in which our partnership may conduct activities and affairs or own property; any amendment, change, modification or restatement of our limited partnership agreement, subject to the requirements of our limited partnership agreement; the dissolution and liquidation of our partnership; the admission, withdrawal or removal of any partner of our partnership or any capital contribution of any partner of our partnership; the determination of the rights, preferences and privileges of any class or series of units or other partnership interests of our partnership, and to a merger or consolidation of our partnership; and (ii) subject to the requirements of our limited partnership agreement, all ballots, consents, approvals, waivers, certificates, documents and other instruments necessary or appropriate, in the sole discretion of our Managing General Partner or the liquidator of our partnership, to make, evidence, give, confirm or ratify any voting consent, approval, agreement or other action that is made or given by our partnership's partners or is consistent with the terms of our limited partnership agreement or to effectuate the terms or intent of our limited partnership agreement; and
- made the consents and waivers contained in our limited partnership agreement, including with respect to the approval of the transactions and agreements entered into in connection with our formation and the spin-off.

The transfer of any unit and the admission of any new partner to our partnership will not constitute any amendment to our limited partnership agreement.

Transfer Agent and Registrar

The Bank of New York in New York, New York, U.S.A. has been appointed to act as transfer agent and registrar for the purpose of registering our limited partnership interests and transfers of our limited partnership interests as provided in our limited partnership agreement. Our partnership will indemnify the transfer agent, its agents and each of their shareholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for its activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Description of Brookfield Infrastructure's Limited Partnership Agreement

The following is a description of the material terms of Brookfield Infrastructure's limited partnership agreement and is qualified in its entirety by reference to all of the provisions of such agreement. Holders of units in our partnership are not limited partners of Brookfield Infrastructure and do not have any rights under its limited partnership agreement. We have included a summary of what we believe are the most important provisions of Brookfield Infrastructure's limited partnership agreement because we conduct our operations through Brookfield Infrastructure and the Holding Entities and our rights with respect to our equity holding in Brookfield Infrastructure are governed by the terms of Brookfield Infrastructure's limited partnership agreement.

Because this description is only a summary of the terms of the agreement, it does not necessarily contain all of the information that you may find useful. For more complete information, you should read Brookfield Infrastructure's limited partnership agreement which is available electronically on the website of the Securities and Exchange Commission at *www.sec.gov* and on our SEDAR profile at *www.sedar.com* and will be made available to our unitholders as described under Item 10.C "Material Contracts" and Item 10.H "Documents on display."

Formation and Duration

Brookfield Infrastructure is a Bermuda exempted limited partnership registered under the Limited Partnership Act 1883 and the Exempted Partnerships Act 1992. Brookfield Infrastructure has a perpetual existence and will continue as a limited liability partnership unless the partnership is terminated or dissolved in accordance with its limited partnership agreement.

Nature and Purpose

Under its limited partnership agreement, the purpose of Brookfield Infrastructure is to: acquire and hold interests in the Holding Entities and, subject to the approval of Infrastructure GP LP, any other subsidiary of Brookfield Infrastructure; engage in any activity related to the capitalization and financing of Brookfield Infrastructure's interests in such entities; and engage in any other activity that is incidental to or in furtherance of the foregoing and that is approved by the Infrastructure GP LP and that lawfully may be conducted by a limited partnership organized under the Limited Partnership Act 1883 and our limited partnership agreement.

Units

Brookfield Infrastructure's units are limited partnership interests in Brookfield Infrastructure. Holders of units are not entitled to the withdrawal or return of capital contributions in respect of their units, except to the extent, if any, that distributions are made to such holders pursuant to Brookfield Infrastructure's limited partnership agreement or upon the liquidation of Brookfield Infrastructure or as otherwise required by applicable law. Except to the extent expressly provided in Brookfield Infrastructure's limited partnership agreement, a holder of units does not have priority over any other holder of units, either as to the return of capital contributions or as to profits, losses or distributions.

In connection with the spin-off, Brookfield Infrastructure issued two classes of units. The first class of units was issued to Brookfield and subsequently transferred to our partnership and the second class of units, referred to as the Redemption-Exchange Units, were issued to wholly-owned subsidiaries of Brookfield. Redemption-Exchange Units are identical to the limited partnership units held by our partnership, except as described below under "—Distributions" and "—No Management or Control" and except that they have the right of redemption described below under the heading "—Redemption-Exchange Mechanism."

Issuance of Additional Partnership Interests

Infrastructure GP LP has broad rights to cause Brookfield Infrastructure to issue additional partnership interests and may cause Brookfield Infrastructure to issue additional partnership interests (including new classes of partnership interests and options, rights, warrants and appreciation rights relating to such interests) for any partnership purpose, at any time and on such terms and conditions as it may determine without the approval of any limited partners. Any additional partnership interests may be issued in one or more classes, or one or more series of classes, with such designations, preferences, rights, powers and duties (which may be senior to existing classes and series of partnership interests) as may be determined by Infrastructure GP LP in its sole discretion, all without approval of our limited partners.

Redemption-Exchange Mechanism

At any time after two years from the date of closing of the spin-off, one or more wholly-owned subsidiaries of Brookfield that hold Redemption-Exchange Units will have the right to require Brookfield Infrastructure to redeem for cash all or a portion of the Redemption-Exchange Units held by such subsidiary, subject to our partnership's right of first refusal, as described below. Any such redeeming subsidiary may exercise its right of redemption by delivering a notice of redemption to Brookfield Infrastructure and our partnership. After presentation for redemption, such redeeming subsidiary will receive, subject to our partnership's right of first refusal, as described below, for each unit that is presented, cash in an amount equal to the market value of one of our units multiplied by the number of units to be redeemed (as determined by reference to the five day volume weighted average of the trading price of our units and subject to certain customary adjustments). Upon its receipt of the redemption notice, our partnership will have a right of first refusal entitling it, at its sole discretion, to elect to acquire all (but not less than all) units described in such notice and presented to Brookfield Infrastructure for redemption in exchange for units on a one for one basis (subject to certain customary adjustments). Upon a redemption for cash, the holder's right to receive distributions with respect to Brookfield Infrastructure's units so redeemed will cease.

Brookfield's aggregate limited partnership interest in our partnership would be approximately 39% (in addition to the 0.2% of our units that were acquired by Brookfield in connection with the satisfaction of Canadian federal and U.S. "back-up" withholding tax requirements upon the spin-off) if it exercised its redemption right in full and our partnership exercised its right of first refusal on the Brookfield Infrastructure units redeemed. Brookfield's total percentage interest in our partnership would be increased if it participates in Brookfield Infrastructure's distribution reinvestment plan or receives additional units of Brookfield Infrastructure under the equity commitment.

Distributions

Distributions by Brookfield Infrastructure will be made in the sole discretion of the Infrastructure GP LP. However, the Infrastructure GP LP will not be permitted to cause Brookfield Infrastructure to make a distribution if Brookfield Infrastructure does not have sufficient cash on hand to make the distribution, the distribution would render Brookfield Infrastructure insolvent or if, in the opinion of the Infrastructure GP LP, the distribution would leave Brookfield Infrastructure with insufficient funds to meet any future contingent obligations.

Except as set forth below, prior to the dissolution of Brookfield Infrastructure, distributions of available cash (if any) in any given quarter will be made by Brookfield Infrastructure as follows, referred to as the Regular Distribution Waterfall:

- first, 100% of any available cash to our partnership until our partnership has been distributed an amount equal to our partnership's expenses and outlays for the quarter properly incurred;
- second, 100% of any available cash then remaining to the owners of Brookfield Infrastructure's partnership interests, pro rata to their percentage interests, until each holder of a Brookfield Infrastructure limited partnership unit has received distributions during such quarter in an amount equal to $0.305, referred to as the First Distribution Threshold;
- third, 85% of any available cash then remaining to the owners of Brookfield Infrastructure's partnership interests, pro rata to their percentage interests, and 15% to the Infrastructure GP LP, until

each holder of a Brookfield Infrastructure limited partnership unit has received distributions during such quarter in an amount equal to $0.33, referred to as the Second Distribution Threshold; and

- thereafter, 75% of any available cash then remaining to the owners of Brookfield Infrastructure's partnership interests, pro rata to their percentage interests, and 25% to the Infrastructure GP LP.

If, prior to the dissolution of Brookfield Infrastructure, available cash is deemed by the Infrastructure GP LP, in its sole discretion, to be (i) attributable to sales or other dispositions of Brookfield Infrastructure's assets and (ii) representative of unrecovered capital, then such available cash shall be distributed to the partners of Brookfield Infrastructure in proportion to the unreturned capital attributable to Brookfield Infrastructure's partnership interests held by the partners until such time as the unreturned capital attributable to each such partnership interest is equal to zero. Thereafter, distributions of available cash made by Brookfield Infrastructure (to the extent made prior to dissolution) will be made in accordance with the Regular Distribution Waterfall.

Upon the occurrence of an event resulting in the dissolution of Brookfield Infrastructure, all cash and property of Brookfield Infrastructure in excess of that required to discharge Brookfield Infrastructure's liabilities will be distributed as follows: (a) to the extent such cash and/or property is attributable to a realization event occurring prior to the event of dissolution, such cash and/or property will be distributed in accordance with the Regular Distribution Waterfall and/or the distribution waterfall applicable to unrecovered capital; and (b) all other cash and/or property will be distributed in the manner set forth below.

- first, 100% to our partnership until our partnership has received an amount equal to the excess of (1) the amount of our partnership's outlays and expenses incurred during the term of Brookfield Infrastructure, over (2) the aggregate amount of distributions received by our partnership pursuant to the first tier of the Regular Distribution Waterfall during the term of Brookfield Infrastructure;
- second, 100% to the partners of Brookfield Infrastructure, in proportion to their respective amounts of unrecovered capital in Brookfield Infrastructure;
- third, 100% to the owners of Brookfield Infrastructure's partnership interests, pro rata to their percentage interests, until each holder of a Brookfield Infrastructure's limited partnership unit has received an amount equal to the excess of (i) the First Distribution Threshold for each quarter during the term of Brookfield Infrastructure (subject to adjustment upon the subsequent issuance of additional partnership interests in Brookfield Infrastructure), over (ii) the aggregate amount of distributions made in respect of a Brookfield Infrastructure's limited partnership unit pursuant to the second tier of the Regular Distribution Waterfall during the term of a Brookfield Infrastructure (subject to adjustment upon the subsequent issuance of additional partnership interests in Brookfield Infrastructure);
- fourth, 85% to the owners of Brookfield Infrastructure's partnership interests, pro rata to their percentage interests, and 15% to the Infrastructure GP LP, until each holder of a Brookfield Infrastructure limited partnership unit has received an amount equal to the excess of (i) the Second Distribution Threshold less the First Distribution Threshold for each quarter during the term of Brookfield Infrastructure (subject to adjustment upon the subsequent issuance of additional partnership interests in Brookfield Infrastructure), over (ii) the aggregate amount of distributions made in respect of a Brookfield Infrastructure's limited partnership unit pursuant to the third tier of the Regular Distribution Waterfall during the term of Brookfield Infrastructure (subject to adjustment upon the subsequent issuance of additional partnership interests in Brookfield Infrastructure);
- thereafter, 75% to the owners of Brookfield Infrastructure's partnership interests, pro rata to their percentage interests, and 25% to the Infrastructure GP LP.

Each partner's percentage interest is determined by the relative portion of all outstanding partnership interests held by that partner from time to time and is adjusted upon and to reflect the issuance of additional partnership interests of Brookfield Infrastructure. In addition, the unreturned capital attributable to each of the partnership interests, as well as certain of the distribution thresholds set forth above, may be adjusted pursuant to the terms of the limited partnership agreement of Brookfield Infrastructure so as to ensure the uniformity of the economic rights and entitlements of (i) the previously outstanding Brookfield Infrastructure's partnership interests and (ii) the subsequently-issued Brookfield Infrastructure's partnership interests.

The limited partnership agreement of Brookfield Infrastructure provides that, to the extent that any Holding Entity or any operating entity pays to Brookfield any comparable performance or incentive distribution, the amount of any incentive distributions paid to the Infrastructure GP LP in accordance with the distribution entitlements described above will be reduced in an equitable manner to avoid duplication of distributions.

The Infrastructure GP LP may elect, at its sole discretion, to reinvest incentive distributions in Redemption-Exchange Units.

No Management or Control

Brookfield Infrastructure's limited partners, in their capacities as such, may not take part in the management or control of the activities and affairs of Brookfield Infrastructure and do not have any right or authority to act for or to bind Brookfield Infrastructure or to take part or interfere in the conduct or management of Brookfield Infrastructure.

Limited partners are not entitled to vote on matters relating to Brookfield Infrastructure, although holders of units are entitled to consent to certain matters as described under "—Amendment of Brookfield Infrastructure's Limited Partnership Agreement," "—Opinion of Counsel and Limited Partner Approval," "—Merger, Sale or Other Disposition of Assets," and "—Withdrawal of the General Partner" which may be effected only with the consent of the holders of the percentages of outstanding units specified below. For the purposes of any approval required from holders of Brookfield Infrastructure's units, if Brookfield and its subsidiaries are entitled to vote, they will be entitled to one vote per unit held subject to a maximum number of votes equal to 49% of the total number of units of Brookfield Infrastructure then issued and outstanding. Each unit shall entitle the holder thereof to one vote for the purposes of any approvals of holders of units.

Meetings

The Infrastructure GP LP may call special meetings of the limited partners at a time and place outside of Canada determined by it on a date not less than 10 days nor more than 60 days after the mailing of notice of the meeting. Special meetings of the limited partners may also be called by limited partners owning 50% or more of the voting power of the outstanding partnership interests of the class or classes for which a meeting is proposed. For this purpose, the partnership interests outstanding do not include partnership interests owned by the Infrastructure GP LP or Brookfield. Only holders of record on the date set by the Infrastructure GP LP (which may not be less than 10 days nor more than 60 days, before the meeting) are entitled to notice of any meeting.

Amendment of Brookfield Infrastructure's Limited Partnership Agreement

Amendments to Brookfield Infrastructure's limited partnership agreement may be proposed only by or with the consent of the Infrastructure GP LP. To adopt a proposed amendment, other than the amendments that do not require limited partner approval discussed below, the Infrastructure GP LP must seek approval of a majority of Brookfield Infrastructure's outstanding units required to approve the amendment or call a meeting of the limited partners to consider and vote upon the proposed amendment.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without its consent, except that any amendment that would have a material adverse effect on the rights or preferences of any class of partnership interests in relation to other classes of partnership interests may be approved by at least a majority of the type or class of partnership interests so affected, or

- enlarge the obligations of, restrict in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by Brookfield Infrastructure to the Infrastructure GP LP or any of its affiliates without the consent of the Infrastructure GP LP which may be given or withheld in its sole discretion.

The provision of Brookfield Infrastructure's limited partnership agreement preventing the amendments having the effects described directly above can be amended upon the approval of the holders of at least 90% of the outstanding units.

No Limited Partner Approval

Subject to applicable law, the Infrastructure GP LP may generally make amendments to Brookfield Infrastructure's limited partnership agreement without the approval of any limited partner to reflect:

- a change in the name of the partnership, the location of the partnership's registered office or the partnership's registered agent,
- the admission, substitution, withdrawal or removal of partners in accordance with the limited partnership agreement,
- a change that the Infrastructure GP LP determines is necessary or appropriate for the partnership to qualify or to continue its qualification as a limited partnership or a partnership in which the limited partners have limited liability under the laws of any jurisdiction or to ensure that Brookfield Infrastructure will not be treated as an association taxable as a corporation or otherwise taxed as an entity for tax purposes,
- an amendment that the Infrastructure GP LP determines to be necessary or appropriate to address certain changes in tax regulations, legislation or interpretation,
- an amendment that is necessary, in the opinion of counsel, to prevent Brookfield Infrastructure or the Infrastructure GP LP or its directors, officers, agents or trustees, from having a material risk of being in any manner subjected to the provisions of the U.S. Investment Company Act or similar legislation in other jurisdictions,
- an amendment that the Infrastructure GP LP determines in its sole discretion to be necessary or appropriate for the creation, authorization or issuance of any class or series of partnership interests or options, rights, warrants or appreciation rights relating to partnership securities,
- any amendment expressly permitted in Brookfield Infrastructure's limited partnership agreement to be made by the Infrastructure GP LP acting alone,
- an amendment effected, necessitated or contemplated by an agreement of merger, consolidation or other combination agreement that has been approved under the terms of Brookfield Infrastructure's limited partnership agreement,
- any amendment that in the sole discretion of the Infrastructure GP LP is necessary or appropriate to reflect and account for the formation by the partnership of, or its investment in, any corporation, partnership, joint venture, limited liability company or other entity, as otherwise permitted by Brookfield Infrastructure's limited partnership agreement,
- a change in its fiscal year and related changes,
- any amendment concerning the computation or allocation of specific items of income, gain, expense or loss among the partners that, in the sole discretion of the Infrastructure GP LP, is necessary or appropriate to (i) comply with the requirements of applicable law, (ii) reflect the partners' interests in Brookfield Infrastructure, or (iii) consistently reflect the distributions made by Brookfield Infrastructure to the partners pursuant to the terms of the limited partnership agreement of Brookfield Infrastructure,

- any other amendments substantially similar to any of the matters described directly above.

In addition, the Infrastructure GP LP may make amendments to Brookfield Infrastructure's limited partnership agreement without the approval of any limited partner if those amendments, in the discretion of the Infrastructure GP LP:

- do not adversely affect Brookfield Infrastructure's limited partners considered as a whole (including any particular class of partnership interests as compared to other classes of partnership interests) in any material respect,
- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any governmental agency or judicial authority,
- are necessary or appropriate to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading,
- are necessary or appropriate for any action taken by the Infrastructure GP LP relating to splits or combinations of units under the provisions of Brookfield Infrastructure's limited partnership agreement, or
- are required to effect the intent expressed in this Form 20-F or the intent of the provisions of Brookfield Infrastructure's limited partnership agreement or are otherwise contemplated by Brookfield Infrastructure's limited partnership agreement.

Opinion of Counsel and Limited Partner Approval

The Infrastructure GP LP will not be required to obtain an opinion of counsel that an amendment will not result in a loss of limited liability to the limited partners if one of the amendments described above under "—No Limited Partner Approval" should occur. No other amendments to Brookfield Infrastructure's limited partnership agreement (other than an amendment pursuant to a merger, sale or other disposition of assets effected in accordance with Brookfield Infrastructure's limited partnership agreement) will become effective without the approval of holders of at least 90% of Brookfield Infrastructure's units, unless it obtains an opinion of counsel to the effect that the amendment will not cause Brookfield Infrastructure to be treated as an association taxable as a corporation or otherwise taxable as an entity for tax purposes (provided that for U.S. tax purposes the Infrastructure GP LP has not made the election described below under "—Election to be Treated as a Corporation") or affect the limited liability under the Limited Partnership Act of 1883 of any of Brookfield Infrastructure's limited partners.

In addition to the above restrictions, any amendment that would have a material adverse effect on the rights or preferences of any type or class of partnership interests in relation to other classes of partnership interests will also require the approval of the holders of at least a majority of the outstanding partnership interests of the class so affected.

In addition, any amendment that reduces the voting percentage required to take any action must be approved by the affirmative vote of limited partners whose aggregate outstanding voting units constitute not less than the voting requirement sought to be reduced.

Election to be Treated as a Corporation

If the Infrastructure GP LP determines that it is no longer in Brookfield Infrastructure's best interests to continue as a partnership for U.S. federal income tax purposes, the Infrastructure GP LP may elect to treat Brookfield Infrastructure as an association or as a publicly traded partnership taxable as a corporation for U.S. federal (and applicable state) income tax purposes.

Dissolution

Brookfield Infrastructure shall dissolve and its affairs shall be wound up, upon the earlier of (i) the service of notice by the Infrastructure GP LP, with the approval of a majority of the members of the independent directors of our Managing General Partner, that in the opinion of the Infrastructure GP LP the coming into force of any law, regulation or binding authority renders illegal or impracticable the continuation of Brookfield Infrastructure; (ii) the election of the Infrastructure GP LP if Brookfield Infrastructure, as determined by the Infrastructure GP LP, is required to register as an "investment company" under the U.S. Investment Company Act or similar legislation in other jurisdictions; (iii) the date that the Infrastructure GP LP withdraws from the our partnership (unless Brookfield becomes the general partner of Brookfield Infrastructure as described below under "—Withdrawal of the General Partner"); (iv) the date on which any court of competent jurisdiction enters a decree of judicial dissolution of Brookfield Infrastructure or an order to wind up or liquidate the Infrastructure GP LP; and (v) the date on which the Infrastructure GP LP decides to dispose of, or otherwise realize proceeds in respect of, all or substantially all of Brookfield Infrastructure's assets in a single transaction or series of transactions.

Brookfield Infrastructure shall not dissolve if within 30 days of the date of dissolution (and provided that a notice of dissolution with respect to Brookfield Infrastructure has not been filed with the Bermuda Monetary Authority), Brookfield executes a transfer deed pursuant to which the new general partner assumes the rights and undertakes the obligations of the original general partner, but only if Brookfield Infrastructure receives an opinion of counsel that the admission of Brookfield as general partner will not result in the loss of limited liability of any limited partner of Brookfield Infrastructure.

Withdrawal of the General Partner

The Infrastructure GP LP may withdraw as general partner without first obtaining approval of unitholders by giving 90 days advance notice, and that withdrawal will not constitute a violation of the limited partnership agreement.

Upon the withdrawal of the Infrastructure GP LP, the holders of a majority of the voting power of outstanding units may select a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability, tax matters and the U.S. Investment Company Act (and similar legislation in other jurisdictions) cannot be obtained, Brookfield Infrastructure will be dissolved, wound up and liquidated. See "—Dissolution" above.

The Infrastructure GP LP may not be removed unless that removal is approved by the vote of the holders of at least 66⅔% of the outstanding class of units that are not Redemption-Exchange Units and it receives an opinion of counsel regarding limited liability tax matters and the U.S. Investment Company Act (and similar legislation in other jurisdictions). Any removal of the Infrastructure GP LP is also subject to the approval of a successor general partner by the vote of the holders of a majority of the voting power of its outstanding units.

In the event of removal of a general partner under circumstances where cause exists or withdrawal of a general partner where that withdrawal violates Brookfield Infrastructure's limited partnership agreement, a successor general partner will have the option to purchase the general partnership interest of the departing general partner for a cash payment equal to its fair market value. Under all other circumstances where a general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partnership interest of the departing general partner for a cash payment equal to its fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached within 30 days of the general partner's departure, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value. If the departing general partner and the successor general partner cannot agree upon an expert within 45 days of the general partner's departure, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, the departing general partner's general partnership interests will automatically convert into units pursuant to a valuation of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

Transfer of the General Partnership Interest

The Infrastructure GP LP may transfer all or any part of its general partnership interests without first obtaining approval of any unitholder. As a condition of this transfer, the transferee must assume the rights and duties of the general partner to whose interest that transferee has succeeded, agree to be bound by the provisions of Brookfield Infrastructure's limited partnership agreement and furnish an opinion of counsel regarding limited liability, tax matters and the U.S. Investment Company Act (and similar legislation in other jurisdictions). Any transfer of the general partnership interest is subject to prior notice to and approval of the relevant Bermuda regulatory authority. At any time, the members of the Infrastructure GP LP may sell or transfer all or part of their units in the Infrastructure GP LP without the approval of the unitholders.

Transactions with Interested Parties

The Infrastructure GP LP, the Infrastructure General Partner and their respective partners, members, shareholders, directors, officers, employees and shareholders, which we refer to as "interested parties", may become limited partners or beneficially interested in limited partners and may hold, dispose of or otherwise deal with units of Brookfield Infrastructure with the same rights they would have if the Infrastructure GP LP and Infrastructure General Partner were not a party to the limited partnership agreement of Brookfield Infrastructure. An interested party will not be liable to account either to other interested parties or to Brookfield Infrastructure, its partners or any other persons for any profits or benefits made or derived by or in connection with any such transaction.

The limited partnership agreement of Brookfield Infrastructure permits an interested party to sell investments to, purchase assets from, vest assets in and enter into any contract, arrangement or transaction with Brookfield Infrastructure, any of the Holding Entities, any operating entity or any other holding vehicle established by Brookfield Infrastructure and may be interested in any such contract, transaction or arrangement and shall not be liable to account either to Brookfield Infrastructure, any of the Holding Entities, any operating entity or any other holding vehicle established by Brookfield Infrastructure or any other person in respect of any such contract, transaction or arrangement, or any benefits or profits made or derived therefrom, by virtue only of the relationship between the parties concerned, subject to our conflicts policy.

Outside Activities of the General Partner

Under Brookfield Infrastructure's limited partnership agreement, the general partner will be required to maintain as its sole activity the role of the general partner of Brookfield Infrastructure. The general partner will not be permitted to engage in any activity or incur any debts or liabilities except in connection with or incidental to its performance as general partner or acquiring, owning or disposing of debt or equity securities of a subsidiary of an Holding Entity or any other holding vehicle established by Brookfield Infrastructure.

Brookfield Infrastructure's limited partnership agreement provides that each person who is entitled to be indemnified by the partnership, as described below under "—Indemnification; Limitations on Liability" (other than the general partner) will have the right to engage in businesses of every type and description and other activities for profit, and to engage in and possess interests in business ventures of any and every type or description, irrespective of whether (i) such businesses and activities are similar to our activities, or (ii) such businesses and activities directly compete with, or disfavor or exclude, the Infrastructure General Partner, the Infrastructure GP LP, Brookfield Infrastructure, any Holding Entity, operating entity, or any other holding vehicle established by Brookfield Infrastructure. Such business interests, activities and engagements will be deemed not to constitute a breach of the limited partnership agreement or any duties stated or implied by law or equity, including fiduciary duties, owed to any of the Infrastructure General Partner, the Infrastructure GP LP, Brookfield Infrastructure, any Holding Entity, operating entity, and any other holding vehicle established by Brookfield Infrastructure (or any of their respective investors), and shall be deemed not to be a breach of the Infrastructure General Partner's fiduciary duties or any other obligation of any type whatsoever of the general partner. None of the Infrastructure General Partner, the Infrastructure GP LP, Brookfield Infrastructure, any Holding Entity, operating entity, any other holding vehicle established by Brookfield Infrastructure or any other person shall have any rights by virtue of Brookfield Infrastructure's limited partnership agreement or the partnership relationship established thereby or otherwise in any business ventures of any person who is entitled to be indemnified by Brookfield Infrastructure as described below under "—Indemnification; Limitations on Liability."

The Infrastructure GP LP and the other indemnified persons described in the preceding paragraph will not have any obligation under Brookfield Infrastructure's limited partnership agreement or as a result of any duties stated or implied by law or equity, including fiduciary duties, to present business or investment opportunities to Brookfield Infrastructure, any Holding Entity, operating entity, or any other holding vehicle established by Brookfield Infrastructure. These provisions will not affect any obligation of such indemnified person to present business or investment opportunities to Brookfield Infrastructure, any Holding Entity, operating entity or any other holding vehicle established by Brookfield Infrastructure pursuant to a separate written agreement between such persons.

Accounts; Reports

Under Brookfield Infrastructure's limited partnership agreement, the Infrastructure GP LP is required to prepare financial statements in accordance with U.S. GAAP. Brookfield Infrastructure's financial statements must be made publicly available together with a statement of the accounting policies used in their preparation, such information as may be required by applicable laws and regulations and such information as the Infrastructure GP LP deems appropriate. Brookfield Infrastructure's annual financial statements must be audited by an independent accountant firm of international standing and made publicly available within such period of time as is required to comply with applicable laws and regulations, including any rules of any applicable securities exchange. Brookfield Infrastructure's quarterly financial statements are unaudited and are made available publicly as and within the time period required by applicable laws and regulations.

The Infrastructure GP LP is also required to use commercially reasonable efforts to prepare and send to the limited partners of Brookfield Infrastructure on an annual basis, additional information regarding Brookfield Infrastructure, including Schedule K-1 (or equivalent) and information related to the passive foreign investment company status of any non-U.S. corporation that we control and, where reasonably possible, any other non-U.S. corporation in which we hold an interest. The Infrastructure GP LP will also, where reasonably possible, prepare and send information required by the non-U.S. limited partners of Brookfield Infrastructure for U.S. federal income tax reporting purposes, including information related to investments in "U.S. real property interests," as that term is defined in Section 897 of the U.S. Internal Revenue Code. The Infrastructure GP LP will also, where reasonably possible and applicable, prepare and send information required by limited partners of Brookfield Infrastructure for Canadian federal income tax purposes.

The Infrastructure GP LP will deliver to our partnership (i) the financial statements of Brookfield Infrastructure, and (ii) the accounts and financial statements of any Holding Entity or any other holding vehicle established by Brookfield Infrastructure that is not consolidated with Brookfield Infrastructure or any Holding Entity or holding vehicle whose accounts are subject to such approval.

Indemnification; Limitations on Liability

Under Brookfield Infrastructure's limited partnership agreement, it is required to indemnify to the fullest extent permitted by law the Infrastructure General Partner, the Infrastructure GP LP, the Manager and any of their respective affiliates (and their respective officers, directors, agents, shareholders, partners, members and employees), any person who serves on a governing body of Brookfield Infrastructure, a Holding Entity, operating entity or any other holding vehicle established by our partnership and any other person designated by its general partner as an indemnified person, in each case, against all losses, claims, damages, liabilities, costs or expenses (including legal fees and expenses), judgments, fines, penalties, interest, settlements or other amounts arising from any and all claims, demands, actions, suits or proceedings, incurred by an indemnified person in connection with its business, investments and activities or by reason of their holding such positions, except to the extent that the claims, liabilities, losses, damages, costs or expenses are determined to have resulted from the indemnified person's bad faith, fraud or willful misconduct, or in the case of a criminal matter, action that the indemnified person knew to have been unlawful. In addition, under Brookfield Infrastructure's limited partnership agreement, (i) the liability of such persons has been limited to the fullest extent permitted by law, except to the extent that their conduct involves bad faith, fraud or willful misconduct, or in the case of a criminal matter, action that the indemnified person knew to have been unlawful and (ii) any matter that is approved by the independent directors will not constitute a breach of any duties stated or implied by law or equity, including fiduciary duties. Brookfield Infrastructure's limited partnership agreement requires it to advance funds to pay the expenses of an indemnified person in connection with a matter in which indemnification may be sought until it is determined that the indemnified person is not entitled to indemnification.

Governing Law

Brookfield Infrastructure's limited partnership agreement is governed by and will be construed in accordance with the laws of Bermuda.

10.C MATERIAL CONTRACTS

The following are the only material contracts, other than contracts entered into in the ordinary course of business, which have been entered into by us within the past two years:

1. the Acquisition Agreements: Securities Purchase Agreement, dated November 19, 2007, between Brookfield Asset Management Inc. and Brookfield Infrastructure Holdings (Canada) Inc.; Securities Purchase Agreement, dated November 16, 2007, between Brookfield Asset Management Inc. and BIP Bermuda Holdings III Limited; Securities Purchase Agreement, dated November 20, 2007, between Brookfield Longview Holdings LLC and Brookfield Infrastructure Corporation; Debt Purchase Agreement, dated November 20, 2007, between Brascan (US) Corporation and Brookfield Infrastructure Corporation; English summary of the Amended and Restated Payment-in-Kind Agreement, dated November 5, 2007, between Brascan Brasil Ltda. and Brookfield Brasil TBE Participações Ltda.; and Asset Purchase Agreement dated December 11, 2007, between Great Lakes Power Limited and Great Lakes Power Transmission LP;
2. Master Purchase Agreement, dated June 18, 2007, between Brookfield Infrastructure Partners Limited and Brookfield Asset Management Inc.;
3. Master Services Agreement, dated December 4, 2007, by and among Brookfield Asset Management Inc., Brookfield Infrastructure Partners L.P., Brookfield Infrastructure L.P., Brookfield Infrastructure Holdings (Canada) Inc. and Brookfield Asset Management Barbados Inc. and others described under Item 6.A "Directors and Senior Management—Our Master Services Agreement";
4. Relationship Agreement, dated December 4, 2007, by and among Brookfield Infrastructure Partners L.P., Brookfield Infrastructure Group Inc., Brookfield Infrastructure L.P., Brookfield Infrastructure Group Corporation and Brookfield Asset Management Inc. and others described under Item 7.B "Related Party Transactions—Relationship Agreement";
5. Equity Commitment, dated December 4, 2007, by and among Brookfield Asset Management Inc., Brookfield Infrastructure Partners L.P. and Brookfield Infrastructure L.P. described under Item 7.B "Related Party Transactions—Equity Commitment and Other Financing";

6. Registration Rights Agreement, dated December 4, 2007, between Brookfield Infrastructure Partners L.P. and Brookfield Asset Management Inc. described under Item 7.B "Related Party Transactions—Registration Rights Agreement";
7. the licensing agreements described under the heading Item 7.B "Related Party Transactions—Licensing Agreement": Trademark Sublicense Agreement, effective as of May 21, 2007, between Brookfield Infrastructure Partners L.P. and Brookfield Global Asset Management Inc. and Trademark Sublicense Agreement, effective as of August 17, 2007, between Brookfield Infrastructure L.P. and Brookfield Global Asset Management Inc.;
8. Amended and Restated Limited Partnership Agreement of Brookfield Infrastructure Partners L.P., dated December 4, 2007, and amended June 13, 2008, described under Item 10.B "Memorandum and Articles of Association—Description of Our Units and Our Limited Partnership Agreement";
9. Second Amended and Restated Limited Partnership Agreement for Brookfield Infrastructure L.P., dated December 4, 2007, and amended June 13, 2008, described under Item 10.B "Memorandum and Articles of Association—Description of Brookfield Infrastructure's Limited Partnership Agreement";
10. Agreement Relating to the Indirect Acquisition of Longview, dated December 4, 2007, between Brookfield Infrastructure Corporation and Brookfield Asset Management Inc. described under Item 7.B "Related Party Transactions—Longview Acquisition Agreement"; and
11. Credit Agreement, dated June 13, 2008, between Brookfield Infrastructure L.P. and Citibank, N.A., Credit Suisse, Toronto Branch, HSBC Bank Canada, HSBC Bank U.S.A., N.A., Toronto Branch, Royal Bank of Canada and The Royal Bank of Scotland plc described under Item 5 "Operating and Financial Review and Prospects—Managements Discussion and Analysis of Financial Condition and Results of Operations—Capital Resources and Liquidity—Senior Secured Credit Facility."

Copies of the agreements noted above will be made available, free of charge, by our Managing General Partner and are available electronically on the website of SEC at *www.sec.gov* and on our SEDAR profile at www.sedar.com. Written requests for such documents should be directed to our Corporate Secretary at Cannon's Court, 22 Victoria Street, Hamilton HM 12, Bermuda. Copies of the agreements noted above will also be available for inspection at the offices of the Manager at 181 Bay Street, Suite 300, Brookfield Place, Toronto, Ontario, M5J 2T3 during normal business hours.

10.D EXCHANGE CONTROLS

There are currently no governmental laws, decrees, regulations or other legislation of Bermuda or the United States which restrict the import or export of capital or the remittance of dividends, interest or other payments to non-residents of Bermuda or the United States holding the Company's securities, except as otherwise described in this Form 20-F under Item 10.E "Taxation."

10.E TAXATION

The following summary discusses certain material United States, Canadian and Bermudian tax considerations related to the holding and disposition of our units as of the date hereof. Holders of our units are advised to consult their own tax advisors concerning the consequences under the tax laws of the country of which they are resident or in which they are otherwise subject to tax of making an investment in our units.

UNITED STATES TAX CONSIDERATIONS

This summary discusses certain United States federal income tax considerations related to the holding and disposition of our units as of the date hereof. This summary is based on provisions of the U.S. Internal Revenue Code of 1986, as amended, or the U.S. Internal Revenue Code, on the regulations promulgated thereunder, or the

U.S. Treasury Regulations, and on published administrative rulings and judicial decisions, all as in effect of the date hereof and all of which are subject to change at any time. This summary is necessarily general and may not apply to all categories of investors, some of which may be subject to special rules (including, without limitation, investors that own more than 5% of our units, dealers in securities or currencies, financial institutions or financial services entities, life insurance companies, holders of our units held as part of a straddle, hedge, constructive sale or conversion transaction with other investments, U.S. persons whose functional currency is not the U.S. dollar, persons who have elected mark-to-market accounting, persons who hold our units through a partnership or other entity which is a pass-through entity for U.S. federal income tax purposes, or persons for whom our units are not a capital asset). Tax-exempt organizations are discussed separately below. The actual tax consequences of the acquisition ownership and disposition of our units will vary depending on your circumstances.

For purposes of this discussion, a "U.S. Holder" is a beneficial holder of one or more of our units that is for U.S. federal income tax purposes (1) an individual citizen or resident of the United States; (2) a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia; (3) an estate the income of which is subject to U.S. federal income taxation regardless of its source or (4) a trust which either (i) is subject to the primary supervision of a court within the United States and one or more United States persons have the authority to control all substantial decisions of the trust or (ii) has a valid election in effect under applicable U.S. Treasury regulations to be treated as a United States person. A "non-U.S. Holder" is a holder that is not a U.S. Holder and who, in addition, is not (i) a partnership or other fiscally transparent entity, (ii) an individual present in the United States for 183 days or more in a taxable year who meets certain other conditions under the substantial presence test in under Section 7701(b)(3) of the U.S. Internal Revenue Code and U.S. Treasury Regulations Section 301.7701(b)-1(c), or (iii) subject to rules applicable to certain expatriates who meet the expatriation rules in Section 877 of the U.S. Internal Revenue Code or former long-term residents of the United States.

If a partnership holds our units, the tax treatment of a partner of such partnership will generally depend upon the status of the partner and the activities of the partnership. If you are a partner of a partnership holding our units, you should consult your own tax advisors.

A non-U.S. Holder who holds more than 5% of our units very likely will be subject to special rules under the Foreign Investment Real Property Tax Act of 1980, or FIRPTA, and such rules are not addressed below. For purposes of determining whether a non-U.S. Holder holds more than 5% of our units, special attribution rules apply. The application of the FIRPTA rules to a non-U.S. Holder who holds (or is deemed to hold) more than 5% of our units could have a material adverse effect on such non-U.S. Holder. Accordingly, we do not believe that it is generally advisable for a non-U.S. Holder who cannot fully credit any U.S. FIRPTA tax against their home country income tax to own more than 5% of our units (either directly or indirectly). If you are a non-U.S. Holder and anticipate owning more than 5% of our units, you should consult your own tax advisors.

This discussion does not constitute tax advice and is not intended to be a substitute for tax planning. You should consult your own tax advisors concerning the U.S. federal, state and local income tax consequences particular to your ownership and disposition of our units, as well as any consequences under the laws of any other taxing jurisdiction.

Partnership Status of Our Partnership and Brookfield Infrastructure

Each of our partnership and Brookfield Infrastructure have made a protective election to be treated as a partnership for U.S. federal income tax purposes. An entity that is treated as a partnership for U.S. federal income tax purposes incurs no U.S. federal income tax liability. Instead, each partner is required to take into account its allocable share of items of income, gain, loss, and deduction of the partnership in computing its U.S. federal income tax liability, regardless of whether cash distributions are made. Distributions of cash by a partnership to a partner are generally not taxable unless the amount of cash distributed to a partner is in excess of the partner's adjusted basis in its partnership interest.

An entity that would otherwise be classified as a partnership for U.S. federal income tax purposes may nonetheless be taxable as a corporation if it is a "publicly traded partnership," unless an exception applies. Our partnership will be publicly traded; however, an exception, referred to as the "Qualifying Income Exception," exists with respect to any publicly traded partnership if at least 90% of such partnership's gross income for every taxable year consists of "qualifying income" and the partnership would not be required to register under the U.S. Investment Company Act if it were a U.S. corporation. Qualifying income includes certain interest income, dividends, real property rents, gains from the sale or other disposition of real property, and any gain from the sale or disposition of a capital asset or other property held for the production of income that otherwise constitutes qualifying income. We intend to manage our affairs so that our partnership meets the Qualifying Income Exception in each taxable year. We believe our partnership will be treated as a partnership and not as a corporation for U.S. federal income tax purposes.

If our partnership fails to meet the Qualifying Income Exception, other than a failure which is determined by the IRS to be inadvertent and which is cured within a reasonable time after discovery, or if our partnership is required to register under the U.S. Investment Company Act, our partnership will be treated as if it had transferred all of its assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which our partnership fails to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed the stock to the holders of our units in liquidation of our partnership. This deemed contribution would likely result in recognition of gain (but not loss) to U.S. Holders of our units. However, U.S. Holders actually or constructively owning less than 5% of our units generally would not recognize the portion of such gain attributable to stock or securities of non-U.S. corporations which we may hold. If, at the time of the contribution, our partnership has liabilities in excess of the tax basis of its assets, all U.S. Holders would generally recognize gain in respect of such excess liabilities upon the deemed transfer. Afterwards, our partnership would be treated as a corporation for U.S. federal income tax purposes.

If our partnership were treated as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, our partnership's items of income, gain, loss and deduction would be reflected only on our partnership's tax return rather than being passed through to our unitholders, and our partnership would be subject to U.S. corporate income tax and branch profits tax with respect to its income, if any, that is effectively connected with a United States trade or business. Moreover, under certain circumstances, our partnership may be classified as a passive foreign investment company, or PFIC, for U.S. federal income tax purposes, and U.S. Holders would be subject to the rules applicable to PFICs discussed below. See "—Consequences to U.S. Holders—Passive Foreign Investment Companies". Subject to the PFIC rules discussed below, distributions made to a U.S. Holder would be treated as either taxable dividend income, which may be eligible for reduced rates of taxation (if such distributions are made in respect of our units traded on the NYSE or if certain other requirements are satisfied), to the extent of our partnership's current or accumulated earnings and profits, or in the absence of earnings and profits, as a nontaxable return of capital, to the extent of the U.S. Holder's tax basis in our units, or as taxable capital gain, after the U.S. Holder's basis is reduced to zero. In addition, dividends, interest and certain other passive income that our partnership receives with respect to U.S. investments generally would be subject to U.S. withholding tax at a rate of 30% (although certain non-U.S. Holders nevertheless may be entitled to certain treaty benefits in respect of their allocable share of such income), and U.S. Holders (other than certain corporate U.S. Holders who own 10% or more of our units) would not be allowed a tax credit with respect to any such tax withheld. In addition, the "portfolio interest" exemption would not apply to certain interest income of our partnership (although certain non-U.S. Holders nevertheless may be entitled to certain treaty benefits in respect of their allocable share of such income). Accordingly, treatment of our partnership as a corporation could materially reduce our unitholders' after-tax returns and, thus, could result in a substantial reduction of the value of our units. In addition to the foregoing consequences, if our partnership were treated as a corporation for U.S. federal income tax purposes, and, as of the time of conversion from partnership status to corporate status, the value of our partnership's U.S. assets equalled income recognized by our partnership subsequent to such conversion would be subject to U.S. corporate income tax. It is not expected that our partnership's U.S. assets will at any time equal or exceed such thresholds. If Brookfield Infrastructure were to be treated as a corporation for U.S. federal income tax purposes, consequences similar to those described above would apply.

The remainder of this section assumes that our partnership and Brookfield Infrastructure will be treated as partnerships for U.S. federal income tax purposes. We expect that a substantial portion of the items of income, gain, deduction, loss and credit realized by our partnership will be realized in the first instance by Brookfield Infrastructure and allocated to our partnership for reallocation to our unitholders. Unless otherwise specified, references in this section to realization of our partnership's items of income, gain, loss, deduction or credit include a realization of such items by Brookfield Infrastructure and the allocation of such items to our partnership.

CONSEQUENCES TO U.S. HOLDERS

Holding of Our Units

Income and Loss

If you are a U.S. Holder, you will be required to take into account, as described below, your distributive share of our partnership's items of income, gain, loss, deduction and credit for each of our partnership's taxable years ending with or within your taxable year. Each item generally will have the same character and source (either U.S. or foreign) as though you had realized the item directly. You will report those items without regard to whether any distribution has been or will be received from our partnership. Although we intend to make cash distributions (which we intend to pay to all of our unitholders on a quarterly basis) in an amount that is generally expected to be sufficient to permit our U.S. Holders to fund their estimated U.S. tax obligations (including any federal, state and local income taxes) with respect to their distributive shares of our partnership's net income or gain, based upon your particular tax situation and simplifying assumptions that we will make in determining the amount of such distributions, your tax liability may exceed cash distributions made to you, in which case you would have to satisfy tax liabilities arising from your units in our partnership from your own funds.

With respect to U.S. Holders who are individuals, certain dividends paid by a corporation, including certain qualified foreign corporations, to us and that are allocable to such U.S. Holders prior to January 1, 2011 may be subject to reduced rates of taxation. A qualified foreign corporation includes a foreign corporation that is eligible for the benefits of specified income tax treaties with the United States. In addition, a foreign corporation is treated as a qualified corporation with respect to its shares that are readily tradable on an established securities market in the United States. Among other exceptions, U.S. Holders who are individuals will not be eligible for reduced rates of taxation on any dividends if the payer is a PFIC in the taxable year in which such dividends are paid or in the preceding taxable year. U.S. Holders that are corporations may be entitled to a "dividends received deduction" in respect of dividends paid by U.S. corporations in which we own stock. You should consult your own tax advisors regarding the application of the foregoing rules to your particular circumstances.

For U.S. federal income tax purposes, your allocable share of our partnership's items of income, gain, loss, deduction or credit will be governed by our limited partnership agreement if such allocations have "substantial economic effect" or are determined to be in accordance with your interest in our partnership. Similarly, our partnership's allocable share of items of income, gain, loss, deduction or credit of Brookfield Partnership will be governed by the limited partnership agreement of Brookfield Infrastructure if such allocations have "substantial economic effect" or are determined to be in accordance with our partnership's interest in Brookfield Infrastructure. We believe that, for U.S. federal income tax purposes, such allocations should be given effect, and our Managing General Partner and the Infrastructure GP LP intend to prepare tax returns based on such allocations. If the IRS successfully challenged the allocations made pursuant to either our limited partnership agreement or the limited partnership agreement of Brookfield Infrastructure, the resulting allocations for U.S. federal income tax purposes may be less favorable than the allocations set forth in such agreements.

Basis

You will have an initial tax basis for your units equal to the amount you paid for your units (or if you received your units pursuant to the spin-off, the amount of dividend income you recognized pursuant to the spinoff) plus your share of our partnership's liabilities, if any. That basis will be increased by your share of our partnership's income and by increases in your share of our partnership's liabilities, if any. That basis will be decreased, but not below zero, by distributions you receive from our partnership, by your share of our partnership's losses and by any decrease in your share of our partnership's liabilities. Under applicable U.S. federal income tax rules, a partner in a partnership has a single, or "unitary," tax basis in his or her partnership interest. As a result, any amount you pay to acquire additional units in our partnership (including through the distribution reinvestment plan) will be averaged with the adjusted tax basis of the units you owned prior to the acquisition of such additional units. The amount you pay to acquire additional units cannot be "traced" to the additional units so acquired. Certain consequences of your "unitary" tax basis are discussed in greater detail below in "Special Considerations for Purchasers of Additional Units."

For purposes of the foregoing rules, the rules discussed immediately below, and the rules applicable to a sale or your units, our partnership's liabilities will generally include our partnership's share of any liabilities of Brookfield Infrastructure.

Limits on Deductions for Losses and Expenses

Your deduction of your share of our partnership's losses will be limited to your tax basis in your units and, if you are an individual or a corporate holder that is subject to the "at risk" rules, to the amount for which you are considered to be "at risk" with respect to our partnership's activities, if that is less than your tax basis. In general, you will be at risk to the extent of your tax basis in your units, reduced by (i) the portion of that basis attributable to your share of our partnership's liabilities for which you will not be personally liable (excluding certain qualified non-recourse financing) and (ii) any amount of money you borrow to acquire or hold your units, if the lender of those borrowed funds owns an interest in us, is related to you, or can look only to your units for repayment. Your at risk amount will generally increase by your allocable share of our partnership's income and gain and decrease by cash distributions you receive from our partnership and your allocable share of losses and deductions. You must recapture losses deducted in previous years to the extent that distributions cause your at risk amount to be less than zero at the end of any taxable year. Losses disallowed or recaptured as a result of these limitations will carry forward and will be allowable to the extent that your tax basis or at risk amount, whichever is the limiting factor, subsequently increases. Upon the taxable disposition of your units, any gain recognized by you can be offset by losses that were previously suspended by the at risk limitation but may not be offset by losses suspended by the basis limitation. Any excess loss above that gain previously suspended by the at risk or basis limitations may no longer be used. You should consult your own tax advisors as to the effects of the at risk rules.

Limitations on Deductibility of Organizational Expenses and Syndication Fees

In general, neither our partnership nor any U.S. Holder may deduct organizational or syndication expenses. Similar rules apply to organizational or syndication expenses incurred by Brookfield Infrastructure. While an election may be made by a partnership to amortize organizational expenses over a 15-year period, we do not intend to make such election for either our partnership or Brookfield Infrastructure. Syndication fees (which would include any sales or placement fees or commissions) must be capitalized and cannot be amortized or otherwise deducted.

Limitations on Interest Deductions

Your share of our partnership's interest expense is likely to be treated as "investment interest" expense. If you are a non-corporate taxpayer, the deductibility of "investment interest" expense is generally limited to the amount of your "net investment income." Your share of our partnership's dividend and interest income will be treated as investment income, although "qualified dividend income" subject to reduced rates of tax in the hands of an individual will only be treated as investment income if you elect to treat such dividend as ordinary income not subject to reduced rates of tax. In addition, state and local tax laws may disallow deductions for your share of our partnership's interest expense.

Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment.

Deductibility of Partnership Investment Expenditures by Individual Partners and by Trusts and Estates

Subject to certain exceptions, all miscellaneous itemized deductions of an individual taxpayer, and certain of such deductions of an estate or trust, are deductible only to the extent that such deductions exceed 2% of the taxpayer's adjusted gross income. Moreover, the otherwise allowable itemized deductions of individuals whose gross income exceeds an applicable threshold amount are subject to reduction by an amount equal to the lesser of (i) 3% of the excess of the individual's adjusted gross income over the threshold amount, or (ii) 80% of the amount of the itemized deductions, such reductions to be reduced on a phased basis beginning in 2006. The operating expenses of our partnership, including our partnership's allocable share of the Base Management Fee or any other management fees (if any), will likely be treated as miscellaneous itemized deductions subject to the foregoing rule. Alternatively, it is possible that our partnership and Brookfield Infrastructure will be required to capitalize amounts paid in respect of the Base Management Fee (as well as amounts paid in respect of any other management fees (if any)). Accordingly, if you are a non-corporate U.S. Holder, you should consult your own tax advisors with respect to the application of these limitations.

Sale or Exchange of Our Units

You will recognize gain or loss on a sale by you of your units equal to the difference, if any, between the amount realized and your tax basis in the units sold. Your amount realized will be measured by the sum of the cash or the fair market value of other property received plus your share of our partnership's liabilities, if any.

Gain or loss recognized by you on the sale or exchange by you of your units will generally be taxable as capital gain or loss and will be long-term capital gain or loss if the units were held for more than one year on the date of such sale or exchange. Under certain circumstances, your gain or loss may be long-term capital gain or loss, in part, and short-term capital gain or loss, in part, under the "split" holding period rules discussed below in "Special Considerations for Purchasers of Additional Units." Assuming you have not elected to treat your share of our interest in any PFICs in which we may invest as a "qualified electing fund", gain attributable to such investment in a PFIC would be taxable in the manner described below in "—Passive Foreign Investment Companies". In addition, certain gain attributable to "unrealized receivables" or "inventory items" could be characterized as ordinary income rather than capital gain. For example, if our partnership holds debt acquired at a market discount, accrued market discount on such debt would be treated as "unrealized receivables." The deductibility of capital losses is subject to limitations.

Special Considerations for Purchasers of Additional Units

Where a partner in a partnership acquires portions of his or her interest at different times, applicable U.S. federal income tax rules provide that the partner has a divided, or "split" holding period in his or her interest. Thus, if you acquire additional units at different times (including acquisitions made through the distribution reinvestment plan) each unit you own (including the additional units you acquire) will have a "split" holding period: a fraction of each unit will have a holding period commencing on the date after the acquisition of the additional units under the plan, and a fraction of each unit will have a holding period attributable to your previously-owned ("historic") units, based on the relative fair market values of the additional units and the historic units (as of the date of the acquisition of the additional units). The foregoing rules apply each time you acquire additional units (including under the distribution reinvestment plan). Nonetheless, each unit will retain an "averaged" adjusted tax basis as described above in "Basis." Subject to the special tracing approach described below, if you dispose of any units (whether historic or additional units) within one year of acquiring additional units, the disposition may give rise to both short-term capital gain (or loss), in part, and long-term capital gain (or loss), in part, as a result of each unit's "split" holding period. Likewise, a cash distribution to you within a year of the acquisition of additional units in excess of your "unitary" adjusted tax basis in all of your units could give rise to both short-term and long-term capital gain. You may under certain circumstances use a "tracing" approach in lieu of having a "split" holding period in your units. The U.S. Treasury Regulations provide that a selling partner in a "publicly traded partnership" may use the actual holding period of the portion of his or her partnership interest if (1) the interest is divided into identifiable units with ascertainable holding periods, (2) the partner can identify the portion of the partnership interest transferred, and (3) the partner elects to use the identification method for all sales or exchanges of his or her interests in the partnership. As described above, our partnership will be a "publicly traded partnership." If you intend to rely on this alternative tracing approach, you must make an election to do so with your first disposition of units. This election applies only to your holding period in your units, not to your basis, which you may not "trace" under the "unitary" tax basis rules described above.

You should consult your own tax advisors regarding the consequences of a "split" holding period in your units, as well the availability and advisability of making the alternative tracing election.

Foreign Tax Credit Limitations

You will generally be entitled to a foreign tax credit with respect to your allocable share of creditable foreign taxes paid on our partnership's income and gains. Complex rules may, depending on your particular circumstances, limit the availability or use of foreign tax credits. Gains from the sale of our partnership's investments may be treated as U.S. source gains. Consequently, you may not be able to use the foreign tax credit arising from any foreign taxes imposed on such gains unless such credit can be applied (subject to applicable limitations) against U.S. tax due on other income treated as derived from foreign sources. Certain losses that our partnership incurs may be treated as foreign source losses, which could reduce the amount of foreign tax credits otherwise available.

Section 754 Election

Our partnership and Brookfield Infrastructure each have made or will make the election permitted by Section 754 of the U.S. Internal Revenue Code, or the Section 754 Election, and in the event we determine that either our partnership or Brookfield Infrastructure is deemed technically terminated pursuant to Section 708 of the U.S. Internal Revenue Code, either our partnership or Brookfield Infrastructure (as applicable) will remake the Section 754 Election. The Section 754 Election is irrevocable without the consent of the IRS. The Section 754 Election generally requires our partnership to adjust the tax basis in its assets, or inside basis, attributable to a transferee of our units under Section 743(b) of the U.S. Internal Revenue Code to reflect the purchase price paid by the transferee for our units. This election does not apply to a person who purchases our units directly from us. For purposes of this discussion, a transferee's inside basis in our partnership's assets will be considered to have two components: (i) the transferee's share of our partnership's tax basis in our partnership's assets, or common basis, and (ii) the adjustment under Section 743(b) of the U.S. Internal Revenue Code to that basis. The foregoing rules would also apply to Brookfield Infrastructure.

Generally, a Section 754 Election would be advantageous to a transferee U.S. Holder if such U.S. Holder's tax basis in its units is higher than the units' share of the aggregate tax basis of our partnership's assets immediately prior to the transfer. In that case, as a result of the Section 754 Election, the transferee U.S. Holder of units would have a higher tax basis in such U.S. Holder's share of our partnership's assets for purposes of calculating, among other items, such U.S. Holder's share of any gain or loss on a sale of our partnership's assets. Conversely, a Section 754 Election would be disadvantageous to a transferee U.S. Holder of our units if such U.S. Holder's tax basis in its units is lower than those units' share of the aggregate tax basis of our partnership's assets immediately prior to the transfer. Thus, the fair market value of our units may be affected either favorably or adversely by the election.

The calculations involved in the Section 754 Election are complex, and we will make them on the basis of assumptions as to the value of our assets and other matters. You should consult your own tax advisors as to the effects of the Section 754 Election.

Uniformity of Our Units

Because we can not match transferors and transferees of our units, we must maintain uniformity of the economic and tax characteristics of our units to a purchaser of our units. In the absence of uniformity, we may be unable to comply fully with a number of U.S. federal income tax requirements. A lack of uniformity can result from a literal application of U.S. Treasury Regulations under Sections 743 of the U.S. Internal Revenue Code to our partnership's Section 743(b) adjustments, the determination that our partnership's Section 704(c) allocations are unreasonable, or other reasons. Section 704(c) allocations would be intended to reduce or eliminate the disparity between tax basis and the value of our partnership's assets in certain circumstances, including on the issuance of additional units. In order to maintain the fungibility of all of our units at all times, we seek to achieve the uniformity of U.S. tax treatment for all purchasers of our units which are acquired at the same time and price (irrespective of the identity of the particular seller of the units or the time when the units are issued by our partnership) through the application of certain tax accounting principles that we believe are reasonable for our partnership. However, the IRS may disagree with us and may successfully challenge our application of such tax accounting principles. Any non-uniformity could have a negative impact on the value of our units.

Foreign Currency Gain or Loss

Our partnership's functional currency will be the U.S. dollar, and our partnership's income or loss will be calculated in U.S. dollars. It is likely that our partnership will recognize "foreign currency" gain or loss with respect to transactions involving non-U.S. dollar currencies. In general, foreign currency gain or loss is treated as ordinary income or loss. You should consult your own tax advisors regarding the tax treatment of foreign currency gain or loss.

Passive Foreign Investment Companies

A U.S. Holder will be subject to special rules applicable to indirect investments in foreign corporations, including an investment in a PFIC.

A PFIC is defined as any foreign corporation with respect to which (after applying the applicable look through rules under 1297(c) of the U.S. Internal Revenue Code) either (i) 75% or more of its gross income for a taxable year is "passive income" or (ii) 50% or more of its assets in any taxable year (generally based on the quarterly average of the value of its assets) produce "passive income." There are no minimum stock ownership requirements for PFICs. Once a corporation qualifies as a PFIC it is as to any person with an interest in such corporation at any time in which it was a PFIC, subject to certain exceptions, always treated as a PFIC, regardless of whether it satisfies either of the qualification tests in subsequent years. Any gain on disposition of stock of a PFIC, as well as income realized on certain "excess distributions" by the PFIC, is treated as though realized ratably over the shorter of your holding period of your units or our holding period for the PFIC. Such gain or income is taxable as ordinary income and dividends paid by a PFIC are not eligible for the preferential tax rate in the hands of individuals who would otherwise be eligible for the preferential tax rate for dividends. In addition, an interest charge would be imposed on you based on the tax treated as deferred from prior years.

If you made an election to treat your proportionate share of our interest in a PFIC as a "qualified electing fund", such election a QEF election, for the first year you are treated as holding such interest, in lieu of the foregoing treatment, you would be required to include in income each year a portion of the ordinary earnings and net capital gains of the PFIC, even if not distributed to our partnership or to you. A QEF election must be made by you on an entity-by-entity basis. To make a QEF election, you would, among other things, be required to submit IRS Form 8621 and supply the IRS with an information statement provided by the PFIC. U.S. Holders should consult their own tax advisors as to the manner in which such direct inclusions affect their allocable share of our income and their tax basis in their units.

Alternatively, in the case of a PFIC that is a publicly traded foreign company, you may make an election to "mark-to-market" your proportionate share of the stock of such foreign company on an annual basis. Pursuant to such an election, you would include in each year as ordinary income the excess, if any, of the fair market value of your proportionate share of such stock over its adjusted basis at the end of the taxable year. You may treat as ordinary loss any excess of the adjusted basis of your proportionate share of the stock over its fair market value at the end of the year, but only to the extent of the net amount previously included in income as a result of the election. Although we may in the future acquire PFICs which are publicly traded foreign companies, it is not expected that interests in any of our current operations will be publicly traded. Thus, you would not be eligible to make a mark-to-market election in respect of your indirect ownership interest in any of our operating entities. With the exception of our social infrastructure operations, based on our analysis of our operating entities and Holding Entities, as well as our expectations regarding future operations, we do not believe that any of the operating entities or any of the Holding entities is or is likely to become a PFIC. Although we do not otherwise intend to invest significant amounts in PFICs, there can be no assurance that a current or future investment will not be or become a PFIC or that an investment in PFIC stock will be eligible for the "mark-to-market" election. In addition, we may be required to hold an existing or future operating entity through a Holding Entity that would be a PFIC in order to ensure that our partnership satisfies the Qualifying Income Exception. See "—Investment Structure", below. To the extent reasonably practicable, we intend to timely provide you with information related to the PFIC status of each entity we are able to identify as a PFIC, including information necessary for you to make a QEF election with respect to each such entity. To the extent reasonably practicable, we intend to make distributions of the earnings of each entity we are able to identify as a PFIC not less frequently than annually so as to minimize amounts that you must treat as excess distributions with respect to any such entity. However, because we cannot assure you that will be the case, and because any gains on a sale of any such entity would remain subject to the PFIC tax regime discussed above (See also "Sale or Exchange of Our Units," above), we urge you to consider timely filing a QEF election with respect to each entity we are able to identify as a PFIC and for which we are able to provide the necessary information for the first year we hold an interest in such entity.

You should consult your own tax advisors regarding the PFIC rules, including the advisability of making a QEF election or, if applicable, a mark-to-market election with respect to each PFIC.

Investment Structure

To manage our affairs so as to ensure that our partnership meets the Qualifying Income Exception for the publicly traded partnership rules (discussed above) and comply with certain requirements in our limited partnership agreement, we may need to structure certain investments through an entity classified as a corporation for U.S. federal income tax purposes. Such investment structures will be entered into as determined in the sole discretion of our Managing General Partner and the Infrastructure GP LP in order to create a tax structure that generally is efficient for our unitholders. However, because our unitholders will be located in numerous taxing jurisdictions, no assurances can be given that any such investment structure will be beneficial to all our unitholders to the same extent, and may even impose additional tax burdens on some of our unitholders. As discussed above, if any such entity were a non-U.S. corporation it may be considered a PFIC. If any such entity were a U.S. corporation, it would be subject to U.S. federal income tax on its operating income, including any gain recognized on its disposal of its investments. In addition, if the investment involves U.S. real estate, gain recognized on disposition of the investment by a corporation would generally be subject to corporate-level tax, whether the corporation is a U.S. or a non-U.S. corporation.

Taxes in Other Jurisdictions

In addition to U.S. federal income tax consequences, because of an investment in our partnership, you may be subject to potential U.S. state and local taxes in the U.S. state or locality in which you are a resident for tax purposes. You may also be subject to tax return filing obligations and income, franchise or other taxes, including withholding taxes, in non-U.S. jurisdictions in which we invest. We will attempt, to the extent reasonably practicable, to structure our operations and investments so as to minimize income tax filing obligations by our investors in non-U.S. jurisdictions, but, there may be circumstances in which we are unable to do so. Income or gains from investments held by us may be subject to withholding or other taxes in jurisdictions outside the

United States, subject to the possibility of reduction under applicable income tax treaties. If you wish to claim the benefit of an applicable income tax treaty, you may be required to submit information to tax authorities in such jurisdictions. You should consult your own tax advisors regarding the U.S. state, local and non-U.S. tax consequences of an investment in our partnership.

U.S. Withholding Taxes

Although each U.S. Holder is required to provide us with a Form W-9, we nevertheless may be unable to accurately or timely determine the tax status of our investors for purposes of determining whether U.S. withholding applies to payments made by our partnership to some or all of our unitholders. In such a case, payments made by our partnership to U.S. Holders may be subject to U.S. "backup" withholding at the applicable rate (currently 28%) or other U.S. withholding taxes (potentially as high as 30%). You would be able to treat as a credit your allocable share of any U.S. withholding taxes paid in the taxable year in which such withholding taxes were paid and, as a result, you may be entitled to a refund of such taxes. In the event you transfer or otherwise dispose of some or all of your units, special rules may apply for purposes of determining whether you or the transferee of such units is subject to U.S. withholding taxes in respect of income allocable to, or distributions made on account of, such units and/or entitled to refunds of any such taxes withheld. See "—Administrative Matters—Certain Effects of a Transfer of Units". You should consult your own tax advisors regarding the treatment of U.S. withholding taxes.

Transferor/Transferee Allocations

Our partnership may allocate items of income, gain, loss, deduction and credit using a monthly or other convention, whereby any such items recognized in a given month by our partnership are allocated to the holders of our units as of a specified date of such month. As a result, if you transfer your units, you may be allocated income, gain, loss and deduction realized by our partnership after the date of transfer. Similarly, if you acquire additional units, you may be allocated income, gain, loss, and deduction realized by our partnership prior to your ownership of such units.

Although Section 706 of the U.S. Internal Revenue Code generally provides guidelines for allocations of items of partnership income and deductions between transferors and transferees of partnership interests, it is not clear that our partnership's allocation method complies with its requirements. If our partnership's convention were not permitted, the IRS might contend that our partnership's taxable income or losses must be reallocated among our unitholders. If such a contention were sustained, your respective tax liabilities would be adjusted to your possible detriment. Our Managing General Partner is authorized to revise our partnership's method of allocation between transferors and transferees (as well as among investors whose interests otherwise vary during a taxable period).

U.S. Federal Estate Tax Consequences

If our units are included in the gross estate of a U.S. citizen or resident for U.S. federal estate tax purposes, then a U.S. federal estate tax might be payable in connection with the death of such person. Individual U.S. Holders should consult their own tax advisors concerning the potential U.S. federal estate tax consequences with respect to our units.

U.S. Taxation of Tax Exempt U.S. Holders of Our Units

Income recognized by a U.S. tax-exempt organization is exempt from U.S. federal income tax except to the extent of the organization's "unrelated business taxable income", or UBTI. UBTI is defined generally as any gross income derived by a tax-exempt organization from an unrelated trade or business that it regularly carries on, less the deductions directly connected with that trade or business. In addition, income arising from a "flow through" entity for U.S. federal income tax purposes that holds operating assets or is otherwise engaged in a trade or business will generally constitute UBTI. Notwithstanding the foregoing, UBTI generally does not include any dividend income, interest income (or certain other categories of passive income) or capital gains recognized by a tax-exempt organization so long as such income is not debt financed, as discussed below. Our partnership does not expect to be engaged in a trade or business, and any operating assets held by us will be held through entities that are treated as corporations for U.S. federal income tax purposes.

The exclusion from UBTI for dividends, interest (or other passive income) and capital gains does not apply to income from “debt-financed property”, which is treated as UBTI to the extent of the percentage of such income that the average acquisition indebtedness with respect to the property bears to the average tax basis of the property for the taxable year. Gain attributable to the sale of previously debt-financed property continues to be subject to these rules for 12 months after any acquisition indebtedness is satisfied. If an entity treated as a partnership for U.S. federal income tax purposes incurs acquisition indebtedness, a tax-exempt partner in such partnership would be deemed to have acquisition indebtedness equal to its allocable portion of such acquisition indebtedness. Our partnership and Brookfield Infrastructure are not prohibited from incurring indebtedness, and at times either or both may do so (e.g., on June 13, 2008, Brookfield Infrastructure entered into a $450.0 million senior secured credit facility). If any such indebtedness were used to acquire property by our partnership or Brookfield Infrastructure, such property would be subject to the rules described above, and, consequently, tax-exempt U.S. Holders may recognize UBTI as a result of an investment in our partnership. Our partnership or Brookfield Infrastructure may use such indebtedness, including indebtedness incurred as a result of the senior secured credit facility, for such purposes. In addition, even if such indebtedness were not used either by our partnership or by Brookfield Infrastructure to acquire property but were instead used to fund distributions to our unitholders, if a tax-exempt U.S. Holder used such proceeds to make an investment outside our partnership, the IRS could assert that such investment constitutes “debt-financed property” subject to the rules described above.

A tax-exempt organization is subject to U.S. federal income tax at the regular graduated rates on the net amount of its UBTI, and a tax-exempt organization deriving gross income characterized as UBTI that exceeds $1,000 in any taxable year is obligated to file a U.S. federal income tax return, even if it has no liability for that year as a result of deductions against such gross income, including an annual $1,000 statutory deduction.

The potential for having income characterized as UBTI may make our units an unsuitable investment for a tax-exempt organization. Tax-exempt U.S. Holders should consult their own tax advisors regarding all aspects of UBTI.

Investments by U.S. Mutual Funds

U.S. mutual funds that are treated as regulated investment companies, or RICs, for U.S. federal income tax purposes are required, among other things, to meet an annual 90% gross income and a quarterly 50% asset value test under Section 851(b) of the U.S. Internal Revenue Code to maintain their favorable U.S. federal income tax status. The treatment of an investment by a RIC in our units for purposes of these tests will depend on whether our partnership will be treated as a “qualified publicly traded partnership”. If our partnership is so treated, then our units themselves are the relevant assets for purposes of the 50% asset value test and the net income from our units is the relevant gross income for purposes of the 90% gross income test. If, however, our partnership is not so treated, then the relevant assets are the RIC’s allocable share of the underlying assets held by our partnership and the relevant gross income is the RIC’s allocable share of the underlying gross income earned by our partnership. Whether our partnership will qualify as a “qualified publicly traded partnership” depends on the exact nature of its future investments, but it is likely that our partnership will not be treated as a “qualified publicly traded partnership.” RICs should consult their own tax advisors about the U.S. tax consequences of an investment in our units.

Consequences to Non-U.S. Holders of Our Units

We will use commercially reasonable efforts to structure our activities to avoid generating income treated as effectively connected with a U.S. trade or business, including effectively connected income attributable to the sale of a "United States Real Property Interest", as defined in the U.S. Internal Revenue Code. Specifically, our partnership will not make an investment directly, or through an entity which would be treated as a pass-through entity for U.S. federal income tax purposes, if we believe at the time of such investment that such investment would generate income treated as effectively connected with a U.S. trade or business. If, as anticipated, our partnership is not treated as engaged in a U.S. trade or business or as deriving income which is treated as effectively connected with a U.S. trade or business, and provided that you are not yourself engaged in a U.S. trade or business, you will not be subject to U.S. tax return filing requirements and generally will not be subject to U.S. federal income tax on interest and dividends from non-U.S. sources and gains from the sale or other disposition of securities or of real property located outside of the United States derived by us.

However, there can be no assurance that the law will not change or that the IRS will not challenge our position that our partnership is not engaged in a U.S. trade or business. If, contrary to our expectations, our partnership is considered to be engaged in a U.S. trade or business, you would be required to file a U.S. federal income tax return even if no effectively connected income is allocable to you. Additionally if our partnership has income that is treated as effectively connected with a U.S. trade or business, you would be required to report that income and would be subject to U.S. federal income tax at the regular graduated rates. In addition, we may be required to withhold U.S. federal income tax on your share of such income. If you are a non-U.S. corporation, you may be subject to branch profits tax as well, at a rate of 30%, or a lower treaty rate, if applicable.

In general, even if our partnership is not engaged in a U.S. trade or business, and assuming you are not otherwise engaged in a U.S. trade or business, you will nonetheless be subject to a withholding tax of 30% on the gross amount on certain U.S. source income which is not effectively connected with a U.S. trade or business. Income subjected to such a flat tax rate is income of a fixed or determinable annual or periodic nature, including dividends and certain interest income. Such withholding tax may be reduced or eliminated with respect to certain types of income under an applicable income tax treaty between the United States and your country of residence or under the "portfolio interest" rules of the U.S. Internal Revenue Code, provided that you provide proper certification as to your eligibility for such treatment. Notwithstanding the foregoing, and although each non-U.S. Holder is required to provide us with a Form W-8, we nevertheless may be unable to accurately or timely determine the tax status of our investors for purposes of establishing whether reduced rates of withholding apply to some or all of our unitholders. In such a case, your allocable share of distributions of U.S.-source dividend and interest income will be subject to U.S. withholding tax at a rate of 30%. As such, if you would not be subject to U.S. tax based on your tax status or are eligible for a reduced rate of U.S. withholding, you may need to take additional steps to receive a credit or refund of any excess withholding tax paid on your account, which may include the filing of a non-resident U.S. income tax return with the IRS. Among other limitations applicable to claiming treaty benefits, if you reside in a treaty jurisdiction which does not treat our partnership as a passthrough entity, you may not be eligible to receive a refund or credit of excess U.S. withholding taxes paid on your account. In the event you transfer or otherwise dispose of some or all of your units, special rules may apply for purposes of determining whether you or the transferee of such units is subject to U.S. withholding taxes in respect of income allocable to, or distributions made on account of, such units and/or entitled to refunds of any such taxes withheld. See "—Administrative Matters—Certain Effects of a Transfer of Units". You should consult your own tax advisors regarding the treatment of U.S. withholding taxes.

The disposition of our units on the NYSE by a non-U.S. Holder will not be subject to U.S. federal income tax, so long as (i) such non-U.S. Holder does not own (and is not deemed to own) more than 5% of our units, and (ii) for the calendar quarter during which such disposition occurs, our units are regularly quoted by brokers and dealers making a market in our units. We do not intend to list our units for trading on any other exchange unless we determine that the foregoing consequences will continue to apply.

A non-U.S. Holder who owns (or is deemed to own) more than 5% of our units very likely will be subject to special rules under the Foreign Investment Real Property Act of 1980, and under those rules, a disposition of our units by such a non-U.S. Holder may be subject to U.S. federal income tax and return filing obligations. If you are a non-U.S. Holder and own or anticipate owning more than 5% of our units (either directly or indirectly), you should consult your tax advisors regarding the application of the foregoing rules to you.

The U.S. federal estate tax treatment of our units with regards to the estate of a non-U.S. citizen who is not a resident of the United States is not entirely clear. If our units are includable in the U.S. gross estate of such person, then a U.S. federal estate tax might be payable in connection with the death of such person. Individual non-U.S. Holders who are non-U.S. citizens and not residents of the United States should consult their own tax advisors concerning the potential U.S. federal estate tax consequences with regards to our units.

Administrative Matters

Tax Matters Partner

Our Managing General Partner will act as our partnership's "tax matters partner." As the tax matters partner, the Managing General Partner will have the authority, subject to certain restrictions, to act on our behalf in connection with any administrative or judicial review of our items of income, gain, loss, deduction or credit.

Information Returns

We have agreed to use commercially reasonable efforts to furnish to you, within 90 days after the close of each calendar year, tax information (including Schedule K-1), which describes on a U.S. dollar basis your share of our partnership's income, gain, loss and deduction for our preceding taxable year. In preparing this information, we will use various accounting and reporting conventions, some of which have been mentioned in the previous discussion, to determine your share of income, gain, loss and deduction. The IRS may successfully contend that certain of these reporting conventions are impermissible, which could result in an adjustment to your income or loss.

We may be audited by the IRS. Adjustments resulting from an IRS audit may require you to adjust a prior year's tax liability, and possibly may result in an audit of your own tax return. Any audit of your tax return could result in adjustments not related to our tax returns as well as those related to our tax returns.

Tax Shelter Regulations

If we were to engage in a "reportable transaction", we (and possibly you and others) would be required to make a detailed disclosure of the transaction to the IRS in accordance with recently issued regulations governing tax shelters and other potentially tax-motivated transactions. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a "listed transaction", or as a "transaction of interest", or that it produces certain kinds of losses in excess of $2 million. An investment in us may be considered a "reportable transaction" if, for example, we recognize certain significant losses in the future. In certain circumstances, a unitholder who disposes of an interest in a transaction resulting in the recognition by such holder of significant losses in excess of certain threshold amounts may be obligated to disclose its participation in such transaction. Our participation in a reportable transaction also could increase the likelihood that our U.S. federal income tax information return (and possibly your tax return) would be audited by the IRS. Certain of these rules are currently unclear, and the scope of reportable transactions can change retroactively, and, therefore, it is possible that they may be applicable in situations other than significant loss transactions.

Moreover, if we were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, you may be subject to (i) significant accuracy-related penalties with a broad scope, (ii) for those persons otherwise entitled to deduct interest on federal tax deficiencies, non-deductibility of interest on any resulting tax liability, and (iii) in the case of a listed transaction, an extended statute of limitations. We do not intend to participate in any reportable transaction with a significant purpose to avoid or evade tax, nor do we intend to participate in any listed transactions. However, no assurances can be made that the IRS will not assert that we have participated in such a transaction.

You should consult your own tax advisors concerning any possible disclosure obligation under the regulations governing tax shelters with respect to the disposition of our units held by you.

Taxable Year

Our partnership currently uses the calendar year as its taxable year for U.S. federal income tax purposes. Under certain circumstances which we currently believe are unlikely to apply, a taxable year other than the calendar year may be required for such purposes.

Constructive Termination

Subject to the electing large partnership rules described below, our partnership will be considered to have been terminated for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of our units within a 12-month period.

A termination of our partnership would result in the close of its taxable year for all holders of our units. If you report on a taxable year other than a fiscal year ending on our partnership's year-end, and you are otherwise subject to U.S. federal income tax, the closing of our partnership's taxable year may result in more than 12 months of our partnership's taxable income or loss being includable in your taxable income for the year of termination. Our partnership would be required to make new tax elections after a termination, including a new Section 754 Election. A termination could also result in penalties and other adverse tax consequences if we were unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject us to, any tax legislation enacted before the termination.

Elective Procedures for Large Partnerships

The U.S. Internal Revenue Code allows large partnerships to elect streamlined procedures for income tax reporting. This election would reduce the number of items that must be separately stated on the Schedules K-1 that are issued to the holders of our units, and such Schedules K-1 would have to be provided to holders on or before the first March 15 following the close of each taxable year. In addition, this election would prevent our partnership from suffering a "technical termination" (which would close our taxable year and require that we make a new Section 754 Election) if, within a 12-month period, there is a sale or exchange of 50% or more of our total units. Despite the foregoing benefits, there are also costs and administrative burdens associated with such an election. Consequently, our partnership may not elect to be subject to the reporting procedures applicable to large partnerships.

Backup and Other Administrative Withholding Issues

For each calendar year, we will report to you and to the IRS the amount of distributions that we pay, and the amount of tax (if any) that we withhold on these distributions. Under the backup withholding rules, you may be subject to backup withholding tax (at the applicable rate, currently 28%) with respect to distributions paid unless: (i) you are a corporation or come within another exempt category and demonstrate this fact when required or (ii) you provide a taxpayer identification number, certify as to no loss of exemption from backup withholding tax and otherwise comply with the applicable requirements of the backup withholding tax rules. If you are an exempt holder, you should indicate your exempt status on a properly completed IRS Form W-9. A Non-U.S. Holder may qualify as an exempt recipient by submitting a properly completed IRS Form W-8BEN. Backup withholding is not an additional tax; the amount of any backup withholding from a payment to you will be allowed as a credit against your U.S. federal income tax liability and may entitle you to a refund.

If you do not timely provide us with IRS Form W-9 or W-8, as applicable, or such form is not properly completed, we may become subject to U.S. "backup" withholding taxes in excess of what would have been imposed had our partnership received certifications from all investors. For administrative reasons, and in order to maintain fungibility of our units, such excess U.S. "backup" withholding taxes, and if necessary similar items, may be treated by our partnership as an expense that will be borne by all unitholders on a pro rata basis (e.g., since it may be impractical for us to allocate any such excess withholding tax cost to the unitholders that failed to timely provide the proper U.S. tax certifications).

Certain Effects of a Transfer of Units

Our partnership may allocate items of income, gain, loss, deduction and credit using a monthly or other convention, whereby any such items recognized in a given month by our partnership are allocated to our unitholders as of a specified date of such month. Any U.S. withholding taxes applicable to dividends received by Brookfield Infrastructure (and, in turn, our partnership) will generally be withheld by our partnership only when such dividends are paid. Because our partnership generally intends to distribute amounts received in respect of dividends shortly after receipt of such amounts, it is generally expected that any U.S. withholding taxes withheld by our partnership on such amounts will correspond to our unitholders who were allocated income and who received the distributions in respect of such amounts. Brookfield Infrastructure may invest in debt obligations or other securities for which the accrual of interest or income thereon is not matched by a contemporaneous receipt of cash. Any such accrued interest or other income would be allocated pursuant to the monthly convention described above. Consequently, our unitholders may recognize income in excess of cash distributions received from our partnership, and any income so included by a unitholder would increase the basis such unitholder has in our units and would offset any gain (or increase the amount of loss) realized by such unitholder on a subsequent disposition of its units. In addition, U.S. withholding taxes generally would be withheld by our partnership only on the payment of cash in respect of such accrued interest or other income, and, therefore, it is possible that some unitholder would be allocated income which may be distributed to a subsequent unitholder and such subsequent unitholder would be subject to withholding at the time of distribution. Consequently, the subsequent unitholder, and not the unitholder who was allocated income, would be entitled to claim any available credit with respect to such withholding.

Brookfield Infrastructure has invested and will continue to invest in certain Holding Entities and operating entities organized in non-U.S. jurisdictions, and income and gains from such investments may be subject to withholding and other taxes in such jurisdictions. If any such non-U.S. taxes are imposed on income allocable to a U.S. Holder, and, thereafter, such U.S. Holder disposed of its units prior to the date distributions are made in respect of such income, under applicable provisions of the U.S. Internal Revenue Code and U.S. Treasury Regulations, the unitholder to whom such income was allocated (and not the unitholder to whom distributions were ultimately made) would, subject to other applicable limitations, be the party permitted to claim a credit for such non-U.S. taxes for U.S. federal income tax purposes. Complex rules may, depending on a unitholder's particular circumstances, limit the availability or use of foreign tax credits, and investors are urged to consult their own tax advisors regarding all aspects of foreign tax credits.

Nominee Reporting

Persons who hold an interest in our partnership as a nominee for another person are required to furnish to us:

(a) the name, address and taxpayer identification number of the beneficial owner and the nominee;

(b) whether the beneficial owner is (1) a person that is not a U.S. person, (2) a foreign government, an international organization or any wholly-owned agency or instrumentality of either of the foregoing, or (3) a tax-exempt entity;

(c) the amount and description of units held, acquired or transferred for the beneficial owner; and

(d) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are U.S. persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the U.S. Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the units with the information furnished to us.

New Legislation or Administrative or Judicial Action

The U.S. federal income tax treatment of our unitholders depends in some instances on determinations of fact and interpretations of complex provisions of U.S. federal income tax law for which no clear precedent or authority may be available. You should be aware that the U.S. federal income tax rules, particularly those applicable to partnerships, are constantly under review (including currently) by the Congressional tax-writing committees and other persons involved in the legislative process, the IRS, the U.S. Treasury Department, and the courts, frequently resulting in revised interpretations of established concepts, statutory changes, revisions to regulations and other modifications and interpretations, any of which could adversely affect the value of our units and be effective on a retroactive basis. For example, changes to the U.S. federal tax laws and interpretations thereof could adversely affect the U.S. federal income tax treatment of publicly traded partnerships, including changes that make it more difficult or impossible for our partnership (or Brookfield Infrastructure) to meet the Qualifying Income Exception so as to be treated as a partnership for U.S. federal income tax purposes that is not taxable as a corporation and changes that reduce the net amount of distributions available to our unitholders. Such changes could also affect or cause us to change the way we conduct our activities, affect the tax considerations of an investment in our partnership, change the character or treatment of portions of our partnership's income (including changes that recharacterize certain allocations as potentially non-deductible fees) and adversely affect an investment in our units.

Our partnership's organizational documents and agreements permit our Managing General Partner to modify our limited partnership agreement from, time-to-time, without the consent of our unitholders, to address certain changes in U.S. federal income tax regulations, legislation or interpretation or to elect to treat our partnership as a corporation for U.S. tax purposes. In some circumstances, such revisions could have a material adverse impact on some or all of our unitholders.

THE FOREGOING DISCUSSION IS NOT INTENDED AS A SUBSTITUTE FOR CAREFUL TAX PLANNING. THE TAX MATTERS RELATING TO US AND OUR UNITHOLDERS ARE COMPLEX AND ARE SUBJECT TO VARYING INTERPRETATIONS. MOREOVER, THE EFFECT OF EXISTING INCOME TAX LAWS, THE MEANING AND IMPACT OF WHICH IS UNCERTAIN AND OF PROPOSED CHANGES IN INCOME TAX LAWS WILL VARY WITH THE PARTICULAR CIRCUMSTANCES OF EACH UNITHOLDER AND IN REVIEWING THIS PROSPECTUS THESE MATTERS SHOULD BE CONSIDERED. UNITHOLDERS SHOULD CONSULT THEIR TAX ADVISORS WITH RESPECT TO THE FEDERAL, STATE, LOCAL AND OTHER TAX CONSEQUENCES OF ANY INVESTMENT IN OUR UNITS.

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

The following is a fair summary of the principal Canadian federal income tax consequences of the holding and disposition of units in our partnership and who, for purposes of the Income Tax Act (Canada), or the Tax Act, holds our units as capital property and deals at arm's length with our partnership, Brookfield Infrastructure, the Managing General Partner, the Infrastructure General Partner, the Infrastructure GP LP and their respective affiliates. Generally, our units will be considered to be capital property to a holder, provided that the holder does not hold our units in the course of carrying on a business of trading or dealing in securities and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. This summary is not applicable to a holder that is a "financial institution" as defined in the Tax Act for purposes of the "mark-to-market" rules, a holder that is a "specified financial institution" as defined in the Tax Act, a holder to whom subsection 261(4) of the Tax Act applies, or a holder an interest in which is a “tax shelter investment” as defined in the Tax Act, or who acquires a unit as a tax shelter investment (and assumes that no such persons hold our units). Any such holders should consult their own tax advisors with respect to an investment in our units.

This summary is based on the current provisions of the Tax Act, the regulations thereunder, or the Regulations, all specific proposals to amend the Tax Act or the Regulations publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof, or the Tax Proposals, and the current published administrative and assessing policies and practices of the Canada Revenue Agency, or CRA. This summary assumes that all Tax Proposals will be enacted in the form proposed although no assurance can be given in this regard. This summary does not otherwise take into account or anticipate any changes in law, whether by judicial, administrative or legislative decision or action or changes in CRA’s administrative and assessing policies and practices, nor does it take into account provincial, territorial or foreign income tax legislation or considerations, which may differ from those described herein. This summary is not exhaustive of all possible Canadian federal income tax consequences that may affect prospective purchasers.

This summary assumes that neither our partnership nor Brookfield Infrastructure will be considered to carry on business in Canada. Our Managing General Partner and the Infrastructure General Partner have advised that they intend to conduct the affairs of each of these entities, to the extent possible, so that none of these entities should be considered to carry on business in Canada for purposes of the Tax Act. However, no assurance can be given in this regard.

Recently enacted rules (referred to herein as the SIFT Rules) will significantly change the taxation of most publicly traded trusts and partnerships and distributions or allocations, as the case may be, from these entities to their investors. Under the SIFT Rules, a “Canadian resident partnership” (within the meaning of the SIFT Rules), the units of which are listed or traded on a stock exchange or other “public market” (within the meaning of the SIFT Rules), and that holds one or more “non-portfolio properties” (within the meaning of the SIFT Rules), or a SIFT Partnership, would be taxed on the income (other than taxable dividends) or capital gains from such properties and on income from businesses carried on by the SIFT Partnership in Canada at a combined tax rate similar to that of a corporation, and allocations of such income to the partners would be taxed as dividends from a taxable Canadian corporation. This summary assumes that our partnership and Brookfield Infrastructure will at no relevant time be a SIFT Partnership on the basis that our partnership and Brookfield Infrastructure are not Canadian resident partnerships. There can be no assurance that the SIFT Rules will not be revised or amended such that the SIFT Rules will apply.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular holder of our units, and no representation with respect to the Canadian federal income tax consequences to any particular holder is made. Consequently, holders of our units are advised to consult their own tax advisors with respect to their particular circumstances.

TAXATION OF CANADIAN RESIDENT LIMITED PARTNERS

The following is a discussion of the consequences under the Tax Act to limited partners who at all relevant times are resident or deemed to be resident in Canada under the Tax Act, or Canadian Limited Partners.

Computation of Income or Loss

Each Canadian Limited Partner is required to include (or, subject to the “at-risk rules” discussed below, entitled to deduct) in computing his or her income for a particular taxation year the Canadian Limited Partner’s pro rata share of the income (or loss) of our partnership for its fiscal year ending in, or coincidentally with, the Canadian Limited Partner’s taxation year end, whether or not any of that income is distributed to the Canadian Limited Partner in the taxation year and regardless of whether our units were held throughout such year. Our partnership will not itself be a taxable entity and is not expected to be required to file an income tax return in

Canada. However, the income (or loss) of our partnership for a fiscal period for purposes of the Tax Act will be computed as if it were a separate person resident in Canada and our members will be allocated a share of that income (or loss) in accordance with our limited partnership agreement. The income (or loss) of our partnership will include our share of the income (or loss) of Brookfield Infrastructure for a fiscal year determined in accordance with Brookfield Infrastructure's limited partnership agreement. For this purpose, our partnership's fiscal year end and that of Brookfield Infrastructure will be December 31.

The income for tax purposes of our partnership for a given fiscal year of our partnership will be allocated to each unitholder in an amount calculated by multiplying such income that is allocable to unitholders by a fraction, the numerator of which is the sum of the distributions received by such unitholder with respect to such fiscal year and the denominator of which is the aggregate amount of the distributions made by our partnership to unitholders with respect to such fiscal year. Generally, the source and character of items of income allocated to a unitholder with respect to a fiscal year of our partnership will be the same source and character as the cash distributions received by such unitholder with respect to such fiscal year.

If, with respect to a given fiscal year, no distribution is made by our partnership to unitholders or our partnership has a loss for tax purposes, one quarter of the income, or loss, as the case may be, for tax purposes of our partnership for such fiscal year that is allocable to unitholders, will be allocated to the unitholders of record at the end of each calendar quarter ending in such fiscal year in the proportion that the number of units held at each such date by a unitholder is of the total number of units issued and outstanding at each such date. Generally, the source and character of such income or losses allocated to a unitholder at the end of each calendar quarter will be the same source and character as the income or loss earned or incurred by our partnership in such calendar quarter. The income of our partnership as determined for purposes of the Tax Act may differ from its income as determined for accounting purposes and may not be matched by cash distributions. In addition, for purposes of the Tax Act, all income of our partnership and Brookfield Infrastructure must be calculated in Canadian currency. Where our partnership (or Brookfield Infrastructure) holds investments denominated in U.S. dollars or other foreign currencies, gains and losses may be realized by our partnership as a consequence of fluctuations in the relative values of the Canadian and foreign currencies.

In computing the income (or loss) of our partnership, deductions may be claimed in respect of reasonable administrative costs, interest and other expenses incurred by our partnership for the purpose of earning income, subject to the relevant provisions of the Tax Act. Our partnership and Brookfield Infrastructure may be required to withhold and remit Canadian federal withholding tax on any management or administration fees or charges paid or credited to a non-resident person, to the extent that such management or administration fees or charges are deductible in computing our partnership's or Brookfield Infrastructure's income from a source in Canada.

In general, a Canadian Limited Partner's share of any income (or loss) from our partnership from a particular source will be treated as if it were income (or loss) of the Canadian Limited Partner from that source, and any provisions of the Tax Act applicable to that type of income (or loss) will apply to the Canadian Limited Partner. Our partnership will invest in limited partnership units of Brookfield Infrastructure. In computing our partnership's income (or loss) under the Tax Act, Brookfield Infrastructure will itself be deemed to be a separate person resident in Canada which computes its income (or loss) and allocates to its partners their respective share of such income (or loss). Accordingly, the source and character of amounts included in (or deducted from) the income of Canadian Limited Partners on account of income (or loss) earned by Brookfield Infrastructure generally will be determined by reference to the source and character of such amounts when earned by Brookfield Infrastructure. The characterization by CRA of gains realized by our partnership or Brookfield Infrastructure on the disposition of investments as either capital gains or income gains will depend largely on factual considerations, and no conclusions are expressed herein. However, the Managing General Partner and the Infrastructure General Partner advise that our partnership and Brookfield Infrastructure are not expected to realize significant gains or losses from dispositions of investments.

A Canadian Limited Partner's share of taxable dividends received or considered to be received by our partnership in a fiscal year from a corporation resident in Canada will be treated as a dividend received by the Canadian Limited Partner and will be subject to the normal rules in the Tax Act applicable to such dividends, including the enhanced dividend gross up and tax credit for eligible dividends when the dividend received by Brookfield Infrastructure is designated as an eligible dividend.

Foreign taxes paid by our partnership or Brookfield Infrastructure and taxes withheld at source (other than for the account of a particular Canadian Limited Partner) will be allocated pursuant to the governing partnership agreement. Each Canadian Limited Partner's share of the business-income tax and non-business-income tax paid in a foreign country for a year will be creditable against its Canadian federal income tax liability to the extent permitted by the detailed rules contained in the Tax Act. Although the foreign tax credit provisions are designed to avoid double taxation, the maximum credit is limited. Because of this, and because of timing differences in recognition of expenses and income and other factors, there is a risk of double taxation.

Our partnership and Brookfield Infrastructure will be deemed to be a non-resident person in respect of amounts paid or credited to them by a person resident or deemed to be resident in Canada, including dividends or interest. Dividends or interest (other than interest exempt from withholding tax) paid by a person resident or deemed to be resident in Canada to Brookfield Infrastructure will be subject to withholding tax under Part XIII of the Tax Act at the rate of 25%. Pursuant to recent amendments made by the "Fifth Protocol" to the Canada—U.S. Tax Treaty, a Canadian resident payer may be required to look-through fiscally transparent partnerships such as our partnership and Brookfield Infrastructure to the residency of limited partners of our partnership who are entitled to relief under that treaty and take into account reduced rates of Canadian federal withholding tax that such limited partners may be entitled to under that treaty. In determining the rate of Canadian federal withholding tax applicable to amounts paid by the Holding Entities to Brookfield Infrastructure, we expect the Holding Entities to look-through Brookfield Infrastructure and our partnership to the residency of the partners of our partnership (including partners who are residents of Canada) and to take into account any reduced rates of withholding tax that Non-Canadian Limited Partners may be entitled to under an applicable income tax treaty or convention in order to determine the appropriate amount of Canadian federal withholding tax to withhold from dividends or interest paid to Brookfield Infrastructure. However, there can be no assurance that CRA would apply its administrative practice in this context.

If our partnership incurs losses for tax purposes, each Canadian Limited Partner will, subject to the REOP Proposals discussed below, be entitled to deduct in the computation of income for tax purposes the Canadian Limited Partner's pro rata share of any net losses for tax purposes of our partnership for its fiscal year to the extent that the Canadian Limited Partner's investment is "at-risk" within the meaning of the Tax Act. The Tax Act contains "at-risk rules" which may, in certain circumstances, restrict the deduction of a limited partner's share of any losses of a limited partnership. Our Managing General Partner and the Infrastructure General Partner do not anticipate that our partnership or Brookfield Infrastructure will incur losses but no assurance can be given in this regard. Accordingly, Canadian Limited Partners should consult their own tax advisors for specific advice with respect to the potential application of the "at-risk rules".

On October 31, 2003, the Department of Finance released for public comment Tax Proposals, or the REOP Proposals, regarding the deductibility of interest and other expenses for purposes of the Tax Act. Under the REOP Proposals, a taxpayer would be considered to have a loss from a source that is a business or property for a taxation year only if, in that year, it is reasonable to assume that the taxpayer will realize a cumulative profit (excluding capital gains or losses) from the business or property during the period that the business is carried on or that the property is held. In general, these proposals may deny the realization of losses by Canadian Limited Partners from their investment in our partnership in a particular taxation year, if, in the year the loss is claimed, it is not reasonable to expect that an overall cumulative profit would be earned from the investment in our partnership for the period in which the Canadian Limited Partner has held and can reasonably be expected to hold the investment. Our Managing General Partner and the Infrastructure General Partner do not anticipate that the activities of our partnership and Brookfield Infrastructure will, in and of themselves, generate losses, but no assurance can be given in this regard. However, unitholders may incur expenses in connection with an acquisition of units in our partnership that could result in a loss that could be affected by the REOP Proposals.

The REOP Proposals have been the subject of a number of submissions to the Minister of Finance (Canada). As part of the 2005 federal budget, the Minister of Finance (Canada) announced that an alternative proposal to reflect the REOP Proposals would be released for comment at an early opportunity. No such alternative proposal has been released to date. There can be no assurance that such alternative proposal will not adversely affect Canadian Limited Partners, or that any revised proposals may not differ significantly from the REOP Proposals described herein. On November 9, 2006, the Minister of Finance (Canada) introduced revised proposed amendments to the Tax Act relating to foreign investment entities, referred to as the FIE Proposals, that will, if enacted, apply to taxation years that begin after 2006. In the 2009 Federal Budget the government announced it was reviewing the FIE Proposals in light of submissions it had received. Each of the defined terms used in this paragraph are as defined in the FIE Proposals. The FIE Proposals generally require a taxpayer (other than an "exempt taxpayer" as defined in the FIE Proposals) that holds a "participating interest" (other than an "exempt interest") in a "foreign investment entity" to include in income annually as income from property an amount determined by multiplying the "designated cost" of the participating interest by the prescribed rate of interest under the Tax Act from time-to-time unless the taxpayer makes a valid election to use either the "accrual method" or the "mark-to-market" method (which election is unlikely to be available in the case of our partnership or Brookfield Infrastructure because of the nature of their investments). Under the FIE Proposals, our units will be an exempt interest and therefore will not be subject to the FIE Proposals. Our partnership's interest in Brookfield Infrastructure will also be an exempt interest.

However, in computing income for Canadian federal income tax purposes, Brookfield Infrastructure will be subject to the FIE Proposals with respect to any interest that is a participating interest in a foreign investment entity (other than an exempt interest) or a tracked interest. For these purposes, an exempt interest includes an interest in a corporation that is a "controlled foreign affiliate" as defined in the Tax Act.

Each of the foreign subsidiaries that will be directly owned by Brookfield Infrastructure, collectively referred to as the controlled foreign affiliates, or CFAs, is expected to be a "foreign affiliate" and a "controlled foreign affiliate", and not a "tracked interest", each as defined in the Tax Act and the FIE Proposals, of Brookfield Infrastructure. Accordingly, the interest of Brookfield Infrastructure in the CFAs would not be subject to the FIE Proposals. However, if any of the CFAs becomes a tracked interest or ceases to be a CFA of Brookfield Infrastructure or if Brookfield Infrastructure acquires an interest in a foreign subsidiary that is a tracked interest or acquires an interest in a foreign subsidiary that is not a CFA, then Brookfield Infrastructure's investment in such CFA or other foreign subsidiary would be subject to the FIE Proposals, unless another exemption is available. Canadian Limited Partners to whom the application of the FIE Proposals may be relevant are advised to consult their own tax advisors for the potential consequences of the application of these proposals having regard to such Canadian Limited Partners' particular circumstances.

Dividends paid by the CFAs to Brookfield Infrastructure will be included in computing the income of Brookfield Infrastructure. To the extent that any of the CFAs or any direct or indirect subsidiary thereof earns income that is characterized as "foreign accrual property income" as defined in the Tax Act, or FAPI, in a particular taxation year of the CFA, the FAPI allocable to Brookfield Infrastructure must be included in computing the income of Brookfield Infrastructure for Canadian federal income tax purposes for the fiscal period of Brookfield Infrastructure in which the taxation year of that CFA ends, whether or not Brookfield Infrastructure actually receives a distribution of that FAPI. If an amount of FAPI is included in computing the income of Brookfield Infrastructure for Canadian federal income tax purposes, an amount may be deductible in respect of the "foreign accrual tax" as defined in the Tax Act applicable to the FAPI. Any amount of FAPI included in income net of the amount of any deduction in respect of foreign accrual tax will increase the adjusted cost base to Brookfield Infrastructure of its shares of the particular CFA in respect of which the FAPI was included. At such time as Brookfield Infrastructure receives a dividend of this type of income that was previously treated as FAPI, that dividend will effectively not be taxable to Brookfield Infrastructure and there will be a corresponding reduction in the adjusted cost base to Brookfield Infrastructure of the particular CFA shares.

Disposition of Our Units

The disposition by a Canadian Limited Partner of a unit of our partnership will result in the realization of a capital gain (or capital loss) by such limited partner. The amount of such capital gain (or capital loss) will generally be the amount, if any, by which the proceeds of disposition of a unit, less any reasonable costs of disposition, exceed (or are exceeded by) the adjusted cost base of such unit. In general, the adjusted cost base of a Canadian Limited Partner's units will be equal to (i) the actual cost of the units (excluding any portion thereof financed with limited recourse indebtedness), plus (ii) the pro rata share of the income of our partnership allocated to the Canadian Limited Partner for the fiscal years of our partnership ending before the relevant time less (iii) the aggregate of the pro rata share of losses of our partnership allocated to the Canadian Limited Partner (other than losses which cannot be deducted because they exceed the Canadian Limited Partner's "at-risk" amount) for the fiscal years of our partnership ending before the relevant time and the Canadian Limited Partner's distributions from our partnership made before the relevant time. The adjusted cost base of each of our units will be subject to the averaging provisions contained in the Tax Act.

Where a Canadian Limited Partner disposes of all of its units, such person will no longer be a partner of our partnership. If, however, a Canadian Limited Partner is entitled to receive a distribution from our partnership after the disposition of all such units, then the Canadian Limited Partner will be deemed to dispose of the units at the later of: (i) the end of the fiscal year of our partnership during which the disposition occurred; and (ii) the date of the last distribution made by our partnership to which the Canadian Limited Partner was entitled. Pursuant to the Tax Proposals, the pro rata share of the income (or loss) for tax purposes of our partnership for a particular fiscal year which is allocated to a Canadian Limited Partner who has ceased to be a partner will generally be added (or deducted) in the computation of the adjusted cost base of the Canadian Limited Partner's units at the time of the disposition. These rules are complex and Canadian Limited Partners should consult their own tax advisors for advice with respect to the specific tax consequences to them of disposing of units of our partnership.

A Canadian Limited Partner will realize a deemed capital gain if, and to the extent that, the adjusted cost base of the Canadian Limited Partner's units is negative at the end of any fiscal year of our partnership. In such a case, the adjusted cost base of the Canadian Limited Partner's units will be nil at the beginning of the next fiscal year of our partnership.

In general, one-half of a capital gain realized by a Canadian Limited Partner must be included in computing such limited partner's income as a taxable capital gain. Where a Canadian Limited Partner disposes of units to a tax-exempt person, more than one-half of such capital gain may be treated as a taxable capital gain if any portion of the gain is attributable to an increase in value of depreciable property held by Brookfield Infrastructure. Canadian Limited Partners contemplating such dispositions should consult their own advisors. The Infrastructure General Partner has advised that it does not expect that Brookfield Infrastructure will hold any depreciable property and therefore expects that only one-half of any capital gains arising from a disposition of our units should be treated as taxable capital gains. One-half of a capital loss is deducted as an allowable capital loss against taxable capital gains realized in the year and any remainder may be deducted against taxable capital gains in any of the three years preceding the year or any year following the year to the extent and under the circumstances described in the Tax Act.

A Canadian Limited Partner that is throughout the relevant taxation year a "Canadian-controlled private corporation" as defined in the Tax Act may be liable to pay an additional refundable tax of 6⅔% on its "aggregate investment income", as defined in the Tax Act, for the year, which is defined to include taxable capital gains.

Eligibility for Investment

Units of our partnership should be "qualified investments" under the Tax Act for trusts governed by registered retirement savings plans, deferred profit sharing plans, registered retirement income funds, registered education savings plans, registered disability savings plans and, commencing in 2009, tax-free savings accounts provided that our units are listed on a designated stock exchange (which would include the NYSE). In certain limited circumstances Units of our partnership might not be a qualified investment. You should consult with a tax advisor in respect of your ownership of Units of our partnership.

TAXATION OF NON-CANADIAN LIMITED PARTNERS

The following summary applies to holders who at all relevant times are not resident and are not deemed to be resident in Canada for purposes of the Tax Act and who do not acquire or hold their investment in our partnership in connection with a business carried on, or deemed to be carried on, in Canada, each a Non-Canadian Limited Partner. The following summary assumes that our units are not "taxable Canadian property" as defined in the Tax Act and that our partnership and Brookfield Infrastructure generally will not dispose of properties that are taxable Canadian property (which includes, but is not limited to, property that is used or held in a business carried on in Canada, shares of corporations resident in Canada that are not listed on a designated stock exchange and listed shares where the number of shares owned exceeds prescribed amounts). Our units will be taxable Canadian property if, at any time within the 60-month period ending at the time of disposition or deemed disposition, the fair market value of all of the properties of our partnership that were taxable Canadian property, certain types of resource properties, income interests in trusts resident in Canada or interests in or options in respect thereof, was greater than 50% of the fair market value of all of its properties. Our Managing General Partner and the Infrastructure General Partner advise that our units are not expected to be taxable Canadian property and that our partnership and Brookfield Infrastructure are not expected to dispose of taxable Canadian property. However, no assurance can be given in this regard.

Taxation of Income or Loss

A Non-Canadian Limited Partner will not be subject to Canadian federal income tax under Part I of the Tax Act on its share of income from a business carried on by our partnership (or Brookfield Infrastructure) outside Canada or the non-business income earned by our partnership (or Brookfield Infrastructure) from sources in Canada. However, a Non-Canadian Limited Partner may be subject to Canadian federal withholding tax under Part XIII of the Tax Act, as described below. Our Managing General Partner and the Infrastructure General Partner, as the case may be, have advised that they intend to organize and conduct the affairs of our partnership or Brookfield Infrastructure such that Non-Canadian Limited Partners should not be considered to be carrying on business in Canada solely by virtue of their investment in our partnership. However, no assurance can be given in this regard.

Our partnership and Brookfield Infrastructure will be deemed to be a non-resident person in respect of certain amounts paid or credited to them by a person resident or deemed to be resident in Canada, including dividends or interest. Dividends or interest (other than interest exempt from withholding tax) paid by a person resident or deemed to be resident in Canada to Brookfield Infrastructure will be subject to withholding tax under Part XIII of the Tax Act at the rate of 25%. Pursuant to recent amendments made by the "Fifth Protocol" to the Canada-U.S. Tax Treaty, a Canadian resident payer may be required to look-through fiscally transparent partnerships such as our partnership and Brookfield Infrastructure to the residency of limited partners of our partnership who are entitled to relief under that treaty and take into account reduced rates of Canadian federal withholding tax that such limited partners may be entitled to under that treaty. In determining the rate of Canadian federal withholding tax applicable to amounts paid by the Holding Entities to Brookfield Infrastructure, we expect the Holding Entities to look-through Brookfield Infrastructure and our partnership to the residency of the partners of our partnership (including partners who are residents of Canada) and to take into account any reduced rates of withholding tax that Non-Canadian Limited Partners may be entitled to under an applicable income tax treaty or convention in order to determine the appropriate amount of Canadian federal withholding tax to withhold from dividends or interest paid to Brookfield Infrastructure. However, there can be no assurance that CRA would apply its administrative practice in this context.

BERMUDA TAX CONSIDERATIONS

In Bermuda there are no taxes on profits, income or dividends, nor is there any capital gains tax, estate duty or death duty. Profits can be accumulated and it is not obligatory to pay dividends. As "exempted undertakings", exempted partnerships and overseas partnerships are entitled to apply for (and will ordinarily receive) an assurance pursuant to the Exempted Undertakings Tax Protection Act 1966 that, in the event that legislation introducing taxes computed on profits or income, or computed on any capital asset, gain or appreciation, is enacted, such taxes shall not be applicable to the partnership or any of its operations until March 28, 2016. Such an assurance may include the assurance that any tax in the nature of estate duty or inheritance tax shall not be applicable to the units, debentures or other obligations of the partnership.

Exempted partnerships and overseas partnerships fall within the definition of "international businesses" for the purposes of the Stamp Duties (International Businesses Relief) Act 1990, which means that instruments executed by or in relation to an exempted partnership or an overseas partnership are exempt from stamp duties (such duties were formerly applicable under the Stamp Duties Act 1976). Thus, stamp duties are not payable upon, for example, an instrument which effects the transfer or assignment of a unit in an exempted partnership or an overseas partnership, or the sale or mortgage of partnership assets; nor are they payable upon the partnership capital.

10.F DIVIDENDS AND PAYING AGENTS

Not applicable.

10.G STATEMENT BY EXPERTS

Not applicable.

10.H DOCUMENTS ON DISPLAY

Any statement in this Form 20-F about any of our contracts or other documents is not necessarily complete. If the contract or document is filed as an exhibit to the Form 20-F the contract or document is deemed to modify the description contained in this Form 20-F. You must review the exhibits themselves for a complete description of the contract or document.

Brookfield Asset Management and our partnership are both subject to the information filing requirements of the Exchange Act, and accordingly are required to file periodic reports and other information with the SEC. As a foreign private issuer under the SEC's regulations, we file annual reports on Form 20-F and other reports on Form 6-K. The information disclosed in our reports may be less extensive than that required to be disclosed in annual and quarterly reports on Forms 10-K and 10-Q required to be filed with the SEC by U.S. issuers.

Moreover, as a foreign private issuer, we are not subject to the proxy requirements under Section 14 of the Exchange Act, and our directors and principal shareholders are not subject to the insider short swing profit reporting and recovery rules under Section 16 of the Exchange Act. Our and Brookfield Asset Management's SEC filings are available at the SEC's website at www.sec.gov. You may also read and copy any document we or Brookfield Asset Management files with the SEC at the public reference facilities maintained by the SEC at SEC Headquarters, Public Reference Section, 100 F Street, N.E., Washington D.C. 20549. You may obtain information on the operation of the SEC's public reference facilities by calling the SEC at 1-800-SEC-0330.

In addition, Brookfield Asset Management and our partnership are required to file documents required by Canadian securities laws electronically with Canadian securities regulatory authorities and these filings are available on our or Brookfield Asset Management's SEDAR profile at www.sedar.com. Written requests for such documents should be directed to our Corporate Secretary at Cannon's Court, 22 Victoria Street, Hamilton HM 12, Bermuda.

10.I SUBSIDIARY INFORMATION

Not applicable.

ITEM 11. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT NON-PRODUCT RELATED MARKET RISK

See the information contained in this Form 20-F under Item 5 “Operating and Financial Review and Prospects.”

ITEM 12. DESCRIPTION OF SECURITIES OTHER THAN EQUITY SECURITIES

Not applicable.

PART II

ITEM 13. DEFAULTS, DIVIDEND ARREARAGES AND DELINQUENCIES

None.

ITEM 14. MATERIAL MODIFICATIONS TO THE RIGHTS OF SECURITY HOLDERS AND USE OF PROCEEDS

None.

ITEM 15. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2008, an evaluation of the effectiveness of our "disclosure controls and procedures" (as defined in Rules 13a-15(e) and 15d-15(e) of the United States Securities Exchange Act of 1934 (the "Exchange Act")) was carried out under the supervision and with the participation of persons performing the functions of principal executive and principal financial officers for us and our Manager. Based upon that evaluation, the persons performing the functions of principal executive and principal financial officers for us have concluded that, as of December 31, 2008, our disclosure controls and procedures were effective: (i) to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms; and (ii) to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including the persons performing the functions of principal executive and principal financial officers for us, to allow timely decisions regarding required disclosure.

It should be noted that while our management, including persons performing the functions of principal executive and principal financial officers for us, believe our disclosure controls and procedures provide a reasonable level of assurance that such controls and procedures are effective, they do not expect that our disclosure controls and procedures or internal controls will prevent all error and all fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Management's Annual Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including persons performing the functions of principal executive and principal financial officers for us, we conducted an evaluation of the effectiveness of our internal control over financial reporting using the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our evaluation under the framework in Internal Control—Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2008.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by Deloitte & Touche, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Changes in Internal Control

There was no change in our internal control over financial reporting during the year ended December 31, 2008, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 16A. AUDIT COMMITTEE FINANCIAL EXPERT

Our Managing General Partner's board of directors has determined that Danesh Varma possesses specific accounting and financial management expertise and that he is an audit committee financial expert as defined by the U.S. Securities and Exchange Commission and is independent within the meaning of the rules of the NYSE. Our Managing General Partner's Board has also determined that other members of the Audit Committee have sufficient experience and ability in finance and compliance matters to enable them to adequately discharge their responsibilities.

ITEM 16B. CODE OF ETHICS

On December 4, 2007, our Managing General Partner adopted a Code of Conduct and Ethics (the "Code") that applies to the members of the board of directors of the Managing General Partner, our partnership and any officers or employees of the Managing General Partner. We have posted a copy of the Code on our website at *www.brookfieldinfrastructure.com/aboutus/governance.*

ITEM 16C. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our Managing General Partner has retained Deloitte & Touche LLP to act as our partnership's and Brookfield Infrastructure's independent accountants.

The table below summarizes the fees for professional services rendered by Deloitte & Touche LLP for the audit of our annual financial statements for the periods ended December 31, 2007 and 2008.

	December 31, 2008		December 31, 2007	
THOUSANDS	**USD**	**%**	**USD**	**%**
Audit fees	**$878**	**100%**	$200	100%
Tax fees	**—**	**—**	—	—
Audit-related fees	**—**	**—**	—	—
Total	**$878**	**100%**	$200	100%

The audit committee of the Managing General Partner pre-approves all audit and non-audit services provided to our partnership and Brookfield Infrastructure by Deloitte & Touche LLP. In connection with the original registration statement all fees paid to Deloitte & Touche LLP were paid by Brookfield Asset Management Inc., and as such have not been disclosed by our partnership.

ITEM 16D. EXEMPTIONS FROM THE LISTING STANDARDS FOR AUDIT COMMITTEE

None.

ITEM 16E. PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PURCHASER

Our partnership may from time-to-time, subject to applicable law, purchase our units for cancellation in the open market, provided that any necessary approval has been obtained.

Brookfield has also advised our partnership that it may from time-to-time, subject to applicable law, purchase our units in the market without making an offer to all unitholders.

On November 3, 2008, our Managing General Partner's board of directors authorized our partnership to purchase for cancellation up to $25 million of our units though the facilities of NYSE, subject to a regulatory limit of 1,167,043 Units in the aggregate. Such purchases are authorized for the period beginning on November 10, 2008 and ending on November 9, 2009, or earlier should our partnership complete its purchases prior to such date. All such purchases are subject to compliance with applicable United States federal securities laws, including Rule 10b-18 under the United States Securities Exchange Act of 1934, as amended, as well as applicable Canadian securities laws. The following table sets forth the number of units of our partnership purchased and cancelled pursuant to the above program for the periods indicated.

Period	Total number of units purchased	Average price paid per unit *(US$)*	Total number of units purchased as part of publicly announced plans or programs	Approximate dollar value of units that may yet be purchased under the program *(US$ MILLIONS)*
November 10, 2008 to November 30, 2008	52,300	$11.02	52,300	$24.4
December 1, 2008 to December 31, 2008	128,302	11.06	128,302	23.0
January 1, 2009 to January 31, 2009	Nil	N/A	Nil	N/A
February 1, 2009 to February 28, 2009	91,100	12.80	91,100	21.8
March 1, 2009, to March 31, 2009	582,900	11.28	582,900	15.3

ITEM 16F. CHANGE IN REGISTRANT'S CERTIFYING ACCOUNTANT

Not Applicable

ITEM 16G. CORPORATE GOVERNANCE

Our corporate practices are not materially different than those required of domestic companies under the NYSE listing standards.

PART III

ITEM 17. FINANCIAL STATEMENTS

Not applicable.

ITEM 18. FINANCIAL STATEMENTS

See the list of financial statements on page F-1 which are filed as part of this annual report on Form 20-F.

ITEM 19. EXHIBITS

Number	Description
1.1	Certificate of registration of Brookfield Infrastructure Partners L.P., registered as of May 29, 2007—incorporated by reference to Exhibit 1.1 to our Partnership's Registration Statement on Form 20-F filed July 31, 2007. (With regard to applicable cross-references in this report, our Partnership's registration statement was filed with the SEC under File No. 1-33632).
1.2	Amended and Restated Limited Partnership Agreement of Brookfield Infrastructure Partners L.P., dated December 4, 2007—incorporated by reference to Exhibit 1.2 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
2.1	Equity Commitment, dated December 4, 2007, by and among Brookfield Asset Management Inc., Brookfield Infrastructure Partners L.P. and Brookfield Infrastructure L.P.—incorporated by reference to Exhibit 2.1 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.1	Second Amended and Restated Limited Partnership Agreement for Brookfield Infrastructure L.P., dated December 4, 2007—incorporated by reference to Exhibit 4.1 to our Partnership's Registration Statement on Form 20-F/A filed December 18, 2007.
4.2	Master Services Agreement, dated December 4, 2007, by and among Brookfield Asset Management Inc., Brookfield Infrastructure Partners L.P., Brookfield Infrastructure L.P., Brookfield Infrastructure Holdings (Canada) Inc. and Brookfield Asset Management Barbados Inc. and others—incorporated by reference to Exhibit 4.2 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.3	Relationship Agreement, dated December 4, 2007, by and among Brookfield Infrastructure Partners L.P., Brookfield Infrastructure Group Inc., Brookfield Infrastructure L.P., Brookfield Infrastructure Group Corporation and Brookfield Asset Management Inc. and others—incorporated by reference to Exhibit 4.3 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.4	Registration Rights Agreement, dated December 4, 2007, between Brookfield Infrastructure Partners L.P. and Brookfield Asset Management Inc.—incorporated by reference to Exhibit 4.4 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.5	Trademark Sublicense Agreement, effective as of May 21, 2007, between Brookfield Infrastructure Partners L.P. and Brookfield Global Asset Management Inc.—incorporated by reference to Exhibit 4.5 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.6	Master Purchase Agreement, dated June 18, 2007, between Brookfield Infrastructure Partners Limited and Brookfield Asset Management Inc.—incorporated by reference to Exhibit 4.6 to our Partnership's Registration Statement on Form 20-F filed July 31, 2007.
4.7	Trademark Sublicense Agreement, effective as of August 17, 2007, between Brookfield Infrastructure L.P. and Brookfield Global Asset Management Inc.—incorporated by reference to Exhibit 4.8 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.

Number	Description
4.8	Securities Purchase Agreement, dated November 19, 2007, between Brookfield Asset Management Inc. and Brookfield Infrastructure Holdings (Canada) Inc.—incorporated by reference to Exhibit 4.9 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.9	Securities Purchase Agreement, dated November 16, 2007, between Brookfield Asset Management Inc. and BIP Bermuda Holdings III Limited—incorporated by reference to Exhibit 4.10 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.10	Securities Purchase Agreement, dated November 20, 2007, between Brookfield Longview Holdings LLC and Brookfield Infrastructure Corporation—incorporated by reference to Exhibit 4.11 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.11	Debt Purchase Agreement, dated November 20, 2007, between Brascan (US) Corporation and Brookfield Infrastructure Corporation—incorporated by reference to Exhibit 4.12 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.12	English summary of the Amended and Restated Payment-in-Kind Agreement, dated November 5, 2007, between Brascan Brasil Ltda. and Brookfield Brasil TBE Participações Ltda.—incorporated by reference to Exhibit 4.13 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.13	Asset Purchase Agreement dated December 11, 2007, between Great Lakes Power Limited and Great Lakes Power Transmission LP—incorporated by reference to Exhibit 4.14 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.14	Agreement Relating to the Indirect Acquisition of Longview, dated December 4, 2007, between Brookfield Infrastructure Corporation and Brookfield Asset Management Inc.—incorporated by reference to Exhibit 4.15 to our Partnership's Registration Statement on Form 20-F/A filed December 13, 2007.
4.15	Credit Agreement, dated June 13, 2008, between Brookfield Infrastructure L.P. and Citibank, N.A., Credit Suisse, Toronto Branch, HSBC Bank Canada, HSBC Bank U.S.A., N.A., Toronto Branch, Royal Bank of Canada and The Royal Bank of Scotland plc.—incorporated by reference to Exhibit 4.16 to our Partnership's Annual Report on Form 20-F filed June 30, 2008 (with regard to applicable cross-references in this report, our Partnership's Annual Report on Form 20-F filed on June 30, 2008 was filed with the SEC under File No. 001-33632).
4.16	Amendment to Second Amended and Restated Limited Partnership Agreement of Brookfield Infrastructure L.P. dated June 13, 2008 by Brookfield Infrastructure General Partner Limited—incorporated by reference to Exhibit 4.17 to our Partnership's Annual Report on Form 20-F filed June 30, 2008.
4.17	Amendment to Amended and Restated Limited Partnership Agreement, dated June 13, 2008 by Brookfield Infrastructure Partners L.P.—incorporated by reference to Exhibit 4.18 to our Partnership's Annual Report on Form 20-F filed June 30, 2008.
12.1	Certification of Samuel Pollock, Chief Executive Officer, Brookfield Infrastructure Group Corporation, pursuant to Section 302 of the Sarbanes Oxley Act of 2002.*
12.2	Certification of John Stinebaugh, Chief Financial Officer, Brookfield Infrastructure Group Corporation, pursuant to Section 302 of the Sarbanes Oxley Act of 2002.*
13.1	Certification of Samuel Pollock, Chief Executive Officer, Brookfield Infrastructure Group Corporation, pursuant to 18 U.S.C. Section 1350, as adopted to Section 906 of the Sarbanes Oxley Act of 2002.*
13.2	Certification of John Stinebaugh, Chief Financial Officer, Brookfield Infrastructure Group Corporation, pursuant to 18 U.S.C. Section 1350, as adopted to Section 906 of the Sarbanes Oxley Act of 2002.*

* Filed electronically herewith.

SIGNATURE

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this registration statement on its behalf.

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.
by its general partner, Brookfield Infrastructure Partners Limited

Dated: April 24, 2009

By: /s/ ALEX ERSKINE
Name: Alex Erskine
Title: Director

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.

As of December 31, 2008 and December 31,2007 and for the year ended December 31, 2008 and for the period from May 21, 2007 (inception) to December 31, 2007.

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Partners of

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.

We have audited the accompanying balance sheets of Brookfield Infrastructure Partners L.P. (the "Partnership") as of December 31, 2008 and 2007, and the related statements of operations, other comprehensive income, accumulated other comprehensive income, partnership capital and of cash flows for the year ended December 31, 2008 and for the period from May 21, 2007 (inception) to December 31, 2007. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2008 and 2007, and the results of its operations and its cash flows for the year ended December 31, 2008 and for the period from May 21, 2007 (inception) to December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2009 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

Independent Registered Chartered Accountants
Licensed Public Accountants
Deloitte & Touche LLP

Toronto, Canada
March 15, 2009

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Partners of Brookfield Infrastructure Partners L.P.

We have audited the internal control over financial reporting of Brookfield Infrastructure Partners L.P. (the "Partnership") as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the financial statements as of and for the year ended December 31, 2008 of the Partnership and our report dated March 15, 2009 expressed an unqualified opinion on those financial statements.

Independent Registered Chartered Accountants
Licensed Public Accountants

Deloitte & Touche LLP

Toronto, Canada
March 15, 2009

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.

As of December 31, 2008 and 2007

BALANCE SHEETS

US$ MILLIONS	2008	2007
ASSETS		
Equity accounted investment (Note 3)	**$546.5**	$544.7
Total assets	**546.5**	544.7
Liabilities and partnership capital		
Accumulated other comprehensive income	**8.6**	1.3
Partnership capital (Note 4)	**537.9**	543.4
Total liabilities and partnership capital	**$546.5**	$544.7

The accompanying notes are an integral part of these financial statements.

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.

For the year ended December 31, 2008 and for the period from May 21, 2007 (inception) to December 31, 2007

STATEMENTS OF OPERATIONS

US$ MILLIONS (EXCEPT PER UNIT INFORMATION)	**2008**	**2007**[(1)]
Earnings from equity accounted investment	**$16.8**	$ 0.7
Net income	**$16.8**	$ 0.7
Earnings per unit *(Note 5)*		
Basic and diluted	**$0.72**	$—

(1) Figures are since inception, May 21, 2007.

The accompanying notes are an integral part of these financial statements.

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.

For the year ended December 31, 2008 and for the period from May 21, 2007 (inception) to December 31, 2007

STATEMENTS OF OTHER COMPREHENSIVE INCOME

US$ MILLIONS	**2008**	**2007**
Net income	**$ 16.8**	$ 0.7
Other comprehensive income (loss)		
Foreign currency translation (loss) gain	**(42.2)**	1.3
Net gains on related hedging items	**49.5**	—
Other comprehensive income	**7.3**	1.3
Comprehensive income	**$ 24.1**	$ 2.0

STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

US$ MILLIONS	**2008**	**2007**
Accumulated other comprehensive income, opening	**$ 1.3**	$ —
Other comprehensive income	**7.3**	1.3
Accumulated other comprehensive income, closing	**$ 8.6**	$ 1.3

STATEMENTS OF PARTNERSHIP CAPITAL

US$ MILLIONS	**2008**	**2007**
Partnership capital, opening	**$543.4**	$542.7
Repurchase of units during the period	**(2.0)**	—
Distributions to unitholders	**(20.3)**	—
Net income for the period	**16.8**	0.7
Partnership capital, closing	**$537.9**	$543.4

The accompanying notes are an integral part of these financial statements.

BROOKFIELD INFRASTRUCTURE PARTNERS L.P.

For the year ended December 31, 2008 and for the period from May 21, 2007 (inception) to December 31, 2007

STATEMENTS OF CASH FLOWS

US$ MILLIONS	2008	2007
Operating activities		
Net income	**$ 16.8**	$ 0.7
Distributions from equity accounted investment	**22.3**	—
Adjustments for non-cash items:		
Earnings from equity accounted investment	**(16.8)**	(0.7)
Cash from operating activities	**22.3**	—
Financing activities		
Distributions to unitholders	**$(20.3)**	$—
Repurchase of units during the year	**(2.0)**	—
Cash used in financing activities	**$(22.3)**	$—
Cash and equivalents		
Change during the period	**—**	—
Balance, beginning of period	**—**	—
Balance, end of period	**$ —**	$—

The accompanying notes are an integral part of these financial statements.

NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND DESCRIPTION OF THE BUSINESS

Brookfield Infrastructure Partners L.P. (the “Partnership” or “BIP”) was formed as a limited partnership established under the laws of Bermuda, pursuant to a limited partnership agreement dated May 21, 2007 as amended and restated. BIP holds a 60% interest in Brookfield Infrastructure L.P. (“Brookfield Infrastructure”), a partnership that has interests in electricity transmission, timber and social infrastructure operations in North and South America, United Kingdom and Australia. Effective January 31, 2008, BIP’s limited partnership units have traded under the symbol “BIP” on the NYSE.

Because BIP does not hold a controlling interest in Brookfield Infrastructure and because of the Financial Accounting Standards Board (“FASB”) Interpretation No. 46, (Revised December 2003), Consolidation of Variable Interest Entities (“FIN”) 46 (R), BIP does not consolidate the results of operations, assets or liabilities of Brookfield Infrastructure. The consolidated financial statements of Brookfield Infrastructure are included elsewhere within this annual report and should be read in conjunction with BIP’s financial statements.

2. SUMMARY OF ACCOUNTING POLICIES

Basis of Presentation

The accompanying financial statements represent the financial position and results of operations for BIP on the basis that its investment in Brookfield Infrastructure is accounted for on an equity accounting basis.

These financial statements are prepared in conformity with generally accepted accounting principles in the United States of America (“U.S. GAAP”).

All figures are presented in millions of United States dollars unless otherwise noted.

Accounting Estimates

The preparation of financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions affecting the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual amounts will differ from those estimates used in the preparation of these financial statements. Investment valuation and income taxes are the primary areas management has made estimates and assumptions.

Investments

Investments in operations in which the Partnership does not have control, but has the ability to exercise significant influence over operating and financial policies are accounted for under the equity method. Under the equity method, investments are stated at cost and are adjusted for the Partnership’s proportional share of undistributed equity earnings or losses of the investment and distributions received from the investment.

The Partnership accounts for its investment in Brookfield Infrastructure, over which it has significant influence, under the equity method.

Investment Valuation

The Partnership recognizes an impairment charge when a decline in the fair value of its investments below their carrying values is judged to be other-than-temporary. The Partnership considers various factors in determining whether to recognize an impairment charge, including the length of time and extent to which the fair value has been less than the Partnership's cost basis, the financial condition and near-term prospects of the investee, and the Partnership's intent and ability to hold the investment for a period of time sufficient to allow for any anticipated recovery in market value.

Income Taxes

Income taxes are recognized using the asset and liability approach. Income tax expense is based on pretax financial accounting income. Deferred tax assets and liabilities are recognized for the expected tax consequences of temporary differences between the tax bases of assets and liabilities and their reported amounts.

Significant management judgment is required in determining the provision for income taxes, deferred tax assets and liabilities, and any valuation allowance recorded against the net deferred tax assets. The Partnership accounts for deferred taxes in accordance with SFAS No. 109, Accounting for Income Taxes, which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. SFAS No. 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that a portion of the deferred tax asset will not be realized.

Foreign Currency Translation and Transactions

The U.S. dollar is the Partnership's functional and reporting currency.

Cash and Cash Equivalents

The Partnership considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

Recently Adopted Accounting Standards

i) SFAS 157, "Fair Value Measurements"

Fair Value Measurements. In September 2006, the FASB issued SFAS 157, "Fair Measurements" ("SFAS 157"). SFAS 157, defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Financial assets and liabilities carried at fair value will be classified and disclosed in one of the following three categories.

Level 1: Quoted market prices in active markets for identical assets or liabilities.
Level 2: Observable market based inputs or unobservable inputs that are corroborated by market data.
Level 3: Unobservable inputs that are not corroborated by market data.

The Company adopted SFAS 157 on January 1, 2008, on a prospective basis, as required for financial assets and financial liabilities.

3. EQUITY ACCOUNTED INVESTMENTS

The Partnership's net investment in equity accounted entities includes the following:

		Book Value December 31	
US$ MILLIONS	**Ownership %**	**2008**	**2007**
Brookfield Infrastructure L.P.	60%	**$546.5**	$544.7

4. PARTNERSHIP CAPITAL

During 2008 the number of issued and outstanding Partnership units changed as follows:

	2008	
US$ MILLIONS (EXCEPT FOR UNIT INFORMATION)	**Book Value**	**Units**
Outstanding at beginning of period	**$543.4**	23,340,871
Repurchase of units during the period	**(2.0)**	(180,602)
Distributions to unitholders	**(20.3)**	—
Net income for the period	**16.8**	—
Outstanding at end of period	**$537.9**	23,160,269

5. EARNINGS PER UNIT

The components of basic and diluted earnings per unit are summarized in the following table:

US$ MILLIONS (EXCEPT FOR UNIT INFORMATION)	**2008**
Net income	$ 16.8
Weighted average units outstanding—basic	23,330,631
Unexercised dilutive options	—
Weighted average units outstanding—diluted	23,330,631

BROOKFIELD INFRASTRUCTURE L.P.

As of December 31, 2008 and December 31, 2007 and for the years ended December 31, 2008, 2007 and 2006.

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Partners of Brookfield Infrastructure L.P.:

We have audited the accompanying consolidated and combined balance sheets of Brookfield Infrastructure L.P. and subsidiaries (the "Partnership") as of December 31, 2008 and 2007, and the related consolidated and combined statements of operations, other comprehensive income, accumulated other comprehensive income, retained earnings and of cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated and combined financial statements present fairly, in all material respects, the financial position of Brookfield Infrastructure L.P. and subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated and combined financial statements, on March 12, 2008, the Partnership acquired 100% of the assets and liabilities of the transmission division of Great Lakes Power Limited. This transaction was accounted for as a reorganization of entities under common control, and therefore the financial statements have been presented giving retroactive effect to the transaction for all periods presented.

Independent Registered Chartered Accountants
Licensed Public Accountants

Deloitte & Touche LLP

Toronto, Canada
March 15, 2009

BROOKFIELD INFRASTRUCTURE L.P.

CONSOLIDATED AND COMBINED BALANCE SHEETS

US$ MILLIONS	As of December 31, 2008	As of December 31, 2007
Assets		
Current assets		
Cash and cash equivalents	**$ 9.2**	$ 221.3
Accounts receivable and other	**53.6**	9.2
Total current assets	**62.8**	230.5
Cost accounted investments	**195.2**	195.2
Equity accounted investments *(Note 3)*	**716.8**	505.8
Property, plant and equipment *(Note 4)*	**174.0**	210.6
Other assets	**12.5**	2.8
Deferred taxes	**13.0**	13.0
	$1,174.3	$1,157.9
Liabilities and partnership capital		
Current liabilities		
Accounts payable and other liabilities	**$ 6.9**	$ 18.9
	6.9	18.9
Corporate borrowings *(Note 5)*	**139.5**	—
Non-recourse borrowings *(Note 6)*	**97.6**	115.0
Deferred tax liabilities	**10.4**	19.5
Preferred shares *(Note 12)*	**20.0**	20.0
	274.4	173.4
Redeemable partnership units *(Note 7)*	**169.3**	354.2
Partnership capital		
Retained earnings	**157.0**	22.4
Accumulated other comprehensive income	**33.6**	21.5
Partnership units *(Note 7)*	**540.0**	586.4
	$1,174.3	$1,157.9

The accompanying notes are an integral part of these financial statements.

BROOKFIELD INFRASTRUCTURE L.P.

CONSOLIDATED AND COMBINED STATEMENTS OF OPERATIONS

	Years ended December 31		
US$ MILLIONS	**2008**	*(Note 2)* **2007**	*(Note 2)* **2006**
Revenue	**$ 32.9**	$33.1	$30.7
Cost of revenue (exclusive of depreciation expense)	**(2.6)**	(1.1)	(1.3)
Depreciation expense	**(7.7)**	(7.2)	(6.2)
Gross margin	**22.6**	24.8	23.2
Selling, general and administrative expenses	**(18.7)**	(4.4)	(3.8)
Dividend income	**14.3**	0.5	—
Other income (loss)	**0.9**	(0.4)	(0.3)
	19.1	20.5	19.1
Interest expense	**(12.9)**	(6.9)	(5.8)
Net income before below noted items	**6.2**	13.6	13.3
Income tax expense	**(1.5)**	(4.4)	(4.4)
Deferred tax (expense) recovery	**(1.9)**	10.6	1.5
Earnings (losses) from equity accounted investments	**25.2**	(7.8)	—
Net income	**$ 28.0**	$12.0	$10.4

The accompanying notes are an integral part of these financial statements.

BROOKFIELD INFRASTRUCTURE L.P.

CONSOLIDATED AND COMBINED STATEMENTS OF OTHER COMPREHENSIVE INCOME

	Years ended December 31		
US$ MILLIONS	**2008**	*(Note 2)* **2007**	*(Note 2)* **2006**
Net income	**$ 28.0**	$12.0	$10.4
Other comprehensive income (loss)			
Foreign currency translations (losses) gains on the net investment in self-sustaining operations	**(70.4)**	12.7	(0.7)
Net gains on related hedging items	**82.5**	—	—
Other comprehensive income (loss)	**12.1**	12.7	(0.7)
Comprehensive income	**$ 40.1**	$24.7	$ 9.7

CONSOLIDATED AND COMBINED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME

	Years ended December 31		
US$ MILLIONS	**2008**	*(Note 2)* **2007**	*(Note 2)* **2006**
Accumulated other comprehensive income, opening	**$21.5**	$ 8.8	$ 9.5
Other comprehensive income (loss)	**12.1**	12.7	(0.7)
Accumulated other comprehensive income, closing	**$33.6**	$21.5	$ 8.8

CONSOLIDATED AND COMBINED STATEMENTS OF RETAINED EARNINGS

	Years ended December 31		
US$ MILLIONS	**2008**	*(Note 2)* **2007**	*(Note 2)* **2006**
Retained earnings, opening	**$ 22.4**	$14.2	$ 3.8
Net income for the period	**28.0**	12.0	10.4
Fair value adjustment on redeemable partnership units *(Note 7)*	**184.9**	—	—
Adjustment related to acquired entity *(Note 7)*	**(44.4)**	—	—
Distributions to unitholders	**(33.9)**	—	—
Distribution from operations	**—**	(3.8)	—
Retained earnings, closing	**$157.0**	$22.4	$14.2

The accompanying notes are an integral part of these financial statements.

BROOKFIELD INFRASTRUCTURE L.P.

CONSOLIDATED AND COMBINED STATEMENTS OF CASH FLOWS

US$ MILLIONS	Years Ended December 31 2008	(Note 2) 2007	(Note 2) 2006
Operating activities			
Net income	**$ 28.0**	$ 12.0	$ 10.4
Adjustment for non-cash items:			
Deferred tax recovery	**1.9**	(10.6)	(1.5)
(Earnings) losses from equity accounted investments	**(25.2)**	7.8	—
Depreciation	**7.7**	7.2	6.2
Change in non-cash working capital	**(6.6)**	(0.4)	4.3
Cash from operating activities	**5.8**	16.0	19.4
Investing activities			
Additional investment in Transelec *(Note 8)*	**(134.9)**	—	—
Acquisition of Ontario Transmission *(Note 8)*	**(93.6)**	—	—
Investment in BGTF *(Note 8)*	**(92.8)**	—	—
Acquisition of PPP assets *(Note 8)*	**(12.3)**	—	—
Additional investment in Longview	**(10.5)**	—	—
Additions to property, plant and equipment	**(8.2)**	(16.8)	(16.9)
Increase in non-recourse borrowings	**4.0**	—	—
Proceeds from hedge settlement *(Note 11)*	**26.8**	—	—
Cash used in investing activities	**(321.5)**	(16.8)	(16.9)
Financing activities			
Corporate borrowings	**139.5**	—	—
Cash contribution upon spin off	**—**	197.9	—
Issuance of preferred shares	**—**	20.0	—
Distributions to unitholders	**(33.9)**	—	—
Repurchase of units	**(2.0)**	—	—
Cash from financing activities	**103.6**	217.9	—
Cash and cash equivalents			
Change during the year	**$(212.1)**	$217.1	$ 2.5
Balance, beginning of year	**221.3**	4.2	1.7
Balance, end of year	**$ 9.2**	$221.3	$ 4.2
Cash interest paid	**$ 12.4**	$ 7.1	$ 6.7

The accompanying notes are an integral part of these financial statements.

BROOKFIELD INFRASTRUCTURE L.P.

For the years ended December 31, 2008, 2007 and 2006

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

1. ORGANIZATION AND DESCRIPTION OF THE BUSINESS

Brookfield Infrastructure L.P. ("Brookfield Infrastructure") was formed as a limited partnership established under the laws of Bermuda, pursuant to a limited partnership agreement dated May 17, 2007 as amended and restated. Brookfield Infrastructure consists of interests in electricity transmission, timber and social infrastructure operations in North and South America, United Kingdom and Australia.

In May 2007, Brookfield Asset Management Inc. ("Brookfield") announced its intention to spin-off a portion of its infrastructure assets through a special dividend to the holders of its Class A limited voting shares and Class B limited voting shares (the "Spin-off"). Prior to the Spin-off, Brookfield restructured its infrastructure division so that portions of its operations were owned by Brookfield Infrastructure. At the time of the reorganization, Brookfield owned approximately 61% of the limited partnership units of Brookfield Infrastructure directly, and a wholly owned subsidiary of Brookfield owned exchangeable units of Brookfield Infrastructure representing approximately 39% of the limited partnership units of Brookfield Infrastructure. Brookfield transferred 60% of the limited partnership units of Brookfield Infrastructure that it owned to Brookfield Infrastructure Partners L.P. ("BIP"), a limited partnership, in consideration for units of BIP. These BIP units were then distributed by Brookfield to holders of its Class A limited voting shares and Class B limited voting shares as a special dividend on January 31, 2008.

2. SUMMARY OF ACCOUNTING POLICIES

Basis of Presentation

The accompanying financial statements reflect Brookfield Infrastructure's accounting for the following investments on the equity accounting basis:

- 17.8% interest in Transelec Chile S.A., or Transelec, the Chilean transmission operations, which were acquired by Brookfield in June 2006.
- 23% interest in Longview Timber Holdings Corp., or Longview, the US timber operations, which were acquired by Brookfield in April 2007.
- 37.5% interest in Island Timberlands Limited Partnership, or Island, the Canadian timber operations, which were acquired by Brookfield in May 2007.
- 9.1% interest in the Brookfield Global Timber Fund L.P., or BGTF, which is a fund established by Brookfield in November 2008, whose sole material asset is an investment Longview.
- 30% interest in Peterborough Hospital, UK and a 50% interest in Long Bay Forensic and Prison Hospitals, Australia, respectively, both of which are Public Private Partnerships ("PPP"). Brookfield Infrastructure acquired the interest in the two social infrastructure PPP's during the year which were previously joint venture investments of a Brookfield company.

Brookfield Infrastructure also has an interest in a group of transmission lines in Brazil, Transmissoras Brasileiras de Energia, commonly referred to as TBE. The investment reflects the direct investment in five Brazilian transmission companies with ownership percentages ranging from 7% to 18%, which is currently being accounted for under the cost accounting basis.

On March 12, 2008, Brookfield Infrastructure acquired 100% of the assets and liabilities of the transmission division of Great Lakes Power Limited (GLPL), ("the Ontario Transmission" operations) which was an entity owned and controlled by Brookfield at the time of the acquisition by Brookfield Infrastructure. This transaction constitutes a reorganization of entities under common control, and has been accounted for in a manner similar to a pooling of interests, resulting in the 2007 and 2006 financial statements being prepared on a combined basis. Accordingly, these financial statements have been presented giving retroactive effect to the transaction described above using historical carrying costs of the assets and liabilities of the Ontario Transmission operations for all periods presented.

The following table illustrates our policy used to account for our significant investments:

METHOD OF ACCOUNTING AT DECEMBER 31, 2008	Ownership %	Method
Ontario Transmission	100.0%	Consolidation
Transelec	17.8%	Equity
Longview	23.0%	Equity
Island Timberlands	37.5%	Equity
BGTF (Note 8)	9.1%	Equity
PPP	30% – 50%	Equity
TBE	7.0% – 18.0%	Cost

These financial statements are prepared in conformity with generally accepted accounting principles in the United States of America ("U.S. GAAP").

All figures are presented in millions of United States Dollars unless otherwise noted.

Accounting Estimates

The preparation of financial statements in accordance with U.S. GAAP requires management to make estimates and assumptions affecting the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual amounts will differ from those estimates used in the preparation of these financial statements. Investment valuation and income taxes are the primary areas where management has made estimates and assumptions.

Investments

Investments in operations in which Brookfield Infrastructure does not have control, but has the ability to exercise significant influence over operating and financial policies, are accounted for under the equity method. Under the equity method, investments are stated at cost and are adjusted for Brookfield Infrastructure's proportional share of undistributed equity earnings or losses of the investment and distributions received from the investment.

Investment Valuation

Brookfield Infrastructure recognizes an impairment charge when a decline in the fair value of its investments below the carrying value is judged to be other-than-temporary. Brookfield Infrastructure considers various factors in determining whether to recognize an impairment charge, including the length of time and extent to which the fair value has been less than Brookfield Infrastructure's cost basis, the financial condition and near-term prospects of the investee, and Brookfield Infrastructure's intent and ability to hold the investment for a period of time sufficient to allow for any anticipated recovery in market value.

Income Taxes

Income taxes are recognized using the asset and liability approach. Income tax expense is based on pre-tax financial accounting income. Deferred tax assets and liabilities are recognized for the expected tax consequences of temporary differences between the tax bases of assets and liabilities and their reported amounts. Significant management judgment is required in determining the provision for income taxes, deferred tax assets and liabilities, and any valuation allowance recorded against the net deferred tax assets. Brookfield Infrastructure accounts for deferred taxes in accordance with SFAS No. 109, Accounting for Income Taxes, which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax bases of recorded assets and liabilities. SFAS No. 109 also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that a portion of the deferred tax asset will not be realized.

Foreign Currency Translation and Transactions

The U.S. dollar is Brookfield Infrastructure's functional and reporting currency. Foreign currency denominated monetary assets and liabilities of Brookfield Infrastructure where the functional currency is other than the U.S. dollar, are translated at the rate of exchange prevailing at period-end and revenues and expenses at average rates during the period. Gains or losses on the translation of these items are included in the statement of operations.

The Ontario Transmission business' functional and reporting currency is the Canadian dollar. Ontario Transmission's monetary assets and liabilities, are translated at the rate of exchange prevailing at period-end and revenues and expenses at average rates during the period. Gain or losses on the translation of these items are included in the statement of operations.

Cash and Cash equivalents

Brookfield Infrastructure considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents.

Revenue Recognition

Dividend income is recognized on the ex-dividend date.

The Ontario Transmission operations business recognizes revenue on an accrual basis, when electricity is wheeled, at the regulated rate established by the Ontario Electricity Board.

Derivative Financial Instruments

Brookfield Infrastructure selectively utilizes derivative financial instruments to manage financial risks primarily relating to foreign exchange risks. Hedge accounting is applied when the derivative is designated as a hedge of a specific exposure and there is reasonable assurance that it will continue to be effective as a hedge based on an expectation of offsetting cash flows or fair value. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as a hedge or the hedging relationship is terminated. Once discontinued, the cumulative change in fair value of a derivative that was previously deferred by the application of hedge accounting is recognized in income over the remaining term of the original hedging relationship. Realized and unrealized gains and losses on foreign exchange forward contracts designated as hedges of currency risks are included in other comprehensive income when the currency risk relates to a net investment in a self-sustaining subsidiary and are otherwise included in income in the same period as when the underlying asset, liability or anticipated transaction affects income.

Derivative financial instruments that are not designated as hedges are carried at estimated fair value, and gains and losses arising from changes in fair value are recognized in income in the period the changes occur.

Property, Plant and Equipment

Property, plant and equipment are recorded at cost, including costs of acquisition incurred by the Ontario Transmission operations business, less accumulated depreciation. The cost of the property, plant and equipment is depreciated over the estimated service lives of the assets as follows:

	Method	Rate
Buildings	Straight-line	40 years
Transmission stations, towers and related fixtures	Straight-line	25 to 40 years
Other equipment	Straight-line	5 to 40 years

Construction work in progress is not depreciated until the assets are put into service.

Capitalization of Interest

Interest on funds used in construction is charged to construction work in progress at the prescribed rate of return applicable to the rate base.

Recently Adopted Accounting Standards

i) SFAS 157, "Fair Value Measurements"

In September 2006, the FASB issued SFAS 157 "Fair Value Measurements" ("SFAS 157"). SFAS 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Financial assets and liabilities carried at fair value will be classified and disclosed in one of the following three categories:

Level 1: Based on quoted market prices in active markets for identical assets or liabilities.

Level 2: Based on observable market-based inputs or unobservable inputs that are corroborated by market data.

Level 3: Unobservable inputs that are not corroborated by market data.

Brookfield Infrastructure adopted SFAS 157 on January 1, 2008, on a prospective basis, as required for financial assets and financial liabilities.

The following table presents additional information about the Partnership's financial assets and liabilities which are measured at fair value on a recurring basis as of December 31, 2008.

	Recurring Fair Value Measurement	
US$ MILLIONS	**Level 2**	**Total**
Accounts receivable and other	**$ 43.6**	**$ 43.6**
Redeemable Partnership units	**169.3**	**169.3**

Future Accounting Policies

ii) SFAS 161, "Disclosures about Derivative Instruments and Hedging Activities", an amendment of FASF Statement 133 In March 2008, the FASB issued Statement No. 161, "Disclosures about Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133" ("FAS 161"). SFAS 161 enhances disclosures for derivative instruments and hedging activities and their effects on an entity's financial position, financial performance and cash flows. Under SFAS 161, an entity is required to disclose the objectives for using derivative instruments in terms of underlying risk and accounting designation; the fair values, gains and losses of derivatives; as well as credit-risk-related contingent features in derivative agreements. SFAS 161 is effective for fiscal years and interim periods beginning after November 15, 2008. The Partnership has adopted this standard effective January 1, 2009.

iii) SFAS 141(R), "Business Combinations" and SFAS 160, "Non-controlling Interests in Consolidated Financial Statements"

In December 2007, the FASB issued SFAS 141(R), "Business Combinations" ("SFAS 141(R)"), replacing SFAS 141. SFAS 141(R) established principles and requirements for how the acquirer of a business recognizes and measures (in its financial statements) the identifiable assets acquired, the liabilities assumed, and any non controlling interest in the acquiree. SFAS 141(R) also provides guidance for recognizing and measuring goodwill acquired in the business combination and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. This Statement applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Brookfield Infrastructure is currently evaluating the impact of the adoption of SFAS 141(R) on its Financial Statements.

3. EQUITY ACCOUNTED INVESTMENTS

Brookfield Infrastructure's net investment in equity accounted entities includes the following:

	December 31, 2008		December 31, 2007	
US$ MILLIONS	**Ownership %**	**Book Value**	**Ownership %**	**Book Value**
Transelec	**17.8%**	**$222.9**	10.7	$128.4
Longview[(1)]	**23.0%**	**205.9**	30.0	212.9
Island Timberlands	**37.5%**	**182.8**	37.5	164.5
BGTF	**9.1%**	**92.6**	—	—
PPP	**30% – 50%**	**12.6**	—	—
		$716.8		$505.8

(1) Includes equity interest and a shareholder loan.

The following tables presents certain summarized financial information in total, for all investments in equity accounted affiliates based on a 100% ownership interest in each entity:

	Years ended December 31	
US$ MILLIONS	**2008**	**2007[(1)]**
Gross revenue	**$ 706.7**	$ 39.3
Costs and expense applicable to gross revenue	**(294.1)**	(20.1)
Gross margin	**412.6**	19.2
Investment income	**8.3**	16.5
Cash taxes	**(1.4)**	—
Interest expense	**(176.5)**	(29.6)
	243.0	6.1
Depreciation, depletion and amortization	**(180.6)**	(12.9)
Deferred taxes and other	**51.5**	(27.0)
Net income (loss)	**$ 113.9**	$(33.8)

(1) Includes result for the period from November 27, 2007 to December 31, 2007.

US$ MILLIONS	As at December 31 2008	2007
Current assets	**$ 596.9**	$ 251.7
Non-current assets	**6,299.8**	6,999.5
Total assets	**$6,896.7**	$7,251.2
Current liabilities	**$ 193.2**	$1,434.1
Non-current liabilities	**4,339.1**	3,494.4
Total liabilities	**$4,532.3**	$4,928.5

4. PROPERTY, PLANT AND EQUIPMENT

			December 31, 2008	December 31, 2007
US$ MILLIONS	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Land	**$ 0.5**	**$ —**	**$ 0.5**	$ 0.5
Buildings	**12.1**	**3.7**	**8.4**	10.9
Transmission stations, towers and related fixtures	**213.8**	**50.5**	**163.3**	193.6
Other equipment	**1.8**	**—**	**1.8**	5.6
	$228.2	**$54.2**	**$174.0**	$210.6

5. CORPORATE BORROWINGS

On June 13, 2008, Brookfield Infrastructure closed a $450 million senior secured revolving credit facility. The facility includes two tranches; tranche A in maximum principal amount of $135 million for general working capital including acquisitions and tranche B in a maximum principal amount of $315 million for acquisitions. The facility is available on a revolving basis for one year unless extended in accordance with the terms of the credit agreement. All amounts outstanding under this facility will be repayable on June 13, 2011. All obligations of Brookfield Infrastructure under the facility are guaranteed by certain subsidiaries of Brookfield Infrastructure and are secured by all of the assets of Brookfield Infrastructure and the guarantors. Loans under the facility accrue interest at a floating rate based on LIBOR plus 2.75%, increasing, in the case of loans under tranche B which are at any time outstanding for a period longer than six months, by 0.50% on each six month anniversary of the date of advance of such loans. Brookfield Infrastructure is required to pay an unused commitment fee under the facility equal to 35% of the applicable margin per annum. In the fourth quarter, $139.5 million was drawn on the credit facility, which remained outstanding as at December 31, 2008.

6. NON—RECOURSE BORROWINGS

US$ MILLIONS	December 31, 2008	December 31, 2007
Series 1 First Mortgage Bonds	**$97.6**	$115.0

The Series 1 bonds bear interest at the rate of 6.6%. Semi-annual payments of interest only are due and payable on June and December 16 each year until and including June 16, 2013. Equal blended semi-annual payments of principal and interest on the Series 1 Bonds will commence on December 16, 2013 and will continue until and including June 16, 2023. The Series 1 Bonds will not be fully amortized by their maturity date. The remaining principal balance of the Series 1 Bonds will be fully due on June 16, 2023. The Series 1 First Mortgage Bonds are secured by a charge on generation and transmission present and future real property assets of Ontario Transmission's operations. Interest on the Bonds is expensed in accordance with the interest rate prescribed by regulation. In 2008, the interest rate was 6.6% (2007—6.6%). The fair market value of the Series 1 Bonds is $90.9 million (2007—$125.4 million) based on current market prices for debt with similar terms.

7. PARTNERSHIP CAPITAL

Brookfield Infrastructure has issued redeemable partnership units that may, at the request of the holder, require Brookfield Infrastructure to redeem all or a portion of the holder's units of Brookfield Infrastructure at the market price for cash after two years from the date of closing of the Spin-off. This right is subject to BIP's right of first refusal which entitles it, at its sole discretion, to elect to acquire any unit so presented to Brookfield Infrastructure in exchange for one of BIP's units (subject to certain customary adjustments). Based on the number of BIP units issued in the Spin-off, Brookfield's aggregate limited partnership interest in Brookfield Infrastructure would be 39% if Brookfield exercised its redemption right in full and BIP fully exercised its right of first refusal. The units are considered mezzanine equity and are recorded at their redemption amount which also equals their fair value. As at December 31, 2008, fair value of these units was lower than book value by $184.9 million, which was recorded in retained earnings.

Brookfield Infrastructure has also issued partnership units that are held by BIP and represent 60% of its capital base.

During 2008 and 2007, the number of issued and outstanding Partnership units changed as follows:

	2008		2007	
US$ MILLIONS (EXCEPT UNIT INFORMATION)	**Book Value**	**Units**	**Book Value**	**Units**
Outstanding at beginning of year	**586.4**	**23,729,328**	586.4	23,729,328
Adjustment related to acquired entity	**(44.4)**	**—**	—	—
Units repurchased	**(2.0)**	**(180,602)**	—	—
Outstanding at end of year	**540.0**	**23,548,726**	586.4	23,729,328

As at December 31, total number of units outstanding were comprised as follows:

	2008	2007
General partnership units	**388,457**	388,457
Limited partnership units	**23,160,269**	23,340,871
Partnership units	**23,548,726**	23,729,328
Redeemable partnership units	**15,112,744**	15,112,744
Total	**38,661,470**	38,842,072

The caption "adjustment related to acquired entity" recorded in the statement of retained earnings and above is related to the acquisition of Ontario Transmission, an entity that was accounted for as a reorganization of entities under common control, as described in Note 2.

8. ACQUISITIONS

Ontario Transmission was acquired by Brookfield Infrastructure on March 12, 2008. With the transaction, Brookfield Infrastructure acquired 550 km of 44 kV to 230 kV transmission lines in Canada that comprise an important component of Ontario's transmission system that connects generation in Northern Ontario to electricity demand in Southern Ontario.

Brookfield Infrastructure acquired the assets and liabilities for $93.6 million. The purchase was financed with cash on hand that was contributed to Brookfield Infrastructure upon spin-off.

This acquisition was recorded at the historical carrying values of Ontario Transmission's assets and liabilities as described below.

US$ MILLIONS	March 12, 2008
Current assets	**$ 5.3**
Property, plant and equipment	**208.4**
Other assets	**1.3**
Current liabilities	**(2.4)**
Non-recourse borrowings	**(119.0)**
Total	**$ 93.6**

On November 3, 2008, Brookfield Infrastructure made an investment of a 9.1% interest in BGTF, a fund established by Brookfield on October 14, 2008. BGTF's sole asset, Longview Timber Holdings Corp. ("Longview"), was seeded into BGTF by Brookfield subsequent to a recapitalization of Longview in which Brookfield Infrastructure did not participate, resulting in a dilution of its interest in Longview to 23% from 30%. Consideration of $92.8 million was contributed by Brookfield Infrastructure in exchange for the ownership interest in BGTF, thereby increasing Brookfield Infrastructure's investment in Longview by 7.0%. Brookfield Infrastructure's total investment in Longview (direct and indirect through BGTF) remained at 30% and did not change as a result of the transactions. Brookfield Infrastructure also has an additional commitment of $10.0 million to fund further acquisitions by BGTF.

On April 3, 2008, the Partnership increased its ownership interest in Transelec to 17.8% from 10.7% for a total purchase consideration of $134.9 million.

On December 5, 2008, Brookfield Infrastructure completed the acquisition of Brookfield Multiplex's interest in two PPP projects, the Peterborough Hospital in the United Kingdom and the Long Bay Forensic and Prison Hospitals in Australia—for a total investment of approximately $12.3 million.

9. INCOME TAXES

Included in the net deferred tax recovery amount of $10.6 million for 2007, is $8.4 million representing the net of $13.0 million deferred tax assets, and $4.6 million deferred tax liability that arose as a result of the initial tax costs in certain subsidiaries being higher or lower then the initial book value of the investments that arose on the formation of Brookfield Infrastructure.

10. RELATED PARTY TRANSACTIONS

In the normal course of operations, Brookfield Infrastructure entered into the transactions described below on market terms with related parties. These transactions have been measured at exchange value and are recognized in the financial statements.

Ontario Transmission has provided advances to and received advances from related parties in the normal course of operations. Ontario Transmission has also provided advances to and received advances from other divisions of GLPL. These advances are non-interest bearing, unsecured and due on demand.

At period end no amounts were due from related parties (as at December 31, 2007—$3.7 million) and $1.7 million was due to related parties (as at December 31, 2007—$0.6 million).

11. DERIVATIVES AND HEDGING

During the year Brookfield Infrastructure exercised its right under a put agreement to sell its interest in TBE. Brookfield Infrastructure expects to receive Brazilian Reais denominated proceeds during the first quarter of 2009 related to the sale upon receipt of regulatory approval. As a hedge against adverse changes in the Brazilian Reais, Brookfield Infrastructure entered into a forward contract to sell a notional amount of Brazilian Reais at a predetermined rate. As a result, Brookfield Infrastructure expects to receive after tax proceeds of approximately $274 million. Brookfield Infrastructure has chosen to apply hedge accounting and accordingly records changes in fair value in Other Comprehensive Income. For the year ended December 31, 2008 Brookfield Infrastructure recorded a gain of $70.5 million related to forward contracts, $26.8 million of which has been realized by Brookfield Infrastructure and $43.7 million which has been recorded as current mark-to-market on an outstanding contract with a notional amount of R$465 million and fixed rate of R$1.91:1.

Brookfield Infrastructure also entered into a forward contract to buy a notional amount of approximately £8 million as a hedge against its future additional investment in the Peterborough Hospital in the United Kingdom (Note 14). Brookfield Infrastructure recorded a loss of $0.3 million as a current mark-to-market on the contract in the statement of operations as of December 31, 2008.

12. PREFERRED SHARES

Preferred shares represent $5 million of preferred shares issued totalling $20 million. The preferred shares are entitled to receive a preferential dividend equal to 6% of their redemption value and are redeemable, in whole or in part, at an amount equal to their redemption value plus accrued and unpaid dividends at any time after the tenth anniversary of their issuance.

13. SEGMENTED INFORMATION

Brookfield Infrastructure's operating segments are electricity transmission and timber. A key measure most often used by the Chief Operating Decision Maker in assessing performance and in making resource allocation decisions is adjusted net operating income ("ANOI") a non-GAAP measure, which enables the determination of cash return on equity deployed. ANOI is defined as net income excluding the impact of depreciation, depletion and amortization, deferred taxes and other non-cash items. The following table provides each segment's results based on the format that management organizes its segments in order to make operating decisions and assess performance. Each segment is presented on both a 100% basis and a proportional basis, taking into account Brookfield Infrastructure's ownership interest in operations accounted for using the consolidation and equity methods. For cost accounted investments, the segment results reflect dividend income.

FOR THE YEAR ENDED DECEMBER 31, 2008 US$ MILLIONS	Electricity Transmission	Partnership Share	Timber[2]	Partnership Share	Corporate	Total[1]
Revenue	**$367.7**	**$ 86.4**	**$ 368.4**	**$124.8**	**$ —**	
Dividend income	**14.3**	**14.3**	**—**	**—**	**—**	
Costs attributed to revenue	**(59.0)**	**(15.8)**	**(239.0)**	**(81.8)**	**(14.0)**	
Net operating income	**323.0**	**84.9**	**129.4**	**43.0**	**(14.0)**	
Other income (expense)	**9.5**	**1.6**	**(1.2)**	**(0.5)**	**1.2**	
Interest expense	**(93.2)**	**(21.1)**	**(90.6)**	**(29.0)**	**(4.3)**	
Cash taxes	**(1.4)**	**(1.4)**	**(1.4)**	**(0.7)**	**—**	
Adjusted net operating income (ANOI)	**237.9**	**64.0**	**36.2**	**12.8**	**(17.1)**	
Depreciation, depletion and amortization	**(70.5)**	**(17.6)**	**(117.8)**	**(36.7)**	**—**	
Deferred taxes and other items	**(41.7)**	**(6.5)**	**91.3**	**30.6**	**(1.5)**	
Net income (loss)	**$125.7**	**$ 39.9**	**$ 9.7**	**$ 6.7**	**$(18.6)**	**$28.0**

FOR THE YEAR ENDED DECEMBER 31, 2007 US$ MILLIONS	Electricity Transmission	Partnership share	Timber	Partnership share	Corporate	Total(1)
Revenue	$ 54.3	$35.5	$ 18.1	$ 6.1	$—	
Dividend income	0.5	0.5	—	—	—	
Costs attributed to revenue	(9.6)	(6.4)	(16.9)	(5.6)	—	
Net operating income	45.2	29.6	1.2	0.5	—	
Other income (expense)	3.0	0.3	(5.1)	(1.9)	—	
Interest expense	(17.7)	(8.0)	(8.6)	(2.7)	—	
Cash taxes	(4.5)	(4.5)	—	—	—	
Adjusted net operating income (ANOI)	26.0	17.4	(12.5)	(4.1)	—	
Depreciation, depletion and amortization	(14.4)	(8.0)	(5.8)	(1.8)	—	
Deferred taxes and other	(16.0)	0.4	(0.5)	(0.3)	8.4	
Net (loss) income(1)	$ (4.4)	$ 9.8	$(18.8)	$(6.2)	$ 8.4	$12.0

FOR THE YEAR ENDED DECEMBER 31, 2006 US$ MILLIONS	Electricity Transmission	Partnership share	Timber	Partnership share	Corporate	Total(1)
Revenue	$ 30.7	$30.7	$ —	$—	$—	
Dividend income	—	—	—	—	—	
Costs attributed to revenue	(5.1)	(5.1)	—	—	—	
Net operating income	25.6	25.6	—	—	—	
Other expenses	(0.3)	(0.3)	—	—	—	
Interest expense	(5.8)	(5.8)	—	—	—	
Cash taxes	(4.4)	(4.4)	—	—	—	
Adjusted net operating income (ANOI)	15.1	15.1	—	—	—	
Depreciation, depletion and amortization	(6.2)	(6.2)	—	—	—	
Deferred taxes and other	1.5	1.5	—	—	—	
Net income	$ 10.4	$10.4	$ —	$—	$—	$10.4

(1) The majority of Brookfield Infrastructure's investments are accounted for using the equity method or cost method of accounting in accordance with U.S. GAAP (Note 2). This results in the earnings from these investments being presented in one line on the Statement of Operations. The above table presents the detailed components making up net income for investments accounted for using the consolidation, equity and cost methods in a more fulsome manner. Accordingly, with the exception of net income, the totals of each line item in the above table will not agree to the Statement of Operations.

(2) Brookfield Infrastructure proportionately accounts for its investment in Longview at a 30% ownership interest, through its direct and indirect interest in the Company.

14. COMMITMENTS, CONTINGENCIES AND GUARANTEES

In the normal course of operations, Ontario Transmission operations executes agreements that provide for indemnification and guarantees to third parties in transactions such as debt issuances. The nature of substantially all of the indemnification undertakings prevents Ontario Transmission operations from making a reasonable estimate of the maximum potential amount Ontario Transmission operations could be required to pay third parties as the agreements do not specify a maximum amount and the amounts are dependent upon the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time. Historically, Ontario Transmission operations has not made significant payments under such indemnification agreements.

The payments for interest in respect of the First Mortgage Bonds for the next 5 years are as follows:

US$ MILLIONS	**2009**	**2010**	**2011**	**2012**	**2013**
	$6.5	**$6.5**	**$6.5**	**$6.5**	**$6.5**

In the normal course of operations, Ontario Transmission operations has committed as at December 31, 2008 to spend approximately $75.0 million on capital projects in future years.

Ontario Transmission operations may, from time to time, be involved in legal proceedings, claims, and litigation that arise in the ordinary course of business which Ontario Transmission operations believes would not reasonably be expected to have a material adverse effect on the financial condition of Ontario Transmission operations.

There are no specified decommissioning costs relating to the Ontario Transmission operations assets. Ontario Transmission operations has a comprehensive repair and capital expenditure program to ensure that its transmission lines are maintained to optimum industry standards. Replacement of the assets occur in accordance with a long term capital plan and would involve typical costs of removal as part of that process. In the circumstance where a portion of a line or other assets were removed completely, there may be some contractual obligations under private or crown easements or other land rights which require the transmission owner to reinstate the land to a certain standard, typically the shape it was prior to the construction of the transmission assets. As well, certain environmental, land use and/or utility legislation, regulations and policy may apply in which Ontario Transmission would have to comply with remediation requirements set by the government. The requirements will typically depend on the specific property characteristics and what criteria the government determines to be appropriate to meet safety and environmental concerns. These asset lives are indeterminate given their nature. As the individual assets or components reach the end of their useful lives, they are retired and replaced. Historically, certain asset components have been replaced a number of times, thus creating a perpetual asset with an indeterminate life. As such, the retirement date for these lines cannot be reasonably estimated and therefore, the fair value of the associated liability cannot be determined at this time. As a result, no liability has been accrued in these financial statements.

Brookfield Infrastructure acquired an interest in the Peterborough Hospital PPP project in the United Kingdome in the fourth quarter of 2008. The project is in the construction phase with construction expected to be complete in late 2011. Brookfield Infrastructure has a commitment to fund its share of the additional equity investment in the project totalling approximately £8 million.

15. SUBSEQUENT EVENTS

As described in Note 11, Brookfield Infrastructure exercised an option to sell its minority interests in TBE and expects to receive after tax proceeds from the sale of approximately R$465 million in April 2009 upon receipt of regulatory approval.

On February 3, 2009, subsequent to year end, Brookfield Infrastructure completed the acquisition of Brookfield Multiplex’s interest in an additional PPP Project—the Royal Melbourne Showgrounds in Australia, for an investment of approximately $3.0 million.

ETC HOLDINGS LTD. AND SUBSIDIARIES

As of December 31, 2008 and December 31, 2007 and for the years then ended Santiago, Chile

ETC HOLDINGS LTD. AND SUBSIDIARIES

December 31, 2008

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

US$:	United States dollars
ThUS$:	Thousands of United States dollars
Ch$:	Chilean peso
UF:	Unidad de Fomento or UF, is an inflation-indexed, Chilean-peso denominated monetary unit. The UF is set daily in advance based on the changes in the Chilean Consumer Price Index (CPI) of the previous months.

REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of ETC Holdings Ltd.

We have audited the accompanying consolidated balance sheets of ETC Holdings Ltd. and subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income (loss), comprehensive (loss) income, retained earnings (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of ETC Holdings Ltd. and subsidiaries as of December 31, 2008 and 2007 and the consolidated results of their operations and their cash flows for the years then ended in conformity with Canadian generally accepted accounting principles, which differ in certain respects from accounting principles generally accepted in the United States of America (see Note 13 to the consolidated financial statements).

As discussed in Note 2c) to the consolidated financial statements, in 2008 the Company changed its accounting policy with respect to embedded derivatives.

Ernst + Young Ltda.

Santiago, Chile
February 6, 2009

ETC HOLDINGS LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

US$ THOUSANDS	As of December 31, 2008	*(Restated, Note 2c)* As of December 31, 2007
Assets		
Current assets		
Cash and cash equivalents *(Note 2h)*	**$ 130,344**	$ 75,303
Trade accounts receivable	**51,365**	47,021
Miscellaneous receivables	**832**	968
Recoverable income taxes *(Note 3)*	**3,229**	7,350
Prepaid expenses	**149**	215
Future income tax asset *(Note 3)*	**239**	2,609
Other current assets *(Note 4)*	**311**	6,969
Derivatives *(Note 8)*	**6,740**	—
Total current assets	**193,209**	140,435
Property, plant, and equipment *(Note 2i,5)*		
Land	**26,201**	30,760
Buildings and infrastructure	**1,106,782**	1,386,358
Machinery and equipment	**484,672**	558,333
Other property, plant and equipment	**2,083**	2,630
Less: Accumulated depreciation	**(121,143)**	(90,420)
Total property, plant, and equipment, net	**1,498,595**	1,887,661
Other assets		
Investments in other companies	**501**	429
Goodwill *(Note 2f)*	**487,927**	488,656
Long-term receivables	**2,456**	3,085
Long-term future income taxes, net *(Note 3)*	**103,509**	130,374
Rights-of-way *(Note 2j)*	**215,760**	273,670
Other intangibles *(Note 2j)*	**17,500**	28,254
Long-term bank deposit *(Note 12a)*	**890,064**	848,813
Derivatives *(Note 8)*	**141,324**	—
Total other assets	**1,859,041**	1,773,281
Total assets	**$3,550,845**	$3,801,377

The accompanying notes are an integral part of these financial statements.

ETC HOLDINGS LTD. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

US$ THOUSANDS	As of December 31, 2008	*(Restated, Note 2c)* As of December 31, 2007
Liabilities and shareholders' equity		
Current liabilities		
Short-term bank loans	**$ 1,327**	$ 2,329
Current portion of long-term bonds payable *(Note 6, 8)*	**23,381**	18,463
Derivatives *(Note 8)*	**5,099**	819
Accounts payable	**58,055**	105,215
Accrued liabilities *(Note 9)*	**5,525**	5,450
Withholdings	**4,287**	2,844
Other current liabilities	**140**	9,648
Total current liabilities	**97,814**	144,768
Long-term liabilities		
Long-term bonds payable *(Note 6, 8)*	**1,378,623**	1,521,619
Long-term bank loans *(Note 7)*	**884,741**	840,234
Long-term derivatives *(Note 8)*	**28,819**	100,021
Long-term provisions *(Note 9)*	**3,022**	2,971
Other long-term liabilities	**4,626**	3,047
Total long-term liabilities	**2,299,831**	2,467,892
Contingencies and commitments *(Note 12)*	**—**	—
Non-controlling interest	**270**	141
Shareholders' equity: *(Note 10,11)*		
Paid-in capital	**1,368,379**	1,207,571
Distributions	**(78,895)**	(35,167)
Accumulated other comprehensive (loss) income	**(191,882)**	64,871
Retained earnings (deficit)	**55,328**	(48,699)
Subtotal: accumulated other comprehensive (loss) income and retained earnings (deficit)	**(136,554)**	16,172
Shareholders' equity, net	**1,152,930**	1,188,576
Total liabilities and shareholders' equity	**$3,550,845**	$3,801,377

The accompanying notes are an integral part of these financial statements.

ETC HOLDINGS LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (LOSS)

US$ THOUSANDS	For the years ended December 31 2008	(Restated, Note 2c) 2007
Sales revenue *(Note 2n)*	**$ 334,794**	$ 242,303
Cost of sales	(40,948)	(26,461)
Depreciation	**(62,752)**	(59,935)
Administrative, selling and other expenses	**(10,840)**	(14,464)
Other expenses, net	**(5,251)**	(2,345)
Income before financing charges and income taxes	**215,003**	139,098
Interest income	**73,319**	75,561
Interest expense, including:	**(228,156)**	(251,574)
Interest on long-term debt	**(227,661)**	(251,067)
Other interest expense	**(495)**	(507)
Foreign exchange (loss) gain, net	**(97,233)**	11,774
Other financial income (expense)	**143,716**	(34,526)
Income (loss) before income taxes	**106,649**	(59,667)
Income taxes (charge) recovery *(Note 3)*	**(2,515)**	22,170
Non-controlling interest	**(107)**	30
Net income (loss) for the year	$ 104,027	$ (37,467)

The accompanying notes are an integral part of these financial statements.

ETC HOLDINGS LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

US$ THOUSANDS	For the years ended December 31 2008	*(Restated, Note 2c)* 2007
Net income (loss) for the year	**$ 104,027**	$(37,467)
Other comprehensive income (loss):		
Translation (losses) gains on the net investment in self-sustaining operation	**(313,113)**	98,086
Net gains (losses) on related hedging items, net of taxes of $(11,423) and $6,460	**55,772**	(31,541)
Net gains on cash flow hedges	**588**	—
Comprehensive (loss) income for the year	**$(152,726)**	$ 29,078

The accompanying notes are an integral part of these financial statements.

ETC HOLDINGS LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (DEFICIT)

US$ THOUSANDS	For the years ended December 31 2008	*(Restated, Note 2c)* 2007
Deficit at the beginning of the year	**$ (48,699)**	$(11,232)
Net income (loss) for the period	104,027	(37,467)
Retained earnings (deficit) at the end of the year	**$ 55,328**	$(48,699)

The accompanying notes are an integral part of these financial statements.

ETC HOLDINGS LTD. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

US$ THOUSANDS	For the years ended December 31 2008	(Restated, Note 2c) 2007
Cash flows from operating activities:		
Net income (loss) for the period	**$ 104,027**	$ (37,467)
Adjustments for items that do not represent cash flows:		
Depreciation	**62,752**	59,935
Foreign exchange loss (gain), net	**97,233**	(11,774)
Future income taxes	**2,515**	(18,829)
Accrued interest to be paid	**52,047**	48,865
Unrealized (gains) losses on derivatives	**(138,465)**	37,617
Other	**(1,289)**	(4,836)
Changes in working capital balances:		
Trade accounts receivable	**(4,208)**	(9,741)
Prepaid expenses and other assets	**66**	(953)
Recoverable taxes	**7,350**	(6,879)
Accounts payable and accrued liabilities	**(15,526)**	6,394
Net cash provided by operating activities	**166,502**	62,332
Cash flows from financing activities:		
Capital contributions	**160,808**	—
Proceeds from bonds	**—**	349,319
Proceeds from loans	**41,500**	—
Long-term bank deposit	**(41,500)**	—
Payments of bonds	**(2,506)**	(357,208)
Distribution of capital	**(43,728)**	(35,167)
Net cash (used in) provided by financing activities	**114,574**	(43,056)
Cash flows from investing activities:		
Acquisition of business—adjustment to purchase price	**(160,808)**	—
Sales of property, plant and equipment	**16,329**	4,381
Purchase of property, plant, and equipment	**(69,372)**	(52,060)
Receipts from (payments on) derivative contracts designated as hedge of net investment	**4,328**	(25,924)
Net cash flows provided by (used in) investing activities	**(209,523)**	(73,603)
Effect of exchange rate changes on cash and cash equivalents	**(16,512)**	8,644
Total net cash flows for the period	**55,041**	(45,683)
Cash and cash equivalents, beginning of the period	**75,303**	120,986
Cash and cash equivalents, end of the period *(Note 2h)*	**$ 130,344**	$ 75,303
Supplemental cash flow information:		
Interest paid	**$ 148,262**	$ 172,866
Income taxes paid	**$ —**	$ 6,015

The accompanying notes are an integral part of these financial statements.

ETC HOLDINGS LTD. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2008 and 2007

1. The Company and Business

ETC Holdings Ltd. (the "Company") was formed in Bermuda on June 15, 2006 with an initial share capital of ThUS$12. The objective of the Company as per its Memorandum of Association is to acquire, hold, pledge and dispose of investments in the equity and debt, directly and indirectly of Rentas Eléctricas I Limitada and Rentas Eléctricas II Limitada (now Transelec Holdings Rentas Limitada) and any other persons and entities that carry on electricity transmission business in Chile, and any activities that are ancillary thereto. As of December 31, 2008 and 2007 the principal asset held by the Company through its indirect subsidiary Transelec Holdings Rentas Limitada is its investment in Transelec S.A. ("Transelec").

References herein to "parent company" are to ETC Holdings Ltd. and references to the "Company" or the "Group" are to ETC Holdings Ltd. together with its consolidated subsidiaries (see Note 2b).

On June 30, 2006, the Company acquired through its indirect subsidiary Rentas Eléctricas IV Limitada 999,900 shares of Transelec (at this time under the name of HQI Transelec Chile S.A.), representing 99.99% of its share capital, from Hydro-Québec International Transmisión Sudamérica S.A. and International Finance Corporation. In the same transaction, another Company's subsidiary Rentas Eléctricas III Limitada acquired 100 shares of Transelec representing 0.01% of its share capital from HQ Puno Ltd.

On October 24, 2006, Rentas Eléctricas IV Limitada acquired from, Rentas Eléctricas III Limitada 100 shares, corresponding to 0.01% of the share capital of HQI Transelec Chile S.A. and having full ownership of this entity, merged the latter by absorption. After the merger Rentas Eléctricas IV Limitada changed its name first to Nueva Transelec S.A. and then to Transelec S.A.

On March 26, 2007, Rentas Eléctricas III Limitada became an incorporated company and changed its name to Rentas Eléctricas III S.A. On May 9, 2007, Rentas Eléctricas Rentas III S.A. acquired 100 shares of Transelec owned by Transelec Holdings Rentas Limitada, corresponding to 0.01% of its share capital and became owner of 100% of Transelec. As a consequence, Rentas Eléctricas III S.A. merged Transelec by absorption. The merged entity continues its operations under name Transelec S.A.

Transelec's business is to exploit and develop electricity transmission systems in Chile. For this purpose it may obtain, acquire and use the respective concessions and permits and exercise all the rights and faculties that the prevailing legislation confers on electrical companies. Transelec's business also includes providing engineering and management consulting services and developing other business and industrial activities related to transmission of electricity. Transelec may act directly or through subsidiaries or other related companies, both in Chile and abroad. As of March 31, 2008 and December 31, 2007 Transelec has one subsidiary Transelec Norte S.A. that is also engaged in the electricity transmission business in Chile.

2. Summary of Significant Accounting Policies

a) Basis of accounting

The consolidated financial statements have been prepared by management following Canadian generally accepted accounting principles ("Canadian GAAP"). The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting period. Actual results could differ from the estimates.

b) Basis of consolidation

The accompanying financial statements reflect the consolidated financial position, results of operations and cash flows of the parent company and its subsidiaries. The effects of all significant transactions with consolidated subsidiaries have been eliminated in consolidation.

As of December 31, 2008 and 2007, the Group was composed of the parent company and the following direct and indirect subsidiaries:

	Participation as of			
	December 31, 2008		December 31, 2007	
	Direct/Indirect	%	Direct/Indirect	%
Rentas Eléctricas I Limitada	**Direct**	**99.97**	Direct	99.96
Transelec Holdings Rentas Limitada	**Indirect**	**99.97**	Indirect	99.96
Transelec S.A.	**Indirect**	**99.97**	Indirect	99.96
Transelec Norte S.A.	**Indirect**	**99.97**	Indirect	99.96

c) Changes in accounting policies

Financial Instruments—Disclosures and Presentation

On December 1, 2006, the Canadian Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA") issued two new accounting standards, Section 3862, Financial Instruments—Disclosures and Section 3863, Financial Instruments—Presentation. These standards replace Section 3861, Financial Instruments—Disclosure and Presentation and enhance the disclosure of the nature and extent of risks arising from financial instruments and how the entity manages those risks. These new standards became effective for the Company on January 1, 2008. Disclosures related to risk management are included in Note 8.

Capital Disclosures

On December 1, 2006, the AcSB issued Section 1535, Capital Disclosures. Section 1535 requires the disclosure of: (i) an entity's objectives, policies and process for managing capital; (ii) quantitative data about an entity's managed capital; (iii) whether an entity has complied with capital requirements; and (iv) if an entity has not complied with such capital requirements, the consequences of such non-compliance. This new standard became effective for the Company on January 1, 2008. Disclosures related to the capital management are included in Note 11.

Accounting for indexation features in the electricity transmission contracts

Contracts for electricity transmission services that Transelec has with some of its clients include indexation formulas that adjust periodically Transelec's remuneration (revenues) for its services. The indexes in the formulas include inflation indexes, foreign exchange rate between Chilean peso and U.S. dollar, prices of metals and prices of other ingredients used in the construction of the transmission assets. The underlying concept of the indexations is to reflect Transelec's investment in the construction of assets used to transport electricity. Those indexations were considered embedded derivatives and were accounted for separately and measured at fair value in the financial statements for the year ended December 31, 2007. During 2008 the Company reconsidered the treatment of those indexation features and concluded that it is acceptable under Canadian GAAP not to bifurcate and recognize them separately as embedded derivatives since they meet criteria of closely related to the economic characteristics and risks of the host contracts under CICA 3855. Instead the entire contracts were considered contract-based intangibles acquired in the business combination (acquisition of Transelec—see Note 1) valued initially at fair value and then amortized over the period of the arrangements.

The Company believes that the new accounting policy provides reliable and more relevant information because (a) it harmonizes the accounting for the transactions with IFRS (see Note 2d) below) that will shortly became the Company's primary GAAP and that provides high quality information about the financial position, performance and changes in financial position of an entity, (b) is subject to lower level of estimations as it does not involve use of unobservable market inputs to determine fair value of the embedded features that need to be used given the absence of active market for energy transmission services in Chile.

The Company recognized the effect of this voluntary change to the alternative accounting policy retroactively in accordance with CICA Section 1506. The difference between the fair value of the derivatives and amortized cost of intangibles of ThUS$14,305 (loss), that was presented in "Other expense, net" line in the consolidated statement of loss, net of corresponding future tax effect of ThUS$2,606 was included as adjustment to loss for the year 2007 and the balance of Deficit for the year ended December 31, 2007.

d) Future accounting pronouncements

Goodwill and Intangible Assets

In February 2008, the AcSB issued CICA Handbook Section 3064, Goodwill and Intangible Assets, replacing Handbook Sections 3062, Goodwill and Other Intangible Assets and 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new section will be applicable to the financial statements relating to fiscal years beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition of intangible assets by profit-oriented enterprises. The Company is currently evaluating the impact of Section 3064 on its financial statements.

Business Combinations and Consolidated Financial Statements

In October 2008 AcSB decided to replace Section 1581, Business Combinations, with Section 1582, Business Combinations; and Section 1600, Consolidated Financial Statements, with Sections 1601, Consolidated Financial Statements, and 1602, Non-controlling Interests.

Section 1582 provides the Canadian equivalent to International Financial Reporting Standard IFRS 3, "Business Combinations" (January 2008). The Section applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2011. Earlier application is permitted.

Section 1601, establishes standards for the preparation of consolidated financial statements, while the new Section 1602 establishes standards for accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. It is equivalent to the corresponding provisions of International Financial Reporting Standard IAS 27, "Consolidated and Separate Financial Statements" (January 2008). The Sections 1601 and 1602 apply to interim and annual consolidated financial statements relating to fiscal years beginning on or after January 1, 2011. Earlier adoption is permitted as of the beginning of a fiscal year. An entity adopting those Sections for a fiscal year beginning before January 1, 2011 needs also to adopt Section 1582. The Company is currently evaluating the impact of those pronouncements on its financial statements.

Rate Regulated Operations

In August 2007, the AcSB issued a decision, effective January 1, 2009, to withdraw the temporary exemption in CICA Handbook Section 1100, Generally Accepted Accounting Principles, which permits the recognition and measurement of assets and liabilities arising from rate regulation. The Company is currently assessing the impact of the AcSB's decision on its financial statements.

Credit risk in the Fair Value of Financial Assets and Financial Liabilities

In January 2009 the Emerging Issue Committee ("EIC") of AcSB issued EIC-173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities. The EIC reached a consensus in that abstract that an entity's own credit risk and the credit risk of the counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. The interpretation is effective in the interim and annual financial statements for periods ending on or after the date of issuance of the abstract. The Company is currently assessing the impact of the abstract on its financial statements.

Adoption of International Financial Reporting Standards ("IFRS")

In February 2008, the AcSB confirmed that Canadian GAAP for publicly accountable enterprises will be converged with IFRS effective in calendar year 2011, with early adoption allowed starting in calendar year 2009. IFRS uses a conceptual framework similar to Canadian GAAP, but there are significant differences on recognition, measurement and disclosures. In the period leading up to the changeover, the AcSB will continue to issue accounting standards that are converged with IFRS, thus mitigating the impact of adopting IFRS at the changeover date. The International Accounting Standard Board (IASB) will also continue to issue new accounting standards during the conversion period, and as a result, the final impact of IFRS on the Company's consolidated financial statements will only be measured once all the IFRS applicable at the conversion date are known.

For ETC Holding Ltd. the changeover to IFRS is not mandatory; however it will be in the future for its subsidiaries in Chile and its shareholders in Canada. As a result, the Company is developing a plan for its conversion to IFRS. A detailed analysis of the differences between IFRS and the current Company's accounting policies as well as an assessment of the impact of various alternatives are in progress.

e) Business combination and purchase price adjustment

As mentioned in the Note 1 above the Company acquired on June 30, 2006, Transelec from Hydro-Québec International Transmisión Sudamérica S.A. and International Finance Corporation (the "Sellers"). The Company accounted for the business combination using the purchase method of accounting. The cost of acquisition was allocated to identifiable net assets on the basis of the estimated fair values at the date of purchase. The excess of acquisition costs over the net assets acquired stated at fair values was allocated to goodwill.

In accordance with the terms of the Purchase Agreement the purchase price was subject to two adjustments dependent on the results of the trunk transmission tariff process developed in accordance with the Short Law enacted on March 13, 2004. The trunk transmission tariff process was concluded with the issuance—on January 15, 2008—of the Trunk Tariff Process Supreme Decree of the Ministerio de Economía, Fomento y Reconstrucción. The first adjustment to the purchase price paid for Transelec and that was pending as of December 31, 2007 was associated to the difference of the investment value (referred to as VI) of some facilities included in the abovementioned Supreme Decree and the value for those facilities established in the Purchase Agreement. The amount of this adjustment was agreed between the Sellers and Transelec being the legal successor of the acquiring entity and paid on April 4, 2008 to the Sellers. The second adjustment related to the recalculation of the revenues by the regulatory organizations Centro de Despacho Económico de Carga ("CDEC") and Centro de Despacho Económico de Carga del Sistema Interconectado del Norte Grande ("CDEC-SING") using as a base new VI of the transmission facilities. Both adjustments, totaling to ThUS$160,808, were recorded in the year ended December 31, 2008 as adjustment to goodwill.

f) Goodwill

The excess of acquisition cost over the net assets acquired in the business combination and stated at fair values was allocated to goodwill. Goodwill is not amortized and is reviewed annually for impairment. A two-step impairment test is used to identify potential goodwill impairment and measure the amount of a goodwill impairment loss to be recognized, if any:

(1) The fair value of a reporting unit is compared with its carrying amount, including goodwill, in order to identify a potential impairment. When the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not to be impaired and the second step of the impairment test is unnecessary.

(2) When the carrying amount of a reporting unit exceeds its fair value, the fair value of the reporting unit's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. When the carrying amount of reporting unit goodwill exceeds the fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess.

For the purpose of testing goodwill for impairment, all goodwill acquired was assigned to one reporting unit—Transelec. No impairment losses were recognized in the periods covered by these consolidated financial statements.

g) Reporting currency and foreign currency translation

The Company keeps its accounting records and prepares financial statements in U.S. dollars. Transelec that is considered a self-sustaining subsidiary keeps its accounting records in Chilean pesos ("Ch$"). Financial statements of Transelec have been translated to U.S. dollars using the current rate method and exchange gains and losses arising from the translation were recognized in a separate component of other comprehensive income.

Exchange rate in effect at the balance sheet date used to translate assets and liability items was as follows:

	As of December 31	
	2008 Ch$	**2007 Ch$**
US$	**636.45**	496.89

Other foreign currency transactions are translated using the temporal method. Translation gains and losses are included in income for the period.

Index-linked assets and liabilities

Transelec has certain assets and liabilities that are denominated in index-linked units of account that are stated at the year-end values of the respective units of account. The principal index-linked unit used in Chile is the Unidad de Fomento ("UF"), which is adjusted daily to reflect the changes in Chile's Consumer Price Index. As of December 31, 2008 and 2007 values for the UF were as follows:

	As of December 31	
	2008 Ch$	**2007 Ch$**
UF	**21,452.57**	19,622.66

h) Cash and cash equivalents and Statement of Cash Flows

The consolidated statements of cash flows have been prepared using the indirect method. Cash and cash equivalents presented in the consolidated statements of cash flows include cash on hand, time deposits, and other highly liquid short-term investment with an original maturities of three months or less when purchased and are detailed as follows:

US$ THOUSANDS	As of December 31 2008	2007
Cash and bank	**$ 4,244**	$ 980
Time deposits	**126,100**	68,802
Repurchase agreements	**—**	5,521
Total	**$130,344**	$75,303

Time deposits are recorded at cost plus accrued interest and UF indexation adjustments, when applicable. Average interest rate on the term deposits was 5.0% as of December 31, 2008 and 6.4 % as of December 31, 2007.

Purchase commitments with resale agreements are valued at the investment value (cost) plus indexation adjustments and interest.

i) Property, plant, and equipment

Property, plant and equipment are stated at acquisition cost less accumulated depreciation and any accumulated impairment losses. Financing costs are capitalized to property, plant and equipment during the construction period. During the year ended December 31, 2008 and 2007, the financial costs that have been capitalized amounted to ThUS$3,506 and ThUS$1,823, respectively.

Depreciation

The depreciation of property, plant and equipment has been calculated on a straight-line method, based on the estimated useful lives of the assets that for major classes of the property, plant and equipment are as follows:

	Years
Transmission lines	40
Electrical equipment	15-35
Non-hydraulic civil projects	40
Other	3-15

Asset retirement

Some of the Company's transmission lines and other assets may have asset retirement obligations. The majority of the Company's rights-of-way on which such assets are located are of perpetual duration. As the Company expects to use majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligation cannot be made at the balance sheet date. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an asset retirement obligation will be recognized at that time.

Impairment

The carrying values of property plant and equipment are reviewed for impairment when events or changes in circumstances indicate the carrying value may not be recoverable. If any such indication exists and where the carrying values exceed the estimated recoverable amount, the assets or cash-generating units are written down to their recoverable amount.

Derecognition

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period the item is being derecognized.

j) Intangibles

Intangibles include rights-of-way, valued at acquisition cost based on their fair values as of June 30, 2006. Rights-of-way have no expiration term and are considered to have an indefinite useful life. Rights-of-way are not amortized until their lives will be determined to be no longer indefinite. The rights-of-way are assessed for impairment annually or more frequently if events or changes in circumstances indicate that the assets might be impaired. The impairment test consists of a comparison of the fair value of the intangible assets with their carrying amount. When the carrying amount exceeds fair value, an impairment loss is recognized in an amount equal to the excess. Rights-of-way amounted to ThUS$215,760 and to ThUS$273,670 as of December 31, 2008 and 2007, respectively.

Other intangibles presented on the consolidated balance sheet include value of the off-market contracts acquired in the business combination. Those contracts are stated at acquisition cost less accumulated amortization. Those intangibles are amortized over period of respective contracts. Remaining life of the contracts ranges between 4 and 8 years as of December 31, 2008.

k) Bonds payable

The bonds payable acquired in the business acquisition were valued at their fair value as of June 30, 2006 that was considered acquisition cost and since then that cost is amortized. Bonds issued after the acquisition date are initially valued at their fair value. The bonds also accrue interest and are subject to UF indexation adjustments, when applicable.

The portion of the bonds principal and interest that are payable within one year are presented in Current liabilities. The remaining portion is included in the Long-term liabilities.

l) Current and future income taxes

The Company has determined its current income tax assets and liabilities in accordance with Chilean tax regulations.

The Company follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax base, using substantively enacted future income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences that aroused on the acquisition of Transelec (see Note 1 and Note 2e) resulted in future income tax assets and liabilities.

m) Staff severance indemnities

Transelec has—under agreements with its employees—an obligation to pay to the employees who have completed 15 years of service (including service in Transelec's legal predecessors before merger with Rentas Eléctricas IV Limitada and Rentas Electricas III Limitada), staff severance indemnities based on the number of the years of service. The employees receive the payment at the time their employment contract ends (and based on latest salary before the termination) due to retirement or voluntary resignation. In addition some employees have additional benefit determined as fixed amount in UF as of December 1, 2000 that will be paid at the time of termination of their contracts. The cost of these non-pension benefits has been determined based on the management's best estimates and accrued as a liability as employees render service.

n) Revenue recognition and tariff-setting

The regulatory framework that governs electrical transmission activity in Chile comes from the By—Law of the Electric Services dated 1982 (DFL(M) No. 1/82), and subsequent amendments thereto, including Law 19.940 (called also the "Short Law") enacted on March 13, 2004. These are complemented by the By—Law of the Electric Services Regulations dated 1997 (Supreme Decree No. 327/97 of the Mining Ministry), and its amendments, and by the Technical Standard for Liability and Quality of Service (R.M.EXTA No. 40 dated May 16, 2005) and subsequent amendments thereto.

The Company's revenues correspond mainly to remuneration from the use of its electricity transmission facilities. This remuneration is earned in part from arrangements subject to the tariff regulation and in part from contractual arrangements with the users of the transmission facilities. The total remuneration for the use of the transmission facilities for both regulated and contractual arrangements includes in general two components: i) the AVNR, which is the annuity of the New Replacement Value (VNR), calculated in such a way that the present value of these annuities, using an annual real discount rate and the economic useful life of each of the facilities equals the cost of replacing the existing transmission facilities with new facilities with similar characteristics at current market prices, plus, ii) the COyM, which corresponds to the cost required to operate, maintain and administrate the corresponding transmission facilities.

Revenues generating from both regulatory and contractual arrangements are recognized and invoiced on a monthly basis, using fixed monthly amounts resulting from the application of the AVNR and COyM values stipulated in the contracts or resulting from the regulated tariffs and indexed as applicable. The transmission service is invoiced usually at the beginning of the month following the month when the service was rendered and thus the revenue recognized each month includes transmission service provided but not invoiced up to the month end.

o) Derivative contracts and hedging

The subsidiaries Transelec Holdings Rentas Limitada and Transelec selectively utilize derivative financial instruments primarily to manage financial risks, principally foreign exchange risk. Hedge accounting is applied when the derivative is designated as a hedge of a specific exposure and there is reasonable assurance that it will continue to be effective as hedge based on an expectation of offsetting cash flows or fair value.

Realized and unrealized gains and losses on cross currency swaps and forwards designated as hedges of currency risks related to a net investment in Transelec (considered a self-sustaining subsidiary with functional currency different from currency of the parent company) are included in the Other Comprehensive Income.

Derivative financial instruments that are not designated as hedges or do not meet hedge effectiveness criteria are carried at estimated fair values, and gains and losses arising from changes in fair values are recognized in income or loss in the period the changes occur and are classified in Other financial income (expense).

Derivative instruments are separately stated on the balance sheet depending on their nature as assets or liabilities.

p) Vacation accrual

The annual cost of staff vacation is recognized as an expense in the financial statements on an accrual basis.

q) Reclassifications

Certain amounts in the prior year's financial statements have been reclassified to conform to the current year's presentation.

3. Current and Future Income Taxes

a) General information

Each consolidated entity prepares and files its individual income tax return. During the year 2008 Rentas Eléctricas I Limitada and Transelec S.A. had taxable losses. Transelec Holdings Rentas Limitada and Transelec Norte S.A. had taxable income.

b) Recoverable—Payable income taxes

As of December 31, 2008 and 2007 the recoverable income taxes are composed as follows:

	As of December 31,	
US$ THOUSANDS	**2008**	**2007**
Provision for income taxes	**$(10,475)**	$ (838)
Provisory income tax payments	**4,627**	5,777
Receivable from tax losses absorbed	**9,678**	2,411
Other	**(601)**	—
Total	**$ 3,229**	$7,350

c) Income tax recovery

The composition of the net income tax benefit (charge) for the years ended December 31, 2008 and 2007 including the effects of future income taxes is as follows:

	As of December 31,	
US$ THOUSANDS	**2008**	***(Restated, Note 2c)*** **2007**
Current income tax	**$(10,475)**	$ (838)
Effect of future income taxes	**7,960**	23,008
Total	**$ (2,515)**	$22,170

d) Future income taxes

As of December 31, 2008 and 2007, the future income taxes, are composed as follows:

US$ THOUSANDS Temporary differences	As of December 31, 2008				As of December 31, 2007 (*Restated—Note 2c*)			
	Future income tax assets		Future income tax liabilities		Future income tax assets		Future income tax liabilities	
	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term	Short-term	Long-term
Staff vacation accrual	**251**	**—**	**—**	**—**	235	—	—	—
Leased assets	**—**	**—**	**—**	**—**	—	77	—	—
Property, plant and equipment	**—**	**114,280**	**—**	**—**	—	116,068	—	—
Intangibles	**—**	**—**	**—**	**14,695**	—	—	—	21,872
Prepaid expenses	**—**	**—**	**—**	**3,498**	—	—	—	4,681
Forward contracts	**—**	**—**	**100**	**—**	1,563	—	—	—
Tax losses(1)	**—**	**10,670**	**—**	**—**	—	36,340	—	—
Swap contracts	**—**	**—**	**—**	**7,575**	—	193	—	—
Embedded derivatives	**—**	**—**	**—**	**—**	—	—	—	—
Bonds	**—**	**6,854**	**—**	**—**	—	9,959	—	—
Off-market contracts	**—**	**—**	**—**	**2,936**	—	—	—	5,255
Staff severance indemnities	**—**	**—**	**—**	**428**	—	—	—	455
Other	**88**	**896**	**—**	**59**	811	—	—	—
Total future income taxes	**339**	**132,700**	**100**	**29,191**	2,609	162,637	—	32,263
Net future income tax assets/liabilities	**239**	**103,509**	**—**	**—**	2,609	130,374	—	—

(1) Total amount of the unused tax losses on which future tax asset was recognized was ThUS$ 62,764 as of December 31, 2008. In accordance with current Chilean tax regulations, tax losses do not expire.

4. Other Current Assets

The detail of the other current assets as of December 31, are as follows:

US$ THOUSANDS	As of December 31, 2008	As of December 31, 2007
Guarantee deposit (restricted cash)	**$—**	$5,830
Accrued interest on the long-term bank deposit (restricted cash)	**234**	780
Other	**77**	359
Total	**$311**	$6,969

5. Property, Plant and Equipment

Property, plant and equipment are detailed in the table below:

US$ THOUSANDS	As of December 31, 2008 Cost	As of December 31, 2008 Accumulated depreciation	As of December 31, 2008 Net book value	As of December 31, 2007 Cost	As of December 31, 2007 Accumulated depreciation	As of December 31, 2007 Net book value
Land	**$ 26,201**	**$ —**	**$ 26,201**	$ 30,760	$ —	$ 30,760
Buildings and infrastructure:						
Buildings	**20,625**	**(1,551)**	**19,074**	25,638	(1,127)	24,511
Access roads	**886**	**(43)**	**843**	1,137	(23)	1,114
Transmission lines	**860,595**	**(49,866)**	**810,729**	1,069,261	(39,472)	1,029,789
Houses and apartments	**123**	**(9)**	**114**	158	(6)	152
Non-hydraulic civil projects	**170,334**	**(12,400)**	**157,934**	214,289	(8,997)	205,292
Works in progress	**54,219**	**—**	**54,219**	75,875	—	75,875
Total buildings and infrastructure	**1,106,782**	**(63,869)**	**1,042,913**	1,386,358	(49,625)	1,336,733
Machinery and equipment:						
Telecommunications equipment	**11,389**	**(3,527)**	**7,862**	14,429	(2,637)	11,792
Furniture, machinery and office equipment	**216**	**(81)**	**135**	268	(54)	214
Service furniture and equipment	**65**	**(12)**	**53**	62	(7)	55
Tools and instruments	**2,089**	**(331)**	**1,758**	2,249	(228)	2,021
Power generation unit	**1,695**	**(308)**	**1,387**	2,112	(221)	1,891
Electrical equipment	**413,894**	**(35,527)**	**378,367**	474,202	(25,761)	448,441
Mechanical, protection and measurement equipment	**49,858**	**(14,425)**	**35,433**	59,895	(10,186)	49,709
Transport and loading equipment	**524**	**(192)**	**332**	627	(132)	495
Computers and software	**4,942**	**(2,871)**	**2,071**	4,489	(1,569)	2,920
Total machinery and equipment	**484,672**	**(57,274)**	**427,398**	558,333	(40,795)	517,538
Other property, plant, and equipment:						
Construction materials	**2,083**	**—**	**2,083**	2,630	—	2,630
Total other property, plant, and equipment	**2,083**	**—**	**2,083**	2,630	—	2,630
Total property, plant and equipment	**$1,619,738**	**$(121,143)**	**$1,498,595**	$1,978,081	$(90,420)	$1,887,661

Depreciation for the year ended December 31, 2008 amounted to ThUS$62,752 (ThUS$59,935 for the year ended December 31, 2007).

Assets under construction classified as Work in progress in the table above are not being depreciated yet.

6. Bonds Payable

The detail of bonds payable as of December 31, 2008 and 2007 is as follows:

Registration or identification number of the instrument	Series	Nominal amount placed	Currency or Indexation unit	Effective interest rate	Maturity date	Periodicity: Interest payment	Periodicity: Principal payment	As of December 31, 2008: Book value (US$ THOUSANDS)	As of December 31, 2007: Book value (US$ THOUSANDS)	Principal/ Interest
Current portion of long-term bonds:										
249	B1	3,949	UF	4.44%	Mar 1, 2009	Semiannually	Semiannually	**$ 164**	$ 159	Interest
249	B2	59,236	UF	4.44%	Mar 1, 2009	Semiannually	Semiannually	**2,473**	2,388	Interest
First issuance	Single	7,946,777	US$	6.71%	Apr 15, 2009	Semiannually	At maturity	**13,690**	7,947	Interest
249	B1	2,000	UF	4.44%	Mar 1, 2009	Semiannually	At maturity	**84**	—	Principal
249	B2	30,000	UF	4.44%	Mar 1, 2009	Semiannually	At maturity	**1,253**	—	Principal
249	B1	2,000	UF	4.44%	Sep 1, 2009	Semiannually	Semiannually	**84**	157	Principal
249	B2	30,000	UF	4.44%	Sep 1, 2009	Semiannually	Semiannually	**1,253**	2,370	Principal
481	D	23,658	UF	4.37%	Jun 15, 2009	Semiannually	At maturity	**797**	998	Interest
480	C	69,398	UF	3.03%	Mar 1, 2009	Semiannually	At maturity	**2,339**	2,741	Interest
First issuance	Private placement	1,703	US$	6.60%	Feb 2, 2009	Semiannually	At maturity	**1,244**	1,703	Interest
Total current portion of bonds payable								**$ 23,381**	$ 18,463	
Long-term bonds payable:										
249	B1	190,000	UF	4.44%	Mar 1, 2022	Semiannually	Semiannually	**7,198**	8,740	Principal
249	B2	2,850,000	UF	4.44%	Mar 1, 2022	Semiannually	Semiannually	**107,975**	131,104	Principal
First issuance	Single	465,000,000	US$	6.71%	Apr 15, 2011	Semiannually	At maturity	**472,658**	484,145	Principal
481	D	13,500,000	UF	4.37%	Dec 15, 2027	Semiannually	At maturity	**455,039**	533,128	Principal
480	C	6,000,000	UF	3.03%	Sep 1, 2016	Semiannually	At maturity	**202,240**	236,946	Principal
First issuance	Private placement	150,000,000	US$	6.60%	May 2, 2013	Quarterly	At maturity	**150,000**	150,000	Principal
Debt issuance costs								**(16,487)**	(22,444)	
Total long-term bonds payable								**$1,378,623**	$1,521,619	

Following is a schedule of the long-term debt (bonds) maturity in each of the five years beginning on January 1, 2009 and 2008 and thereafter:

US$ THOUSANDS Year	As of December 31, 2008	As of December 31, 2007
2008	**$ —**	$ 2,527
2009	**2,157**	2,527
2010	**2,157**	2,527
2011	**486,684**	489,200
2012	**4,314**	5,055
2013	**154,314**	155,055
Thereafter	**752,378**	883,191
Total	**$1,402,004**	$1,540,082

7. Bank Loans

Following is a schedule of the long-term bank maturity in each of the five years beginning on January 1, 2009 and 2008 and thereafter:

US$ THOUSANDS Year	As of December 31, 2008	2007
2008	**$ —**	$ —
2009	**—**	—
2010	**884,741**	840,234
2011	**—**	—
2012	**—**	—
2013	**—**	—
Thereafter	**—**	—
Total	**$884,741**	$840,234

As of December 31, 2008 and 2007 the balance of the bank loans corresponds to loan obtained from Scotia & Trust (Cayman) Ltd. The loan bears interest of 6 months LIBOR plus 3%. Effective interest rate of the loan is 4.85% as of December 31, 2008.

8. Fair Value of Financial Instruments and Risk Management

a) Classification of financial instruments

The classification of financial instruments under the new accounting standards effective January 1, 2008 (see Note 2c), and their carrying amounts are as follows:

US$ THOUSANDS	As of December 31, 2008				As of December 31, 2007			
Financial assets	HFT(1)	L&R(2)	HTM(3)	Total	HFT(1)	L&R(2)	HTM(3)	Total
Cash and cash equivalents	**$130,344**	**$ —**	**$ —**	**$ 130,344**	$75,303	$ —	$ —	$ 75,303
Trade accounts receivable	**—**	**$51,365**	**—**	**51,365**	—	47,021	—	47,021
Guarantee deposit (restricted)	**—**	**—**	**—**	**—**	5,830	—	—	5,830
Accrued interest on the long-term bank deposit (restricted)(4)	**—**	**—**	**234**	**234**	—	—	780	780
Derivative financial instruments, including:								
Not designated for hedge accounting(5)	**91,376**	**—**	**—**	**91,376**	—	—	—	—
Designated as hedges of net investment and cash flow hedges(6)	**56,688**	**—**	**—**	**56,688**	—	—	—	—
Long-term bank deposit	**—**	**—**	**890,064**	**890,064**	—	—	848,813	848,813
Investments in other companies	**501**	**—**	**—**	**501**	429	—	—	429
Long-term receivables	**—**	**2,456**	**—**	**2,456**	—	3,085	—	3,085
Total	**$278,909**	**$53,821**	**$890,298**	**$1,223,028**	$81,562	$50,106	$849,593	$981,261

US$ THOUSANDS **Financial liabilities**	**As of December 31, 2008** HFT(1)	Other than HFT(1)	**As of December 31, 2007** HFT(1)	Other than HFT(1)
Accounts payable and other short-term payables	**$ —**	**$ 58,055**	$ —	$ 105,215
Debt (including current and non-current portion)	**—**	**2,288,072**	—	2,382,645
Derivatives financial instruments, including:				
Not designated for hedge accounting(7)	**33,918**	**—**	100,840	—
Designated as hedge of net investment(8)	**—**	**—**	9,479	—
Other long-term payables	**—**	**4,626**	—	3,047
Total	**$33,918**	**$2,350,753**	$110,319	$2,490,907

(1) *Held for trading.*
(2) *Loans and receivables.*
(3) *Held-to-maturity.*
(4) *Classified in other current assets.*
(5) *Classified in other non-current assets.*
(6) *ThUS$6,740 classified in other current assets and ThUS$49,948 in other non-current assets.*
(7) *Includes current and non-current portion.*
(8) *Classified in other non-current liabilities.*

b) Fair value of financial instruments

The carrying amount of all financial instruments, except for long-term bonds, approximates their fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would be required to pay or would be entitled to receive at the balance sheet date. The fair values of the long-term bonds payable, based on year-end quoted market prices for the same or similar debt instruments of the same remaining maturities, are provided in the following table:

US$ THOUSANDS **Description**	**As of December 31, 2008** Carrying value	Fair value	**As of December 31, 2007** Carrying value	Fair value
Long-term bond payable	**1,378,623**	**1,348,715**	1,521,619	1,534,830

c) Use of derivatives

Transelec entered into eleven US$/UF cross currency swaps contracts totaling to ThUS$270,000 to hedge part of its exchange rate risk exposure related to bonds denominated in US$. Initially part of those swaps were designated as cash flow hedges, however given ineffectiveness observed after the inception date hedge accounting was not applied and all changes in the fair value of the swaps are recorded in income. Fair value of the swap contracts recognized on the consolidated balance sheet amounts to ThUS$16,876 (net liability) as of December 31, 2008, and to ThUS$100,840 (liability) as of December 31, 2007. The swaps contracts mature in 2011 (the same maturity as the debt being hedged).

As of December 31, 2008 Transelec has also opened 6 foreign currency forwards to sell ThUS$54,000 designated as cash flow hedges to mitigate the short-term impact of fluctuations in the exchange rate on the revenues stream. The fair value recognized on the balance sheet as of December 31, 2008 amounts to ThUS$588 (asset). The contracts mature during the 1st semester of 2009.

As of December 31, 2007, Transelec had opened 3 forward contracts to buy ThUS$12,400 not designated for hedge accounting. The fair value of these forward contracts recognized on the consolidated balance sheet was ThUS$284 (liability) as of December 31, 2007. The contracts expired in 1st quarter of 2008.

The subsidiary Transelec Holdings Rentas Limitada uses financial derivative instruments (US$/Ch$ forwards and swaps) as hedge of a portion of its net investment in Transelec controlled in Chilean pesos in order to reduce the exposure to changes in currency exchange rates. The nominal amount of these contracts was ThUS$250,000 as of December 31, 2008 and ThUS$530,451 as of December 31, 2007. Changes in the fair value of these derivative contracts are recorded in other comprehensive income (loss). Amounts excluded from the measure of effectiveness of net investment hedges are recognized in earnings in the period in which they arise. Fair values of the derivatives recognized on the consolidated balance sheet were ThUS$ 56,100 (asset) as of December 31, 2008 and ThUS$9,195 (liability) at December 31, 2007.

On August 8, 2008, Transelec Holdings Rentas Limitada entered into eighteen US$/UF cross currency swap contracts totaling to ThUS$345,000. The swaps are considered as economic cash flow hedges to offset the variability of expected future cash flows related to US$ debt, however hedge accounting was not applied and all changes in the fair value of the swaps are recorded in income. Fair value of the swap contracts recognized on the consolidated balance sheet amounts to ThUS$74,332 (asset) as of December 31, 2008. The swaps contracts mature in 2011 (the same maturity as the debt being hedged).

d) Risk management

The Company is exposed to the following risks as a result of holding financial instruments: market risk (i.e. interest rate risk, currency risk and other price risks that impact the fair values of financial instruments); credit risk; and liquidity risk. The following is a description of these risks and how they are managed:

Market risk

Market risk is defined for these purposes as the risk that the fair value or future cash flows of a financial instrument held by the Company will fluctuate because of changes in market prices. Market risk includes the risk of changes in interest rates, currency exchange rates and changes in market prices due to factors other than interest rates or currency exchange rate such as equity prices, commodity prices or credit spreads.

The Company endeavours to maintain a matched position in respect of the book values of foreign currency assets and liabilities and the impact of changes in interest rates on net income from floating rate assets and liabilities. This is achieved generally by intent of funding assets with financial liabilities in the same currency and with similar interest rate characteristics and holding financial contracts such as interest rate and foreign exchange derivatives to minimize residual exposures. Unmatched positions are carried from time to time within predetermined limits, principally to reduce borrowing costs or when hedging is impractical or uneconomic. Financial instruments held by the Company that are subject to market risk include principally borrowings and derivative instruments such as interest rate and currency swaps and forwards. The categories of financial instruments that can potentially give rise to significant variability are described in the following paragraphs.

Interest rate risk

The observable impacts on the fair values and future cash flows of financial instruments that can be directly attributable to interest rate risk include changes in the net income from financial instruments whose cash flows are determined with reference to floating interest rates and changes in the value of financial instruments whose cash flows are fixed in nature.

The Company's assets largely consist of long duration physical assets. Accordingly, the Company's financial liabilities consist primarily of long-term fixed rate debt or floating rate debt that partially has been swapped to fixed rates with interest rate derivatives. Debts instruments are recorded on the balance sheet are at their amortized cost.

The result of a 50 basis point increase in interest rates on the Company's net floating rate between assets and liabilities (swap) would have resulted in a corresponding increase in net income before tax of US$0.7 million as at December 30, 2008 on an annualized basis.

The Company holds financial instruments to hedge the net investment in self-sustaining operation whose functional currency is other than the U.S. dollar (Transelec). The result of a 50 basis point increase in interest rates on the Company's net floating rate between assets and liabilities (swap) would have resulted in a corresponding decrease the value of these hedging instrument by US$0.9 million as at December 31, 2008, which would be recorded in other comprehensive income and offset by changes in the U.S. dollar carrying value of the net investment being hedged.

Currency risk

Changes in currency rates will impact the carrying value of financial instruments denominated in currencies other than functional currencies of the consolidated entities in addition to any changes in the value of the financial instruments in the relevant currency due to other risks.

The Company has bonds payable denominated in Unidad de Fomento (UF), changes in the translated value of which are recorded in net income. The impact of a 1% change in the U.S. dollar against UF would result in a US$6.3 million gain (loss).

The Company holds financial instruments to hedge the net investment in self-sustaining operation whose functional currency is other than the U.S. dollar (Transelec). A 1% increase in the U.S. dollar exchange rate would increase the value of these hedging instruments by US$2 million as at December 31, 2008, which would be recorded in other comprehensive income and offset by changes in the U.S. dollar carrying value of the net investment being hedged.

Credit risk

Credit risk is the risk of loss due to the failure of a borrower or counterparty to fulfill its contractual obligations causing a financial loss. The Company's exposure to credit risk in respect of financial instruments relates primarily to counterparties obligations regarding accounts receivable, bank deposits and derivative contracts.

The Company assesses the credit worthiness of each counterparty before entering into contracts and ensures that counterparty meet minimum credit quality requirements. Management evaluates and monitors counterparty credit risk for bank deposits and derivative financial instruments and endeavours to minimize counterparty credit risk through diversification and other credit risk mitigation techniques. The credit risk of derivative financial instruments is limited to the positive fair value of the instruments which tends to be a relatively small proportion of the notional value. Substantially all of the Company's derivative financial instruments involve counterparties that are branches of global banks or other financial institutions with high credit ratings from international credit rating agencies. The Company does not expect to incur credit losses in respect of any of these counterparties.

The Company monitors also its credit risk exposure related to accounts receivable from clients on an on-going basis and periodically evaluates necessity to establish allowances for doubtful accounts based on the information about counterparty financial condition. Currently management believes there is no significant credit risk related to its receivables. The maximum exposure in respect to receivables is equal to their carrying value.

The Company earns a significant part of its revenues (approx. 71% in the year ended December 31, 2008) from one client, which is a Chilean electricity generating company. As of December 31, 2008 approx. 34% of the trade accounts receivable are due from that client.

Liquidity risk

Liquidity risk is the risk that the Company cannot meet a demand for cash or fund an obligation as it comes due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price.

To ensure the Company is able to react to investment opportunities quickly and on a value basis as well as to pay its obligations on due dates, the Company maintains relatively high level of liquidity. The primary source of liquidity consists of cash and cash equivalents as well as trade accounts receivable. As of December 31, 2008 Transelec has 3 unused credit line facilities totaling to ThUS$60,000 and available to finance working capital needs of which ThUS$15,000 expire in March 2009, ThUS$15,000 expire in November 2009 and ThUS$30,000 expire in February 2010. In addition, Transelec has available unused credit facility of up to UF3.2 million (approx. ThUS$108,000) available up to September 2010 to finance expansion projects or refinance debt.

The Company is subject to the risks associated with debt financing, including the ability to refinance indebtedness at maturity.

These risks are mitigated through the use of long-term debt secured by high quality assets, maintaining debt levels that are in management's opinion relatively conservative, and by diversifying maturities over an extended period of time.

9. Accrued Liabilities and Provisions

Accrued liabilities as of December 31, 2008 and 2007 are composed as follows:

US$ THOUSANDS **Description**	**As of December 31, 2008**	**2007**
Accrued payroll	**$3,099**	$3,132
Vacation accrual	**1,477**	1,382
Staff severance indemnities (short-term portion)	**949**	936
Total	**$5,525**	$5,450

Long-term provisions presented on the balance sheet as of December 31, 2008 includes obligation for staff severance indemnities of ThUS$3,022 (ThUS$2,971 as of December 31, 2007) determined in accordance with accounting policy described in the Note 2m). Total amount of cost benefit for staff severance indemnities recognized in the year ended December 31, 2008 was ThUS$655 (ThUS$1,381 in the period ended December 31, 2007).

10. Shareholders' Equity

The detail of changes in the Shareholders' Equity during the year ended December 31, 2008 and 2007 is shown in the table below:

US$ THOUSANDS	Paid-in capital	Distributions	Other comprehensive income	Deficit	Total
Balance as of January 1, 2007	$ 348,812	$ —	$ (1,674)	$ (11,232)	$ 335,906
Increase of capital	858,759	—	—	—	858,759
Distributions	—	(35,167)	—	—	(35,167)
Translation gain on the net investment in self-sustaining operation	—	—	98,086	—	98,086
Loss on hedging instruments	—	—	(31,541)	—	(31,541)
Net loss for the year	—	—	—	(37,467)	(37,467)
Balance as of December 31, 2007 *(Restated)*	1,207,571	(35,167)	64,871	(48,699)	1,188,576
Increase of capital	160,808	—	—	—	160,808
Distributions	—	(43,728)	—	—	(43,728)
Translation loss on the net investment in self-sustaining operation	—	—	(313,113)	—	(313,113)
Gain on hedging instruments	—	—	56,360	—	56,360
Net income for the year	—	—	—	104,027	104,027
Balance as of December 31, 2008	$1,368,379	$(78,895)	$(191,882)	$ 55,328	$1,152,930

As of December 31, 2008 and 2007 the authorized share capital was divided into 1,400,012,000 shares of nominal value of US$1 per share.

On June 27, 2007 the shareholders decided that the principal amount of each holder's promissory convertible notes outstanding at that date and totaling to ThUS$858,759 be immediately converted into such number of ordinary shares of the Company as contemplated by such holder's note agreement and any accrued and unpaid interest amounts owing under such holder's note on the conversion date shall become payable in cash. Following the conversion the Company's shareholders keep the same percentage of the ownership interest in the Company as existing before the conversion.

On December 27, 2007, July 11, 2008 and December 29, 2008 the Company distributed to its shareholders funds amounting to ThUS$35,167, ThUS$36,412 and ThUS$7,316 respectively.

Shareholders in the Company and their participation are as follows as of December 31, 2008 and 2007:

Shareholder	Participation as of December 31, 2008	Participation as of December 31, 2007
CPP Investment Board Private Holding Inc.	**27.728%**	27.744%
BIP Bermuda Holdings III Limited	**17.750%**	10.700%
Bryson International Limited	**10.036%**	17.044%
4358520 Canada Inc.	**22.101%**	22.114%
4358538 Canada Inc.	**3.900%**	3.902%
Infra—PSP Canada Inc.	**18.485%**	18.496%
Total	**100.000%**	100.000%

11. Capital Management

The capital of the Company consists of the components of shareholders' equity as presented on the Company's consolidated balance sheet.

The Company's objectives when managing this capital is to maintain an appropriate balance between holding a sufficient amount of capital to support its operations and providing shareholders with a prudent amount of leverage to enhance returns. Company's financial debt, which consists of debt of consolidated subsidiaries and totaling to ThUS$2,288,072 million at December 31, 2008 (ThUS$2,382,645 million as of December 31, 2007). Part of this debt is secured by the long-term bank deposit that the Company has in Scotiabank & Trust (Cayman) Ltd. amounting to ThUS$890,064 million and ThUS$848,813 million as of as of December 31, 2008 and 2007, respectively.

The Company is in full compliance with capital requirements and covenants related to equity as of December 31, 2008.

12. Contingencies and Restrictions

The Company is subject to some covenants in respect of its corporate debt and is in full compliance with all such covenants as at December 31, 2008.

a) Pledge on assets

In January 2008, the Company requested an irrevocable standby letter of credit for US$41,600,000 to secure the Debt Service Escrow to Bank of Nova Scotia Agreed by Transelec S.A in the Bond debts Indentures.

In February 2008, the Company requested an irrevocable standby letter of credit for US$4,000,000 to secure the Debt Service Escrow to Bank of Nova Scotia Agreed by Transelec S.A in the Bond debts Indentures.

On June 29, 2007 the Company's subsidiaries Transelec Holdings Rentas Limitada and Rentas Electricas I Limitada which directly hold 100% of interest in Transelec S.A. pledged their shares in Transelec and Transelec Norte S.A. in favor of The Bank of Nova Scotia, HSBC Bank Canada, The Bank of New York and holders of the bonds issued by Transelec Holdings Rentas Limitada to secure its obligations to those entities resulting from the issuance of the bonds in private placement made in February 2007. The outstanding balance of the bonds (including accrued interest) amounts to ThUS$151,245 and ThUS$151,703 as of December 31, 2008 and December 31, 2007, respectively.

ETC Holdings Ltd. holds funds amounting to ThUS$890,064 and ThUS$848,813 as of December 31, 2008 and 2007, respectively in the long-term bank deposit account in Scotiabank & Trust (Cayman) Ltd. Those funds are pledged to secure a bank loan provided by the same institution to subsidiary Rentas Eléctricas I Limitada. The outstanding balance of the loan payable classified in long-term liabilities amounts to ThUS$884,741 and ThUS$840,234 as of December 31, 2008 and 2007, respectively. In the event of default Scotiabank & Trust (Cayman) Ltd. has a right to set off and apply the deposit against the loan.

b) Litigations, lawsuits and demands from regulators

1. On December 5, 2002, the Superintendency of Electricity and Fuel (SEC) in Ordinary Official Letter No. 7183, charged the Company for its alleged responsibility in the interruption of electrical supply in the Central Interconnected System (SIC) on September 23, 2002. The Company presented the answers in a timely manner and these were added to the corresponding evidence. By Exempt Resolution No. 1438 of August 14, 2003, the Superintendency applied various fines to Transelec for a total of Annual Tax Units (UTA) 2,500 equivalent as of December 31, 2008 to ThUS$1,775. As of December 31, 2008, the Company had appealed the complaint before the Santiago Court of Appeals,

and placed a deposit of 25% of the original fine. The Company maintains that it is not responsible for this situation since it considers it a case of force majeure.

2. In Ordinary Official Letter No. 1210 dated February 21, 2003 the SEC filed charges for the alleged responsibility of Transelec in the interruption of electric service in the SIC, on January 13, 2003. By Resolution No. 808, of April 27, 2004, the SEC imposed a fine of 560 UTA equivalent as of December 31, 2008, to ThUS$398, against which a writ of administrative reconsideration was filed, which was rejected. The Company appealed the complaint before the Santiago Court of Appeals and placed a deposit of 25% of the original fine. The Company maintains that it is not responsible for this situation since it considers it a case of force majeure.

3. On September 30, 2005 the SEC through Exempt Resolution No. 1117, applied the following sanctions to the Company: a fine of 560 UTA equivalent as of December 31, 2008 to ThUS$450, for allegedly not having coordinated to ensure electric service, as determined in the investigation of the general failure of the SIC on November 7, 2003; a fine of 560 UTA equivalent as of December 31, 2008, to ThUS$398, in the Company's condition as the owner of the installations, for allegedly operating the installations without adhering to the operation scheduling set forth by the CDEC-SIC, without justified cause, as determined in the investigation of the general failure of the SIC on November 7, 2003. As of December 31, 2008, the Company had appealed the charges before the SEC, which is pending resolution; Management believes it has no responsibility in these events.

4. On December 17, 2004, the SEC through Exempt Resolution No. 2334 fined the Company 300 UTA, equivalent as of December 31, 2008, to ThUS$213, for its alleged responsibility in the interruption of electrical supply south of Temuco, caused by a truck crashing into a structure of the Charrúa—Temuco line. As of December 31, 2008, the Company had filed a motion of invalidation and administrative reconsideration, firmly sustaining that it was a case of force majeure and that the charges are not applicable and should be annulled.

5. On December 31, 2005, the SEC through Official Letter No. 1831, filed charges against the Company for allegedly infringing on various provisions of the electrical regulations while operating its installations, which would have caused the interruption of electrical supply in the SIC on March 21, 2005. By SEC Exempt Resolution SEC No. 220, of February 7, 2006, the Company was fined 560 UTA equivalent as of December 31, 2008, to ThUS$398. An appeal was filed to order generation of power again on February 16, 2006, which is still outstanding. As of December 31, 2008, the Company had presented the required evidence.

As of December 31, 2008, the Company has recognized a provision for these contingent obligations for the amount of ThUS$2,787. This estimation considers the fact that similar cases are being heard in the Appeals Court, and that, the Appeals Court and Supreme Court have confirmed the decision of the SEC. In addition, there are similar cases with a reconsideration petition before the SEC for which the SEC has maintained the previously established fines.

c) Guarantees

At the Company's request Banco Santander Chile gave guarantees totaling ThUS$1,933 and ThUS$533 as of December 31, 2008 and 2007, respectively to the Chilean Ministry of Economy, Development and Reconstruction and some other parties to ensure completion by the Company of certain works related to the transmission system.

As of December 31, 2008 and 2007, the Company has received financial guarantees from contractors and third parties, mainly to guarantee the completion of construction and maintenance work amounting to ThUS$16,937 and ThUS$16,229, respectively.

13. Differences Between Canadian and United States Generally Accepted Accounting Principles

Canadian GAAP varies in certain respects from US GAAP. Such differences involve certain methods for measuring the amounts shown in the financial statements that are discussed below. The principal methods applied in the preparation of the accompanying financial statements which have resulted in the amounts which differ from those that would have otherwise been determined under US GAAP are described below.

The reconciliations presented below include only differences related to measurement of items in the financial statements and does not contemplate additional disclosures that may be required under US GAAP.

a) Embedded derivatives

The Company entered into certain contracts for electricity transmission that have embedded features corresponding to foreign currency, prices of commodities used in the construction of transmission assets and inflation indexes. As described in the Note 2c) the Company concluded that those indexation features represent embedded derivatives, however those derivatives may not require bifurcation and separate accounting as they are closely related to the economic characteristics and risks of the host contracts under CICA Section 3855. Instead the entire contracts are considered contract-based intangibles acquired in the business combination. Under US GAAP Statement of Financial Accounting Standards No. 133. Accounting for Derivative Instruments and Hedging Activities ("SFAS 133") includes different criteria for considering embedded derivatives as clearly and closely related to the economic characteristics and risks of the host contract, especially with regards to foreign currency derivatives. The Company concluded that the embedded features require bifurcation and fair value accounting with changes in fair value recorded in earnings under SFAS 133. Effects of the bifurcation of the embedded derivatives and their respective tax effects were included as an adjustment in the reconciliation to US GAAP as of and for the years ended December 31, 2008 and 2007 in paragraph b) below.

b) Effects of conforming to US GAAP

The adjustments to reported net income (loss) required to conform to US GAAP were as follows:

US$ THOUSANDS	For the year ended December 31, 2008	2007
Net income (loss) as shown in the Canadian GAAP financial statements	**$ 104,027**	$(37,467)
Embedded derivatives (paragraph a)	**40,604**	14,095
Adjustments of deferred income taxes (paragraph a)	**(6,903)**	(2,396)
Net income (loss) under US GAAP	**137,728**	(25,768)
Other comprehensive (loss) income, net as shown in the Canadian GAAP financial statements	**(256,753)**	66,545
Adjustments to US GAAP	**—**	—
Other comprehensive (loss) income under US GAAP	**(256,753)**	66,545
Total comprehensive (loss) income under US GAAP	**$(119,025)**	$ 40,777

The adjustments to reported Shareholders' equity required to conform to US GAAP were as follows:

US$ THOUSANDS	As of December 31, 2008	2007
Shareholders' equity as shown in the Canadian GAAP financial statements	**1,152,930**	1,188,576
Embedded derivatives (paragraph a)	**54,699**	14,095
Adjustments of deferred income taxes (paragraph a)	**(9,299)**	(2,396)
Shareholders' equity under US GAAP	**1,198,330**	1,200,275

The following summarizes the changes in shareholders' equity under US GAAP during the years ended December 31, 2008 and 2007:

US$ THOUSANDS	For the year ended December 31, 2008	2007
Opening balance	**1,200,275**	335,906
Contribution and increase of capital	**160,808**	858,759
Net investment in self-sustaining foreign operation	**(313,113)**	98,086
Gain (loss) on hedging instruments	**56,360**	(31,541)
Net income (loss) for the year	**137,728**	(25,768)
Distributions	**(43,728)**	(35,167)
Closing balance	**1,198,330**	1,200,275

c) Recent US GAAP accounting pronouncements

Business Combinations and Noncontrolling Interest in Consolidated Financial Statements

In December 2007, FASB issued SFAS No. 141 (revised 2007), "Business Combinations" ("SFAS No. 141(R)"). The objective of SFAS No. 141 (R) is to improve the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. To accomplish that, this Statement establishes principles and requirements for how the acquirer (1) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, (2) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase and (3) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) shall be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. In December 2007, the FASB also issued SFAS No. 160, "Noncontrolling Interest in Consolidated Financial Statements". SFAS No. 160 amends Accounting Research Bulletin No. 51, "Consolidated Financial Statements", to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. According to SFAS No. 160, "a noncontrolling interest, sometimes called a minority interest, is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent". The objective of SFAS No. 160 is to improve the relevance, comparability, and transparency of the financial information that a reporting entity provides in its consolidated financial statements. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The Company is evaluating the impact, if any, of the adoption of SFAS No. 141 (R) and SFAS No. 160.

Hierarchy of Generally Accepted Accounting Principles

In May 2008, the FASB issued SFAS No. 162, Hierarchy of Generally Accepted Accounting Principles ("SFAS No. 162"), which identifies the framework, or hierarchy for selecting accounting principles to be used in preparing financial statements presented in conformity with U.S. GAAP. SFAS No. 162 amends the existing U.S. GAAP hierarchy established and set forth in the American Institute of Certified Public Accountants ("AICPA") Statement of Auditing Standards No. 69. The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles ("SAS 69"). The framework serves as a guide in determining the appropriate accounting treatment to be used for a transaction or event. The Company does not expect SFAS No. 162 to have an impact on the Company's current accounting practices. The Standard will become effective 60 days following the SEC's approval of Public Company Accounting Oversight Board ("PCAOB") amendments to AU Section 411. The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles.

Useful Life of Intangible Assets

In April 2008, the FASB issued FSP No. FAS 142-3, Determination of the Useful Life of Intangible Assets ("FSP No. FAS 142-3"), which amends the factors considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142. FSP No. 142-3 requires a consistent approach between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of an asset under SFAS No. 141(R). The FSP also requires enhanced disclosures when an intangible asset's expected future cash flows are affected by an entity's intent and/or ability to renew or extend the arrangement. FSP No. 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, January 1, 2009 for the Company, and is to be applied prospectively. Early adoption is prohibited. The Company is evaluating the impact, if any, of the adoption of FSP No. FAS 142-3.

ISLAND TIMBERLANDS LIMITED PARTNERSHIP

December 31, 2008

CONSOLIDATED FINANCIAL STATEMENTS

ISLAND TIMBERLANDS LIMITED PARTNERSHIP

December 31, 2008

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ISLAND TIMBERLANDS LIMITED PARTNERSHIP

December 31, 2008

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Partners of Island Timberlands Limited Partnership

We have audited the consolidated balance sheet of Island Timberlands Limited Partnership as at December 31, 2008 and the consolidated statements of operations, comprehensive income and accumulated other comprehensive income, partners' equity and cash flows for the year ended. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as at December 31, 2008 and the results of its operations and its cash flows for the year ended in accordance with Canadian generally accepted accounting standards.

/s/ Deloitte & Touche LLP

Independent Registered Chartered Accountants
January 27, 2009

ISLAND TIMBERLANDS LIMITED PARTNERSHIP

CONSOLIDATED STATEMENT OF OPERATIONS

US$thousands	Year ended December 31 2008	2007
Sales	**$184,266**	$212,775
Operating costs and expenses		
Manufacturing and production costs	**128,290**	139,576
Depreciation, depletion and amortization	**18,437**	20,263
Selling, general and administrative	**8,944**	9,001
	155,671	168,840
Operating income	**28,595**	43,935
Other expenses (income)		
Interest expense	**26,979**	26,451
Other expenses (income) *(Note 11)*	**1,108**	(3,859)
Gain on sale of assets *(Note 6)*	**(5,631)**	(7,432)
Return of investment *(Note 1)*	**(223)**	—
Management fee—performance bonus *(Note 4)*	**(35,923)**	8,298
	(13,690)	23,458
Net income for the year	**42,285**	20,477
Allocated as follows:		
Limited Partners interests	**42,285**	20,477
General Partner interest	**—**	—
	$ 42,285	$ 20,477

The accompanying notes are an integral part of these financial statements.

ISLAND TIMBERLANDS LIMITED PARTNERSHIP

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME AND ACCUMULATED OTHER COMPREHENSIVE INCOME

US$thousands	Year ended December 31 2008	2007
Net income	**$42,285**	$20,477
Other comprehensive (loss) income		
Amortization of gain on fair values of derivatives designated as cash flow hedges	**(77)**	(107)
Effect of foreign currency translation of foreign operation	**(30)**	15
Other comprehensive loss	**(107)**	(92)
Comprehensive income	**$42,178**	$20,385
Accumulated other comprehensive income, beginning of year	**5,376**	5,468
Other comprehensive loss	**(107)**	(92)
Accumulated other comprehensive income, end of year	**$ 5,269**	$ 5,376

The accompanying notes are an integral part of these financial statements.

ISLAND TIMBERLANDS LIMITED PARTNERSHIP

CONSOLIDATED STATEMENT OF PARTNERS' EQUITY

US$thousands	Limited Partners	General Partner	Total 2008	Total 2007
Partners' equity, beginning of year	**$433,388**	$ 6	**$433,394**	$452,128
Contributions	**—**	—	**—**	—
Net income	**42,285**	—	**42,285**	20,477
Transitional adjustment	**—**	—	**—**	(23)
Equity Distribution *(Note 1)*	**(223)**	—	**(223)**	—
Distributions	**(5,000)**	—	**(5,000)**	(39,188)
	470,450	6	**470,456**	433,394
Accumulated other comprehensive income	**5,269**	—	**5,269**	5,376
Partners' equity, end of year	**$475,719**	$ 6	**$475,725**	$438,770

The accompanying notes are an integral part of these financial statements.

ISLAND TIMBERLANDS LIMITED PARTNERSHIP

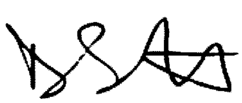
CONSOLIDATED BALANCE SHEET

US$thousands	As at December 31 2008	As at December 31 2007
Assets		
Current assets		
Cash	**$ 6,998**	$ 14,464
Accounts receivable	**2,077**	2,260
Inventories *(Note 5)*	**26,984**	28,882
Prepaid expenses	**750**	1,024
	36,809	46,630
Property, plant and equipment *(Note 6)*	**106,797**	107,781
Timberlands and logging roads *(Note 7)*	**754,099**	765,783
Long-term receivable *(Note 4)*	**7,705**	—
	$905,410	$920,194
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 16,718**	$ 22,796
Performance bonus—interest payable	**1,073**	1,283
Management fee—performance bonus *(Note 4)*	**—**	14,476
	17,791	38,555
Management fee—performance bonus payable *(Note 4)*	**—**	28,172
Other liabilities *(Note 8)*	**4,020**	7,142
	21,811	73,869
Long-term debt *(Note 9)*	**410,000**	410,000
Less: Deferred debt issue costs	**(2,126)**	(2,445)
	407,874	407,555
	429,685	481,424
Partners' equity *(Note 10)*	**475,725**	438,770
	$905,410	$920,194

Contingencies (Note 14)

Commitments (Note 16)

Approved on behalf of the Island Timberlands General Partner



Darshan Sihota

The accompanying notes are an integral part of these financial statements.

ISLAND TIMBERLANDS LIMITED PARTNERSHIP

CONSOLIDATED STATEMENT OF CASH FLOWS

US$thousands	**Year ended December 31 2008**	**2007**
Operating activities		
Net income for the year	**$ 42,285**	$ 20,477
Items not involving cash		
Depreciation, depletion and amortization	**18,437**	20,263
Amortization of deferred debt issue costs	**319**	346
Return of investment *(Note 1)*	**(223)**	—
Gain on sale of assets	**(5,631)**	(7,432)
Change in non-cash operating items		
Accounts receivable	**183**	487
Inventories	**1,898**	(5,821)
Prepaid expenses	**274**	(84)
Accounts payable and accrued liabilities and performance bonus—interest payable	**(6,288)**	3,794
Management fee—performance bonus payable	**(50,353)**	2,648
Other liabilities	**(3,229)**	355
	(2,328)	35,033
Investing activities		
Acquisition of timberland assets purchase price adjustment	**—**	5,188
Additions to property, plant and equipment, and timberlands and logging roads	**(7,702)**	(8,769)
Proceeds from sale of property and equipment	**7,564**	14,529
	(138)	10,948
Financing activity		
Distributions to limited partners	**(5,000)**	(39,188)
(Decrease) increase in cash	**(7,466)**	6,793
Cash, beginning of year	**14,464**	7,671
Cash, end of year	**$ 6,998**	$ 14,464
Supplemental cash flow information:		
Interest paid	**$ 26,869**	$ 24,858

The accompanying notes are an integral part of these financial statements.

ISLAND TIMBERLANDS LIMITED PARTNERSHIP
US$ THOUSANDS

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2008

1. Primary business activity

Island Timberlands Limited Partnership ("Island" or the "Partnership") was formed pursuant to the limited partnership agreement made as of March 23, 2005 and as amended and restated as of May 27, 2005 for the purpose of carrying on the business of investment in, and management, operation, and disposition of timberlands in British Columbia, Canada and such other locales as may be approved in accordance with this Agreement.

Island's assets consist primarily of timberlands, land, logging roads and equipment, and a 50% interest in Strathcona Helicopters Ltd. ("Strathcona"). All of the transferred assets are located in the coastal region of British Columbia, Canada. The Partnership's principal business is growing and harvesting timber, and selling logs to worldwide markets. Island's secondary business interest is real estate development and sales.

Island's interest in Strathcona is expected to be fully dissolved in 2009 as a result of the winding up of this company which began in 2008. The decision by the Strathcona board was the result of Island and Western Forest Products Ltd. ("Western") being able to access equivalent services more cost effectively elsewhere in the marketplace. Strathcona paid out a dividend of $987 to its investors during 2008, which resulted in a net return of equity in the amount of $223.

2. Significant accounting policies

These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which in these circumstances conform, in all material respects, with United States generally accepted accounting principles ("US GAAP"), except as described in Note 18.

(a) Basis of presentation

The consolidated financial statements include the accounts of the Partnership and its interest in Strathcona through use of the proportionate consolidation method until the winding up of Strathcona is completed. Management expects that the wind-up will be completed in 2009. Intercompany transactions and balances have been eliminated.

The functional currency of Island is the U.S. dollar.

All currency amounts in these consolidated financial statements are in United States dollars ("U.S. dollars") unless otherwise stated.

(b) Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated into U.S. dollars at the period-end exchange rates. Non-monetary assets and liabilities are translated at exchange rates in effect when the assets are acquired or liabilities are incurred. Revenue and expense items denominated in foreign currencies are translated at average rates of exchange prevailing during the period. Exchange gains and losses arising from translation are included in operations.

(c) Measurement uncertainties

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the year. On an ongoing basis management reviews its estimates based on currently available information. Actual results could differ from those estimates. Significant estimates used in the preparation of these consolidated financial statements include, among other things, but not limited to, the recoverability of accounts receivable, the estimated net realizable value of inventories, the expected economic lives of and the estimated future operating results and net cash flows from the timberlands and property, plant and equipment, the anticipated costs and timing of asset retirement obligations, and the valuation calculations which form the basis of Management Fee—Performance Bonus obligations (Note 4) to Brookfield Timberlands Management ("BTM").

Asset retirement obligations are recognized in the period in which they arise and are stated as the fair value of estimated future costs. These estimates require extensive judgement about the nature, cost and timing of the work to be completed, and may change with future changes to costs, environmental laws and regulations and remediation practices.

(d) Accounts receivable

Accounts receivable are stated net of an allowance for doubtful accounts.

(e) Inventories

Logs and boomsticks are valued at the lower of average cost and net realizable value in accordance with the Canadian Institute of Chartered Accountants ("CICA") Handbook, Section 3031. See Note 3(a). Materials and supplies are valued at the lower of average cost and replacement cost.

Island continues to value log inventories at the lower of cost and net realizable value which is based on pooling logs as an aggregate product. The cost basis for produced logs is a weighted twelve month rolling average, one month in arrears, and adjusted as required for extraordinary events such as a market closure. Purchased logs are valued on a vendor specific basis at the lower of acquired cost and the net realizable value.

(f) Property, plant and equipment

Property, plant and equipment are carried at cost less accumulated depreciation. Plant and equipment are depreciated on a straight-line basis at rates that reflect the economic lives of the assets based on the following annual rates:

Buildings	3% – 5%
Plant and equipment	10% – 20%

Property, plant and equipment includes land that has been designated as having a higher value to non-timberland owners ("HBU land"). HBU land is not depreciated. Betterments to HBU land are capitalized and included as part of the special project or parcel of land until it is sold.

The Partnership reviews for the impairment of property, plant, and equipment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable from the expected undiscounted future cash flows from its use and eventual disposition. The amount of any impairment loss is determined as the excess of the carrying value of the asset over its fair value.

(g) Timberlands and logging roads

Timberlands and logging roads are carried at cost less accumulated depletion and amortization. Site preparation and planting costs are capitalized as reforestation. Reforestation is transferred to a merchantable timber classification after 30 years.

Depletion of the timberlands is based on the volume of timber estimated to be available over the harvest cycle.

Amortization of logging roads occurs as timber is harvested and is based upon rates determined with reference to the volume of the timber estimated to be removed using these roads.

Timberlands and logging roads are tested for impairment in value whenever events or changes in circumstances indicate their carrying value may not be recoverable. Recoverability is assessed by comparing the carrying amount to the projected future net cash flows the long-lived assets are expected to generate. The amount of any impairment loss is determined as the excess of the carrying value of the asset over its fair value.

(h) Asset retirement obligations

Obligations associated with the retirement of tangible long-lived assets are recorded as liabilities when those obligations are incurred, with the amount of the liabilities initially measured at fair value. These obligations are capitalized to the book value of the related long-lived assets and are depreciated over the useful life of the asset. The obligation is accreted over time to the estimated amount ultimately payable, through charges to operations.

(i) Deferred debt issue costs

Debt issue costs related to long-term debt are deferred and amortized over the respective terms of the debt to maturity.

(j) Revenue recognition

Revenue is derived primarily from the sale of logs and related products. The Partnership recognizes sales to external customers when significant risks and rewards of ownership are transferred, which is generally when the product is shipped and title passes, and collectibility is reasonably assured.

(k) Shipping and handling costs

Island classifies shipping and handling costs in cost of products sold in the consolidated statement of operations.

(l) Income taxes

The partners are individually liable for any taxes related to their respective shares of the Partnership's taxable income. Accordingly, no provision for income taxes is required, except for the Partnership's share of the provision for income taxes of Strathcona.

(m) Future accounting changes

Convergence with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board ratified a strategic plan that will result in Canadian GAAP, as used by public companies, being converged with International Financial Reporting Standards ("IFRS") over a transitional period currently expected to be complete by 2011. As the International Accounting Standards Board has projects underway that should result in new pronouncements and since this Canadian convergence initiative is very much in its infancy as of the date of these consolidated financial statements, the Partnership is continuing to assess the impact of the ultimate adoption of IFRS on the Partnership.

Capital disclosures, Section 1535

CICA Handbook Section 1535, Capital Disclosures, requires additional disclosures with respect to the Partnership's management of capital. Adoption of the CICA recommendations had no impact on the Partnership's financial statements. The Partnership is expected to adopt this new standard effective January 1, 2009.

3. Changes in accounting policies

(a) Inventories, Section 3031

Effective January 1, 2008, the Partnership adopted, on a prospective basis, the recommendations of the CICA Handbook Section 3031, Inventories. This section provides an expanded definition of cost and requires that inventory be measured at the lower of cost and net realizable value. Additionally, there are increased guidelines on the grouping of inventories along with disclosure requirements regarding accounting policies, carrying values, and the treatment of any inventory write downs.

Under the new standard, logs from harvesting operations are valued at the lower of 12 month moving average cost and net realizable value on a product basis. Since the costs of each product are not separately identifiable, they are allocated between the products based on the relative sales value of each product. Purchased logs are measured at the lower of actual cost and net realizable value. Boomsticks are valued at net realizable value to reflect degradation that occurs from use.

The adoption of this standard did not have a significant impact on the financial statements of the Partnership.

(b) Financial Instruments, Section 3862 and 3863

As new financial instruments standards will be included in the proposed GAAP standards for private enterprises currently under development by the CICA, it has been decided by the CICA that private enterprises will not be required to apply the CICA Handbook Sections 3862 and 3863 which would have otherwise applied to the financial statements of the Partnership for the year ended December 31, 2008. The Partnership has elected to use this exemption but will continue to apply the requirements of CICA Sections 1530, 3855 and 3865.

(c) Assessing Going Concern, Section 1400

In June 2007, Section 1400 of the CICA Handbook was amended to require management to assess and disclose an entity's ability to continue as a going concern. This section applies for interim and annual periods beginning on or after January 1, 2008. Island adopted this Section on January 1, 2008.

The North American forest products industry is currently experiencing a very challenging economic environment. Demand for most products has weakened substantially, especially in domestic and US markets. Island has forecasted financial results and cash flows for 2009 using the Partnership's best estimates of market and operating conditions. These forecasts indicate that the Partnership will be able to maintain current liquidity. The Partnership expects to continue to meet all of its debt covenants and remains well positioned for a market turnaround. The Partnership sees no immediate impediments to its ability to continue as a viable going concern.

4. Management fee—performance bonus

Pursuant to the terms of the Management Agreement (the "Agreement") between Island and BTM, management fees are payable to BTM as compensation for the services provided by BTM on behalf of Island. These fees are comprised of a base management fee which is payable quarterly, and a performance fee which becomes payable annually upon the achievement of specified performance thresholds.

The performance bonus is calculated annually based on cash distributed by the business combined with independent valuation reports. The final calculation of the annual amount owing with respect to the performance fee is subject to a clawback calculation for every five year period starting in 2011 and every fifth year thereafter. In accordance with the terms of this clawback clause, if Island has paid BTM annual performance fees which are in excess of the amount that would have been paid if the performance fee had been calculated for each five year period, rather than annually, the excess amount will be repaid by BTM to Island.

In May 2007, the 2006 performance fee payable to BTM was finalized at $39.5 million. This fee is payable in installments over a 7 year-period, bearing interest at a rate of 6.02%. The performance fee payment in the year ended December 31, 2008 for the second instalment of the 2006 performance fee was $5.7 million (2007–$5.7 million for the first instalment of the 2006 performance fee) along with a performance fee interest payment of $2.0 million during the year.

During 2007 an additional performance fee payable was calculated. It was finalized and fully paid during 2008 in the amount of $8.8 million.

During the year ended December 31, 2008, as a result of a change in management's estimates in the fee payable based on cash distributions and independent business valuations a total of $35.9 million was recorded as an accrued clawback. The clawback provision has resulted in an estimated long-term receivable of $7.7 million at December 31, 2008. The final clawback will be calculated as at December 31, 2010 and will be payable in 2011.

The obligation is considered subordinate to the Senior Bonds, and accordingly has not been included in calculating compliance with the covenants of the Trust Indenture. As long as the Partnership remains in compliance with the covenants stated in the Trust Indenture, payments may be made on the management fee payable.

5. Inventories

US$thousands	2008	2007
Logs and boomsticks	**$25,642**	$26,842
Materials and supplies	**1,342**	2,040
	$26,984	$28,882

6. Property, plant and equipment

			Net book value	
US$thousands	Cost	Accumulated depreciation	2008	2007
HBU and other land	**$103,852**	**$ —**	**$103,852**	$104,410
Buildings	**1,176**	**465**	**711**	873
Plant and equipment	**4,599**	**2,365**	**2,234**	2,498
	$109,627	**$2,830**	**$106,797**	$107,781

In the year ended December 31, 2008, Island sold HBU and other land for net proceeds of $5,983 (2007–$14,446), realizing a gain on sale of $4,112 (2007–$7,349). Island also sold buildings and equipment for net proceeds of $1,581 (2007–$83) and realized a gain on sale of $1,519 (2007–$83).

7. Timberlands and logging roads

US$thousands	Cost	Accumulated depletion and amortization	Net book value 2008	Net book value 2007
Timberlands	**$790,343**	**$53,368**	**$736,975**	$751,645
Reforestation	**14,016**	**—**	**14,016**	10,088
Logging roads	**19,621**	**16,513**	**3,108**	4,050
	$823,980	**$69,881**	**$754,099**	$765,783

8. Other liabilities

US$thousands	2008	2007
Restructuring liabilities	**$3,636**	$6,744
Asset retirement obligations	**384**	398
	$4,020	$7,142

Pursuant to the timberland acquisition from Weyerhaeuser Company Limited ("WYL"), Island was obligated to reimburse Cascadia Forest Products Ltd. ("Cascadia") (now Western, a company under common control of one of the limited partners) for certain restructuring and severance costs related to closure activities. That obligation was settled in 2008 with a final payment of $0.3 million.

At the time of acquisition, Island also assumed responsibility for certain property subdivisions and environmental obligations that could potentially arise pursuant to the subdivision process. In 2008, a revision was made to the estimated future cost resulting in a decrease of $1.6 million in the provision which has been included in other non-operating income (Note 11).

9. Debt

US$thousands	2008	2007
U.S. secured bonds repayable on August 30, 2015, interest at 5.58%	**$100,000**	$100,000
U.S. secured bonds repayable on August 30, 2025, interest at 6.17%	**210,000**	210,000
U.S. secured bonds repayable on August 30, 2030, interest at 6.27%	**100,000**	100,000
	$410,000	$410,000

The bonds are payable to Island Timberlands Finance Corp. ("IT Finance"), an entity under common control. The bonds are secured by a fixed and floating charge over the Partnership assets and covenants exist that restrict the Partnership's ability to create additional encumbrances and incur further debt. A debt service reserve account equal to six months' interest has been guaranteed by issuing two secured irrevocable letters of credit aggregating $12,382. The fair value of the long-term debt at December 31, 2008 has been estimated by management at $417,987 (2007–$384,893).

During 2008, the Partnership completed a $10 million increase in the demand secured operating credit facility from $20 million to $30 million. There were no borrowings on the facility at December 31, 2008. At December 31, 2008, the Partnership had four letters of credit totaling $12.5 million outstanding.

10. Partners' equity

	Number of units authorized and issued	Participation %
Limited Partners interests	**53,168,984**	99.999
General Partner interest	**1**	0.001

11. Other non-operating expenses/(income)

US$thousands	2008	2007
Interest income	**$ (298)**	$ (733)
Foreign exchange	**2,458**	(2,702)
Remediation costs	**208**	—
Severance	**287**	(181)
Changes in estimated restructuring liabilities	**(1,647)**	—
Other	**100**	(243)
	$ 1,108	$(3,859)

12. Related party transactions

In addition to the related party transactions disclosed elsewhere, the Partnership had the following transactions with related parties which have been recorded at the exchange amounts agreed to by the parties:

(a) Island engages in various transactions with Western. Reference to transactions with Western include those with Cascadia, which was effectively purchased by Western in 2006. During the year, each entity purchased and sold logs, as well as boom gear, to each other. These transactions were recorded at the exchange amount determined with reference to current market pricing. As well, certain overhead and administrative fees were charged between Island and Western for services that are provided from one entity to the other. During the year, Island billed $21,376 (2007–$16,041) to Western and recognized billings from Western in the amount of $1,618 (2007–$8,644).

(b) Pursuant to the WYL asset purchase agreement, the Partnership provided a limited guarantee in favour of WYL of the obligations of Western under the WYL asset purchase agreement (the "Island Guarantee"). Western has agreed to indemnify the Partnership in respect of any liability that it incurs under the Island Guarantee. As security for the indemnity, Western has assumed responsibility for a debenture, originally issued by Cascadia, in the amount of $100,000 in favour of the Partnership, which charges all of Western's purchased Cascadia real property and grants a security interest over all such present and after-acquired personal property. The debenture places certain restrictions on Western of the type typically found in grants of security of this nature, including restrictions on the ability to make distributions to its shareholders without the consent of the Partnership.

(c) Island engaged BTM for management services pursuant to the Agreement. During the year, Island was billed $2,392 (2007–$2,316) for these services. The 2008 billings exclude any performance bonus related charges identified in Note 4.

(d) Under a loan agreement with IT Finance, Island incurred interest payments in the amount of $24,807 (2007–$24,807).

(e) Under an agreement with Brookfield, on the sale of Cascadia in 2006, Island received an amount equivalent to the excess of the sale proceeds over $100,000 plus carrying costs from May 26, 2005. Along with the estimate of $4,649 recorded at December 31, 2006, an additional excess amount of $539 was recorded in

2007 as a reduction of the purchase price paid by Island for the acquisition of the timberland assets. The full amount of $5,188 was received by Island during 2007.

(f) Island holds a 50% interest in Strathcona. During the year, Island utilized Strathcona for helicopter transport services totalling $239 (2007–$1,079).

(g) Island engaged a Brookfield affiliate, Carma Developers LP ("Carma"), to assist in advancing various HBU development opportunities. During the year, Island was billed $845 (2007–$501) by Carma for their direct services plus the costs of external consultants engaged by Carma on Island's behalf. All costs were capitalized to HBU and other land.

(h) The following receivable (payable) balances with entities under common control are outstanding at the end of the year:

US$thousands	2008	2007
Western	**$ (15)**	$ 6
Carma	**(83)**	(27)
Brookfield	**6,632**	(43,931)
IT Finance	**(8,269)**	(8,260)
Strathcona	**—**	(256)
	$(1,735)	$(52,468)

13. Employee benefit plans

Island maintains a defined contribution employee pension plan for salaried employees and contributes to an industry plan for hourly employees. Pension expense for the year was $757 (2007–$701).

14. Contingencies

Island is subject to legal claims in the ordinary course of its business. Although there can be no assurance as to the disposition of these matters, it is the opinion of Island's management, based upon the information currently available, that the expected outcome of these matters, individually or in aggregate, will not have a material adverse effect on the results of operations or financial condition of the Partnership.

15. Segment information

Island manages its business as a single operating segment (Note 1). All of the operations and assets are located in British Columbia.

US$thousands	2008	2007
Sales by location of customer		
Canada	**$ 67,416**	$ 73,365
United States	**33,587**	72,152
Asia	**83,263**	67,258
	184,266	212,775
Sales by product line		
Logs	**184,299**	212,280
Other	**(33)**	495
	$184,266	$212,775

16. Commitments

At December 31, 2008, the Partnership was committed to payments under operating leases for equipment and office premises through to 2013. Annual future minimum payments over the term of these commitments are as follows:

US$thousands	
2009	$2,871
2010	1,635
2011	912
2012	482
2013	87
	$5,987

17. Financial instruments

(a) Fair values

The Partnership's financial instruments consists of cash, accounts receivable, accounts payable and long-term debt. The carrying values of accounts receivable and accounts payable approximate their fair values due to the short term to maturity of these instruments. The estimated fair value of the long-term debt is disclosed in Note 9.

(b) Credit risk

Island is exposed to credit risk on accounts receivable, which are primarily from certain customers granted payment terms. To manage its credit risk, Island regularly reviews credit limits and account balances. With most customers, possession, title, and risk pass after receipt of payment which further reduces credit risk.

(c) Foreign exchange risk

The majority of the Partnership's operational costs and expenses are incurred in Canadian dollars. Therefore, an increase in the value of the Canadian dollar relative to the US dollar increases the expense in US dollar terms.

18. Differences between Canadian and United States generally accepted accounting principles

The Partnership's consolidated financial statements have been prepared in accordance with Canadian GAAP, which differs in some respects from US GAAP. There are no material measurement differences that would affect these financial statements had they been prepared in accordance with US GAAP. The following are the significant differences in accounting principles as they pertain to the consolidated financial statements.

(a) Joint ventures

The Partnership accounts for its investments in Strathcona using the proportionate consolidation method. Under US GAAP, this investment would be accounted for using the equity method. This difference does not affect net income (loss).

The following summarizes the Partnership's proportionate interest in Strathcona including intercompany revenue and expenses.

US$thousands	**2008**	2007
Income (loss)		
Revenues	**$ (33)**	$ 496
Expenses	**398**	497
Net income (loss)	**(431)**	(1)
Cash flows (used in) provided by		
Operating activities	**(911)**	22
Investing activities	**1,404**	(22)
Financing activities	**$ (493)**	$ —

(b) Consolidated cash flows

Under US GAAP, the consolidated cash flows would not be significantly different from the presentation under Canadian GAAP, except that the interest in Strathcona would be shown as an equity investment and not proportionately consolidated.

(c) Presentation of consolidated financial statements

Under US GAAP, certain presentation adjustments would be required. Within the statement of operations, the following items include other expense (income), gain on sale of assets and management fee—performance bonus would be presented as an operating item. These adjustments have no impact on partners' equity or net income.

(d) Recent accounting pronouncements—US GAAP

The Fair Value Option for Financial Assets and Financial Liabilities

In February 2007, the FASB issued Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities—Including an amendment of FASB Statement No. 115 ("SFAS 159"). This statement gives entities the option to measure certain financial assets and liabilities at fair value, with changes in fair value recorded in earnings. SFAS 159 is effective for fiscal year beginning January 1, 2008. The adoption of SFAS 159 did not have a material impact on its financial condition or results of operations.

Non-Controlling Interest in Consolidated Financial Statements

In December 2007, the FASB issued Statement of Financial Accounting Standards No. 160, Non-Controlling Interest in Consolidated Financial Statements ("SFAS 160"), a revised standard on accounting for non-controlling interests and transactions with non-controlling interest holders in consolidated financial statements. This statement specifies that non-controlling interests are to be treated as a separate component of equity, not as a liability or other item outside of equity. Because non-controlling interests are an element of equity, increases and decreases in the parent's ownership interest that leave control intact are accounted for as capital transactions rather than as step acquisitions or generating dilution gains or losses. The carrying amount of the non-controlling interests is adjusted to reflect the changes in ownership interests, and any difference between the amount by which the non-controlling interests are adjusted and the fair value of the consideration paid or received is recognized directly in equity attributable to the controlling interests.

This standard requires net income and comprehensive income to be displayed for both the controlling and the non-controlling interests. Additional required disclosures and reconciliations include a separate schedule that shows the effects of any transactions with the non-controlling interests on the equity attributable to the controlling interests.

The Statement is effective for periods beginning on or after January 1, 2009. SFAS 160 will be applied prospectively to all non-controlling interests, including any that arose before the effective date. Island does not expect the adoption of SFAS 160 to materially affect its consolidated financial statements.

LONGVIEW TIMBER HOLDINGS, CORP.

December 31, 2008 and 2007

US$ THOUSANDS

LONGVIEW TIMBER HOLDINGS, CORP.

December 31, 2008 and 2007

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of Longview Timber Holdings, Corp. Longview, Washington

We have audited the accompanying consolidated balance sheets of Longview Timber Holdings, Corp. and subsidiaries (the "Company") (a subsidiary of Brookfield Asset Management) as of December 31, 2008 and 2007, and the related consolidated statements of operations, shareholders' equity, and cash flows for the year ended December 31, 2008, and the period April 20, 2007 to December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2008 and 2007, and the results of its operations and its cash flows for the year ended December 31, 2008, and the period April 20, 2007 to December 31, 2007, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

March 5, 2009

LONGVIEW TIMBER HOLDINGS, CORP.

CONSOLIDATED BALANCE SHEET

US$ THOUSANDS	As at December 31 2008	2007
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 23,682**	$ 45,948
Accounts and notes receivable, net	**5,296**	4,991
Deferred tax assets (Note 8)	**1,303**	1,717
Inventories (Note 2)	**6,582**	8,900
Prepaid expenses and other current assets (Note 3)	**2,331**	3,581
Total current assets	**39,194**	65,137
Property, plant and equipment, net (Note 4)	**3,446**	3,430
Timber, timberlands and logging roads, net (Note 5)	**1,923,849**	1,855,162
Investment (Note 6)	**705**	705
Deferred debt issuance costs (Note 7)	**12,734**	2,896
Total assets	**$1,979,928**	$1,927,330
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 3,462**	$ 2,414
Accounts payable—related party (Note 13)	**2,212**	715
Other tax payable	**765**	517
Other accrued liabilities (Note 9)	**12,197**	3,290
Other accrued liabilities—related party (Note 13)	**1,801**	11,664
Swap liabilities (Note 14)	**—**	32,124
Bridge loan (Note 10)	**—**	1,200,000
Total current liabilities	**20,437**	1,250,724
Long-term debt (Note 11)	**1,070,000**	—
Long-term debt—related party (Note 13)	**220,575**	200,000
Minority interests (Note 15)	**10,679**	8,176
Total liabilities	**1,321,691**	1,458,900
Shareholders' equity (Note 16)	**658,237**	468,430
Total liabilities and shareholders' equity	**$1,979,928**	$1,927,330

The accompanying notes are an integral part of these financial statements.

LONGVIEW TIMBER HOLDINGS, CORP.

CONSOLIDATED STATEMENTS OF OPERATIONS

US$ THOUSANDS	For the year ended December 31, 2008	For the Period from April 20, 2007 to December 31, 2007
Net sales	**$ 174,225**	$121,224
Cost of products sold	**(91,934)**	(60,976)
Depletion, depreciation, and amortization	**(99,380)**	(67,609)
Gross loss	**(17,089)**	(7,361)
Selling, administrative and general expenses	**(22,766)**	(15,182)
Operating loss	**(39,855)**	(22,543)
Interest income	**763**	3,078
Interest expense	**(80,935)**	(76,987)
Other income (expense) net	**6,451**	1,318
Loss on sale of assets	**(797)**	—
Loss on sale of higher and better use lands	**(1,398)**	—
Total interest and other expense	**(75,916)**	(72,591)
Loss from continuing operations before income taxes	**(115,771)**	(95,134)
Provision for taxes (Note 8):		
Current	**(1,444)**	(34)
Deferred	**(414)**	(189)
	(1,858)	(223)
Loss from continuing operations	**(117,629)**	(95,357)
Discontinued operation (Note 18):		
Income from operation (net of taxes of $346)	**—**	538
Loss on sale of assets	**—**	(884)
Net loss	**$(117,629)**	$ (95,703)

The accompanying notes are an integral part of these financial statements.

LONGVIEW TIMBER HOLDINGS, CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

US$ THOUSANDS	For the year ended December 31, 2008	For the Period from April 20, 2007 to December 31, 2007
Cash provided by (used in) operating activities:		
Net loss	**$ (117,629)**	$ (95,703)
Adjustments to reconcile net loss to cash provided by (used in) operating activities:		
Depletion, depreciation and amortization	**99,380**	67,609
Amortization of deferred debt issuance costs	**1,425**	—
Loss on sale of assets	**797**	—
Loss on sale of higher and better use lands	**1,398**	—
Loss on sale of assets from discontinued operation	**—**	884
Loss on derivative valuation	**3,231**	10,883
Deferred income taxes	**414**	535
Minority interest in net loss	**(957)**	(827)
Termination of interest rate swap agreements	**(53,447)**	—
Changes in:		
Accounts and notes receivable—net	**(304)**	(4,991)
Inventories	**876**	(2,410)
Prepaid expenses and other current assets	**808**	73
Other non-current assets	**(559)**	(1,826)
Accounts payable and other accrued liabilities	**9,743**	8,876
Other accrued liabilities—related party	**(3,577)**	21,078
Other tax payable	**247**	(2,542)
Cash provided by (used for) operating activities	**(58,154)**	1,639
Cash provided by (used in) investing activities:		
Acquisition, net of cash acquired of $78	**—**	(2,226,499)
Disposal of Manufacturing Operations, net of cash transferred of $5	**—**	293,318
Additions to capital assets	**(175,303)**	(2,387)
Proceeds from the sale of fixed assets—net of selling costs	**7,120**	—
Cash used for investing activities	**(168,183)**	(1,935,568)
Cash provided by (used in) financing activities:		
Proceeds from Bridge loan	**—**	1,350,000
Repayment of Bridge loan	**(1,200,000)**	(150,000)
Proceeds from long-term debt	**1,070,000**	—
Repayment of short-term borrowings	**—**	(14,500)
Proceeds from long-term debt—related party	**15,787**	200,000
Proceeds from bridge loans—related party	**256,475**	—
Repayment of bridge loans—related party	**(256,475)**	—
Additions to deferred debt issuance costs	**(10,704)**	—
Issuance of common stock	**330,172**	835,978
Issuance of preferred stock	**—**	85
Minority interest	**3,460**	9,003
Dividends	**(4,644)**	(250,689)
Cash provided by financing activities	**204,071**	1,979,877
Change in cash and cash equivalents		
Cash and cash equivalents, beginning of period	**(22,266)**	45,948
Cash and cash equivalents, end of period	**45,948**	—
	$ 23,682	$ 45,948
Supplemental disclosures:		
Cash paid for interest	**$ 71,938**	$ 51,837
Cash paid for taxes	**1,500**	—
Supplemental disclosure of noncash investing and financing activities:		
Shareholder interest capitalized into principal	**$ 3,788**	$ —
Shareholder loan PIK fee capitalized into principal	**$ 1,000**	$ —

The accompanying notes are an integral part of these financial statements.

LONGVIEW TIMBER HOLDINGS, CORP.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

US$ THOUSANDS	Preferred Stock Shares	Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Total
Balance at April 20, 2007	—	$—	—	$—	$ —	$ —	$ —	**$ —**
Issuance of common stock			7,765,850	78	835,900			**835,978**
Issuance of preferred stock	125	125				(40)		**85**
Change in fair value of derivative instruments							(21,241)	**(21,241)**
Net loss						(95,703)		**(95,703)**
Comprehensive loss								**(116,944)**
Dividends						(250,689)		**(250,689)**
Balance at December 31, 2007	125	125	7,765,850	78	835,900	(346,423)	(21,241)	**468,430**
Issuance of common stock			3,254,326	33	330,139			**330,172**
Change in fair value of derivative instruments							(18,092)	**(18,092)**
Net loss						(117,629)		**(117,629)**
Comprehensive loss								**(135,721)**
Dividends						(4,644)		**(4,644)**
Balance at December 31, 2008	125	$125	11,020,176	$111	$1,166,039	$(468,705)	$(39,333)	**$ 658,237**

The accompanying notes are an integral part of these financial statements.

LONGVIEW TIMBER HOLDINGS, CORP.

US$ THOUSANDS

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Accounting Policies

Nature of business

General

Longview Timber Holdings, Corp. ("Timber") is a real estate investment trust ("REIT") engaged in the ownership and management of timberlands in Oregon and Washington, which principally produce logs for sale. All of the facilities are located in the United States ("U.S."). Timber owns and manages approximately 655,000 acres of valuable timberlands in the Pacific Northwest composed primarily of softwoods.

A REIT is a company that derives most of its income from investments in real estate, which includes timberlands. A corporation that qualifies as a REIT generally will not be subject to corporate taxes on income and gains from investments in real estate to the extent that it distributes such income and gains to its shareholders. The principal REIT qualifying investment consists of timberlands. As a REIT, Timber will be required to pay federal corporate income tax on earnings from non-real estate investments, and on earnings from real estate investments that are not distributed to its shareholders.

Background

On February 2, 2007, Brookfield Asset Management Inc. ("Brookfield") and Longview Fibre Company entered into an Agreement and Plan of Merger whereby Brookfield would acquire all of Longview Fibre Company's outstanding common shares for $24.75 per share in cash and would assume all existing debt (the "Acquisition"). The shareholders approved the Acquisition and the sale was closed on April 20, 2007. With the closing of this transaction, Brookfield newly established Timber, Longview Timber Holdings LLC, and Longview Timber LP, to own the Timber Operations and the Manufacturing Operations of Longview Fibre Company. Longview Timberlands LLC and Longview Timber, Corp. were additionally established as subsidiaries of Longview Fibre Company on May 31, 2007.

On November 4, 2008, Timber purchased approximately 67,600 acres in Washington from Mid-Valley Resources Inc., a subsidiary of Hampton Affiliates ("Hampton Purchase"), a large timber company, for $163 million.

Ownership Structure

Following the close of the Acquisition by Brookfield, the following ownership structure was formed:

Company	Ownership
Longview Timber Holdings, Corp. (Timber)	—Longview Timber Holdings, Corp. owns 100% of Longview Timber Holdings LLC
Longview Timber Holdings LLC	—Longview Timber Holdings LLC owns 99% of Longview Timber LLC
	—Remaining 1% is owned by a Brookfield subsidiary
Longview Timber LLC	—Longview Timber LLC owns 100% of Longview Fibre Company—Longview REIT
	—Longview Timber LLC owns 1% of Longview Timberlands LLC
Longview Fibre Company	—Longview Fibre Company owns 99% of Longview Timberlands LLC
	—Longview Fibre Company owns 100% of Longview Timber, Corp—a taxable subsidiary

Longview Timberlands LLC owns and manages substantially all of the timberlands and properties. Longview Timber, Corp. owns various harvesting assets and conducts timber brokerage activities.

Purchase Price Allocation of the Acquisition

Brookfield acquired the stock and outstanding debt of Longview Fibre Company on April 20, 2007 for $2,252 million. The purchase was financed with $1,350 million of bridge financing, $200 million of long-term debt from a related party, and $702 million of cash. The total purchase price was allocated between the Timber Operations and the Manufacturing Operations based upon the respective fair values of each operation, as follows:

US$ MILLIONS	April 20, 2007
Timber Operations	$1,958
Manufacturing Operations	294
Total	$2,252

Subsequent to the Acquisition, the Manufacturing Operations were sold to a related party for total proceeds of $253 million, including $92 million of debt (see Note 18). Additionally and immediately after the Acquisition, the Manufacturing Operations sold eight converting facilities located in the central and eastern United States to a third party for net proceeds of $48 million.

The purchase price of the Timber Operations was allocated based upon fair values to the following classes of assets and liabilities:

US$ MILLION	April 20, 2007
Current assets	$ 23
Capital assets	1,938
Other non-current assets	10
Current liabilities	(10)
Other non-current liabilities	(3)
Total	$1,958

Basis of presentation

The consolidated financial statements presented herein are those of Timber and its subsidiaries, and are derived from the records of such entities after the elimination of intercompany balances and transactions. For fiscal year 2007, the reporting period was April 20, 2007 to December 31, 2007. For fiscal year 2008, January 1, 2008 to December 31, 2008 reflects the reporting year for Timber and its subsidiaries. Reference to Timber also includes, as applicable, reference directly or indirectly to any of its subsidiaries.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and highly liquid investments purchased with maturities of three months or less at date of acquisition.

Accounts and Notes Receivable and Allowance for Doubtful Accounts

Accounts and notes receivable are comprised mainly of trade accounts receivable primarily from the sale of products on credit. Credit is extended to customers based on an evaluation of their financial condition. The adequacy of the allowance for doubtful accounts is based on historical experience and past due status, in addition to management's evaluation of material customer accounts including ability to pay, bankruptcy, payment history, and other factors.

Bad debt expense associated with uncollectible accounts was $32 thousand and $61 thousand for the year ended December 31, 2008 and the period April 20, 2007 to December 31, 2007, respectively.

Inventories

Inventories are stated at the lower of cost or market. If actual demand or market conditions are less favorable than those projected by management, inventory write-downs may be required. Cost is determined on a first-in, first-out basis except for supplies, which are stated using the average cost method.

Timber, Timberlands and Logging Roads. Timber depletion and Logging Roads amortization

Timber, timberlands and logging roads are stated at cost, net of accumulated depletion and amortization. Timber, upon reaching the age of 35 years, is considered merchantable and available for harvesting, with all timber younger than 35 years of age being classified as premerchantable. Timber is tracked on a county-by-county basis whereby capital costs and estimated recoverable timber volumes are accumulated in the county in which the related timber is located. Expenditures for reforestation, including costs such as site preparation, tree planting, fertilization and herbicide application for the two years after planting, are capitalized and depleted as timber is harvested. After two years of age, plantation maintenance and tree farm management costs, consisting of recurring items necessary to the ownership and administration of the timber and timberlands, are recorded as a current period expense.

Provision for depletion of merchantable timber represents a charge per unit of production (“depletion rate”) applied to actual harvest volumes. A single depletion rate is applied to all merchantable timber regardless of its age, species or quality in any particular case. A separate depletion rate will be determined for the timberlands acquired in the Hampton Purchase. The depletion rates are validated to a computer growth index model that tracks the timber volumes through the growth cycle and is based upon actual growth rates from permanent timber growth plots throughout the Pacific Northwest. The depletion rates will be adjusted periodically for timber maturity, estimated growth, and actual harvest volumes and when there is a significant acquisition or disposition.

Direct costs associated with the building of primary and major secondary access logging roads are capitalized and amortized on the straight-line basis over estimated useful lives ranging from 3 to 15 years. Bridges are amortized over an estimated useful life of 35 years. Costs incurred for logging roads that serve short-term harvest needs are expensed as incurred. Costs for road base construction of mainline roads, such as clearing and grading, are not amortized and remain a capitalized cost until disposition as they provide permanent value to the timberlands.

Gains or losses on timberland exchanges are recognized in earnings when the exchange has commercial substance, in accordance with the Statement of Financial Accounting Standards (“SFAS”) No. 153, “Exchanges of Nonmonetary Assets, an amendment of APB No. 29.” An exchange is considered to have commercial substance when future cash flows are expected to change significantly as a result of the exchange.

Property, Plant and Equipment and Depreciation

Property, plant and equipment are recorded at cost, net of accumulated depreciation. Plant and equipment include those additions and improvements that add to production capacity or extend useful life. Cost includes interest capitalized during the construction period on all significant asset acquisitions. Impairment is reviewed annually, or whenever events or circumstances indicate that the carrying value of an asset or group of assets may not be recovered pursuant to SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets”. Impairment evaluates whether or not the undiscounted future cash flows generated by an asset will exceed its carrying value. If estimated future cash flows indicate the carrying value of an asset or group of assets may not be recoverable, impairment exists, and the asset’s net book value is written down to its estimated fair value. When properties are sold or otherwise disposed of, the cost and the related accumulated depreciation are removed from the respective accounts, and the resulting profit or loss is recorded in income. The costs of maintenance and repairs are charged to income when incurred.

Depreciation is computed on the straight-line basis over the estimated useful lives of the assets. The estimated useful lives of assets range is 40 years for buildings and from 4 to 10 years for machinery and equipment.

Revenue recognition

Revenues are recognized from sales to customers when title and risk of loss pass to the customer and when the sales price is fixed or determinable. For substantially all sales, ownership transfers upon receipt by customers of logs ("FOB-destination") or upon shipment to customers of logs ("FOB-shipping point").

Recent accounting pronouncements and developments

In July 2006, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109" ("FIN 48"). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes". FIN 48 provides that a tax benefit from an uncertain tax position may be recognized when it is more-likely-than-not that the position will be sustained upon examination, including resolutions of any related appeals or litigation processes, based on the technical merits. Income tax positions must meet a more-likely-than-not recognition threshold at the effective date to be recognized upon the adoption of FIN 48 and in subsequent periods. This interpretation also provides guidance on measurement, de-recognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006 and the adoption of FIN 48 did not have a material effect on these financial statements. If applicable, Timber recognizes interest and penalties to unrecognized tax benefits within the income tax expense line in the accompanying consolidated statement of operations. Accrued interest and penalties are included within the related tax liability line in the consolidated balance sheet.

In September 2006, FASB issued SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 does not impose fair value measurements on items not already accounted for at fair value; rather, it applies, with certain exceptions, to other accounting pronouncements that either require or permit fair value measurements. Under SFAS No. 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal or most advantageous market. The standard clarifies that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In February 2008, the FASB issued FSP No. 157 2, "Effective Date of FASB Statement No. 157", which delays the effective date of SFAS No. 157 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the consolidated financial statements on a recurring basis, until fiscal years beginning after November 15, 2008. These non-financial items include assets and liabilities such as non-financial assets and liabilities assumed in a business combination, reporting units measured at fair value in a goodwill impairment test and AROs initially measured at fair value. In October 2008, the FASB issued FSP No. 157 3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active" ("FSP FAS 157 3"), which clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157 3 was effective upon issuance, including prior periods for which financial statements had not been issued. Timber adopted the provisions of SFAS No. 157 for assets and liabilities recognized at fair value on a recurring basis effective January 1, 2008, and the adoption of SFAS No. 157 did not have a material impact on Timber's consolidated financial statements.

In December 2007, the FASB issued SFAS 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" ("SFAS 160"). SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests ("NCI") and classified as a component of equity. This new consolidation method will change the accounting for transactions with minority interest holders. SFAS 160 is effective for fiscal years beginning after December 15, 2008 and, as such, Timber will adopt this standard in fiscal 2009 and has not yet determined the impact, if any, of SFAS 160 on the consolidated financial statements.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS No. 141(R)"). SFAS No. 141(R) applies to all transactions or other events in which an entity obtains control of one or more businesses. SFAS No. 141(R) establishes how the acquirer of a business should recognize, measure and disclose in its financial statements the identifiable assets and goodwill acquired, the liabilities assumed and any noncontrolling interest in the acquired business. SFAS No. 141(R) is applied prospectively for all business combinations with an acquisition date on or after the beginning of the first annual reporting period beginning on or after December 15, 2008, with early application prohibited. SFAS No. 141(R) will not have an impact on Timber's historical consolidated financial statements and will be applied to business combinations completed, if any, on or after January 1, 2009.

In March 2008, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 161, "Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133" ("SFAS No. 161"). SFAS No. 161 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand how and why an entity uses derivative instruments and their effects on an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008 with early application encouraged. Timber is currently evaluating the impact of adopting SFAS No. 161 on its disclosures included within the notes to consolidated financial statements.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

2. Inventories

Inventories consisted of the following:

US$ THOUSANDS	**December 31, 2008**	**December 31, 2007**
Logs	**$1,787**	$3,446
Seed, cones, seedling budcaps	**365**	898
Rock and gravel	**1,411**	1,686
Nursery bed stock	**2,773**	2,585
Supplies	**246**	285
Total inventories	**$6,582**	$8,900

3. Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets consisted of the following:

US$ THOUSANDS	December 31, 2008	December 31, 2007
Insurance	**$ 98**	$ 106
US Forest Service timber deposits	**32**	1,000
Timber—land deals	**625**	2,295
Timber deed—Hampton Purchase	**1,058**	—
Planting	**457**	—
Other	**61**	180
Total prepaid expenses and other current assets	**$2,331**	$3,581

Prepaid timber for land deals represents payments that have been made for fees and other costs associated with the purchase and sale of timberland. When payments associated with the purchase or sale of land are made, they are recorded in the prepaid timber—land deals account until the purchase or sale is finalized.

Prepaid timber deed—Hampton Purchase represents $1.5 million of timber cutting rights recorded at acquisition. At December 31, 2008 timber cutting rights recorded was $1.1 million, net of depletion.

4. Property, Plant and Equipment, net

Property, plant and equipment consisted of the following:

	December 31, 2008		
US$ THOUSANDS	Cost	Accumulated Depreciation	Net Book Value
Land	$1,440	$ —	$1,440
Buildings	73	(3)	70
Equipment	2,421	(485)	1,936
Total property, plant and equipment, net	$3,934	$(488)	$3,446

	December 31, 2007		
US$ THOUSANDS	Cost	Accumulated Depreciation	Net Book Value
Land	$1,440	$ —	$1,440
Buildings	80	(1)	79
Equipment	1,981	(70)	1,911
Total property, plant and equipment, net	$3,501	$ (71)	$3,430

During the year ended December 31, 2008, Timber sold equipment for net proceeds of $94 thousand realizing a gain on sale of $22 thousand. During the period ended December 31, 2007, there were no disposals.

5. Timber, Timberlands and Logging Roads, net

Timber, timberlands and logging roads consisted of the following:

US$ THOUSANDS	December 31, 2008		
	Cost	Accumulated Depletion And Amortization	Net Book Value
Timber	$1,744,405	$(165,546)	$1,578,859
Timberlands	176,130	—	176,130
Hampton Purchase	161,307	—	161,307
Logging roads	7,980	(427)	7,553
Total timber, timberlands and logging roads, net	$2,089,822	$(165,973)	$1,923,849

US$ THOUSANDS	December 31, 2007		
	Cost	Accumulated Depletion And Amortization	Net Book Value
Timber	$1,739,165	$(67,352)	$1,671,813
Timberlands	176,639	—	176,639
Logging roads	6,896	(186)	6,710
Total timber, timberlands and logging roads, net	$1,922,700	$(67,538)	$1,855,162

During the year ended December 31, 2008, Timber sold timber and timberlands (including higher and better use lands) for net proceeds of $7 million realizing a loss on sale of $2 million. During the period ended December 31, 2007, there were no disposals.

Timber acquired approximately 67,600 acres from Mid-Valley Resources Inc., a subsidiary of Hampton Affiliates on November 4, 2008 for $163 million. The purchase was financed with $70 million of long-term debt, $16 million of long-term debt from a related party, and $77 million of cash. Timber is in the process of calculating a separate depletion rate for the acquired merchantable timber. Of the purchase price of $163 million, $1.5 million was recorded as a prepaid timber deed in current assets and the remaining was recorded in long-term capital assets.

6. Investment

Investment of $705 thousand represents Timber's interest in IFA Nurseries Inc., a company which provides various reforestation goods and services. Timber accounts for its investment in IFA Nurseries, Inc., on the cost method.

7. Deferred Debt Issuance Costs

Debt issuance costs of $12.7 million, net of amortization, as of December 31, 2008 relates to the 2008 long-term debt financing and the loan commitment fee paid in 2007. Deferred debt issuance costs, net of amortization, of $2.9 million as of December 31, 2007 relates to the loan commitment fee paid in 2007. Deferred debt issuance costs are deferred and amortized over the respective terms to maturity.

Amortization expense for the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007 was $1.4 million and $0.1 million, respectively.

8. Income Taxes

For the year ended December 31, 2008, the provision for income taxes has been computed based on Timber's reporting as a REIT for federal income tax purposes. As a REIT, Timber is not subject to corporate income taxes on REIT qualifying income and gains from investments in real estate if it distributes such income and gains to our shareholders. Timber's non-REIT activities, including the harvesting and sale of logs, are subject to corporate income taxes. The tax years 2005 through 2008 are subject to examination by the tax authorities. With few exceptions, Timber is no longer subject to US federal, state, local examinations by tax authorities for years before 2005.

The provision (benefit) for income taxes consisted of the following:

US$ THOUSANDS	For the Year ended December 31, 2008	For the Period April 20, 2007 to December 31, 2007
Current:		
Federal	**$1,444**	$—
State	**—**	34
Total current tax	**1,444**	34
Deferred:		
Federal	**414**	566
State	**—**	(31)
Total deferred tax	**414**	535
Total provision for income taxes	**$1,858**	$569

An analysis of the income tax provision (benefit) follows:

US$ THOUSANDS	For the Year ended December 31, 2008	For the Period April 20, 2007 to December 31, 2008
Expected federal income tax provision (benefit) at statutory rate	**$(40,520)**	$(33,297)
REIT losses not subject to income taxes	**42,378**	33,769
Deferred tax expense from non REIT activities	**—**	97
Total provision for income taxes	**$ 1,858**	$ 569

The tax effect of temporary differences giving rise to deferred tax assets is as follows:

US$ THOUSANDS	December 31, 2008	December 31, 2007
Deferred tax assets:		
REIT net operating loss carry-forward from prior years	**$ 907**	$1,321
Non-REIT current year net operating loss carry-forward	**396**	396
Total deferred tax assets	**$1,303**	$1,717

Timber has recorded a deferred tax asset of $1.3 million reflecting the benefit of loss carry-forwards. Timber expects to utilize the benefit of these losses in 2009.

9. Other Accrued Liabilities

Other accrued liabilities consisted of the following:

US$ THOUSANDS	December 31, 2008	December 31, 2007
Workers' payroll and benefit liability	**$ 571**	$ 856
Accrued interest payable—long-term debt	**11,626**	—
Accrued interest payable—bridge loan	**—**	2,434
Total other accrued liabilities	**$12,197**	$3,290

10. Bridge Loan

The Bridge Loan was with three lenders—Merrill Lynch USA, Royal Bank of Canada and The Bank of Nova Scotia. The Bridge Loan was repaid on April 3, 2008, with the proceeds of the long-term debt financing. The related interest expense recorded was $14.0 million and $54.3 million during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively.

11. Long-Term Debt

On April 3, 2008 the Bridge Loan was refinanced with a combination of long-term debt of $1.0 billion and a short-term related party bridge loan. The long-term debt is provided by Metropolitan Life Insurance Company and a syndicate of lenders. On November 4, 2008 the Hampton Purchase was partially financed with additional long-term debt of $70 million provided by Metropolitan Life Insurance Company and a syndicate of lenders. The long-term debt is collateralized with the timber, timberlands, and logging roads.

The long-term debt consists of four fixed interest rate tranches ranging from 4.73% to 6.31%. There are also two variable interest rate tranches ranging from 5.03% to 5.92% at December 31, 2008. The long-term debt matures as follows: $453.3 million on April 3, 2013; $308.3 million on April 3, 2015; and $308.3 million on April 3, 2018. Timber intends to refinance the long-term debt as it matures with similar long term debt facilities. The related interest expense recorded was $39.1 million during the year ended December 31, 2008.

Timber's long-term debt agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-value ratio of 0.60. It also includes a restriction on distributions if the cash coverage ratio is less than 1.25 on a rolling eight quarter basis. As of December 31, 2008 Timber did not meet the cash coverage ratio minimum and therefore only permitted cash distributions will be allowed until such time that Timber's cash coverage ratio is at least 1.25 on a rolling eight quarter basis. As of December 31, 2008, Timber was in compliance with the covenants of its long-term debt agreements.

12. Employee Benefit Plans

Timber has no participation in any retiree medical plans or health care insurance plans. Timber has a defined contribution pension program for its salaried employees and a limited term supplemental defined contribution pension program for some of its employees. Timber also has a matching 401k program. Each of these programs is current. The amount contributed was $597 thousand and $343 thousand during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively.

13. Related Parties

The Accounts Payable—related amount of $2.2 million is with Longview GP LLC ("LVGP"), a US company indirectly owned by Brookfield. Pursuant to the terms of an April 2, 2008, Management Agreement ("Special Distribution Agreement") between Longview Timber LLC and LVGP, a special distribution is payable to LVGP as compensation for services provided by LVGP to Longview Timber LLC and its subsidiaries. The amount is calculated based on 1.00% per annum of the sum of all effective Capital Contributions to Longview Timberlands, LLC. The Special Distribution Agreement replaced the original management fee arrangement between Longview Timberlands, LLC and Brookfield Timberlands Management LP ("BTM"), a Brookfield subsidiary. The special distribution is payable semi-annually. The amount paid to LVGP during 2008 was $5.4 million. The balance payable is recorded in the amount of $2.2 million as of December 31, 2008 as a current liability in accounts payable—related party.

Pursuant to the terms of a Management Agreement between Longview Timberlands LLC, a subsidiary of Timber, and BTM, management fees were payable to BTM as compensation for services provided by BTM to Longview Timberlands LLC. The fee was calculated annually using independent timberlands appraisal reports and was paid quarterly to BTM. The fee paid to BTM was $2.7 million and $6.0 million during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively. This Agreement concluded on April 2, 2008 and was replaced with the Special Distribution Agreement.

The Accounts Payable—related party amount at December 31, 2007 of $715 thousand was with Longview Fibre Paper and Packaging Inc. ("PPI"). Pulp logs sold to PPI was $18.9 million and $3.6 million during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively. There was a Service Agreement between Timber and PPI for various administrative services. The amount paid was $18 thousand and $56 thousand during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively. The Service Agreement effectively concluded in June, 2008.

Long-term debt—related party at December 31, 2008 reflects debt held formerly held by Brascan US Corporation now held by a lending syndicate consisting of Brookfield Global Timber Fund I, LP, BGTF 1 (Norma), LLC, and Brookfield Infrastructure Corporation ("BIC"). On November 3, 2008, the lending syndicate and Timber agreed to defer payment of accrued interest on the long-term debt—related party from August 20, 2008 until an undetermined future date. A 1% fee based on the principal balance as of August 20, 2008 and a 50 bps increase in the spread was given as consideration for the deferral. The intent is to repay the deferred interest at a future date. The long-term debt—related party reflects $215.8 million long-term debt; $3.8 million interest payable; and $1 million payment in kind fee. The current interest rate calculation is LIBOR plus 3.5%. The long-term debt —related party is scheduled to mature April 20, 2010 at which time the intent is to refinance the obligation with a similar long term debt facility. The related interest expense recorded was $15.0 million and $11.7 million during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively. The balance payable is recorded in the amount of $1.8 million and $11.7 million as of December 31, 2008 and December 31, 2007, respectively, as a current liability in other accrued liabilities—related party account.

On April 3, 2008 Brookfield US Corporation and Trilon Bancorp (Europe) Zrt provided $247.5 million in short term bridge financing for the purpose of refinancing the Bridge Loan. An additional $8.9 million was drawn between August and September 2008. The principal balance and all accrued interest was fully repaid in a series of transactions between October and November 2008. The related interest expense recorded was $7.3 million during the year ended December 31, 2008.

14. Accounting for Derivative Instruments and Hedging Activities

Timber used fixed interest rate swap agreements ("swaps") to manage changes in cash flow as a result of changes in interest rate movements on certain of the variable rate debt under the Bridge loan. Timber has designated these swaps as cash flow hedges. To receive hedge accounting treatment, all of the swaps were formally documented at the inception of each hedge and the hedges must be highly effective at swap inception and at least quarterly in offsetting changes to future cash flows on hedged transactions. If the swaps are highly effective, the change in fair value, net of income taxes, is recorded in other comprehensive income or loss, except for any ineffectiveness portion of the fair value change, which is recognized in earnings. If the swaps were not to be highly effective, then Timber would record the change in fair value in earnings.

Timber terminated the swaps in connection with the re-financing of the Bridge Loan. $53.5 million was paid to the counterparties. The loss on termination is reported in the Consolidated Statement of Cash Flows in the same category as the nature of the item being hedged, in accordance with SFAS 104 "Statement of Cash Flows—Net Reporting of Certain Cash Receipts and Cash Payments and Classification of Cash Flows from Hedging Transactions, an Amendment to FASB Statement No. 95."

The accumulated other comprehensive loss recorded was $21.3 million and $21.2 million during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively. The expense recorded was $3.2 million and $10.9 million during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively. During the year ended December 31, 2008 and the period ended December 31, 2007 Longview Timber LLC recognized zero and $32.1 million, respectively, in other liabilities.

15. Minority Interests

Minority interests represent the interests of Longview GP, LLC in the equity of Longview Timber LLC. Longview GP, LLC is a US company indirectly owned by Brookfield. Longview GP, LLC's equity ownership in the net assets of Timber was $10.7 million which is recorded as minority interest in non-current liabilities. The minority interest in the net loss which is recorded in other income-expense was $1.0 million and $0.8 million during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively.

16. Shareholders' Equity

Preferred stock

Timber is authorized to issue 125 shares of non-voting preferred stock with a par value of $1 thousand. On May 10, 2007, Timber issued 125 shares of preferred stock to 125 individual stockholders, each stockholder receiving one share. Preferred stock has a par value of $1 thousand per share, with liquidation preference of the same amount. The dividend rate for preferred shares is 12.5%. The shares are callable with a premium of 20% through December 31, 2009. The premium reduces 5% per annum such that there will be no premium after December 31, 2012.

Longview Fibre Company, a subsidiary of Timber, is authorized to issue 125 shares of non-voting preferred stock with a par value of $1,000. On May 10, 2007, Longview Fibre Company issued 125 shares of preferred stock to 125 individual stockholders, each stockholder receiving one share. Preferred stock has a par value of $1 thousand per share, with liquidation preference of the same amount. The dividend rate for preferred shares is 12.5%. The shares are callable with a premium of 20% through December 31, 2009. The premium reduces 5% per annum such that there will be no premium after December 31, 2012. These shares are included in minority interests, net of issuance costs.

Common stock

Timber is authorized to issue 15,000,000 shares of common stock with a par value of $0.01.

Timber issued 11,020,176 shares of common stock during the year ended December 31, 2008 and the period ended December 31, 2007 as follows:

US$ THOUSANDS (EXCEPT SHARE AMOUNTS)

Date	Description	Contribution
September 30, 2008	8,174 Common shares	$ 880
October 14, 2008	330,425 Common shares	35,579
October 28, 2008	2,109,512 Common shares	212,500
November 3, 2008	806,215 Common shares	81,213
Total		$330,172

US$ THOUSANDS (EXCEPT SHARE AMOUNTS)

Date	Description	Contribution
April 20, 2007	6,924,280 Common shares	$692,428
May 31, 2007	70 Common shares	59,400
October 31, 2007	841,500 Common shares	84,150
Total		$835,978

Timber's Common Stock is owned 66.5% by Brookfield Global Timber Fund I, LP, a US company in which Brookfield has indirect ownership; 10.5% by Brookfield PIV LLC, a US company in which Brookfield has indirect ownership; and 23% by Brookfield Infrastructure Corporation ("BIC") which is 40% owned by Brookfield.

Dividends

Timber distributed dividends amounting to $4.6 million and $250.7 million during the year ended December 31, 2008 and for the period from April 20, 2007 to December 31, 2007, respectively.

17. Commitments and Contingencies

Legal matters and litigation

Timber is subject to legal proceedings and claims that arise in the ordinary course of the business. Although there can be no assurance as to the disposition of these matters and the proceedings, it is the opinion of Timber's management, based upon the information available at this time, that the expected outcome of these matters, individually or in aggregate, will not have a materially adverse effect on the ongoing results of operations, the financial condition of the business, or cash flows.

18. Discontinued Operation

On May 31, 2007, Longview Fibre Company, a subsidiary of Timber, completed the sale of all assets and liabilities (Timber Harvest Assets and Manufacturing Operations) of PPI, a subsidiary of Longview Fibre Company, to Brascan (US) Corporation, a subsidiary of Brookfield, for total proceeds of $253 million, including $92 million of the intercompany debt. Subsequently, Longview Timber, Corp and Longview Timberlands LLC, newly-established subsidiaries of Longview Fibre Company, re-acquired the Timber Harvest Assets from PPI in exchange for $13 million of cash which is equal to the fair market value of the Timber Harvest Assets. This transaction resulted in Longview Fibre Company selling the Manufacturing Operations of PPI for $240 million, including $92 million of intercompany debt.

Details of assets and liabilities sold, net as a result of restructuring transactions are as follows:

US$ THOUSANDS		**As of May 31, 2007**
Assets:		
Current assets	$264,030	
Capital assets	46,598	
Other assets	143,710	**$454,338**
Less Liabilities:		
Current liabilities	100,627	
Long-term liabilities	205,711	**306,338**
Total		**$148,000**

The results of operations for the Manufacturing Operations from April 20, 2007 to May 31, 2007 and a loss on sale of assets were reported within discontinued operations in the accompanying consolidated statement of operations. The Consolidated Statement of Cash Flows does not separately report the cash flows of the discontinued operations. Details of revenue and loss from discontinued operations are as follows:

US$ THOUSANDS	**For the Period April 20, 2007 to May 31, 2007**
Net sales	**$75,756**
Income from operations (net of taxes of $346)	**538**
Loss on sale of assets	**(884)**
Net	**$ (346)**

Exhibit 12.1

CERTIFICATION

I, Samuel Pollock, certify that:

1. I have reviewed this Annual Report on Form 20-F of Brookfield Infrastructure Partners L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the period covered by the Annual Report that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: April 24, 2009

/s/ Samuel Pollock

Name: Samuel Pollock
Title: CEO, Brookfield Infrastructure Group Corporation

Exhibit 12.2

CERTIFICATION

I, John Stinebaugh, certify that:

1. I have reviewed this Annual Report on Form 20-F of Brookfield Infrastructure Partners L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the period covered by the Annual Report that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: April 24, 2009

/s/ John Stinebaugh

Name: John Stinebaugh
Title: CFO, Brookfield Infrastructure Group Corporation

Exhibit 13.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, who is carrying out the functions of chief executive officer for Brookfield Infrastructure Partners L.P. (the "Partnership") pursuant to a Master Services Agreement, dated December 4, 2007, among Brookfield Asset Management Inc., the Partnership, Brookfield Infrastructure L.P., Brookfield Infrastructure Holdings (Canada) Inc., Brookfield Asset Management Barbados Inc. and others, hereby certifies, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge on the date hereof, (i) the annual report of the Partnership on Form 20-F for the fiscal year ended December 31, 2008 (the "Annual Report"), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained in such Annual Report fairly presents in all material respects the financial condition and results of operations of the Partnership.

Dated: April 24, 2009

/s/ Samuel Pollock

Samuel Pollock
CEO, Brookfield Infrastructure Group Corporation

Exhibit 13.2

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, who is carrying out the functions of chief financial officer for Brookfield Infrastructure Partners L.P. (the "Partnership") pursuant to a Master Services Agreement, dated December 4, 2007, among Brookfield Asset Management Inc., the Partnership, Brookfield Infrastructure L.P., Brookfield Infrastructure Holdings (Canada) Inc., Brookfield Asset Management Barbados Inc. and others, hereby certifies, pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge on the date hereof, (i) the annual report of the Partnership on Form 20-F for the fiscal year ended December 31, 2008 (the "Annual Report"), fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained in such Annual Report fairly presents in all material respects the financial condition and results of operations of the Partnership.

Dated: April 24, 2009

/s/ John Stinebaugh

John Stinebaugh
CFO, Brookfield Infrastructure Group Corporation

Exhibit 1, Tab 4, Schedule 1

Materiality Threshold

MATERIALITY THRESHOLD

An applicant must provide justification for changes from year to year to its rate base, capital expenditures, OM&A and other items above a materiality threshold. The materiality thresholds differ for each applicant, depending on the magnitude of the revenue requirement.

GLPT's revenue requirement is equal to $39,365,100. In accordance with Chapter 2 of the *Filing Requirements for Transmission and Distribution Applications*, dated May 27, 2009, the default materiality threshold is 0.5% of revenue requirement for distributors[1] with a revenue requirement greater than $10 million and less than or equal to $200 million. GLPT's revenue requirement falls within this range, and therefore GLPT's materiality threshold is $196,825 ($39,365,100 * 0.5%).

[1] Although GLPT is a transmitter, GLPT assumes that the same threshold calculation will apply.

EXHIBIT 2 - RATE BASE

Exhibit 2, Tab 1, Schedule 1

Rate Base Overview

RATE BASE OVERVIEW

For purposes of providing historical rate base additions, GLPT has included information on projects that were completed by GLPL in 2007 and by GLPTLP in 2008-2010. Because GLPTLP acquired all of the transmission assets of GLPL and there are capital expenditures made by GLPL that have not yet been added to rate base, GLPTLP is seeking approval of those capital expenditures undertaken by GLPL. As a result, throughout this section, reference to GLPT will encompass both GLPL and GLPTLP, unless otherwise specified.

1.0 Summary of Rate Base

As indicated in the table below, GLPT's rate base for 2010 has been forecasted to be $209.000 million, being the total of the average of the forecasted opening and closing net fixed assets ($208.598 million) and an allowance for working capital ($0.4012 million).

Table 2-1-1 A – Rate Base Calculation

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Opening Net Fixed Assets**		$158,094.1	$192,332.5	$203,313.9	$207,775.3	$209,778.5
Closing Net Fixed Assets**		192,332.5	203,313.9	207,775.3	209,778.5	207,417.5
Average Fixed Assets	196,576.9	175,213.3	197,823.2	205,544.6	208,776.9	208,598.0
Working Capital Allowance	157.4	157.4	157.4	157.4	157.4	401.2
Rate Base	**$196,734.2**	**$175,370.7**	**$197,980.6**	**$205,702.0**	**$208,934.3**	**$208,999.2**

**Opening and Closing Net Fixed Assets have been reduced by the Net Book Value of a capital addition removed from Rate Base as a result of EB-2005-0241's settlement agreement.

GLPT did not re-calculate a working capital allowance for the years 2007 through 2009, and therefore GLPT used the 2006 Approved working capital allowance as a proxy for each of those years. GLPT re-calculated the working capital allowance for the 2010 test year, the details of which can be found at Exhibit 4, Tab 2, Schedule 1.

For the years 2006-2010, Exhibit 2, Tab 2, Schedule 1 provides the following on an account basis:

- the opening and closing gross and net book values;
- the fixed asset additions and disposals;
- annual depreciation; and
- proof of continuity.

The details of GLPT's rate base additions are discussed below.

2.0 Capital Expenditures

2.1 Capital Expenditure Budgeting Process and Asset Management Approach

For a discussion of GLPT’s approach to asset management and capital budgeting, please refer to Exhibit 2, Tab 5, Schedule 1.

2.2 Capital Expenditure Projects

Set out below are descriptions of capital expenditures for 2007-2010 that exceed a materiality threshold of $196,825.[1] The in-service date of each capital expenditure described in this section has occurred or will occur between 2007 and 2010.

Further information on various projects described below has been filed with the Board by means of a request for confidentiality. Please refer to the confidential filing as a supplement to the evidence presented in this section.

2.2.1 2010 Capital Expenditures in Service

GLPT's total capital expenditures in service in 2010 are forecasted to be approximately $5,045,900. There are five capital projects for 2010 that are forecasted to exceed GLPT's materiality threshold of $196,825, totalling approximately $3,111,900. Explanations for these six projects are provided below and comprise approximately 61.7% of GLPT's forecasted 2010 capital expenditures in service.

1. Third Line TS 115 kV Redevelopment Project – $1,230,000

<u>Introduction</u>

Third Line Transmission Station ("Third Line TS"), located in Sault Ste. Marie, Ontario, is GLPT's largest station. The station has two sections, a 230 kV section and a 115 kV

[1] GLPT has provided descriptions of capital expenditures that exceed the materiality threshold identified at Exhibit 1, Tab 4, Schedule 1.

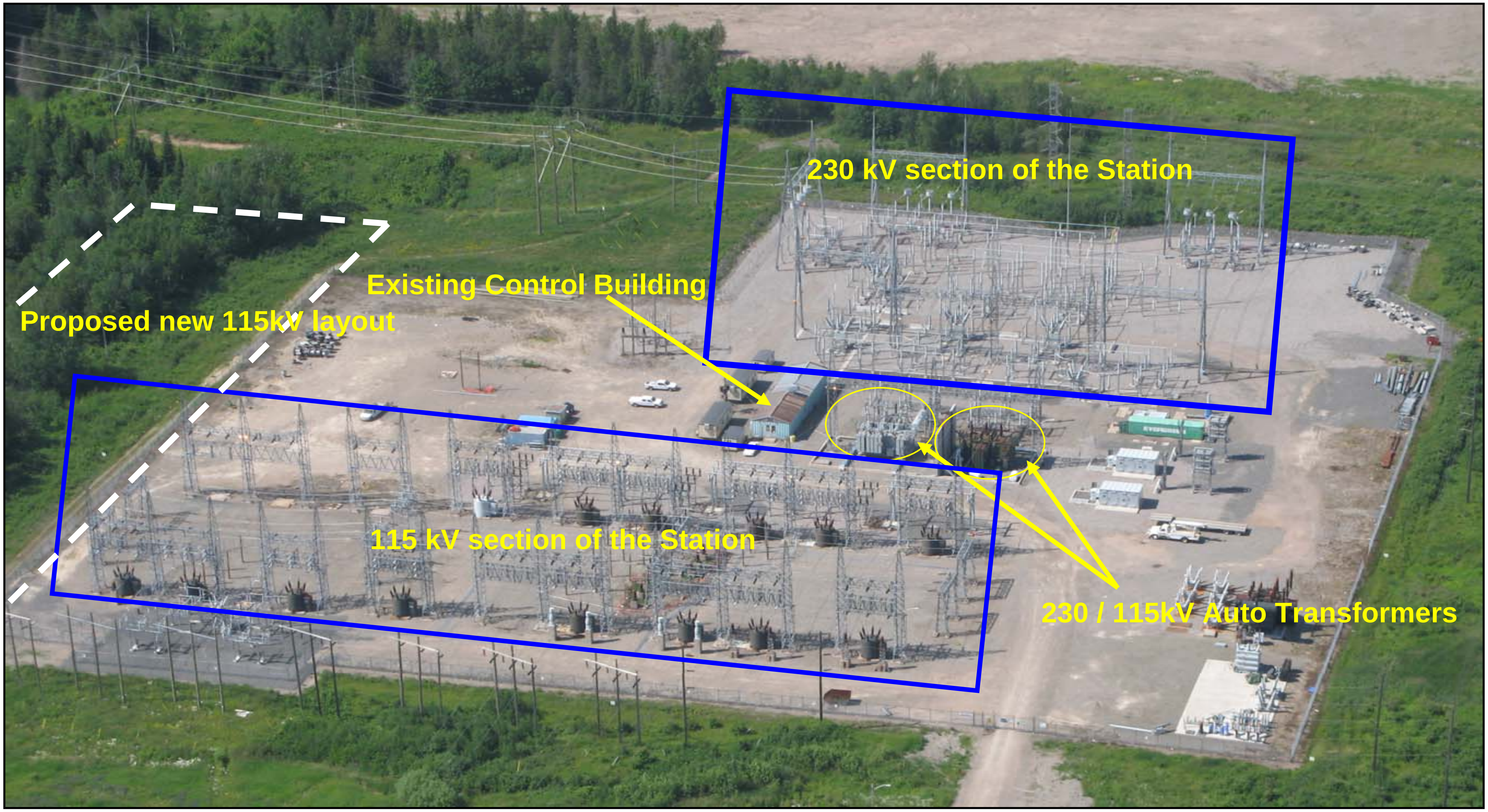
section. The Third Line TS 115 kV redevelopment project (the "Redevelopment Project") relates only to the 115 kV section of Third Line TS. Third Line TS is part of the Ontario bulk power system and the IESO-controlled grid. If either of the 115 kV or the 230 kV sections of Third Line TS were to be degraded, destroyed, or otherwise made unavailable, this could adversely affect the reliability and operability of the Ontario bulk power system and thereby threaten the supply of power to numerous customers in the province. The station is also an important connection point that facilitates a parallel circuit with the Hydro One Networks Inc. ("HONI") transmission system, and thereby provides N-1 contingency for the Ontario bulk electricity system for this section of the East-West tie, as shown in *Figure 2-1-1 A***.**

Figure 2-1-1 A - Overview of GLPT System and Third Line TS Location

<u>Background</u>

Third Line TS is the only supply point for the entire City of Sault Ste. Marie. The existing station, which is depicted in *Figure 2-1-1 B* and in the line drawing provided at **Appendix "A"**, is configured such that the 230 kV section of the station is connected to the 115kV section by two 230/115 kV autotransformers. Also emanating from the station are three 230 kV circuits and nine 115 kV circuits, which connect various loads and generation facilities. The station serves the largest load in the GLPT system, as it supplies power to the City of Sault Ste. Marie through PUC Distribution Inc., and to large industrial loads that include ESSAR Steel Inc., St. Marys Paper Inc. and Flakeboard Inc. Each of these loads are connected directly to and depend exclusively upon the 115 kV section of Third Line TS for reliable supply. Local generation connections include Lake Superior Power and Clergue generating stations.

1 *Figure 2-1-1 B - Aerial Photo of Site*



Third Line TS was originally constructed in 1967/68. The construction included the termination of P21G, P22G , Sault circuit Nos. 1, 2 and 3, as well as Algoma circuit Nos. 1 and 2. The station has evolved from its original conception. Each connection point was constructed and modified in accordance with the standards then applicable.

With respect to the 115 kV section of the station, there have been some recent modifications made to maintain reliability prior to the preparation of a third party review, as follows:

- In 2007, a tie breaker located between the 115 kV Algoma circuits Nos. 2 and 3 was installed so as to increase the reliability of the local area supply by ensuring that the loss of the station's North bus would not result in the loss of the two Algoma circuits. This was previously approved by the Board in EB-2005-0241. For additional details on the project, see page ■ of this schedule; and

- In 2008, GLPT installed additional conductor underneath the existing main north and south bus sections. Additional details on this project can be found at page ■ under section 2.2.2.1 of this schedule.

<u>Project Description</u>

In 2008, Third Line TS was reviewed by Wardrop Engineering Inc. ("Wardrop"), an independent third party, to determine the future of the 115 kV section of the station. The recommendation set out in the December 24, 2008 report from Wardrop (the "Wardrop Report") was to construct a new 115 kV section on undeveloped GLPT land to the west of the existing station site, as well as partially on the existing station site, as further described below. This would enhance GLPT's ability to operate and maintain the facility, improve reliability and significantly mitigate safety and environmental concerns associated with the 115 kV section of the station.

The Redevelopment Project will involve the construction of a new 115 kV section for Third Line TS. The new section will be constructed in part on the existing station site and in part on undeveloped GLPT lands immediately to the west of the existing station site, as shown in *Figure 2-1-1 B* and as depicted in *Figures 2-1-1 C* and *2-1-1 D*, as well as in the simplified line diagram in **Appendix A**. As noted, the work is strictly in relation to the 115 kV section of the station. There are no changes planned for the 230 kV section. The Redevelopment Project will involve the construction of a new breaker and a half layout,[2] complete with 17 new SF6 circuit breakers and 34 associated disconnect switches, as well as 9 motorized operated air breaks, bus work and equipment. The bus work will include the installation of a new bus conductor and associated steel support structures. The equipment would include, but not be limited to, a control building, protection and control (P&C) relays, remote terminal unit (RTU), supervisory control and data acquisition (SCADA) termination equipment, AC/DC systems, potential transformers (PTs), fencing and ground grid.

[2] The proposed breaker and a half layout is far more reliable than the current station design due to the fact that an outage to a breaker, either forced or planned, would not result in an associated transmission line outage, nor would the failure of a single element result in a complete station outage.

Figure 2-1-1 C - Existing 115 kV Facilities at Third Line TS

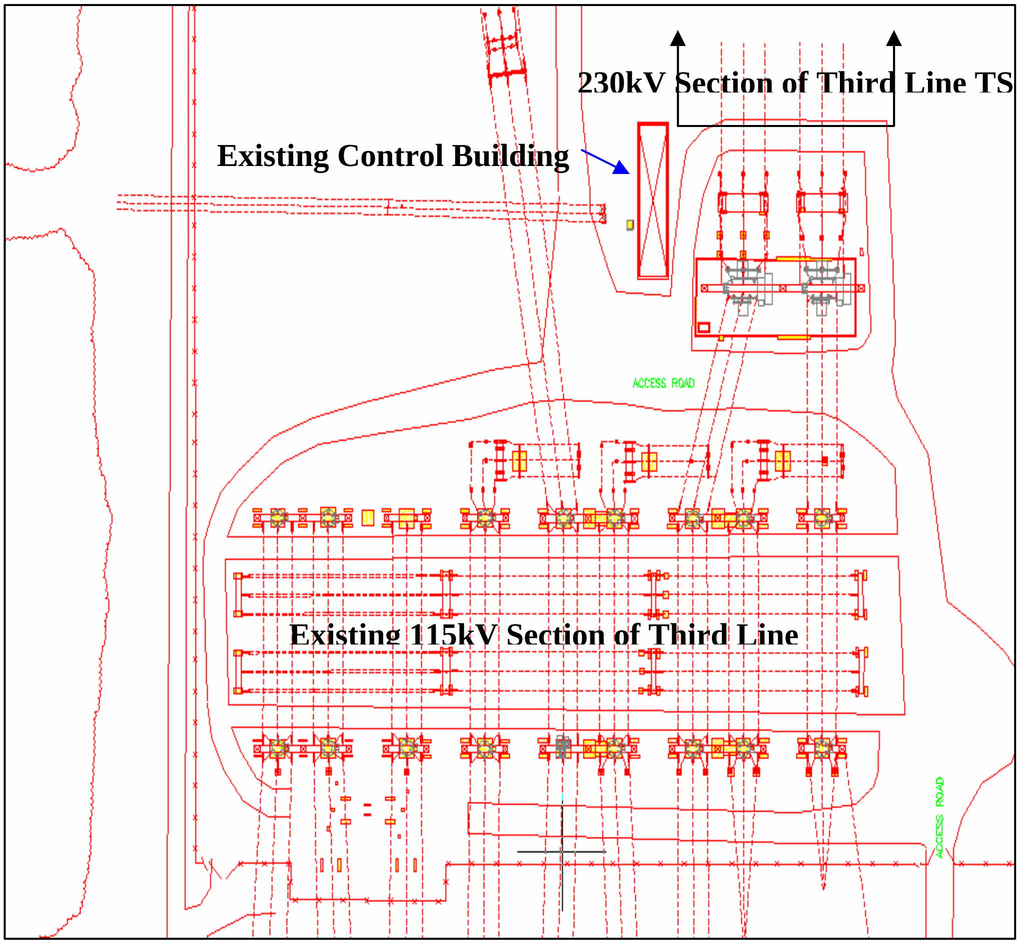
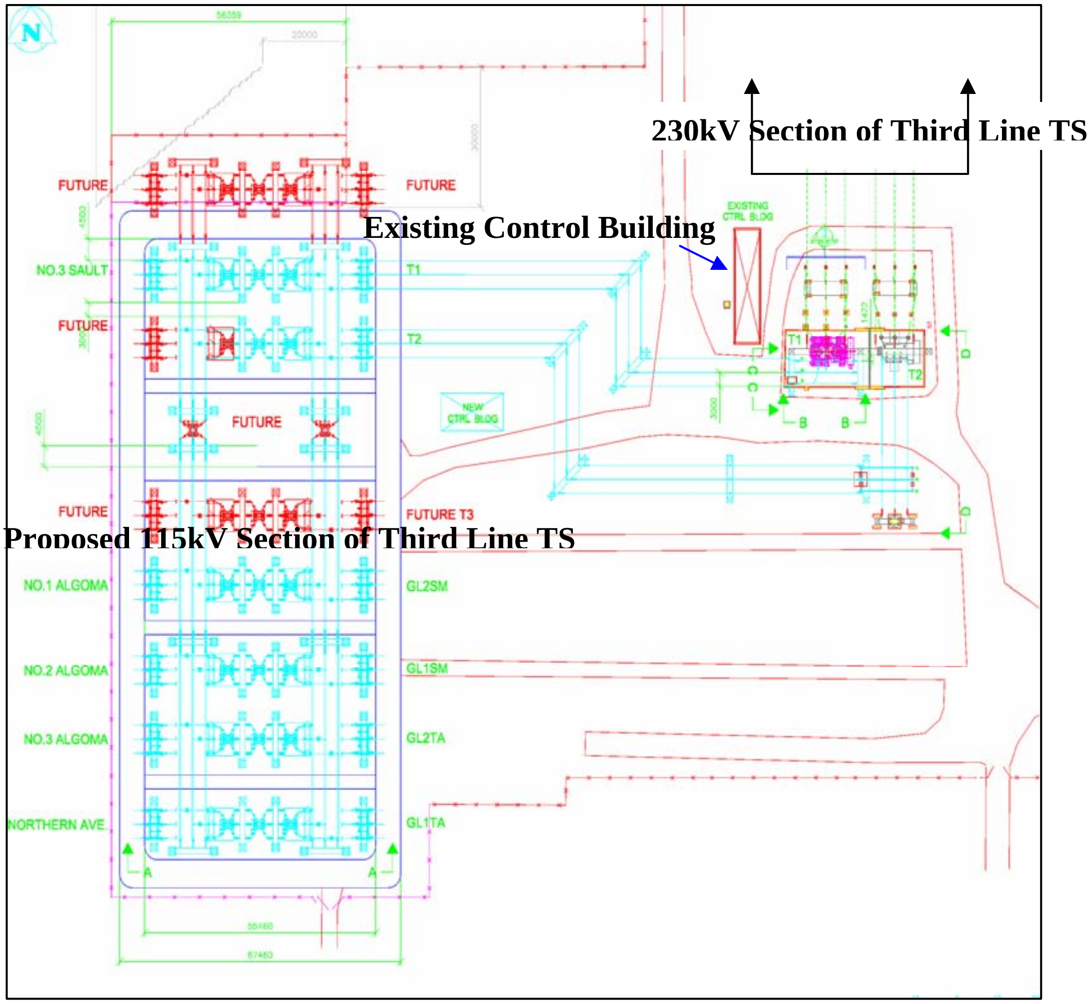


Figure 2-1-1 D – Proposed 115 kV Facilities at Third Line TS



The Redevelopment Project will be carried out in three phases, as follows:

- In Phase I, which is expected to be carried out and completed during 2010, GLPT will (a) carry out site clearing and excavation for subsurface preparation, including drainage, (b) install new perimeter fencing, (c) excavate and install the foundations and ground grid and backfill to final grade, (d) construct frameworks for the control building, and (e) complete the station design. While this work is associated with the new 115 kV section of the station that is to be constructed, it is necessary for these elements, particularly the fencing and ground grid, to be in place in order to allow for the safe and secure execution of the Redevelopment Project. The fencing and ground grid will be physically connected to the fencing and ground grid that are currently in place for the existing station and as a result the new fencing and ground grid will become part of the existing station. Consequently, GLPT is seeking to add the capital expenditures related to the fencing and ground grid to the rate base for the test year.

- In Phase II, which is expected to be carried out and completed during 2011, GLPT will, from January to approximately July 2011, (a) erect and commission all civil works, (b) install and commission busworks, (c) install, cable and commission high voltage electrical devices, (d) complete the control building, (e) install, cable and commission all communication and protection devices, and (f) transfer control of all yard devices to GLPT's Ontario System Control Centre / IESO. From approximately July 2011 to December 2011, GLPT will (a) transfer the existing T1 115 kV source to energize the new 115 kV section of the station, (b) transfer the Sault No. 3 115 kV circuit, Algoma Nos. 1, 2 and 3 115 kV circuits, and the Northern Avenue 115 kV circuit to the new 115 kV section of the station, and (c) retire one bay in the existing 115 kV yard to make physical room for the transfer of PUC 115 kV circuits to the new 115 kV section of the station, as well as to allow for the isolation and de-energizing of T2 and existing 115 kV station yard devices and to allow for the transfer of the T2 115 kV source to the new section of the station. Upon the conclusion of Phase II, the new 115 kV section of the station would be fully in-service.

- In Phase III, which is expected to be carried out and completed during 2012, GLPT will (a) perform relay re-verification of all new protections in accordance with IESO requirements applicable to the installation of new protections, and (b) retire and remove electrical equipment and demolish foundations and structures which comprise the existing 115 kV section of the station. Phase III is expected to be completed by September 2012.

Project Costs and Capitalization

The Redevelopment Project has a total estimated cost of $23,500,000. Of this, the estimated cost of Phase I, which is to be completed during 2010, is $10,230,000. The estimated cost of Phase II, to be completed during 2011 is $12,000,000 and the estimated cost of Phase III, to be completed during 2012, is $1,270,000. Because of the Redevelopment Project, certain assets will come out of rate base and be dealt with in future years.

GLPT seeks approval from the Board for all phases of the Redevelopment Project. GLPT further seeks the Board's approval for the addition of $1,230,000 into rate base in 2010. This amount reflects the portion of the Phase I project costs that are associated with elements of the Redevelopment Project that would go into service during 2010. In particular, this amount is associated with the development and construction of fencing and the ground grid, which would be tied into the existing fencing and ground grid. The Redevelopment Project, which carries an estimated cost that is in excess of 10% of GLPT's current rate base, is a very significant project for GLPT. As such, although the fencing and ground grid will become part of the existing station and be in service in 2010, this rate base addition is conditional upon the Board determining the need for all phases of the Redevelopment Project in this proceeding. Upon receiving approval in this proceeding, GLPT would seek to bring the costs of the project into rate base as part of a future application for 2011 and 2012 rates, which it intends to file in 2010.

Project Need

The need for the Redevelopment Project is driven by several related factors, which are described below. These factors include equipment age, equipment ratings, configuration, monitoring and regulatory obligations. Each factor represents an important consideration on its own and a potentially significant risk that needs to be addressed. It is the combination of these factors and their associated risks, along with the importance of Third Line TS to the load and generation that it serves, as well as to the Ontario bulk electricity system, which makes the Redevelopment Project important. As a prudent utility, GLPT is faced with increasing risks associated with the 115 kV section of Third Line TS and is, therefore, proposing to carry out the Redevelopment Project using the phased approach described above.

Equipment Age

The circuits, breakers, disconnect switches, bus components (insulators), PTs and protection equipment (relays) are at the end of their typical useful life and are therefore in need of replacement. Six of the PTs at Third Line TS are of the same vintage and from the same manufacturer as other PTs in GLPT's system that have failed within the past two years.[3] One of those failures involved the explosion of a PT in April 2009 at Mackay TS. Fortunately, this explosion occurred at night and, as such, did not result in any impacts on public or employee health or safety. If such an event were to occur at Third Line TS, it would cause a service interruption and have the potential to cause significant safety and environmental impacts.

Protection relays are also at the end of their typical useful life and are unable to facilitate the collection of fault information, which is essential for GLPT to be able to gain an understanding of the root causes of events which help facilitate "protections mis-operation mitigation" plans as per NERC standards.[4] Moreover, the probability of relay malfunction is expected to be greater as protection relay equipment ages. As such, to fulfill its obligations to operate and maintain the system in accordance with applicable

[3] There have been three such failures within this period.
[4] NERC - PRC-003-1 - Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems.
NERC – PRC-004-1 - Analysis and Mitigation of Transmission and Generation Protection System Misoperations.

reliability standards and with good utility practice,[5] the replacement of this aging equipment is necessary.

The equipment in the 115 kV section of the station is still operating as designed and is expected to continue to do so because GLPT maintains the equipment in accordance with good utility practices. However, because of the age of the equipment, the probability of failure grows at an increasing rate each year. This gives rise to increased reliability risks, including an increased risk of failure and of the consequences of such failure. Potential consequences of such failure include personal injury, harmful environmental impacts (due to the presence of bulk oil breakers), property damage and reliability impacts (such as the loss of supply to all connected loads and loss of connection with all connected generation).

Equipment Ratings

The voltage ratings on the existing breakers and disconnect switches are inadequate when compared to the Third Line TS normal operating voltage of 122 kV and the performance standards required under the Market Rules.[6] Because this equipment is being operated beyond its design standards, this section of the station is being over-stressed, thereby increasing the probability of equipment failure.

With respect to capacity, GLPT identified portions of the Overhead Cross Bus that are inadequate. The IESO subsequently reflected these findings in an operating instruction

[5] Transmission System Code, s. 5.1.2.
[6] Market Rules, Appendix 4.1 – IESO Controlled Grid Performance Standards.

memorandum issued to GLPT in respect of the station.[7] This operating instruction memorandum imposes operating restrictions on the station. In response, the 115 kV section of the station was modified with the installation of three critical areas of temporary, low-level, bus to bypass conductors, which are sufficiently rated for the current station capacity (the "Temporary Cross Bus").[8] The Third Line TS – Temporary Bus Installation project is described in section 2.2.3.1 of Exhibit 2, Tab 1, Schedule 1. It was the intention to put in place this temporary solution until such time as the 115 kV portion of the station was rebuilt. The alternative to the Temporary Cross Bus was a load rejection scheme, which if triggered would have resulted in outages to major industrial customers. As a result, the Temporary Cross Bus avoids these outages and provides for better reliability. Once the Temporary Cross Bus was installed, the IESO lifted all operating restrictions set out in its memorandum.

Configuration

The 115 kV section of the station employs source and customer connections on conductors that continuously cross overhead of both the North and South main buses in 27 different places (the "Overhead Cross Bus"). In addition, this section of the station employs temporary conductors that are situated beneath the North and South main buses and the Temporary Cross Bus to bypass conductors. These characteristics of the station's configuration give rise to significant operating and maintenance challenges and risks.

[7] IESO, Operating Instruction Memorandum, GLP SCO, Thermal Constraints on Third Line T1 115kV Bus Connections, November 3, 2007.

First, the Overhead Cross Bus cannot be effectively maintained or replaced. To ensure safe working conditions, the maintenance of the Overhead Cross Bus would require the isolation of both main buses, either through a total station outage or through multiple complex outages. While a total station outage would be impractical due to the need to interrupt service to the entire City of Sault Ste. Marie and all of the industrial loads as well as the generation connections that are served by the station, multiple complex outages would leave the station vulnerable in each instance to single contingency failures during the multiple outage sequences.

Second, if there were a failure of any one of the 27 Overhead Cross Buses, then both the North and South main buses would be taken out simultaneously. This is because such a failure would cause the overhead conductor to come into contact with both the North and South main buses, which in turn would result in a complete outage of the station and cause an outage for all connected loads.

Third, depending on the amount of snow on the ground, the configuration of the Temporary Cross Bus could at times during the year become non-compliant with electrical safety clearances. This presents a risk to unqualified persons who may enter the station. This is due in particular to clearance issues that arise from the physical location of the main North and South buses, which restrict the height at which the temporary buses could be installed. To be prudent, GLPT has installed temporary physical barriers that enclose each temporary bus beneath areas of the existing main North and South buses and, as such, the area is off-limits to all maintenance vehicles and to unqualified personnel.

The configuration problems associated with the Overhead Cross Bus and the Temporary Cross Bus pose an ongoing risk that requires GLPT to carefully and proactively manage the condition of the Overhead Cross Bus and the Temporary Cross Bus, which would be expected to deteriorate over time and which could result in a failure of the Overhead Cross Bus, giving rise to consequences such as those described above.

Monitoring

Through recent condition assessments, including annual infrared scans and bus inspections, GLPT has found that there are bus connections that require increased monitoring due to higher than normal heating, as well as due to a number of insulators that are cracked. The conditions of the Overhead Cross Bus conductors and associated insulators are monitored at an increased frequency. While the situation is currently manageable, GLPT believes that it is prudent to move forward with the Redevelopment Project in accordance with the timelines set out in the evidence. Should the conditions deteriorate further, GLPT would have to de-energize the station and undertake the necessary repairs. This would be a very difficult task and would require a complete station outage of at least a 10 hour duration, resulting in a loss of supply to the entire City of Sault Ste. Marie and all connected customers for this period.

Regulatory

To date, GLPT has exercised good utility practice to maintain system reliability with respect to Third Line TS. However, because of the risks described above, in particular the age of the equipment, to continue to maintain its system in accordance with good utility practice GLPT must proactively ensure continued reliability by replacing the 115 kV portion of the station. GLPT has maximized the useful life of these assets through ongoing maintenance and incremental improvements for many years. However, at this point in time, nothing short of replacing the 115 kV portion of the station would be sufficient to enable GLPT to continue to meet its obligations under the Transmission System Code[9] (“TSC”) and the Market Rules.[10] GLPT must therefore complete the Redevelopment Project in the manner described.

<u>Project Outcome</u>

The Redevelopment Project would improve reliability by mitigating the escalating risk associated with the age of the existing 115 kV section of Third Line TS and by replacing the existing section with a new 115 kV section that, due to its enhanced capacity and improved configuration, would provide greater reliability, maintainability, and operational flexibility. As a result, the Redevelopment Project would ensure that the facility is in line with the current TSC, the Market Rules and other applicable standards,[11]

[9] OEB – TSC – Section 5 – Requirements for Operations and Maintenance, Subsection 5.1.2; Section 8 - General Technical Requirements, Subsection 8.1.1.
[10] IESO Market Rules – Chapter 4- Grid Connection Requirements, Sections 2, 3, 3.3, 5, 6.1, 6.1A;
[11] OEB TSC – Section 4.6 – Compliance with Facility Standards, Subsection 4.6.1;

while improving safety and reducing environmental risk. In particular, the Redevelopment Project would be expected to bring about the following benefits:

- *Enhanced Reliability* - The station will be constructed in accordance with the most current standards, having regard for IESO guidelines and all other applicable standards. In general, the proposed breaker and a half layout is much more reliable than the current station design due to the fact that an outage to a breaker, either forced or planned, would not result in an associated transmission line outage nor would a single element failure result in a complete station outage as is currently the case. Except in the circumstance of a physical, catastrophic failure, loads would not likely be subject to interruptions because of outages to station elements. The Redevelopment Project would provide an N-1 contingency within the station that is currently not in place.

- *Improved Ability to Maintain* **-** Upon project completion, GLPT will be able to perform maintenance activities on all equipment in the station with minimal impacts to reliability. One major advantage of the proposed configuration is that all bus components would be accessible (and would therefore be able to be maintained in accordance with good utility practice).[12] Should issues arise with components, GLPT would be able to isolate bus sections with minimal impact on reliability.

IESO Market Rules – Chapter 4- Grid Connection Requirements, Sections 2, 3, 3.3, 5, 6.1, 6.1A
IESO Market Rules, Grid Connection Requirements Appendices – Appendix 4.1 – IESO Controlled Grid Performance Standards;
[12] OEB – TSC – Section 5, Requirements for Operations and Maintenance, Subsection 5.1.2

- *Improved Ability to Operate* **-** With the addition of the motorized operated air breaks ("MOAB"), a transmission line outage (either forced or planned) would not result in impacts to the station bus configuration. This is because the MOABs would isolate the line from the station, thereby allowing all breakers to remain in the closed position.

- *Improved Safety* - Safety issues associated with the age and configuration of the existing 115 kV section would be addressed. In particular, clearances would meet or exceed Electrical and Utility Safety Association ("EUSA") standards and newer equipment would have lower risk of catastrophic failure. As a result, it is expected that the probability of a safety related event will be significantly lower than at present.

- *Reduced Environmental Risk* **-** The Redevelopment Project would result in the elimination of 38,500 gallons of oil from Third Line TS due to the removal of the 14 remaining bulk oil breakers. GLPT notes that, upon completion of this project, GLPT would have no 115/230 kV bulk oil breakers in its entire system.

- *Reduced Maintenance Costs* **-** As the major overhaul maintenance cycle for the proposed SF6 breakers is six years, compared to the 4 year cycle for bulk oil breakers, maintenance costs are expected to be reduced dramatically. A rough estimate of the difference in maintenance costs indicates that the proposed SF6 breakers would cost approximately $4,250 to maintain on an annualized basis, as compared to the bulk oil breakers, which would cost approximately $87,500 on an annualized basis.[13] Moreover, due to the age of the bulk oil breakers, additional testing and unplanned maintenance outside of the normal maintenance cycle would be required.

- *Station Expandability* **-** The proposed design provides sufficient space within the station to permit future growth at minimal incremental cost, relative to current project costs. This would relate to any additional 115 kV circuits or a third autotransformer, should the need arise. For example, this would allow the station to accommodate growth arising from the need to connect renewable energy generation facilities.

- *Regulatory Compliance* **-** GLPT applied for and has received a System Impact Assessment ("SIA") from the IESO. The SIA included a notification of approval, conditional upon there being no material changes to the project. The IESO concluded that the Redevelopment Project will improve the connectivity of 115 kV transmission elements and the reliability of power supply at Third Line TS under various breaker failure scenarios and that the proposed project will not have a materially adverse impact on the reliability of the IESO-controlled grid.

[13] SF6 Breakers: 17 breakers x $1500 every 6 years = $4250 per year. Bulk Oil Breakers: 14 breakers x $25,000 every 4 years = $87,500 per year.

Alternatives Explored

Wardrop was contracted by GLPT in 2008 to carry out a review of the 115 kV section of Third Line TS. Wardrop's review involved examining the station, providing recommendations for the short-term resolution of existing deficiencies, as well as providing recommendations for meeting long-term needs in a cost effective and technically efficient manner. The objective of the review was to provide feasible options that will allow simplified constructability, good maintainability, maximized reliability, flexibility for future expansion, outage requirements with minimal interruption to customer service, negligible vulnerability to station operation and good value for the associated cost. These objectives represented the criteria for evaluating the various options. Wardrop was also instructed to develop its recommendation with a view to upgrading all components to a minimum capacity of 2000 Amperes, as well as to minimize civil works and to reuse structures where possible.

Wardrop identified and considered five options. Option #1 was eliminated on account of it not providing an adequate solution. The preliminary cost estimates for Options #2 - 5 were within 10% of one another. Wardrop recommended that Option #5 be implemented by GLPT as it is the best option. Option #5 provides the best balance between cost and improved operational and maintenance flexibility, while resolving all of the operational limitations and restrictions of the station in its current configuration. The Redevelopment Project as discussed in this schedule therefore reflects Wardrop's Option #5. The alternatives to the Redevelopment Project that were considered by Wardrop are as follows:

- Option #1 called for direct upgrades to the limiting bus sections using cable, SF6 bus duct, or overhead lines and replacement of all breakers and disconnect switches. Wardrop eliminated this option because it was found to provide an inadequate resolution to the problem of overhead conductor maintenance issues, as well as because it would require outages that cause unreasonable disruptions in service. In addition, Option #1 was found to not maximize reliability, maintainability or expandability.
- Option #2 called for the construction of a new 115 kV switchyard on undeveloped GLPT land on the west end of the station, as well as on the existing station property, using "folded" diameters with a breaker and a third configuration. This option was found to provide good reliability, minimal disruptions in service due to outages, good maintainability, flexible operability, expandability and favourable value versus cost. To meet IESO requirements, expansion of the switchyard under this option would require the installation of bus tie breakers. This adds 2 breakers to these configurations as a maximum of 6 circuit breakers on any high voltage bus should trip as a result of any fault. This option was found to offer straightforward constructability, low staging complexity and minimal outages. While Option #2, with two less breakers, is estimated to be about $1.39 M less

than the Redevelopment Project, the Redevelopment Project was found to offer superior operational and maintenance flexibility.

- Option #3 called for the construction of a new 115 kV switchyard on undeveloped GLPT land to the west of the station using "folded" diameters with a breaker and a half configuration. This option was found to provide good reliability, minimal disruptions in service due to outages, good maintainability, flexible operability, expandability and favorable value versus cost. To meet IESO requirements, expansion of the switchyard under this option would require the installation of bus tie breakers. This adds 2 breakers to these configurations as a maximum of 6 circuit breakers on any high voltage bus should trip as a result of any fault. This option would also require the use of temporary power cables for successful implementation. As a result of these technical shortfalls and slightly higher costs relative to the Redevelopment Project, Wardrop eliminated this option as a candidate for implementation.

- Option #4 called for the construction of a new 115 kV switchyard on the existing station property, as well as on undeveloped GLPT land to the west of the station, using "linear" diameters with a breaker and a half configuration. This option was found to provide good reliability, minimal disruptions in service due to outages, good maintainability, flexible operability, expandability and favorable value versus cost. To meet IESO requirements, expansion of the switchyard under this option would require the installation of bus tie breakers. This adds 2 breakers to these configurations as a maximum of 6 circuit breakers on any high voltage bus should trip as a result of any fault. This option would also require the use of temporary power cables for successful implementation. Additionally for this option, the deficiency of a transformer bus crossing both main buses can result in a total station outage upon a failure of an overhead conductor. As a result of these technical shortfalls and slightly higher costs relative to the Redevelopment Project, Wardrop eliminated this option as a candidate for implementation.

- Option #5, which is the Redevelopment Project, called for construction of a new 115 kV switchyard on undeveloped GLPT land to the west of the existing property, as well as partially on the existing station property using the "linear" diameters of breaker and a half configuration. This option was found to provide good reliability, minimal disruptions in service due to outages, good maintainability, flexible operability, expandability and favorable value versus cost. This option was also found to offer straightforward constructability, low staging complexity and minimal outages. Option #5 had the second lowest estimated cost of the options considered. While Option #2, with two less breakers, is estimated to be about $1.39 M less than Option #5, this estimated cost difference is reasonable relative to the incremental benefits of Option #5 over Option #2, as identified in the Wardrop Report:

    - Option #5 offers "very good" operating flexibility vs. "good" operating flexibility for Option #2;

- Option #5 offers "very good reliability and very good maintainability" vs. "good reliability and good maintainability" for Option #2;
- Option #5 offers "very good access to all equipment" and allows for aerial lift access to maintain all equipment vs. "good access to equipment" and aerial lift access only to equipment on the outside of the switchyard; and
- Option #5 offers the advantage of GLPT staff being "familiar with the linear layout of a breaker and a half similar to Mackay TS" vs. GLPT "staff unfamiliarity with operation and layout of a folded breaker and a third configuration" for Option #2.

For these reasons, the Wardrop Report concludes that Option #5 offers superior operational and maintenance flexibility in comparison to Option #2 and, on this basis, Wardrop recommends that Option #5 be implemented.

<u>Conclusion</u>

Based on the facts set out above, GLPT seeks approval of the Redevelopment Project and the inclusion in rate base for the test year of the capital expenditures related to the fencing and ground grid, which are to be in service in 2010.

2. Steelton Ground Grid Refurbishment – $584,000

Need:

Steelton TS is a 115 kV transmission station located within the City of Sault Ste. Marie. As part of GLPT's inspection process, annual condition assessments are performed and potential issues are identified. Through this process, it was noted that Steelton TS required further investigation of the ground grid and civil works. In principle, a safe grounding design has the following two objectives:

i. to provide means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service, and

ii. to assure that a person in the vicinity of grounded facilities is not exposed to the danger of critical electric shock.

Specifically, GLPT obtained a report from ABB Inc. that assessed this station with respect to the ground grid and civil works. The results have concluded that there is a need for modifications to the existing ground grid as per the current Institute of Electrical and Electronics Engineers ("IEEE") and Electrical Safety Authority ("ESA") standards.[14] This work will be undertaken for health and safety reasons.

Summary:

This project involves the design and construction of a new ground grid as per all applicable standards. Specifically, this project involves the addition of ground rods and copper conductor as well as the application of additional crushed stone in order to meet the objectives stated above. Also included are repairs to concrete foundations and enhancements to yard drainage and general landscaping.

Outcome:

Expected results include:

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[14] IEEE – Standard 2000-80 - IEEE Guide for Safety in AC Substation Grounding; ESA – Rules 36-300, 36-302, 36-304, 36-308, 36-310, 36-312.

- Enhanced public and employee safety; and
- Compliance with IEEE and ESA standards.

3. Building Upgrades - $541,000

Need:

Station condition assessments are performed annually, during which control buildings are inspected and assessed. Issues are identified through this process and improvement projects are assigned on a priority basis. The investment improves the condition and expected life of aging transmission station control building facilities and associated infrastructure throughout the GLPT system. Inaction has the potential to result in unsafe building structures, as well as potential damage to equipment, drawings and manuals due to weather exposure.

Summary:

This project involves the replacement of roof structures, windows, doors and HVAC systems, as well as the purchase of portable storage facilities. Specific projects include:

- Ice hood installation at Watson TS;
- Upgrades to GLPT's portion of the office complex in response to an energy audit;
- Upgrades to the documentation vault where critical documentation is stored;

- Purchase of a storage facility for the Wawa area; and
- Radio tower communications building replacements.

Outcome:

Building upgrade projects will result in improved facilities through the replacement of aging building components. Some projects will reduce safety hazards. Some projects will lower the probability of business disruptions.

4. Third Line Series Reactor Installation / Capacitor Replacement - $457,300

Need:

Third Line TS is a 230/115 kV station located in Sault Ste. Marie. The station consists of two 250 MVA 230/115/34.5 kV autotransformers, associated breakers and switchgear. The TS is the only supply point for the City of Sault Ste. Marie.

GLPT has had three failures located on the 34.5 kV Third Line autotransformer tertiary system with the most recent being the failure of a tertiary reactor on the T1 autotransformer. Due to the critical significance of this autotransformer, an engineering study was initiated to identify any issues in order to extend the life of the existing equipment. The study recommended that series reactors be installed and that the existing capacitors be replaced to help protect the surrounding equipment, thereby improving safety and reliability.

Summary:

The project involves the installation of two banks of dry type air core series reactors and the replacement of the existing capacitor banks. The reactors will be physically located on the autotransformer 34.5 kV tertiary system, at Third Line TS, in series with the capacitor banks.

Outcome:

The project will result in a reduction of equipment heating and voltage distortion, thus reducing the risk of equipment failure leading to increased reliability as well as enhanced worker safety. In mitigating the damaging effects of heating and voltage distortion, the equipment is expected to perform as expected for its entire life cycle. The series reactor and capacitor banks will remain in service and not be affected by the Redevelopment Project.

This is the second and final phase of the project. The first phase, discussed in section 2.2.2 of this schedule, will be completed in 2009.

5. GIS Software Purchase & Installation - $299,600

Need:

A geographic information system (GIS) is an information system for capturing, storing, analyzing, managing and presenting data which is spatially referenced (i.e. linked to location). GIS is an information system capable of integrating, storing, editing, analyzing, sharing, and displaying geographically referenced information. GIS applications are tools that allow users to create interactive queries (user created searches), analyze spatial information, edit data, maps, and present the results of all these operations. GLPT's transmission system is comprised of transmission lines located entirely in northern Ontario, which are predominantly located in forest zones with dense vegetation.

GLPT currently has no GIS system, which affects its ability to spatially manage the following:

- Landowner and parcel information;
- Environmental information (i.e. ready access to treated structures, sensitive areas, species at risk and transmission line water crossings);
- Access road information;
- Vegetation information (i.e. ROW widths, ROW maintenance and cycle information);
- Asset information (i.e. structures and ROWs); and
- Emergency response (i.e. finding causes of outages).

The implementation of GIS is an essential asset management tool that will ensure that business and regulatory requirements are not compromised and that asset lifecycles are maximised.

Summary:

GLPT plans to implement a GIS solution that will include the following in a phased approach:

- Environmental management;
- Forestry and vegetation program management;
- Outage planning and scheduling;
- Asset investment planning;
- Capital and maintenance planning;
- Regulatory reporting requirements;
- Property information; and
- Work management.

Outcome:

Results include enhanced landowner and parcel management. For example, by having the GIS system, GLPT will be better able to manage surveying, transmission expansion, right of way widths and more. Moreover, environmental management is enhanced as a GIS allows for the more efficient and reliable tracking and management of species at risk in various environmentally sensitive areas.

GLPT will be able to more effectively manage vegetation by monitoring right of way widths and cycle information through a GIS. Access roads and trails will also be more readily apparent and manageable.

The information in the GIS will enhance GLPT's approach to capital and maintenance expenditures. The system will allow for expedient identification of faults related to outages, resulting in an improved emergency response system. The improved emergency response system will allow GLPT to provide a higher level of service in a safer and more cost effective manner.

This is the second phase of the project. The first phase is forecasted to be completed in 2009 and is discussed in section 2.2.2 of this schedule.

2.2.2 2009 Capital Expenditures in Service

GLPT's total capital expenditures in service in 2009 are forecasted to be approximately $8,939,700. There are 13 capital projects for 2009 that are forecasted to exceed GLPT's materiality threshold of $196,825, totalling approximately $7,096,400. The explanations for these 13 projects, provided below, comprise approximately 79.4% of GLPT's forecasted 2009 capital expenditures in service.

In 2009, GLPT had capital expenditures in service on one additional project that was previously approved by the Board. The 2009 amount of $280,900 was incremental to the approved amount, and therefore GLPT is seeking to add this amount to rate base in this proceeding. The amount of $280,900 forms part of the $8,939,700 noted above, and represents approximately 3.1% of the total capital expenditures in service in 2009. GLPT describes this project as project number 14 below.

1. Echo River TS Protection Upgrades - $900,000

Need:

Echo River TS is a 230 kV transmission station located 26 km east of Sault Ste. Marie. Presently, both the autotransformer protection and the 34.5 kV bus differential and backup protections are electromechanical relays. As the electromechanical relays are no longer manufactured and it is not possible to find replacement parts, they are obsolete. In addition, the electromechanical relays provide no fault or operation data. The relays have aging, moving parts and need to be replaced with microprocessor based relays.

Troubleshooting of equipment and line faults, as well as fault locations with the electromechanical relays, cannot be done on a timely basis as per NERC standards.[15]

Summary:

This project replaced the mix of obsolete electromechanical relays, which provided no fault or operation data, and older vintage solid state relays with modern microprocessor based relay units. A breaker failure scheme for a 230 kV breaker has been added to the protections to clear fault sources for the breaker should it fail to operate.

Power Line Carrier ("PLC") communications facilities have been incorporated into this project. These carry Supervisory Control and Data Acquisition ("SCADA") information and provide communication assisted transfer trip facilities by which the breaker fail scheme clears the 230 kV fault sources, as required under the TSC.[16] The PLC facilities also carry the local voice phone circuit and the Central Information Retrieval System ("CIRS") IP data.

The station's battery system was rebuilt into two redundant battery systems that are electrically and physically separate as per TSC requirements.[17]

Outcome:

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[15] NERC - PRC-003-1 — Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems;
NERC – PRC-004 - Analysis and Mitigation of Transmission and Generation Protection System Misoperations
[16] OEB - TSC – Section 8.2 – Protection and Control – Subsection 8.2.1
[17] OEB – TSC – Section 10.8 – Battery Banks and Direct Current Supply

Operation of the new relay protections at Echo River T.S. is expected to be more dependable and precise in comparison to the electromechanical relays. The gathering of relay operation and fault history data can now be accomplished remotely. As a result, troubleshooting of equipment and line faults will now be more prompt and fault location data can be obtained and analyzed more efficiently.

Under the electromechanical relay arrangement, maintenance was on a 4 year cycle. Under the new microprocessor based relay arrangement, maintenance occurs on a 6 year cycle as per NPCC criteria.[18] As a result, maintenance costs will be reduced.

2. System Wide Cyber Security Requirements - $832,000

Detailed information on this rate base addition has been filed with the Board in confidence.

3. Third Line TS T2 Autotransformer Protections Upgrade - $809,300

Need:

In 2009, the T2 autotransformer protections at Third Line TS were replaced due to age and their limited functionality. Specifically the protections did not provide the capability of remotely gathering event information nor did they provide a sync-check function which allows for the 230kV and 115kV sections of the station to be connected properly and safely should they become electrically separated.

[18] NPCC – Directory 3 – Table 1 - Maintenance Intervals for Protection Groups

Summary:

This project included the replacement and relocation of all protections associated with the T2 autotransformer.

Outcome:

The project has resulted in:

- Enhancements to reliability as aging relays are replaced;
- Enhancements to fault analysis capabilities; and
- Enhancements to station operability with the addition of sync-check functions.

The autotransformer will remain in service and not be affected by the Redevelopment Project.

4. Batchawana TS Ground Refurbishments - $631,300

Need:

Batchawana TS is a 115 kV transmission station located north of Sault Ste. Marie. As part of GLPT's inspection process, as mentioned in section 2.1.1, annual condition assessments are performed and potential issues are identified. Through this process, it was noted that Batchawana TS required further investigation of the ground grid and civil works. In principle, a safe grounding design has the following two objectives:

i. to provide means to carry electric currents into the earth under normal and fault conditions without exceeding any operating and equipment limits or adversely affecting continuity of service; and

ii. to assure that a person in the vicinity of grounded facilities is not exposed to the danger of critical electric shock.

Specifically, GLPT obtained a report from ABB Inc. that assessed this station with respect to the ground grid and civil works. The results have concluded that there is a need for modifications to the existing ground grid as per IEEE and ESA standards.[19] This work has been undertaken for health and safety reasons.

Summary:

This project involves the design and construction of a new ground grid as per all applicable standards. Specifically, this project involves the addition of ground rods and copper conductor as well as the application of additional crushed stone in order to meet the objectives stated above. Also included are repairs to concrete foundations and enhancements to yard drainage general landscaping and fencing.

Outcome:

Expected results include:

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[19] IEEE – Standard 2000-80 - IEEE Guide for Safety in AC Substation Grounding; ESA – Rules 36-300, 36-302, 36-304, 36-308, 36-310, 36-312.

- Increased public and employee safety;
- Compliance with IEEE and ESA standards; and
- Increased facility security.

5. Mackay TS - Capacitive Voltage Transformer Replacement - $550,100

Need:

Capacitive Voltage Transformers (“CVT”) permit a step down of voltage in order to connect protection relays for the analysis of system data. This allows for the monitoring of system conditions, which provides a means of protecting employees, the environment and GLPT’s assets.

Two Potential Transformers (“PT”), which serve the same function as a CVT, failed at Mackay TS in 2008 and one failed in 2009. The implications of not replacing failing PTs include a greater potential for injury to public or workers resulting from equipment failure, as well as an increasing probability of asset damage as a result of protections misoperations.

Summary:

The project consists of the replacement of all of the existing PTs with CVTs as CVTs serve the same function and are more cost effective to purchase and install.

Outcome:

Upon completion, it is expected that the replacements will create a safer work environment and enhance system reliability because of the reduced risk of equipment failure.

6. GIS Software Purchase & Installation - $399,400

This is the first phase of the GIS Software project described above, in section 2.2.1 of this schedule.

7. Third Line Series Reactor Installation / Capacitor Replacement - $450,000

This is the first phase of the two phase Third Line Series Reactor Installation project, described in section 2.2.1 of this schedule.

8. Vegetation Management Mapping Development - $408,700

Need:

GLPT’s transmission system is comprised of transmission lines located entirely in northern Ontario, which are predominantly located in forest zones with dense vegetation. GLPT’s transmission system extends through two different yet comparably dense forest zones. As many of the lines are low profile lines, it is of particular importance for GLPT to effectively manage vegetation.

The objective of the NERC Vegetation Management Standard[20] is to prevent vegetation related outages which could lead to cascading.[21] Requirement 1.2 of this standard states the following:

> **R1.2.** The Transmission Owner . . . shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

Currently, GLPT's management of requirement 1.2 of the NERC standard is manually intensive and subject to human error. In order to continuously improve and become more effective and efficient at managing this requirement, there is a need to move forward with this project.

[20] NERC – FAC-003 Standard
[21] Cascading – Defined by NERC – The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Given the geography, vegetation and characteristics of GLPT's transmission lines, not proceeding with this work increases the potential for vegetation related outages which could lead to the following consequences:

- Decline in customer delivery point reliability;
- Added system constraints;
- Negative customer impacts; and
- Non-compliance with the TSC.

Summary:

This project involves the use of Light Detection and Ranging (LIDAR) technology for purposes of capturing data on all 115 and 230 kV rights of way in order to identify the distances between transmission lines and vegetation. LIDAR is an optical remote sensing technology that measures properties of scattered light to find range and/or other information of a distant target. The prevalent method to determine distance to an object or surface is to use laser pulses. This project will assist in the collection and processing of data and will accurately identify clearance issues associated with transmission lines and vegetation. The information will be stored in a database to be used as a supporting tool for effectively managing the vegetation management program. The data collected will also be used in conjunction with the GIS system (discussed earlier in this schedule) to support GLPT's asset strategy and investment plans.

Outcome:

Upon completion, the data collected will aid GLPT in assessing the transmission lines and identifying clearance problems and danger vegetation as per the requirements above. It will allow GLPT to effectively manage the vegetation program in a cost effective manner, thus improving customer delivery point performance and bulk system reliability.

9. Algoma 115kV Structure Reinforcement - $321,100

Need:

As part of GLPT's condition assessments, it has been determined that a number of structures between Third Line TS and Northern Avenue TS require immediate attention. The aging assets are a concern as the probability of failure increases with age. A select number of the existing 45 year old structures on the 115kV Algoma circuit are stressed beyond acceptable limits. Given the close proximity to the public and the importance of customer reliability in the City of Sault Ste. Marie, this reinforcement is needed to extend the life of these assets.

Summary:

This project includes the installation of cross-bracing to reduce stresses to acceptable limits. In addition, the project will reinforce the base of each pole using steel braces driven alongside the pole and banded to the pole.

Outcome:

On completion, the project will reduce stresses to acceptable levels, thereby reducing the probability of structure failure, improving reliability and reducing public safety concerns.

10. Centralized Information Retrieval System (CIRS) - $205,900

Need:

The IESO oversees the reliability of the power system in Ontario, and requires that all Transmitters meet all applicable standards including NERC standards.[22]

These standards require that GLPT analyze any transmission protection system misoperations, and develop and implement a corrective action plan to avoid any future misoperations. In support of these efforts, a large number of relays have been replaced. These relays now need to be configured and connected to the CIRS system.

Without a remote connection to automatically push data to GLPT's centralized server upon an event, there is a risk of losing information should multiple events occur within a short period of time as a result of limited storage capabilities of relays. This results in the inability to accurately analyze fault information and to subsequently create mitigation plans as well as regulatory non-compliance and the probability of future protections misoperations.

[22] NERC - PRC-003-1 — Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems; NERC – PRC-004 - Analysis and Mitigation of Transmission and Generation Protection System Misoperations.

Summary:

This project will update the existing CIRS to include recent protection system changes arising from the replacement of relays.

Outcome:

Upon project completion it is expected that GLPT will have enhanced capability to determine the root causes of disturbances and will allow for the more accurate development and implementation of corrective action plans to avoid future misoperations. This enhancement will improve reliability of supply as protections systems will operate as designed.

11. Magpie TS – Battery & Charger Replacement - $200,700

Need:

Batteries and chargers provide the supply of secure DC power to protection, control and data acquisition systems which are essential to the operation of the transmission system. The battery charger replacements are determined by reviewing the condition of the asset as well as the age and type. Typically, the type of battery determines the life expectancy. The Magpie single battery system is a lead calcium battery, originally installed in 1989. The battery is 20 years old with a typical life expectancy of 20 years.

This project includes the replacement of the lead calcium batteries with a new battery bank as well as the associated charging system. Failure to proactively manage these batteries and chargers will result in frequent station protections failures. This will lead to negative impacts on customer delivery point reliability, as well as possible equipment damage.

Summary:

This project involves the replacement of the existing lead calcium battery, complete with its accompanying charger.

Outcome:

Proactive replacement will ensure the continued health and reliability of the batteries and chargers, thereby resulting in increased system and customer reliability.

12. Clergue 115kV Circuit Insulator Replacement - $198,700

Need:

The Clergue 115 kV transmission lines connect industrial load and local generation, and are located within the city of Sault Ste. Marie. Over a two year span, on two separate occasions, Feb 21/07 and Aug 22/08, transmission line dead-end insulators failed resulting in damage to nearby vehicles. On both occasions there was potential for injury. In 2008, a proactive approach was taken and a contractor was hired to spray-wash all of the 115 kV insulators in the area in an attempt to free any debris or contamination that may cause them to fail. At the same time an engineering study was initiated to determine the root cause of the failures in order to eliminate the hazard. The results of the review determined that the failures were caused by defective insulators.

Project Summary:

This project involved the replacement of all porcelain dead-end insulators with new polymeric type insulators.

Project Outcome:

As a result of completing this project, transmission customer delivery point reliability is maintained. In addition, there has been a reduction in potential safety hazards related to equipment failure has also occurred, which is of particular importance, as the Clergue circuits travel directly through the city of Sault Ste. Marie.

13. Fleet, IT Infrastructure, Office Furniture & Equipment - $1,189,300

In the course of GLPT transitioning to a stand-alone entity, it was required that the company purchase a number of assets from Great Lakes Power Limited ("GLPL"). The assets were purchased from the related company at their Net Book Value[23] as of June 30, 2009. The assets purchased include the following:

- Fleet assets (consisting of 15 pick-up trucks, 1 bucket truck, 13 trailers and 11 off-road vehicles, i.e. ATV's and snow machines) at $352,100;

[23] Net Book Value is equal to the total purchase price, less the accumulated depreciation related to each specific asset.

- IT Infrastructure assets at $579,700;
- Office Furniture and Equipment at $197,700; and
- Other Equipment at $59,800.

Historically, small assets such as vehicles, IT infrastructure and office furniture were owned by the Distribution division of GLPL. As a result of the recent re-organizations within GLPL and the progression towards a stand-alone transmission business, it was required that the assets used by the transmission business be owned and recorded on the books of the transmission business. An analysis was completed to identify the assets required to be purchased by the transmission business, and the transaction was completed at June 30, 2009.

14. Transmission Reinforcement Project - $280,900

This project was approved in EB-2005-0241 for total spending of $80,889,800 between 2005 and 2006. Capital expenditures of $280,900 were put into service in 2009. GLPT is seeking a rate base addition of the full amount of $280,900, as the spending is incremental to the amount already approved in rate base. As explained in section 2.2.4.2 below, there were incremental rate base additions driven by unanticipated changes in project scope related to the structure replacements for P21G, and incremental costs related to a transformer being damaged during shipping. The costs put into service in 2009 represent final clean-up costs related to the project, and are due in part to an accrual variance realized in 2009. After 2009, the only item outstanding is related to the outstanding claim by Comstock Canada Ltd., which is also described in section 2.2.4.2 below.

2.2.3 2008 Capital Expenditures in Service

GLPT's total capital expenditures in service in 2008 were $11,058,700. Of the total capital expenditures in service in 2008, $10,114,700 (91.5%) is related to new projects that have not been reviewed by the Board and $944,000 (8.5%) is related to projects that were previously approved by the Board (EB-2005-0241). Of the previously approved projects, GLPT spent $264,900 more than what was approved by the Board. GLPT is therefore seeking total 2008 rate base additions of $10,114,700 for the new projects and $264,900 for the previously approved projects, for a total of $10,379,600. Section 2.2.3.1 below describes the capital additions in service related to the new projects. Section 2.2.3.2 follows, describes the previously approved projects and the incremental costs related to those projects.

2.2.3.1 New Capital Projects

GLPT's total capital expenditures in service for 2008, related to new projects, was $10,114,700. There were 8 capital projects that exceeded GLPT's materiality threshold of $196,825, totalling $9,180,100. These 8 projects represent 90.8% of GLPT's total 2008 capital expenditures in service related to new projects and are described below.

1. MacKay TS Refurbishment - $4,863,700

Need:

Annual condition assessments determined the need to investigate the possibility of replacing the majority of the existing station equipment at Mackay TS. Further investigation identified concerns regarding aging equipment, inadequate equipment ratings and operational issues, as well as maintenance costs. This resulted in the need to proactively replace all station equipment that has the highest risk of affecting safety, security and system reliability.

With respect to the breakers at Mackay TS, at the time of the project the breakers were greater than 50 years old and were at the end of their useful life. The fault interrupting capability of the breakers was inadequate when compared to the applicable station fault levels. In particular, the station fault magnitude at Mackay TS at 132 kV was 10.944 kA. There were two types of breakers in service at Mackay TS. GM-H bulk oil breakers and BQOB bulk oil breakers. Notably, as spare parts for these types of breakers are no longer available, each type of breaker is obsolete. The GM-H breakers were 61 years old and provided an interrupting rating at 132 kV of 10.93 kA. The BQOB breakers were 56 years old and provided an interrupting rating at 132 kV of 6.5 kA. This means that if either the GM-H breakers or the BQOB breakers were to interrupt 10.94 kA of current, there would likely be a failure as the breakers would be operating outside of their designed specifications. When coupled with the age of the breakers, these circumstances were identified as leading to a high probability of failure should this equipment have to interrupt faults at the station.

In addition to the inadequate fault interrupting ratings of the circuit breakers, the breaker continuous current ratings were inadequate when compared to maximum station current. In particular, whereas the maximum station load flow at Mackay TS was 830 amperes, the GM-H and BQOB breakers had continuous current ratings of only 800 amperes. Under certain conditions, the breakers could therefore be subject to loading above their nameplate ratings. In such a scenario, the station would have lacked operational flexibility and generation would need to be constrained as a result.

An additional factor was that the maximum voltage rating of 115 kV on three of the BQOB bulk oil breakers was below the required northern Ontario voltage threshold of 132 kV as dictated under the IESO's Market Rules.[24] The maximum voltage rating of 121 kV on 10 of the 16 disconnect switches at the station was below this requirement as well. The continuous current rating of 600 amperes for these disconnect switches was also inadequate when compared to the station's maximum current of 830 amperes. Generally, operating equipment outside of engineered specifications gives rise to a greater risk of equipment failure and reduces the life expectancy of such equipment.

In addition to the operational constraints and risks described above, because the breakers were bulk oil type breakers, their failure could have resulted in adverse environmental

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[24] Market Rules, Grid Connection Requirements, Appendix 4.1 – IESO controlled Grid Performance Standards.

impacts. This is because the original installation of the breakers at Mackay TS did not include oil containment. From a health and safety perspective, the station's PTs did not meet current clearance standards.

By not taking proactive measures to refurbish Mackay TS, exposure to known safety concerns would have continued, as would the decline in equipment health. Consequences of this include, but are not limited to:

- Reduced equipment availability;
- Increased probability of failures and equipment outages; and
- Increased risks of safety and environmental events.

*Summary***:**

This refurbishment included the replacement of five bulk oil breakers with SF6 breakers and the replacement of ten disconnect switches. Five additional motorized operated disconnect switches and one manually operated disconnect switch were also installed in order to increase station and line / bus operability and maintainability. Also included was the replacement of the existing protections and the relocation of station CVTs and PTs.

Outcome:

As a result of completing the project, system reliability has been improved, future maintenance costs have been reduced and operational risks have been reduced. Mackay

TS also has improved system operability with the addition of the five motorized operated disconnect switches and the one mannually operated disconnect switch. In addition, there has been an improvement in safety and a reduction in environmental risk.

2. Third Line TS Miscellaneous Projects - $1,862,300

Third Line TS is described at page 5 of this schedule. In 2008, GLPT undertook a number of projects related to Third Line TS that were completed to improve the level of equipment health, the safety of personnel, overall reliability, and to prepare the station for the Third Line TS Redevelopment Project. These projects are described as a single project, although the total spending is comprised of multiple smaller-scale projects.

Need:

(i) Asbestos Removal - Through station assessments as part of GLPT's asset management approach, it was identified that the control building at Third Line TS contained asbestos wall panelling. Asbestos is a designated substance, as defined in the *Occupational Health and Safety Act*,[25] and poses a significant risk to employees. With the Redevelopment Project planned to begin in 2010, it was deemed necessary that action be taken to remove all asbestos from the control building so as to mitigate this risk.

(ii) Cable Trench Installation - A cable trench was installed in preparation for the Redevelopment Project. This cable trench is currently being used for the two

[25] A "Designated Substance" is a biological, chemical or physical agent or combination thereof, prescribed as a designated substance to which the exposure of workers is prohibited, regulated, restricted, limited or controlled.

autotransformers, as well as for the tie-breaker, and has been designed and installed so as to provide the additional capacity that will be needed to support the Redevelopment Project.

(iii) Human Machine Interface (“HMI”) Installation – The HMI is a system that allows for the local operation of equipment at Third Line TS, as an alternative to remote control from the OSCC through GLPT’s SCADA system. The former HMI at Third Line TS was a mechanically operated HMI that required significant space within the control room. The former system used a number of aging, electro-magnetic contactors that were prone to misoperation, giving rise to a high probability of failure. In the event of such a failure, GLPT would not be able to safely operate the station equipment locally. Due to the out-dated technology and lack of available spare parts, the former system was obsolete. As such, GLPT removed the panels and wiring associated with the former HMI and replaced these with a new, computer-based HMI that uses current technology.

(iv) Transformer On-line Dissolved Gas Analysis (“DGA”) Monitor Installation – The two autotransformers at Third Line TS supply power to the City of Sault Ste. Marie, as well as all directly connected industrial customers and generation. GLPT performs annual gas sampling on all autotransformers in order to assist in determining their condition. Since the two autotransformers are critical to the supply of power to all of the above-noted end-users, on-line continuous monitoring equipment was installed to detect internal issues with the autotransformers in advance of failure. Data from this continuous monitoring can, as a result of this work, be accessed remotely through GLPT's centralized information retrieval system (CIRS).

Summary:

(i) Asbestos Removal - This work involved the removal of all asbestos fibre board. Also removed was redundant equipment and wiring that, so as not to disturb the asbestos fibre board, had never been removed. New metal sheeting and lighting, as well as a cable tray and grounding bus, were installed in conjunction with this work.

(ii) Cable Trench Installation – As part of the T1 autotransformer replacement and Tie Breaker Installation, a cable trench was installed. This cable trench is sized to accommodate the autotransformers and tie breaker, as well as additional equipment that will be installed during the Redevelopment Project.

(iii) HMI Installation – The aging, mechanical equipment control panels and wiring were removed and replaced with a computer controlled HMI. This results in a lower probability of equipment mis-operation, while freeing up space that is needed in preparation for the Redevelopment Project.

(iv) The transformer on-line DGA monitoring system was purchased and installed so as to provide the capability to remotely access data from a centralized location at GLPT's office complex. This supports GLPT's increased focus on condition-based monitoring, which is an integral element of GLPT's asset management approach discussed in Exhibit 2, Tab 5, Schedule 1.

Outcome:

This project has been completed and provides a number of benefits, including:

- the elimination of a designated substance, namely asbestos, thus mitigating health and safety risks to employees and contractors;
- the control building and adjacent areas at Third Line TS being prepared for the upcoming Redevelopment Project;
- a cable trench being installed so as to provide immediate benefits for use in support of the autotransformers and tie breaker, as well as capacity to accommodate further use as part of the Redevelopment Project;
- the replacement of aging equipment control facilities with a modern means of control that will enhance equipment availability; and

the capability for engineering staff to continuously monitor gas analysis results so as to detect issues prior to major equipment failures and, ultimately, to improve reliability.

3. Magpie TS Line Protection Upgrades - $629,000

Need:

Magpie TS is a 115 kV transmission station located in northern Ontario, near the Town of Wawa.

Condition assessments identified that the 115 kV lines emanating from Magpie TS were protected by obsolete electromechanical and solid-state relays, which were beyond the end of their normal life expectancy. These relays did not have any synch-check capability, which is vital for reconnection of the lines to the network after any outage. Also, due to the lack of fault recording capabilities, it was difficult and sometimes impossible to detect and analyse the root causes of forced outages which is a requirement of NERC.[26] Moreover, the redundant protections together with the associated circuits had to be fully separated to be in compliance with the TSC.[27] These include: DC, AC, control and communication circuits. Lastly, due to the presence of obsolete, manual controls there was a need to upgrade the Human-Machine Interface ("HMI") at Magpie TS to computerized controls.

In simple terms, this project was required to address the end of life protection components. Failure to proactively replace the aging relays would have resulted in the deterioration of performance of protection systems and may have resulted in equipment damage and a decline in equipment reliability thus impacting system reliability.

Summary:

This project involved the installation of new protection panels with microprocessor based relays with event and fault recording, as well as synch-check capabilities. It also included

[26] NERC - PRC-003-1 — Regional Procedure for Analysis of Misoperations of Transmission and Generation Protection Systems, NPCC – PRC-004 - Analysis and Mitigation of Transmission and Generation Protection System Misoperations.
[27] OEB – TSC – Section 8.2 – Protection and Control – Subsection 8.2.1(a).

the addition of permissive transfer-trip schemes and equipment for increased reliability, as well as full separation of redundant protection circuits.

Outcome:

With completion of this project, Magpie TS provides a high degree of dependability and security as well as reduction of maintenance frequency. Under the previous electromechanical relay arrangement, maintenance was on a 4 year cycle, while under the new microprocessor based relays, maintenance occurs on a 6 year cycle.[28] The upgraded protection facility dramatically increases service quality and continuity and reduces maintenance frequency. The upgrade also allows for easier detection and analysis of the root causes of forced outages and facilitates the development of action plans to reduce future mis-operations as per NERC guidelines.[29]

4. Clergue TS Protection Upgrades - $596,200

Need:

Clergue TS is a 115 kV transmission station located in the City of Sault Ste. Marie. The 12 kV breakers at Clergue TS were lacking in breaker failure protection, and the 12 kV bus protections were aging and had reached the end of their useful life. This is because they were electromechanical relays, rather than modern microprocessor relays. The

[28] NPCC - Maintenance Criteria for Bulk Power System Protection – Section 5 General Criteria – Table 1
[29] NERC – PRC-003, PRC-004

transformers also lacked backup differential protection and, as such, the station requires enhancements in its design as per the TSC.[30]

The project was required to address the end of life issues, increase reliability, and create better fault detection and coordination of protections as per all applicable reliability standards.

Summary:

The project provided breaker failure protections for 12 kV breakers 143 and 144, and replaced the bus protections with microprocessor based relays. The project also replaced station service feeder protections as well as the transformer protections, with new microprocessor-based relays. The new transformer differential relay is GLPT's current standard relay for protection of transformers.

Outcome:

With the backup protections installed, the system now has contingency so as to allow each protection group to be tested without taking the transformers out of service. In addition, if the differential protection fails, the backup protections will allow for continued uninterrupted service. Maintenance cycles are extended and therefore maintenance costs are reduced because of microprocessor relay use.[31] Overall, the project increases reliability and allows for better fault detection and coordination of

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[30] OEB TSC – Section 8.2 – Protection and Control, Subsection 8.2.1
[31] NPCC - Maintenance Criteria for Bulk Power System Protection – Section 5 General Criteria – Table 1

protections.

5. Magpie Structure/Component Replacement - $525,200

Need:

The Magpie, Mission, Harris and Steephill 115 kV transmission lines are located in the Wawa area, within proximity to the Magpie River region which is a remote part of northern Ontario. The lines consist of 337 wood structures spanning approximately 43 km.

Based on condition assessments carried out in 2006, it was identified that 10 structures, as well as 125 insulators, required replacement. The installation of an inline disconnect switch to minimize disruptions to customers was also required.

Based on the condition assessments, this project was identified to address the deterioration of transmission wood pole structures and to address defective insulators in order to maintain reliability and safety. This project addressed this in a systematic and cost effective manner. Failure to complete this work would have resulted in an increased risk to public safety and reliability. This could result from structure or insulator failure.

Summary:

Ten structures were replaced as a result of their deteriorated condition. As well, 125 insulators were replaced due to their history of failures. The costs of the project were driven primarily by the structure replacements.

Outcome:

As a result of completing this project, transmission customer delivery point reliability is maintained. A reduction in potential safety hazards related to equipment failure has occurred. This is important because this is a high traffic area for public snowmobile and ATV travel.

6. Power Potential Transformer at Magpie TS - $245,400

Need:

The existing station service is supplied through a rural distribution circuit. This circuit did not provide station service with the same degree of reliability as the provision of station service through a transmission circuit. As a result of this deficiency in power quality, the electronic P&C equipment at Magpie TS was adversely affected and was faced with an ongoing and unreasonable risk of harm. Moreover, there was no redundancy in station service supply.

Summary:

This project included the purchase and installation of one station service voltage transformer ("SSVT") at Magpie TS. This provides station service through the transmission system. The project also included the addition of a transfer switch that has increased the reliability of station service by providing a redundant supply.

Outcome:

The results include greater reliability in station supply and extension of the life of the existing assets**.**

7. Third Line TS – Temporary Bus Installation – $246,000

Need:

GLPT identified portions of the overhead cross bus at Third Line TS as being inadequate. The IESO subsequently reflected these findings in an operating instruction memorandum issued to GLPT in respect of the station in November 2007. This operating instruction memorandum imposed operating restrictions on the station. In response, the 115 kV section of the station was modified with the installation of three critical areas of temporary, low-level, bus to bypass conductors, which are sufficiently rated for the current station capacity. This is referred to as the “Temporary Cross Bus” and was put in place as a temporary solution until such time as the 115 kV portion of the station could be rebuilt. The alternative to installing the Temporary Cross Bus would have been a load rejection scheme that, if triggered, would have resulted in outages to major industrial customers.

Summary:

Third Line TS is described at section 2.2.1 of this schedule. This project involved the installation of additional conductor underneath the existing main north and south bus sections.

Outcome:

This project enabled GLPT to avoid the need for outages to major industrial customers, provide better reliability and led to the IESO lifting the operating restrictions.

8. Third Line TS – Transformer Refurbishment (T2) – $212,400

Need:

Third Line TS is described at section 2.2.1 of this schedule. T1 is a GE transformer, manufactured and installed in 1968. In October 2006 it suffered an internal fault and was subsequently replaced. Due to the fact that the parallel transformer, T2, is of the same make and vintage, an extensive refurbishment was performed to not only detect any failing components but to extend the life of the transformer as well.

Summary:

This project included the complete removal of oil for processing and to allow for internal inspection of the main tank components and the tap changer. Various components were replaced, including the main tank drain valve, explosion vent main tank, switches on tap changer compartments, numerous gaskets and temperature gauges. The project also included a series of diagnostic tests, including doble testing and ratio testing.

Outcome:

The refurbishment extends the useful life of the T2 transformer at Third Line TS, and increases the overall reliability of the station.

2.2.3.2 Previously Approved Capital Projects

GLPT's total capital expenditures in service, related to previously approved projects, is $943,998. Of this, there were two projects that exceeded GLPT's materiality threshold. These projects were approved in GLPT's last rate proceeding (EB-2005-0241). These two projects total $871,286 (92.3%) of the total 2008 capital expenditures on projects previously approved by the Board. There was an incremental cost associated with these projects that is sought as a rate base addition of $192,100. An additional project, which was below GLPT's materiality threshold, exceeded its projected cost and results in a rate base addition of $72,800, for a total rate base addition of $264,900 (see Table 2-1-1 B, below). The two projects that exceed the materiality threshold are described below.

1. **Clergue Line Protection Upgrades - $389,100**

This project was approved in EB-2005-0241 for total spending of $310,200 in the 2005 test year. Total project costs were $389,100. The project went into service in 2008.

Therefore, in this Application GLPT is requesting approval for a 2008 Rate Base addition of $78,900.

The increase in cost can be attributed primarily to a change from the original scope of work. The project was delayed when GLPT reviewed its asset management plans and determined that coordinating this project with other projects at Clergue TS would provide economies of scale to help offset the increase in cost due to the change in project scope. This coordination allowed for a reduction of mobilization / demobilization and project management costs that would have been higher had the projects been completed independently.

2. Patrick Street TS Refurbishment - $482,200

This project was approved in EB-2005-0241 for total spending of $4,869,000 in the 2006 test year. Total project costs were $4,982,300. Of this, $4,500,100 was capitalized in 2006, and $482,200 was capitalized in 2008. Therefore, in this Application, GLPT is requesting approval for a 2008 Rate Base addition of $113,200.

The delay in capitalization and increase in cost relates primarily to coordination of outages relative to the production schedules of the affected customers.

2.2.4 2007 Capital Expenditures in Service

GLPT's total capital expenditures in service in 2007 were $17,174,900. Of the total capital expenditures in service in 2007, $7,088,000 (41.3%) was related to new projects that have not been reviewed by the Board and $10,086,900 (58.7%) was related to projects that were previously approved by the Board (EB-2005-0241). Of the previously approved projects, GLPT spent $2,382,500 more than what was approved by the Board. GLPT is therefore seeking total 2007 rate base additions of $7,088,000 for the new projects and $2,382,500 for the previously approved projects, for a total of $9,470,500. Section 2.2.4.1 below describes the capital additions in service related to the new projects. Section 2.2.4.2 follows, and describes the previously approved projects and the incremental costs related to those projects.

2.2.4.1 New Capital Projects

GLPT's total capital expenditures in service for 2007 related to new projects, was $7,088,000. There were 3 capital projects that exceeded GLPT's materiality threshold of $196,825, totalling $5,599,700. These 3 projects represent 79.0% of GLPT's total 2007 capital expenditures in service related to new projects and are described below.

1. Third Line TS T1: 250 MVA Autotransformer Replacement - $4,702,700

Third Line TS is described in section 2.2.1 of this schedule.

Need:

T1 is a GE autotransformer, manufactured and installed in 1968. In October 2006 it had an internal fault. Through regular oil sample analysis it was identified that internal arcing was occurring and that failure was imminent. The autotransformer was taken out of service and the oil removed followed by an internal inspection. Upon completion of the inspection, it was found that one of the tertiary winding reactors had failed. The faulty reactor was bypassed and the tertiary winding disconnected from service. The autotransformer was then tested to ensure correct operation and placed back into service without the use of the tertiary winding, thus resulting in a reduction of system reliability and operational constraints.

The implications of not replacing the faulted autotransformer include:

- An increase in system operational constraints;
- Decrease in system reliability;
- Increased risk of customer impact; and
- Increased risk of failure resulting in potential safety issues as well as increased costs for corrective emergency action.

Summary:

A "like for like" replacement of the faulted Third Line autotransformer was initiated where a new 250 MVA autotransformer was ordered, installed and placed into service in November 2007. The autotransformer that was removed from service has now become the system spare.

Outcome:

The IESO performed an SIA and stated that the installation causes no adverse effects to the transmission system. The replacement of T1 has improved the reliability of supply to the City of Sault Ste. Marie. The autotransformer will remain in service and not be affected by the Redevelopment Project.

2. No. 3 Sault Sleeve Replacement - $637,600

Need:

The No. 3 Sault 115 kV transmission line runs from Third Line TS to MacKay TS, which is located in the Montreal River region. The transmission line conductor is approximately fifty years old. Sleeve issues were identified in 2005. A sleeve is a piece of equipment used to splice conductors when installing over long distances. On two separate occasions, upon loading the line to allowable (engineered) limits, the lines failed at the sleeved joints. This resulted in the loss of service on No. 3 Sault and gave rise to potentially significant public safety concerns at the points of breakage because GLPT's ROWs are often used for recreational purposes. Load constraints were therefore imposed by GLPT on No. 3 Sault to ensure public and employee safety. In addition, GLPT had Hydro One Networks Inc. perform an infra-red scan in an attempt to detect other defective sleeves.

Summary:

The project includes a like for like replacement of existing sleeves on the No. 3 Sault 115 kV transmission line.

Outcome:

Load constraints on No. 3 Sault were lifted, allowing for normal use of the line. In addition, the potential public and employee safety concerns associated with the sleeves has been mitigated.

3. Install 115 kV Line CVT's at Magpie TS - $259,500

Magpie TS, described in section 2.2.2.1 of this Exhibit 2, Tab 1, Schedule 1, is a 115 kV transmission station located in northern Ontario, near the Town of Wawa.

Need:

The existing 115 kV Harris and Mission lines, which emanate from Magpie, had only one CVT for line protections, thereby limiting protection capability. As a result, additional CVTs had to be installed in advance of the Magpie Protections upgrades (see 2.2.3.1 of this schedule).

Summary:

Four additional new CVTs were installed.

Outcome:

Improved customer delivery point reliability due to enhanced protections are described in the context of the Magpie Protections upgrade project in section 2.2.3.1 of this schedule.

2.2.4.2 Previously Approved Capital Projects

GLPT's total capital expenditures in service, related to previously approved projects, is $10,086,900. Of this, there were 4 projects that exceeded GLPT's materiality threshold. These projects were approved in GLPT's last rate proceeding (EB-2005-0241). These four projects total $9,994,000 (99.1%) of the total 2007 capital expenditures on projects previously approved by the Board. There was an incremental cost associated with these projects that is sought as a rate base addition of $2,133,500. An additional project, which was below GLPT's materiality threshold, was below its projected cost and results in a rate base reduction of $32,000, for a total rate base addition of $2,101,500 (see Table 2-1-1 B, below). The four projects that exceed the materiality threshold are described below.

1. Transmission Reinforcement Project - $7,797,500

This project was approved in EB-2005-0241 for total spending of $80,889,800 between 2005 and 2006. Capital expenditures of $7,797,500 were made in 2007. Of this amount, GLPT is now seeking a rate base addition of $2,538,300. As explained below, this additional rate base amount reflects capital expenditures driven by unanticipated changes in project scope related to the structure replacements for P21G. The balance of the 2007 capital expenditures are in respect of works that GLPT had planned to have in service during 2006. This was the result of a transformer being damaged during shipping.

Of the $2,538,300 in 2007 rate base additions, approximately $2,400,000 was expended on account of unanticipated changes in project scope for the P21G structure replacement. The scope changes were primarily associated with line P21G, a 230 kV line in GLPT's system. While the project had initially planned for the replacement of some towers that had reached the end of their useful life, as well as addressing clearance issues, during the course of the project it was determined that a greater number of towers needed replacement due to their condition and potential clearance issues. This change had schedule and cost implications, which are reflected in the 2007 capital expenditure for this project.

The remaining 2007 rate base addition of $138,300 represents, among other minor variances, expenditures that GLPT had planned to have in service by the end of 2006, but were delayed on account of equipment problems encountered due to a transformer being damaged during shipping. The equipment problems resulted in GLPT making these capital expenditures in 2007 rather than in 2005 or 2006.

Table 2-1-1 B below demonstrates the budgeted and actual costs of the Transmission Reinforcement Project, as well as the variances. It should be noted that the table below incorporates all capital additions up to and including 2009.

Table 2-1-1 B – Transmission Reinforcement Project Variances

BUDGET	Anjigami Line	Sault #3	Sault Line	Stations	P21G	
	1a	1b	2	3a	4	GLP TOTAL
Material	$ 6,756.3	$ 1,328.9	$ 8,143.5	$ 11,686.1	$ 993.4	$ 28,908.2
Construction	10,360.4	2,513.4	9,328.5	4,627.2	1,565.6	28,395.1
Engineering/PM	1,714.7	435.0	1,747.2	2,447.0	255.9	6,599.8
Owner Cost/Commissioning/AFUDC	1,769.3	307.5	1,805.9	2,235.0	187.6	6,305.3
Contingency	3,090.1	687.7	3,153.8	3,149.3	600.5	10,681.4
	23,690.8	5,272.5	24,178.9	24,144.6	3,603.0	80,889.8

ACTUAL	Anjigami Line	Sault #3	Sault Line	Stations	P21G	
	1a	1b	2	3a	4	GLP TOTAL
Material	$ 7,006.5	$ 931.3	$ 8,082.0	$ 18,806.6	$ 2,391.9	$ 37,218.5
Construction	10,719.3	1,761.4	9,788.6	7,446.6	2,541.2	32,257.2
Engineering/PM	2,093.0	531.0	2,132.7	2,986.8	383.9	8,127.3
Owner Cost/Commissioning/AFUDC	1,562.4	271.5	1,594.8	1,973.7	281.4	5,683.8
Contingency	2,811.5	627.6	3,086.8	(6,525.7)	422.2	422.4
	24,192.8	4,122.8	24,684.9	24,688.1	6,020.6	83,709.2

VARIANCE	Anjigami Line	Sault #3	Sault Line	Stations	P21G	
	1a	1b	2	3a	4	GLP TOTAL
Material	$ 250.2	$ (397.6)	$ (61.5)	$ 7,120.5	$ 1,398.5	$ 8,310.3
Construction	358.9	(752.0)	460.1	2,819.4	975.6	3,862.1
Engineering/PM	378.3	96.0	385.5	539.8	128.0	1,527.5
Owner Cost/Commissioning/AFUDC	(206.9)	(36.0)	(211.1)	(261.3)	93.8	(621.5)
Contingency	(278.6)	(60.1)	(67.0)	(9,675.0)	(178.3)	(10,259.0)
	502.0	(1,149.7)	506.0	543.5	2,417.6	2,819.4

GLPT also reminds the Board of the outstanding claim by Comstock Canada Inc. (“Comstock”) in respect of this Transmission Reinforcement Project. As noted in GLPL’s Section 86 application in EB-2007-0647 and in GLPL’s rate application EB-

2005-0241, Comstock claimed additional costs under the Design-Build Contract with GLPL. It was noted in EB-2007-0647 that the claim would be adjudicated by the Ontario Superior Court or pursuant to alternative dispute resolution provisions agreed to by the parties. As this claim remains outstanding, GLPT is not able to comment on any details of the proceeding. However, the Board should be aware that, subject to the outcome of the proceeding, GLPT may return to the Board to seek a further rate base addition. As discussed in Exhibit 9, Tab 2, Schedule 1, GLPT is seeking a deferral account in respect of these amounts.

2. Third Line Tie Breaker - $1,479,500

This project was approved in EB-2005-0241 for total spending of $1,072,500 in the 2005 test year. Total project costs of $1,479,500 were capitalized in 2007. Therefore, in this Application, GLPT is requesting approval for a 2007 Rate Base addition of $407,000. These additional costs were incurred due to the discontinuation of the contract arising from a dispute with the contractor. GLPT made all payments for work completed by the initial contractor. GLPT then retained another contractor to complete the project. The transition gave rise to additional costs related to mobilization, demobilization and confirmation of engineering work initially prepared by the first contractor. The second contractor was selected because it was already engaged on a related project and, during the competitive process which led to the awarding of the original contract to the first contractor, the proposal from the second contractor was the next highest ranked proposal.

3. Gartshore Transmission Station – Relocation - $495,200

This project was approved in EB-2005-0241 for total spending of $7,260,200 in the 2006 test year. Total project costs were $6,397,200. Of this, $5,902,000 was capitalized in 2006, and $495,172 was capitalized in 2007. Because the project was completed at a lower cost than originally planned, GLPT is not requesting approval for any 2007 Rate Base additions related to this project. GLPT's rate base is in fact reduced by the under-spent amount of $863,000

The project was substantially completed in 2006. However, some additional work was required in 2007 to complete the relocation.

4. Mackay Line and Bus Protections - $221,800

This project was approved in EB-2005-0241 for total spending of $170,500 in the 2006 test year. The total project costs of $221,771 were capitalized in 2007. Therefore, in this Application, GLPT is requesting approval for a 2007 Rate Base addition of $51,271.

The project scope was expanded slightly, resulting in a delay in completion, and an increase in the total cost of the project.

3.0 Reconciliation of Approved Projects

In order to assist the OEB in reconciling previously approved projects to actual approved spending, GLPT provides *Table 2-1-1 B* below. The top portion of the table reconciles all projects that were unrelated to the Transmission Reinforcement Project ("TRP").

Below the "Cumulative Totals" section of the table, GLPT introduces TRP so that the table reconciles to total capital additions in service in each year.

Table 2-1-1 C – Comparison of Actual CapEx vs. Approved CapEx (in $000's)

Year Approved	Project	Approved Spending	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Forecast	Total Actual	Variance
2005	Andrews TS Redevelopment	**$1,420.0**	$1,592.0	$0.0	$0.0	$0.0	$0.0	**$1,592.0**	**$172.0**
2005	Northern Ave TS Refurb	**2,475.0**	2,635.9	-	-	-	-	**2,635.9**	**160.9**
2005	Third Line PLC Replace	**885.0**	907.7	-	-	-	-	**907.7**	**22.7**
2005	Gartshore Line Refurb	**300.0**	287.5	-	-	-	-	**287.5**	**(12.5)**
2005	Steelton TS Load Rejection Scheme	**152.0**	88.2	-	-	-	-	**88.2**	**(63.8)**
2005	Hollingsworth Line Refurb	**275.0**	150.1	-	92.9	-	-	**243.0**	**(32.0)**
2005	IMO Metering	**150.0**	-	-	-	-	-	**-**	**(150.0)**
2005	Patrick/Leigh's Bay CCT Protections	**152.9**	-	-	-	-	-	**-**	**(152.9)**
2005	Anjigami TS Bus Protections	**155.4**	-	-	-	-	-	**-**	**(155.4)**
2005	Clergue Lines Protections	**310.2**	-	-	-	389.1	-	**389.1**	**78.9**
2005	CIRS Phases 1 & 2	**480.5**	-	800.0	-	-	-	**800.0**	**319.5**
2005	Cyber Security Requirements	**506.0**	-	-	-	-	-	**-**	**(506.0)**
2005	New 115kV Tie Breaker	**1,072.5**	-	-	1,479.5	72.7	-	**1,552.2**	**479.7**
2005	Hollingsworth TS Refurb	**1,835.5**	-	2,112.8	-	-	-	**2,112.8**	**277.3**
2005	Other Projects under $150k	**1,715.0**	665.1	-	-	-	-	**665.1**	**(1,049.9)**
		-	-	-	-	-	-	**-**	**-**
2006	Algoma Lines Refurb	**341.0**	-	559.0	-	-	-	**559.0**	**218.0**
2006	IMO Metering	**150.0**	-	-	-	-	-	**-**	**(150.0)**
2006	Mackay TS Line and Bus Protections	**170.5**	-	-	221.8	-	-	**221.8**	**51.3**
2006	Patrick St. Refurb	**4,869.0**	-	4,500.1	-	482.2	-	**4,982.3**	**113.3**
2006	New Gartshore TS Phase 2	**7,260.2**	-	5,902.0	495.2	-	-	**6,397.2**	**(863.0)**
2006	Other Projects under $150k	**601.5**	-	434.9	-	-	-	**434.9**	**(166.6)**
					-	-	-		
	Subtotal	**25,277.2**	6,326.5	14,308.7	2,289.4	944.0	-	**23,868.6**	**(1,408.6)**
Other Spending (Not previously approved)									
2007	Other 2007 Capital Additions	**-**	-	-	7,088.0	-	-	**7,088.0**	**7,088.0**
2008	Other 2008 Capital Additions	**-**	-	-	-	10,114.7	-	**10,114.7**	**10,114.7**
2009	Other 2009 Capital Additions	**-**	-	-	-	-	8,658.8	**8,658.8**	**8,658.8**
	Subtotal	**-**	-	-	7,088.0	10,114.7	8,658.8	**25,861.5**	**25,861.5**
	Total	**$25,277.2**	$6,326.5	$14,308.7	$9,377.3	$11,058.6	$8,658.8	**$49,730.1**	**$24,452.9**
	Cumulative Total		**6,326.5**	**20,635.2**	**30,012.6**	**41,071.2**	**49,730.1**		
	Cumulative as % of Approved		**25.0%**	**81.6%**	**118.7%**	**162.5%**	**196.7%**		
	TRP	**80,889.8**	**50,171.9**	**25,458.7**	**7,797.5**	**-**	**280.9**	**83,709.0**	**2,819.2**
	Grand Total in Service	**$106,167.0**	**$56,498.4**	**$39,767.4**	**$17,174.8**	**$11,058.6**	**$8,939.7**	**$133,439.1**	**$27,272.1**

The above table demonstrates quite clearly that GLPT has been able to support a significant capital program. Although project delays occurred in some cases, the vast majority of the projects were completed at a cost that is comparable to the Board approved spending. In addition, GLPT is forecasting to spend an additional $26 million by the end of 2009 on other projects (described in Section 2.0 above). GLPT will not earn any return or recover any costs related to these projects until 2010.

4.0 Capitalization Policy

GLPT records capital assets at cost in accordance with Generally Accepted Accounting Principles. The cost of an item of property, plant or equipment includes direct acquisition, construction or development costs, such as materials and labour, and overhead costs directly attributable to the acquisition, construction or development activity. Allowance for Funds Used During Construction are attributed to all capital projects in accordance with the Accounting Procedures Handbook. The costs incurred to enhance the service potential of an item of property, plant or equipment are also capitalized.

5.0 Amortization

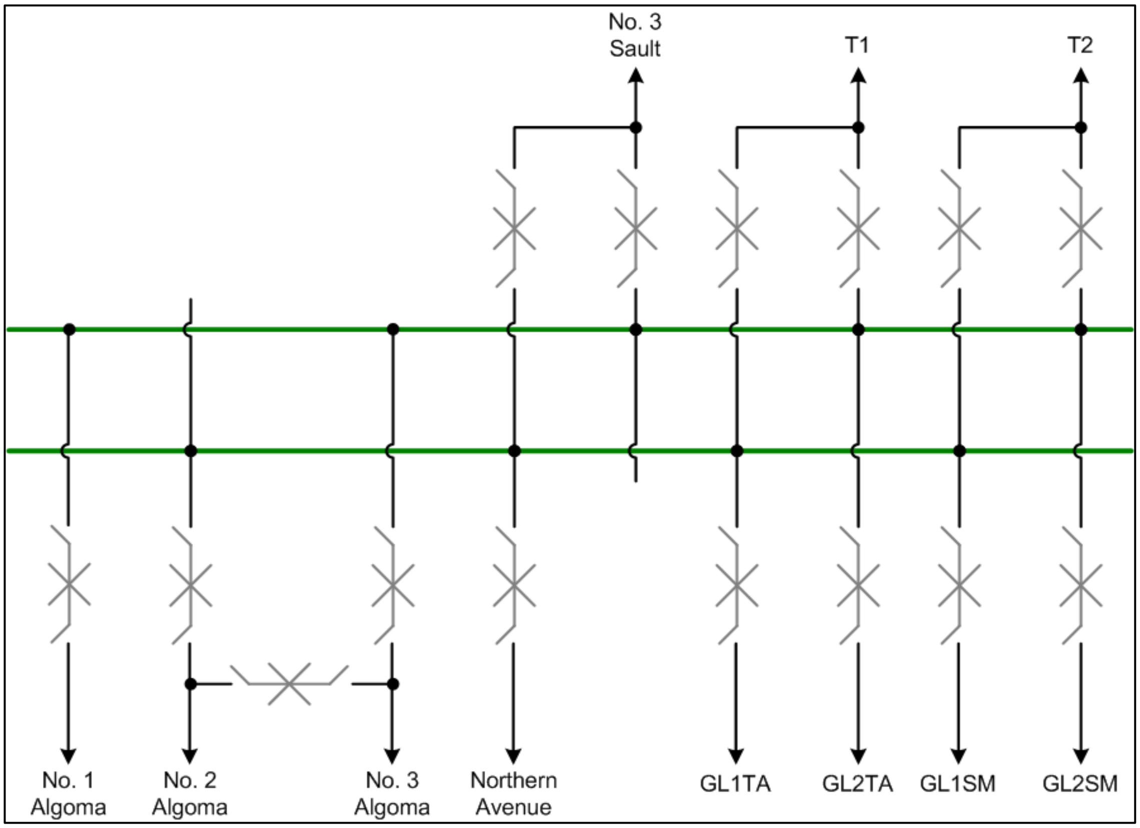
GLPT utilizes straight-line depreciation calculations based on the depreciable gross book value of each asset class. The rates utilized by GLPT, set out in Exhibit 4, Tab 2, Schedule 7, were based on historical practice, as well as utilizing utility guides such as the Accounting Procedures Handbook. GLPT has a subclass within account 1715 for substation control equipment consistent with the Accounting Procedures Handbook definitions. However, GLPT has historically depreciated this according to the system supervisory equipment rate of 6.67%.

6.0 Working Capital Allowance

The working capital allowance for 2007-2010 was calculated by GLPT utilizing the working cash study completed for GLPT's 2005 Transmission Rate Application. Please refer to Exhibit 2, Tab 4, Schedule 1 for the calculation of GLPT's working capital allowance for the years 2007-2010.

APPENDIX "A"

(a) Simplified Single Line Diagram for Existing 115 kV Section



(b) Simplified Single Line Diagram for Proposed 115 kV Section

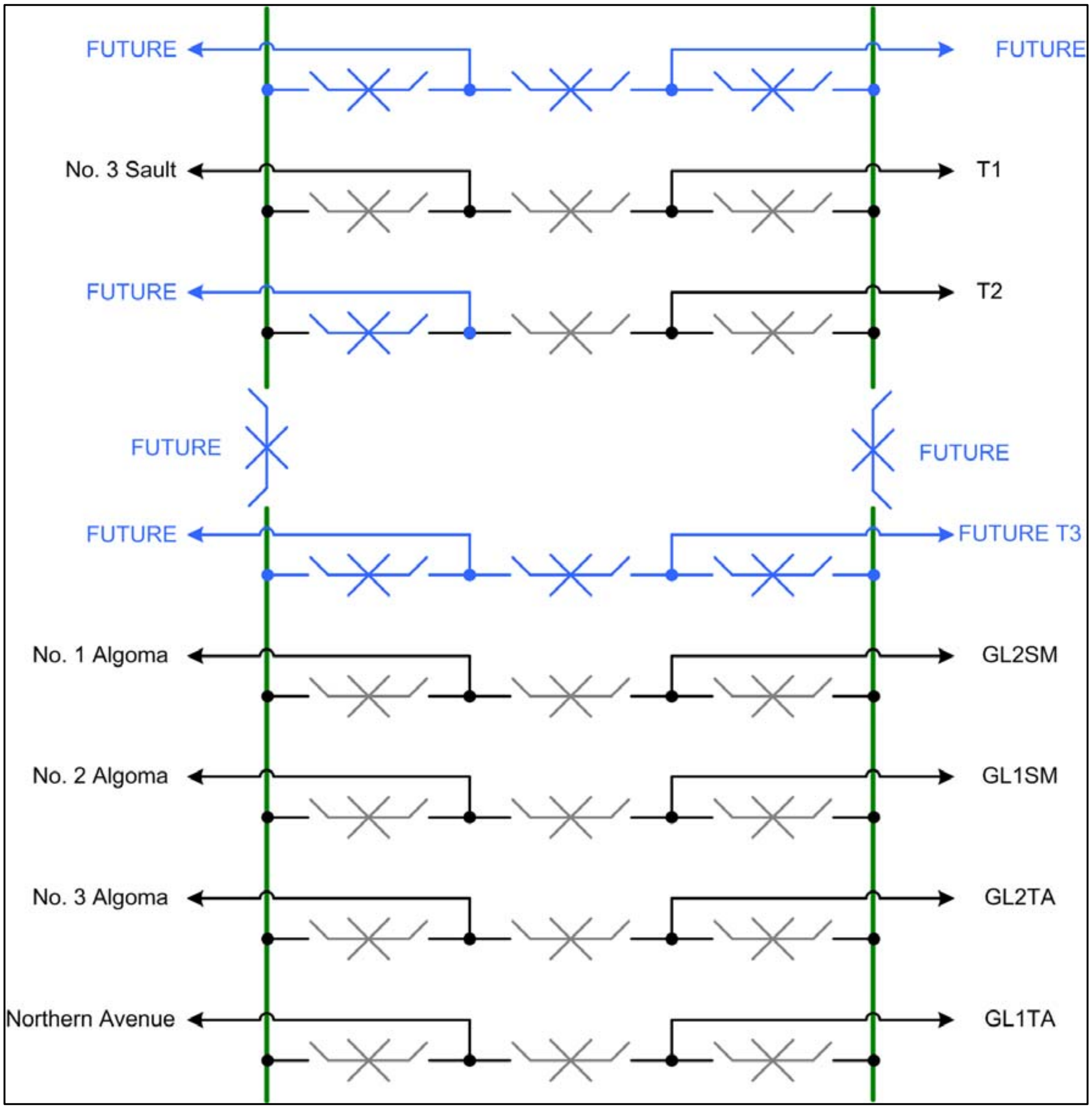


Exhibit 2, Tab 1, Schedule 2

Capital Expenditures Table

CAPITAL EXPENDITURES TABLE

In order to assist the Board in assessing GLPT's current situation, GLPT has provided *Table 2-1-2 A* below. The table breaks GLPT's capital expenditures down to the categories of sustainment, development, and operations. GLPT defines the various expenditures as follows:

Sustainment – Capital expenditures that constitute the replacement of existing assets.

Development - Capital expenditures that build or develop new assets, or enhance the efficiency of GLPT's transmission system.

Operations – Capital expenditures that are required for operating the utility such as minor fixed assets, components, fleet, information technology, and tools.

Table 2-1-2 A – Capital Expenditures Table

($000's)	**2006**	**2007**	**2008**	**2009**	**2010**
Sustainment Capital Expenditures	$15,227.8	$9,360.4	$10,991.0	$6,656.8	$3,721.9
Development Capital Expenditures	24,479.5	7,798.0	62.1	808.1	300.0
Operations Capital Expenditures	60.1	16.5	5.9	1,474.8	1,024.0
Total Capital Expenditures	**$39,767.4**	**$17,174.9**	**$11,059.0**	**$8,939.7**	**$5,045.9**
Depreciation	**$5,492.4**	**$6,085.3**	**$6,511.6**	**$6,936.6**	**$7,406.9**

GLPT's Operations capital expenditures have increased in 2009 and 2010 compared to prior years. Because of the arrangement with GLPL's distribution business, fleet assets and information technology assets were not in the transmission rate base. These assets were acquired as part of GLPT's transition to a stand-alone entity, where the company is now responsible for ownership and maintenance of a stand-alone fleet of transportation and work equipment, stand-alone information technology infrastructure, minor fixed assets and components.

Exhibit 2, Tab 1, Schedule 3

Confidential Filing

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WITH PRACTICE DIRECTION ON

CONFIDENTIAL FILINGS]

Exhibit 2, Tab 2, Schedule 1

Summary and Continuity Statements

RATE BASE - SUMMARY AND CONTINUITY STATEMENTS

Table 2-2-1 A – 2005 Asset Continuity

Account	Description	2005 Opening Gross Assets	2005 Opening Accumulated Depreciation	2005 Opening Net Fixed Assets	Add: 2005 Additions	Less: 2005 Disposals	Accumulated Disposal Adjustment	2005 Depreciation	2005 Closing Gross Assets	2005 Closing Accumulated Depreciation	2005 Closing Net Fixed Assets
1705	Land	544,437	-	544,437	-	-	-	-	544,437	-	544,437
1715	Station Equipment	82,862,074	(24,418,176)	58,443,898	12,772,606	(70,099)	(22,072)	(2,178,483)	95,564,581	(26,548,633)	69,015,948
1720	Towers and Fixtures	23,147,286	(5,857,494)	17,289,792	-	-	-	(578,682)	23,147,286	(6,436,176)	16,711,110
1725	Poles and Fixtures	35,241,848	(7,950,932)	27,290,917	23,334,736	(9,881,927)	(8,647,157)	(908,717)	48,694,658	(7,624,879)	41,069,779
1730	Overhead Conductors & Devices	18,553,671	(5,581,036)	12,972,635	19,901,730	(1,070,006)	(431,973)	(653,726)	37,385,395	(5,596,730)	31,788,665
1740	Underground Conductors & Devices	160,387	(144,348)	16,039	-	-	-	(6,415)	160,387	(150,764)	9,623
1745	Road and Trails	497,389	(373,707)	123,682	-	-	-	(9,756)	497,389	(383,464)	113,926
1908	Buildings and Fixtures	5,264	(2,334)	2,929	30,413	-	-	(819)	35,677	(3,153)	32,524
1915	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	-
1920	Computer Equipment - Hardware	19,094	(13,366)	5,728	-	-	-	(3,819)	19,094	(17,184)	1,909
1925	Computer Software	28,367	(14,184)	14,184	-	-	-	(5,673)	28,367	(19,857)	8,510
1930	Transportation Equipment	-	-	-	-	-	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	1,386,249	(1,079,486)	306,763	24,100	-	-	(77,807)	1,410,350	(1,157,293)	253,056
1960	Miscellaneous Equipment	15,483	(2,322)	13,161	-	-	-	(1,548)	15,483	(3,871)	11,612
1990	Other Tangible Property	757,041	(757,041)	-	-	-	-	-	757,041	(757,041)	-
	Subtotal	**163,218,590**	**(46,194,427)**	**117,024,163**	**56,063,585**	**(11,022,032)**	**(9,101,202)**	**(4,425,447)**	**208,260,144**	**(48,699,044)**	**159,561,100**
1715	Disallowed 2005 Addition	-	-	-	(1,485,600)	-	-	18,570	(1,485,600)	18,570	(1,467,030)
	Total for Regulatory Purposes	**163,218,590**	**(46,194,427)**	**117,024,163**	**54,577,985**	**(11,022,032)**	**(9,101,202)**	**(4,406,877)**	**206,774,544**	**(48,680,474)**	**158,094,070**
	Construction Work in Progress (CWIP)			34,605,483							22,620,858
	Property, Plant and Equipment, net (per Financial Statements)			**151,629,647**							**182,181,958**
	*Equal to Subtotal plus CWIP										

Table 2-2-1 B – 2006 Asset Continuity

Account	Description	2006 Opening Gross Assets	2006 Opening Accumulated Depreciation	2006 Opening Net Fixed Assets	Add: 2006 Additions	Less: 2006 Disposals	Accumulated Disposal Adjustment	2006 Depreciation	2006 Closing Gross Assets	2006 Closing Accumulated Depreciation	2006 Closing Net Fixed Assets
1705	Land	544,437	-	544,437	-	-	-	-	544,437	-	544,437
1715	Station Equipment	95,564,581	(26,548,633)	69,015,948	24,869,970	(448,610)	(36,623)	(2,643,952)	119,985,941	(28,780,598)	91,205,344
1720	Towers and Fixtures	23,147,286	(6,436,176)	16,711,110	536,602	-	-	(580,918)	23,683,888	(7,017,094)	16,666,794
1725	Poles and Fixtures	48,694,658	(7,624,879)	41,069,779	7,923,983	-	-	(1,214,918)	56,618,640	(8,839,797)	47,778,844
1730	Overhead Conductors & Devices	37,385,395	(5,596,730)	31,788,665	6,425,468	-	-	(983,881)	43,810,863	(6,580,610)	37,230,252
1740	Underground Conductors & Devices	160,387	(150,764)	9,623	-	-	-	(6,415)	160,387	(157,179)	3,208
1745	Road and Trails	497,389	(383,464)	113,926	-	-	-	(9,756)	497,389	(393,220)	104,169
1908	Buildings and Fixtures	35,677	(3,153)	32,524	-	-	-	(1,381)	35,677	(4,534)	31,143
1915	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	-
1920	Computer Equipment - Hardware	19,094	(17,184)	1,909	-	-	-	(1,909)	19,094	(19,094)	-
1925	Computer Software	28,367	(19,857)	8,510	-	-	-	(5,673)	28,367	(25,530)	2,837
1930	Transportation Equipment	-	-	-	-	-	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	1,410,350	(1,157,293)	253,056	9,900	-	-	(79,095)	1,420,249	(1,236,388)	183,861
1960	Miscellaneous Equipment	15,483	(3,871)	11,612	1,461	-	-	(1,597)	16,944	(5,468)	11,476
1990	Other Tangible Property	757,041	(757,041)	-	-	-	-	-	757,041	(757,041)	-
	Subtotal	**208,260,144**	**(48,699,044)**	**159,561,100**	**39,767,383**	**(448,610)**	**(36,623)**	**(5,529,496)**	**247,578,917**	**(53,816,553)**	**193,762,364**
1715	Disallowed 2005 Addition	(1,485,600)	18,570	(1,467,030)	-	-	-	37,140	(1,485,600)	55,710	(1,429,890)
	Total for Regulatory Purposes	**206,774,544**	**(48,680,474)**	**158,094,070**	**39,767,383**	**(448,610)**	**(36,623)**	**(5,492,356)**	**246,093,317**	**(53,760,843)**	**192,332,474**
	Construction Work in Progress (CWIP)			22,620,858							2,192,647
	Property, Plant and Equipment, net (per Financial Statements)			**182,181,958**							**195,955,012**
	*Equal to Subtotal plus CWIP										

Table 2-2-1 C – 2007 Asset Continuity

Account	Description	2007 Opening Gross Assets	2007 Opening Accumulated Depreciation	2007 Opening Net Fixed Assets	Add: 2007 Additions	Less: 2007 Disposals	Accumulated Disposal Adjustment	2007 Depreciation	2007 Closing Gross Assets	2007 Closing Accumulated Depreciation	2007 Closing Net Fixed Assets
1705	Land	544,437	-	544,437	-	-	-	-	544,437	-	544,437
1715	Station Equipment	119,985,941	(28,780,598)	91,205,344	15,724,905	(142,193)	(108,142)	(2,966,411)	135,568,654	(31,712,957)	103,855,696
1720	Towers and Fixtures	23,683,888	(7,017,094)	16,666,794	-	-	-	(592,097)	23,683,888	(7,609,192)	16,074,696
1725	Poles and Fixtures	56,618,640	(8,839,797)	47,778,844	2,025,031	-	-	(1,404,150)	58,643,672	(10,243,947)	48,399,725
1730	Overhead Conductors & Devices	43,810,863	(6,580,610)	37,230,252	(580,268)	-	-	(1,060,060)	43,230,595	(7,640,670)	35,589,925
1740	Underground Conductors & Devices	160,387	(157,179)	3,208	-	-	-	(3,208)	160,387	(160,387)	-
1745	Road and Trails	497,389	(393,220)	104,169	-	-	-	(9,756)	497,389	(402,976)	94,413
1908	Buildings and Fixtures	35,677	(4,534)	31,143	-	-	-	(1,335)	35,677	(5,870)	29,807
1915	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	-
1920	Computer Equipment - Hardware	19,094	(19,094)	-	-	-	-	-	19,094	(19,094)	-
1925	Computer Software	28,367	(25,530)	2,837	4,967	-	-	(3,665)	33,334	(29,195)	4,139
1930	Transportation Equipment	-	-	-	-	-	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	1,420,249	(1,236,388)	183,861	222	-	-	(80,025)	1,420,471	(1,316,413)	104,058
1960	Miscellaneous Equipment	16,944	(5,468)	11,476	-	-	-	(1,694)	16,944	(7,162)	9,782
1990	Other Tangible Property	757,041	(757,041)	-	-	-	-	-	757,041	(757,041)	-
	Subtotal	**247,578,917**	**(53,816,553)**	**193,762,364**	**17,174,858**	**(142,193)**	**(108,142)**	**(6,122,401)**	**264,611,581**	**(59,904,902)**	**204,706,680**
1715	Disallowed 2005 Addition	(1,485,600)	55,710	(1,429,890)	-	-	-	37,140	(1,485,600)	92,850	(1,392,750)
	Total for Regulatory Purposes	**246,093,317**	**(53,760,843)**	**192,332,474**	**17,174,858**	**(142,193)**	**(108,142)**	**(6,085,261)**	**263,125,981**	**(59,812,052)**	**203,313,930**
	Construction Work in Progress (CWIP)			2,192,647							5,605,203
	Property, Plant and Equipment, net (per Financial Statements)			**195,955,012**							**210,311,883**

*Equal to Subtotal plus CWIP

Table 2-2-1 D – 2008 Asset Continuity

Account	Description	2008 Opening Gross Assets	2008 Opening Accumulated Depreciation	2008 Opening Net Fixed Assets	Add: 2008 Additions	Less: 2008 Disposals	Accumulated Disposal Adjustment	2008 Depreciation	2008 Closing Gross Assets	2008 Closing Accumulated Depreciation	2008 Closing Net Fixed Assets
1705	Land	544,437	-	544,437	-	-	-	-	544,437	-	544,437
1715	Station Equipment	135,568,654	(31,712,957)	103,855,696	10,303,062	(264,891)	(85,632)	(3,387,848)	145,606,824	(34,921,546)	110,685,278
1720	Towers and Fixtures	23,683,888	(7,609,192)	16,074,696	-	-	-	(592,097)	23,683,888	(8,201,289)	15,482,599
1725	Poles and Fixtures	58,643,672	(10,243,947)	48,399,725	717,522	-	-	(1,450,006)	59,361,193	(11,693,953)	47,667,241
1730	Overhead Conductors & Devices	43,230,595	(7,640,670)	35,589,925	-	-	-	(1,046,704)	43,230,595	(8,687,374)	34,543,221
1740	Underground Conductors & Devices	160,387	(160,387)	-	-	-	-	-	160,387	(160,387)	-
1745	Road and Trails	497,389	(402,976)	94,413	24,653	-	-	(9,807)	522,042	(412,783)	109,259
1908	Buildings and Fixtures	35,677	(5,870)	29,807	-	-	-	(1,335)	35,677	(7,205)	28,472
1915	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	-
1920	Computer Equipment - Hardware	19,094	(19,094)	-	5,075	-	-	(85)	24,169	(19,178)	4,991
1925	Computer Software	33,334	(29,195)	4,139	8,337	-	-	(2,035)	41,671	(31,230)	10,441
1930	Transportation Equipment	-	-	-	-	-	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	1,420,471	(1,316,413)	104,058	-	-	-	(57,156)	1,420,471	(1,373,569)	46,902
1960	Miscellaneous Equipment	16,944	(7,162)	9,782	-	-	-	(1,694)	16,944	(8,857)	8,087
1990	Other Tangible Property	757,041	(757,041)	-	-	-	-	-	757,041	(757,041)	-
	Subtotal	**264,611,581**	**(59,904,902)**	**204,706,680**	**11,058,649**	**(264,891)**	**(85,632)**	**(6,548,768)**	**275,405,339**	**(66,274,411)**	**209,130,928**
1715	Disallowed 2005 Addition	(1,485,600)	92,850	(1,392,750)	-	-	-	37,140	(1,485,600)	129,990	(1,355,610)
	Total for Regulatory Purposes	**263,125,981**	**(59,812,052)**	**203,313,930**	**11,058,649**	**(264,891)**	**(85,632)**	**(6,511,628)**	**273,919,739**	**(66,144,421)**	**207,775,318**
	Construction Work in Progress (CWIP)			5,605,203							3,199,350
	Property, Plant and Equipment, net (per Financial Statements)			**210,311,883**							**212,330,278**

*Equal to Subtotal plus CWIP

Table 2-2-1 E – 2009 Forecasted Asset Continuity

Account	Description	2009 Opening Gross Assets	2009 Opening Accumulated Depreciation	2009 Opening Net Fixed Assets	Add: 2009 Forecast Additions	Less: 2009 Forecast Disposals	2009 Forecast Depreciation	2009 Forecast Closing Gross Assets	2009 Forecast Closing Accumulated Depreciation	2009 Forecast Closing Net Fixed Assets
1705	Land	544,437	-	544,437	384,611	-	-	929,048	-	929,048
1715	Station Equipment	145,606,824	(34,921,546)	110,685,278	5,711,861	-	(3,605,382)	151,318,686	(38,526,928)	112,791,758
1720	Towers and Fixtures	23,683,888	(8,201,289)	15,482,599	-	-	(590,672)	23,683,888	(8,791,961)	14,891,927
1725	Poles and Fixtures	59,361,193	(11,693,953)	47,667,241	-	-	(1,463,455)	59,361,193	(13,157,408)	46,203,785
1730	Overhead Conductors & Devices	43,230,595	(8,687,374)	34,543,221	378,781	-	(1,046,902)	43,609,376	(9,734,276)	33,875,100
1740	Underground Conductors & Devices	160,387	(160,387)	-	-	-	-	160,387	(160,387)	-
1745	Road and Trails	522,042	(412,783)	109,259	408,680	-	(9,550)	930,722	(422,333)	508,388
1908	Buildings and Fixtures	35,677	(7,205)	28,472	176,350	-	(2,511)	212,027	(9,716)	202,311
1915	Office Furniture & Equipment	-	-	-	197,742	-	(9,887)	197,742	(9,887)	187,855
1920	Computer Equipment - Hardware	24,169	(19,178)	4,991	665,381	-	(127,370)	689,551	(146,549)	543,002
1925	Computer Software	41,671	(31,230)	10,441	584,441	-	(32,231)	626,112	(63,461)	562,651
1930	Transportation Equipment	-	-	-	344,595	-	(59,135)	344,595	(59,135)	285,461
1940	Tools, Shop and Garage Equipment	-	-	-	7,506	-	(751)	7,506	(751)	6,755
1955	Communication Equipment	1,420,471	(1,373,569)	46,902	79,798	-	(24,171)	1,500,268	(1,397,740)	102,528
1960	Miscellaneous Equipment	16,944	(8,857)	8,087	-	-	(1,694)	16,944	(10,551)	6,393
1990	Other Tangible Property	757,041	(757,041)	-	-	-	-	757,041	(757,041)	-
	Subtotal	**275,405,339**	**(66,274,411)**	**209,130,928**	**8,939,747**	**-**	**(6,973,711)**	**284,345,086**	**(73,248,122)**	**211,096,963**
1715	Disallowed 2005 Addition	(1,485,600)	129,990	(1,355,610)	-	-	37,140	(1,485,600)	167,130	(1,318,470)
	Total for Regulatory Purposes	**273,919,739**	**(66,144,421)**	**207,775,318**	**8,939,747**	**-**	**(6,936,571)**	**282,859,486**	**(73,080,992)**	**209,778,493**
	Construction Work in Progress (CWIP)			3,199,350						3,989,629
	Property, Plant and Equipment, net (per Financial Statements) *Equal to Subtotal plus CWIP			**212,330,278**						**215,086,593**

Table 2-2-1 F – 2010 Forecasted Asset Continuity

Account	Description	2010 Forecast Opening Gross Assets	2010 Forecast Opening Accumulated Depreciation	2010 Forecast Opening Net Fixed Assets	Add: 2010 Forecast Additions	Less: 2010 Forecast Disposals	2010 Forecast Depreciation	2010 Forecast Closing Gross Assets	2010 Forecast Closing Accumulated Depreciation	2010 Forecast Closing Net Fixed Assets
1705	Land	929,048	-	929,048	-	-	-	929,048	-	929,048
1715	Station Equipment	151,318,686	(38,526,928)	112,791,758	3,781,288	-	(3,766,846)	155,099,974	(42,293,773)	112,806,200
1720	Towers and Fixtures	23,683,888	(8,791,961)	14,891,927	-	-	(589,247)	23,683,888	(9,381,208)	14,302,680
1725	Poles and Fixtures	59,361,193	(13,157,408)	46,203,785	46,000	-	(1,456,203)	59,407,193	(14,613,611)	44,793,582
1730	Overhead Conductors & Devices	43,609,376	(9,734,276)	33,875,100	-	-	(1,046,986)	43,609,376	(10,781,261)	32,828,115
1740	Underground Conductors & Devices	160,387	(160,387)	-	-	-	-	160,387	(160,387)	-
1745	Road and Trails	930,722	(422,333)	508,388	-	-	(15,540)	930,722	(437,873)	492,849
1908	Buildings and Fixtures	212,027	(9,716)	202,311	541,000	-	(19,209)	753,027	(28,925)	724,102
1915	Office Furniture & Equipment	197,742	(9,887)	187,855	-	-	(19,774)	197,742	(29,661)	168,080
1920	Computer Equipment - Hardware	689,551	(146,549)	543,002	248,000	-	(235,670)	937,551	(382,218)	555,332
1925	Computer Software	626,112	(63,461)	562,651	299,587	-	(159,052)	925,699	(222,513)	703,186
1930	Transportation Equipment	344,595	(59,135)	285,461	130,000	-	(117,026)	474,595	(176,161)	298,434
1940	Tools, Shop and Garage Equipment	7,506	(751)	6,755	-	-	(1,501)	7,506	(2,252)	5,254
1955	Communication Equipment	1,500,268	(1,397,740)	102,528	-	-	(15,289)	1,500,268	(1,413,030)	87,239
1960	Miscellaneous Equipment	16,944	(10,551)	6,393	-	-	(1,694)	16,944	(12,245)	4,699
1990	Other Tangible Property	757,041	(757,041)	-	-	-	-	757,041	(757,041)	-
	Subtotal	**284,345,086**	**(73,248,122)**	**211,096,963**	**5,045,875**	**-**	**(7,444,038)**	**289,390,961**	**(80,692,160)**	**208,698,801**
1715	Disallowed 2005 Addition	(1,485,600)	167,130	(1,318,470)	-	-	37,140	(1,485,600)	204,270	(1,281,330)
	Total for Regulatory Purposes	**282,859,486**	**(73,080,992)**	**209,778,493**	**5,045,875**	**-**	**(7,406,898)**	**287,905,361**	**(80,487,890)**	**207,417,471**
	Construction Work in Progress (CWIP)			3,989,629						15,697,341
	Property, Plant and Equipment, net (per Financial Statements)			**215,086,593**						**224,396,142**

*Equal to Subtotal plus CWIP

Exhibit 2, Tab 2, Schedule 2

Customer Additions and System Expansions

CUSTOMER ADDITIONS AND SYSTEM EXPANSIONS

GLPT anticipates no customer additions or system expansions in the 2010 test year.

Exhibit 2, Tab 3, Schedule 1

Accumulated Depreciation

ACCUMULATED DEPRECIATION

Table 2-3-1 A – Accumulated Depreciation Continuity

($000's) USofA	Description	2006 Opening Accumulated Depreciation	2006 Annual Depreciation	2006 Disposals	2006 Closing Accumulated Depreciation	2007 Annual Depreciation	2007 Disposals	2007 Closing Accumulated Depreciation	2008 Annual Depreciation	2008 Disposals	2008 Closing Accumulated Depreciation
1705	Land	-	-	-	-	-	-	-	-	-	-
1715	Station Equipment	$26,548.6	$2,644.0	$412.0	$28,780.6	$2,966.4	$34.1	$31,713.0	3,387.8	$179.3	$34,921.5
1720	Towers and Fixtures	6,436.2	580.9	-	7,017.1	592.1	-	7,609.2	592.1	-	8,201.3
1725	Poles and Fixtures	7,624.9	1,214.9	-	8,839.8	1,404.2	-	10,243.9	1,450.0	-	11,694.0
1730	Overhead Conductors & Devices	5,596.7	983.9	-	6,580.6	1,060.1	-	7,640.7	1,046.7	-	8,687.4
1740	Underground Conductors & Devices	150.8	6.4	-	157.2	3.2	-	160.4	-	-	160.4
1745	Road and Trails	383.5	9.8	-	393.2	9.8	-	403.0	9.8	-	412.8
1908	Buildings and Fixtures	3.2	1.4	-	4.5	1.3	-	5.9	1.3	-	7.2
1915	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	-
1920	Computer Equipment - Hardware	17.2	1.9	-	19.1	-	-	19.1	0.1	-	19.2
1925	Computer Software	19.9	5.7	-	25.5	3.7	-	29.2	2.0	-	31.2
1930	Transportation Equipment	-	-	-	-	-	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	1,157.3	79.1	-	1,236.4	80.0	-	1,316.4	57.2	-	1,373.6
1960	Miscellaneous Equipment	3.9	1.6	-	5.5	1.7	-	7.2	1.7	-	8.9
1990	Other Tangible Property	757.0	-	-	757.0	-	-	757.0	-	-	757.0
	Less: Disallowed 2005 Addition	(18.6)	(37.1)	-	(55.7)	(37.1)	-	(92.9)	(37.1)	-	(130.0)
	Totals	**$48,680.5**	**$5,492.4**	**$412.0**	**$53,760.8**	**$6,085.3**	**$34.1**	**$59,812.1**	**$6,511.6**	**$179.3**	**$66,144.4**

Table 2-3-1 A – Accumulated Depreciation Continuity (Cont'd)

($000's) USofA	Description	2009 Opening Accumulated Depreciation	Forecasted 2009 Annual Depreciation	Forecasted 2009 Disposals	2009 Closing Accumulated Depreciation	Forecasted 2010 Annual Depreciation	Forecasted 2010 Disposals	2010 Closing Accumulated Depreciation
1705	Land	-	-	-	-	-	-	-
1715	Station Equipment	$34,921.5	3,605.4	$0.0	$38,526.9	$3,766.8	$0.0	$42,293.7
1720	Towers and Fixtures	8,201.3	590.7	-	8,792.0	589.2	-	9,381.2
1725	Poles and Fixtures	11,694.0	1,463.5	-	13,157.4	1,456.2	-	14,613.6
1730	Overhead Conductors & Devices	8,687.4	1,046.9	-	9,734.3	1,047.0	-	10,781.3
1740	Underground Conductors & Devices	160.4	-	-	160.4	-	-	160.4
1745	Road and Trails	412.8	9.6	-	422.3	15.5	-	437.9
1908	Buildings and Fixtures	7.2	2.5	-	9.7	19.2	-	28.9
1915	Office Furniture & Equipment	-	9.9	-	9.9	19.8	-	29.7
1920	Computer Equipment - Hardware	19.2	127.4	-	146.5	235.7	-	382.2
1925	Computer Software	31.2	32.2	-	63.5	159.1	-	222.5
1930	Transportation Equipment	-	59.1	-	59.1	117.0	-	176.2
1940	Tools, Shop and Garage Equipment	-	0.8	-	0.8	1.5	-	2.3
1955	Communication Equipment	1,373.6	24.2	-	1,397.7	15.3	-	1,413.0
1960	Miscellaneous Equipment	8.9	1.7	-	10.6	1.7	-	12.2
1990	Other Tangible Property	757.0	-	-	757.0	-	-	757.0
	Less: Disallowed 2005 Addition	(130.0)	(37.1)	-	(167.1)	(37.1)	-	(204.3)
	Totals	**$66,144.4**	**$6,936.6**	**$0.0**	**$73,081.0**	**$7,406.9**	**$0.0**	**$80,487.8**

Exhibit 2, Tab 4, Schedule 1

Working Capital Allowance

WORKING CAPITAL ALLOWANCE

GLPT's allowance for working capital for the 2010 test year is summarized in the following table:

Table 2-4-1 A – Working Capital Allowance

Allowance for Working Capital 2010
($000's)

Expense Category	Annual Expense	Revenue Lag (Days)	Expense Lag (Days)	Net Lag (Days)	Working Cash Needed
OM&A					
Labour and Labour Related Costs	$5,674.8	35.5	22.7	12.8	$199.0
Insurance	$211.5	35.5	(114.6)	150.1	$87.0
Other Expenses	$5,219.3	35.5	18.9	16.6	$237.4
Goods & Services Tax					
Revenue	($1,968.3)			35.3	($190.4)
OM&A	$271.5			23.5	$17.5
Capital Expenditures	$787.7			23.5	$50.7
Total Working Cash Requirement					**$401.2**

GLPT's working cash allowance for 2010 has been calculated using the results of the working cash study accepted by the Board (subject to adjustments arising from the Settlement) in GLPL's 2005 transmission rate application (EB-2005-0241).

As part of GLPT's next rate application, GLPT plans to revisit the methodology used in the working cash study.

Exhibit 2, Tab 5, Schedule 1

Asset Management

ASSET MANAGEMENT AND CAPITAL BUDGETING

1.0 GLPT's Approach to Asset Management

GLPT's approach to asset management involves managing existing infrastructure and optimizing the replacement of assets.

1.1 Managing Existing Infrastructure

As part of managing existing infrastructure, GLPT deploys a comprehensive maintenance program which includes a variety of activities for inspecting and maintaining its lines and stations.

1.1.1 Lines

For transmission lines, visual inspections are carried out either by GLPT crews or by external consultants. GLPT crews conduct patrol inspections of transmission lines annually to assess condition and to identify structural problems and hazards. Because GLPT's transmission lines are primarily located in rural areas of northern Ontario, where the terrain is rugged and the vegetation is dense, specialized equipment or expertise is required. Analyses may also be performed by external consultants to provide additional detailed information on structures, conductors and insulators.

Where these inspections identify immediate deficiencies or potential hazards, GLPT undertakes the appropriate corrective maintenance to resolve the identified issue.

The information collected through inspections is compiled in a searchable database where it is used for long term maintenance planning and to identify trends in asset conditions.

GLPT also collects real-time data from lines on a continuous basis using its Supervisory Control and Data Acquisition system ("SCADA"). The data collected through SCADA relates to power flow, fault data and power quality, and supplements the information collected through the inspection activities identified above.

1.1.2 Stations

For transmission stations, a range of inspection and maintenance activities are carried out by GLPT. These include visual inspections, functional tests, infra-red inspections, oil sampling and dissolved gas analysis ("DGA"). These activities are conducted primarily by GLPT crews. However, where specialized equipment or expertise is required (for example infra-red inspections), those activities are conducted by external consultants. A more detailed list of activities and their frequencies are set out in *Table 2-5-1* A below. The preventative maintenance activities listed in the table are based on good utility practice and manufacturer specifications.

1 *Table 2-5-1 A – Frequency of Maintenance Activities*

Equipment	1 Month	6 Months	1 Year	2 Years	4 Years	6 Years	Overhauls (Based on duty)
Power, SS and grounding transformers		Visual inspection, operate fans and heaters				Insulation, winding resistance, ratio, Doble, check and calibrate temp/gas alarms and trips, connections, arresters, DGA	
ULTC & Voltage Regulators		Visual inspection, operate +/- 1 tap, record counter reading	Full range operation, Doble, megger, calibrate controls			Oil filtering	Contact inspection (50k for MR)
Breaker – Vacuum		Visual inspection, check heaters, AC/DC, etc.	Operate via SCADA			Functional tests, timing, contact resistance, Doble, lubrication	

Equipment	1 Month	6 Months	1 Year	2 Years	4 Years	6 Years	Overhauls (Based on duty)
Breaker – SF6		Visual inspection, check gas pressure, heaters, AC/DC, etc.	Operate via SCADA	Functional tests, timing, contact resistance, Doble, lubrication . Metalclad only.		Functional tests, timing, contact resistance, Doble, lubrication	Contact inspection based on duty
Breaker – Bulk oil		Visual inspection, draining water, operate compressor, check heaters, AC/DC,	Operate via SCADA		Functional tests, timing, pressure relief valve, contact resistance, Doble, lubrication		Contact inspection based on duty
Breaker – Min. oil		Visual inspection, check gas and oil levels, heaters, AC/DC, etc.	Operate via SCADA	Functional tests, timing, contact resistance, Doble, lubrication. Metalclad only.		Functional tests, timing, contact resistance, Doble, lubrication	Contact inspection based on duty

Equipment	1 Month	6 Months	1 Year	2 Years	4 Years	6 Years	Overhauls (Based on duty)
Circuit Switcher		Visual inspection, check mech box heater, AC/DC	Operate via SCADA			Functional tests, contact resistance, Doble, lubrication	
Disconnect Switch		Visual inspection, check mech box heater, AC/DC				Contact resistance and pressure, insulation, connections, adjustment, lubrication	
Motorized Operated Air Break		Visual inspection, check mech box heater, AC/DC	Operate via SCADA			Contact resistance and pressure, insulation, connections, adjustment, lubrication , doble	Inspection based on duty
Batteries / chargers	Visual inspection, check voltage, record SG of pilot cell	Top up electrolyte if applicable, equalize	Capacity test, intercell and internal resistance, SG on all cells, calibrate charger				
Current Transformers		Visual inspection				DGA, Doble, ratio, connections	
PT's and CVT's		Visual inspection				DGA, Doble, ratio, capacitance, connections	

Equipment	1 Month	6 Months	1 Year	2 Years	4 Years	6 Years	Overhauls (Based on duty)
Capacitors		Visual inspection	Capacitance, df, connections				
Reactors		Visual inspection	Reactance, connections				
Infrared			Annual Station Infrared Scans.				
Oil Containment	Visual – check Imbiber, take sample,						
Stations - General		Grounding, structures, foundations, vegetation, housekeeping	Thermal scan, oil containment systems			Grounding assessment, insulator cleaning, connections, arresters, metalclad	

The information gathered from the activities described in the table is documented and reviewed. Where immediate deficiencies or potential hazards are identified, GLPT undertakes the appropriate corrective maintenance to resolve the identified issue. Where corrective maintenance is not required, the information is retained in order to support GLPT's long term station maintenance planning and to assist in the identification of asset condition trends.

GLPT also collects real-time system data on a continuous basis using SCADA. The data collected through SCADA relates to power flow, fault data and power quality, and supplements the information collected through the inspection and maintenance activities identified above.

1.1.3 Asset Condition Assessments

In addition to the activities undertaken specifically for lines and stations, GLPT annually carries out asset condition assessments using internal professional engineering staff. Periodically, GLPT retains external consultants to undertake additional asset condition assessments. During the test year GLPT plans to retain an external consultant to undertake (1) a relay and remote terminal unit condition assessment, (2) a wood pole structure condition assessment, and (3) a transmission configuration study. The costs associated with these studies will be included in Construction Work in Progress (CWIP) until such time as the related projects come into service.

1.2 Optimizing Asset Replacement

In order to optimize GLPT's asset replacement strategy, the maintenance and condition assessment program documentation is reviewed and assessed. The combination of the inspection and maintenance reports, coupled with the internal condition assessments, as well as third party analyses and SCADA information allow GLPT's engineering staff to effectively determine which facilities require capital improvements. This becomes GLPT's list of capital expenditure proposals. The capital expenditure proposals are analyzed using the information collected through all of the above noted sources and are reviewed in conjunction with the criteria described below in order to assist in the prioritization of projects. The prioritization of projects is based on:

- Health and Safety:
  - exposure to the public and employees;
  - likelihood of an event occurring; and
  - the consequences of an event.
- Environment:
  - exposure to the public and employees;
  - likelihood of an event occurring; and
  - the consequences of an event.
- Reliability:
  - customer delivery point reliability statistics;
  - unsupplied energy statistics; and
  - specific system events (i.e. faults, equipment overloading, etc.).
- Regulatory:
  - applicable standards as per the TSC; and
  - compliance with mandated requirements, such as:
  - cyber security;

  - environmental protection (i.e. oil containment); and
  - vegetation management (i.e. NERC FAC-003).
- Resourcing:
  - resource adequacy – equipment and human;
  - market conditions – contractors and raw materials; and
  - timelines and budget constraints.
- Synergies:
  - location relative to other projects (i.e. coordination of crews for multiple projects within close proximity reduces costs).
- Stakeholder Feedback:
  - suggestions and feedback from annual stakeholder sessions.

Once prioritized and approved, the list of proposals becomes GLPT’s capital program portfolio.

2.0 Capital Expenditure Forecast

GLPT’s forecast rate base additions for 2010 are described in Exhibit 2, Tab 1, Schedule 1.

It should be noted that the forecasts for 2011 and 2012 provided below are estimates that are subject to change as the priority of projects is refined or in response to new circumstances or information that becomes available.

For 2011, GLPT’s rate base additions are forecast to be in the range of $24 - $30 million. These additions are driven primarily by the Redevelopment Project at Third Line TS, and by the refurbishment of the Algoma circuits.

For 2012, GLPT's rate base additions are forecast to be in the range of $13 - $17 million. These additions are driven primarily by the completion of the Algoma circuit refurbishment, the completion of the Redevelopment Project at Third Line TS, and by the replacement of GLPT's SCADA system at its OSCC.

3.0 Enhancements to GLPT's Asset Management Plan

GLPT's comprehensive approach to asset management and capital budgeting provides GLPT with an effective means of identifying and prioritizing capital expenditures. GLPT continues to refine and improve its asset management approach to ensure its continued effectiveness. In particular, GLPT has and will be implementing a range of new asset management tools, which include geographic information systems (GIS)[1], asset management software, document management, vegetation management tools,[2] and work management systems.

[1] See Section 2.2.1 and Section 2.2.2 of Exhibit 2, Tab 1, Schedule 1 for a description of this project.
[2] See Section 2.2.2 of Exhibit 2, Tab 1, Schedule 1 for a description of this project.

EXHIBIT 3 - OPERATING REVENUE

Exhibit 3, Tab 1, Schedule 1

Operating Revenue

OPERATING REVENUE

1.0 Revenues

GLPT's operating revenue consists of transmission services revenue earned in the normal course of business. This revenue is received monthly from the Independent Electricity System Operator ("IESO") 14 business days after the end of the month in which it was earned.

A numerical summary of GLPT's revenue for the period of 2006 Approved – 2010 Forecast is set out below. Variances in operating revenue are driven primarily by variations in provincial peak loads from year to year.

Table 3-1-1 A – Numerical Summary of Operating Revenue

USofA	Description	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
4110	Transmission Services Revenue	34,785.4	34,686.2	35,567.6	35,073.4	31,958.2	34,696.2
	Total Revenue	**$34,785.4**	**$34,686.2**	**$35,567.6**	**$35,073.4**	**$31,958.2**	**$34,696.2**
	Year-over-year Variance		**($99.2)**	**$881.4**	**($494.2)**	**($3,115.2)**	**$2,738.0**

GLPT's 2006 approved transmission services revenue is based on the Uniform Transmission Rates ("UTR") and revenue allocators for transmitters approved in 2005.[1]

GLPT's 2007 actual revenue for January through October is based on the same rates and allocators as 2006. Actual revenue for November and December of 2007 is based on the

[1] Board Order EB-2005-0241, RP-2001-0034, RP-2001-0035, RP-2001-0036, RP-1999-0044

rates and allocators approved in EB-2007-0759, a result of a revenue requirement application from Hydro One Networks Inc. (“HONI”).

GLPT’s 2008 actual revenue is based on the same EB-2007-0759 rates and allocators.

GLPT’s 2009 revenue for January through June is based on the rates and allocators approved in EB-2008-0113, a result of an application from HONI. Beginning July 1, 2009, GLPT’s revenue is based on the rates and allocators approved in EB-2008-0272, also a result of an application from HONI.

In calculating a 2010 revenue forecast, GLPT has applied the most recently approved rates and allocators from EB-2008-0272 to the provincial charge determinants forecasted in Exhibit 8, Tab 2, Schedule 1 of this Application. The resultant revenue forecast is the revenue that GLPT would expect to receive in 2010 if there is no change to the UTR. The forecast demonstrates the deficiency that GLPT would expect to incur in 2010 with no change in revenue requirement.

Table 3-1-1 B – 2010 Test Year Revenue Forecast

	Network	Line Connection	Transformation Connection	
2010 Forecasted Charge Determinants (kW)	254,748,844	244,853,648	210,289,084	
2009 Approved Uniform Rates ($/kW/Month)	2.66	0.70	1.57	
2009 Approved GLPT Allocation Factor	0.02944	0.02944	0.02944	
2010 GLPT Revenue Forecast ($)	19,947,983	5,039,550	9,708,654	**34,696,188**
2010 Test Year Revenue Requirement				39,365,065
Gross Revenue Deficiency/(Sufficiency)				**$4,668,878**

Exhibit 3, Tab 1, Schedule 2

Other Revenue

OTHER INCOME

1.0 Other Income

GLPT's other income consists of:

- Revenues and Expenses from Merchandising, Jobbing, Etc.;
- Gains and Losses on Disposition of Utility and Other Property; and
- Interest and Dividend Income.

The table below outlines the trend of other income between the approved 2006 figures and the forecasted 2010 figures.

Table 3-1-2 A – Summary of Other Income

($000's) USofA	Description	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
4325	Revenues from Merchandising, Jobbing, Etc.	-	509.4	(92.2)	66.4	(400.0)	(42.3)
4330	Expenses of Merchandising, Jobbing, Etc.	-	(466.8)	119.2	(66.5)	400.0	42.3
4355	Gain on Disposition of Utility and Other Property	-	(213.4)	-	-	-	-
4360	Loss on Disposition of Utility and Other Property	-	-	5.3	100.1	-	-
4405	Interest and Dividend Income						
	Carrying charges	-	(61.2)	53.7	121.1	65.9	-
	Interest on bank balance	-	(117.0)	(120.9)	(92.7)	(14.0)	(7.2)
	Total Other Income	**$0.0**	**($349.0)**	**($34.9)**	**$128.4**	**$51.9**	**($7.2)**
	Year-over-year Variance			**($34.9)**	**$163.3**	**($76.5)**	**($59.1)**

GLPT is not anticipating any property, plant or equipment will be disposed of in the test year at a gain or loss.

It is anticipated that GLPT will earn approximately $7,200 in Interest and Dividend Income related to interest earned on cash held in GLPT's bank account. This is a significant decrease compared to prior years due primarily to interest rates on bank balances having decreased significantly. GLPT earned 2.25% on outstanding balances for the majority of 2008, while the majority of 2009 has yielded interest at a rate of 0.30%.

As a result, GLPT is not anticipating a significant income from interest earned on its bank balance.

EXHIBIT 4 - OPERATING COSTS

Exhibit 4, Tab 1, Schedule 1

Summary of Operating Costs

SUMMARY OF OPERATING COSTS

1.0 Overview of GLPT's Operating Costs

GLPT's operating costs include operations, maintenance and administration ("OM&A"); depreciation and amortization, income taxes, and capital and property taxes. A summary of GLPT's operating costs is set out in the table below:

Table 4-1-1 A – Summary of Operating Costs

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Operations, Maintenance & Administration	$5,927.0	$5,661.1	$6,089.6	$7,201.9	$7,994.1	$11,105.6
Depreciation & Amortization	6,000.8	5,492.4	6,085.3	6,511.6	6,936.6	7,406.9
Income Taxes	5,360.7	5,388.9	4,590.2	3,229.1	1,797.7	2,861.5
Capital & Property Taxes	866.5	698.6	626.1	632.2	673.2	403.7
Retirement of Readily Identifiable Assets	1,855.8	1,649.1	1,649.1	1,649.1	1,649.1	-
Total Operating Costs	**$20,010.8**	**$18,890.1**	**$19,040.4**	**$19,224.0**	**$19,050.7**	**$21,777.7**

Additional information for each item in the table can be as follows:

- *OM&A* – Exhibit 4, Tab 2, Schedule 1,
- *Depreciation & Amortization* – Exhibit 4, Tab 2, Schedule 6,
- *Income Taxes* – Exhibit 4, Tab 3, Schedule 2, and
- *Capital & Property Taxes* – Exhibit 4, Tab 3, Schedules 3 and 4, respectively.

Exhibit 4, Tab 2, Schedule 1

OM&A Overview

OM&A OVERVIEW

1.0 Summary

This evidence provides an overview of GLPT's operations, maintenance and administration (OM&A) expenditures and the factors that have affected these expenditure levels during the period from 2006 up to and including the 2010 test year. GLPT's proposed OM&A expenditures for the 2010 test year will allow for the continued safe, reliable and cost-efficient operation of the transmission system. GLPT has determined these expenditure levels through implementation of its OM&A budgeting process and asset management program, which are described below. GLPT's OM&A budgeting process is further discussed at Exhibit 1, Tab 2, Schedule 2 and its approach to asset management is further discussed at Exhibit 2, Tab 5, Schedule 1.

GLPT's OM&A activities involve the following:

- *Operations* includes activities relating to inspection, general engineering, testing, system control and work planning.

- *Maintenance* relates to preventative maintenance activities and corrective maintenance. Preventative maintenance includes maintenance carried out on a cyclical basis for structures and devices to avoid failure. Corrective maintenance is activity relating to the repair and replacement of equipment that either has failed or is about to fail.

- *Administration* relates to activities which include accounting, general administration, information technology and regulatory activities.

A summary of GLPT's OM&A expenses is presented in Table 4-2-1 A, below.

Table 4-2-1 A - Summary of OM&A Expenses

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Total OM&A	$5,927.0	$5,661.1	$6,089.6	$7,201.9	$7,994.1	$11,105.6
Variance		($266.0)	$428.5	$1,112.3	$792.1	$3,111.5

GLPT's OM&A expenses are summarized, by functional area, in Table 4-2-1 B, below:

Table 4-2-1 B – OM&A Expenses by Functional Areas

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Operations	$1,930.5	$1,996.9	$2,167.4	$2,634.6	$3,174.8	$4,136.2
Maintenance	1,494.2	1,493.7	1,607.0	2,194.4	1,685.3	2,810.5
Administration	2,502.4	2,170.5	2,315.2	2,372.9	3,134.0	4,159.0
Total OM&A	**$5,927.0**	**$5,661.1**	**$6,089.6**	**$7,201.9**	**$7,994.1**	**$11,105.6**

2.0 GLPT's OM&A Budgeting Process

GLPT's budgeting process is described at Exhibit 1, Tab 2, Schedule 2. As noted in that section, GLPT uses a bottom up approach that considers the needs of the organization for the upcoming year in order to arrive at an OM&A budget that addresses those needs. In addition, GLPT utilizes information gathered from a number of sources to implement an effective maintenance program that is expected to maximize the operational life of assets in service and meet all reliability requirements.

For operations costs, all planned human resources, purchased services, materials, and other costs are identified and accounted for. GLPT forecasts the operations portion of its OM&A budget based on a review of its historic operations costs and with consideration to available resources (internal and external) and the planned operations program. GLPT seeks to maximize its use of internal resources before relying on external resources. Where external resources are required, GLPT typically utilizes them on a temporary or contract basis to minimize overall costs.

With respect to maintenance costs, GLPT applies good utility practice in setting its maintenance program, while considering its legal and license obligations, the safety of its employees and the public, as well as environmental commitments. GLPT undertakes two distinct types of maintenance activities – preventative and corrective. Preventative activities (including inspections, work and test maintenance, overhauls and diagnostic activities) follow a routine, scheduled program (see Exhibit 2, Tab 5, Schedule 1), while corrective activities (including minor repairs, part and component replacements, etc.) are identified from the results of the preventative activities. Due to the interdependent nature of these activities, GLPT does not distinguish between preventative and corrective maintenance activities in its budgeting process.

Administration expenses are generally categorized as either variable or non-variable. Non-variable administration costs include items such as property insurance, regulatory expenses and Electrical Safety Authority fees. These costs remain relatively stable from year-to-year, subject primarily to inflationary increases. Variable administration costs relate to items such as human resources and outside services employed, as well as other costs that can fluctuate on a year-over-year basis. As with operations expenses, GLPT forecasts the administration portion of its OM&A budget based on a review of its historic administration expenses and consideration of work needs and available resources, both internal and external. For administration costs, GLPT seeks to maximize the use of its internal resources before relying on external resources. When external resources are required, GLPT typically utilizes them on a temporary or contract basis to minimize overall costs.

3.0 Cost Management

GLPT strives to keep its OM&A costs down by achieving efficiencies that minimize costs, while allowing effective operation of the business. Some examples of GLPT's cost efficiencies are set out below.

3.1 Temporary Resources

In order to deal with requirements that are only short term in nature, GLPT may employ temporary or contract resources rather than full-time employees. This allows GLPT to reduce its payroll burden and to reduce other expenses that are associated with employing individuals on a full-time basis. If circumstances result in a short-term need becoming a longer-term need, then a temporary or contract employee or employees may be employed on a full-time basis in order to retain the benefits to the organization of the individual having received training and having accumulated operational experience. GLPT has found this manner of employing human resources to be effective in minimizing costs, and will continue to implement this approach.

3.2 Lease of Building & Communication Equipment

As described in Exhibit 4, Tab 2, Schedule 5, GLPT leases the office complex in which it resides, as well as a large portion of the communications equipment used by the company.

3.2.1 Office Complex

In the case of the office complex, GLPT leases the entire complex at 2 Sackville Road in Sault Ste. Marie from Great Lakes Power Limited ("GLPL"), and subleases a portion of the complex to Algoma Power Inc. (which is the owner of the distribution business formerly known as Great Lakes Power Distribution Inc.). GLPT is responsible for its proportion of a per-square-foot lease cost that is based on an appraisal prepared by an independent third party. When GLPT's total annual lease costs are considered against the potential cost consequences of GLPT owning the complex and including it in rate base, GLPT is reducing its overall costs by approximately $114,000 in the test year. This is presented in the table below.

Table 4-2-1 C – Savings on Office Complex

	GLPT Share
NBV of Building at June 30, 2009 (Rate Base)	$2,600,000
Annual Depreciation (2.5%)	65,000
Annual Return (blended rate of 8.42%)	218,920
Total Annual Cost of Capital for Building	283,920
GLPT's Annual Lease Cost in OM&A	169,755
Estimated Rate-Payer Savings	**$114,165**

3.2.2 Communications Equipment

GLPT licences its Supervisory Control and Data Acquisition ("SCADA") equipment and its fibre optic equipment from GLPL. The annual licensing fee for the SCADA equipment is approximately $294,000. The annual licensing fee for the fibre optic equipment is approximately $63,200. Together, these costs are equal to less than half of the depreciation expense on the equipment. If GLPT were to own this equipment outright, the minimum incremental cost to ratepayers would be the additional depreciation expenses of $294,000 and approximately $91,000, plus the return on investment required as a result of the capital costs residing in rate base.

As described in Exhibit 4, Tab 2, Schedule 5, there is no alternative fibre optic system provider in the area of GLPT's system. If GLPT had to purchase or recreate the existing network, very significant investments would be needed. It is estimated that such a system would require an investment of several million dollars.

3.2.3 Outage Restoration

Through the development and implementation of GLPT's integrated vegetation management program for maintaining its transmission system rights-of-way (See section 5(a) of this schedule), GLPT has reduced the frequency and size of vegetation-related outages. By reducing the number and extent of such outages, GLPT is able to avoid costs associated with outage restoration, including the costs of dispatching work crews to often remote locations to carry out emergency work activities. As a result, GLPT's outage restoration expenses have decreased by $40,000 on an annual basis as of 2010, as compared to at the time of GLPT's last Board approved transmission rates. GLPT anticipates that its outage restoration expenses will continue to decrease as it continues with the integrated vegetation management program.

3.2.4 Energy Audit

In May 2009, GLPT retained an engineering firm to prepare an energy audit on behalf of the transmission and distribution businesses and to evaluate and assess opportunities for improving electrical systems at the office complex located at 2 Sackville Road in Sault Ste. Marie. While the resulting Energy Audit Report applies to the entire building, GLPT will be implementing the recommendations contained in the report in respect of its portion of the complex only. The energy audit considered the building's perimeter and electrical heating, ventilation and air conditioning systems, lighting, and the cost benefits of alternatives. Recommendations included upgrading aging HVAC systems with natural gas-based heating and higher efficiency cooling systems, upgrading lights and improving the building envelope. For the entire office complex, the resulting energy savings were estimated to be approximately $70,000 per year with an estimated payback period for the necessary up front investments of just over 3 years.

3.2.5 Vegetation Management

As part of its vegetation management program, GLPT has introduced the use of mechanical tree removal techniques along its rights-of-way (ROWs). This approach has particularly been used for purposes of re-establishing ROW edges so as to restore ROWs to their required widths. This new approach has reduced the cost of removal per tree significantly and has increased the efficiency of tree removal so as to provide increased coverage in a given year.

3.2.6 Health, Safety and Environment

While the health and safety function has historically been staffed separately from the environmental function, GLPT carries out both of these functions for the company through only one dedicated position. In addition to providing opportunities for synergies in delivering and administering the programs, this allows GLPT to reduce staffing costs for these programs by $80,000 per year while maintaining its high standards for health and safety and environmental performance.

4.0 OM&A Cost Drivers

An account-by-account summary of GLPT's OM&A costs for 2006 to the 2010 test year is provided in Table 4-2-1 C. The key drivers that give rise to the costs within the accounts for operations, maintenance and administration are discussed below.

Table 4-2-1 C – OM&A Costs by Uniform System of Accounts

($000's) USofA	Description	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
	Transmission Expenses - Operation						
4805	Operation Supervision and Engineering	$47.0	$405.0	$383.1	$641.5	$384.1	$475.5
4810	Load Dispatching	1,048.8	1,019.1	1,024.0	945.9	1,165.9	1,600.2
4815	Station Buildings and Fixtures Expense	355.4	238.6	247.9	258.9	582.3	886.7
4820	Transformer Station Equipment - Labour	36.4	52.5	81.6	294.8	434.8	396.1
4825	Transformer Station Equipment - Supplies and Exp.	69.6	29.9	68.0	83.4	194.9	82.2
4830	Overhead Line Expenses	59.9	100.8	124.4	153.9	118.9	177.1
4845	Miscellaneous Transmission Expenses	265.5	97.8	177.9	166.9	223.3	437.5
4850	Rents	48.0	53.2	60.5	89.2	70.7	80.9
	Transmission Expenses - Maintenance						
4910	Mtce of Transformer Station Buildings and Fixtures	87.3	10.7	23.2	17.5	69.9	91.8
4916	Mtce of Transformer Station Equipment	621.3	554.7	556.8	377.2	302.8	582.3
4930	Mtce of Poles, Towers, and Fixtures	40.8	16.5	18.7	24.5	10.3	18.5
4935	Mtce of Overhead Conductors and Devices	144.9	116.9	157.2	271.1	95.7	207.8
4940	Mtce of Overhead Lines - Right of Way	600.0	794.9	851.1	1,400.8	1,102.7	1,800.0
4945	Mtce of Overhead Lines - Roads and Trails Repairs	-	-	-	103.2	103.8	110.0
	Administrative and General Expenses						
5605	Executive Salaries and Expenses	486.5	427.8	401.3	403.4	499.7	1,102.7
5615	General Administrative Salaries and Expenses	1,471.7	1,019.4	1,056.6	988.6	1,230.8	1,286.0
5620	Office Supplies and Expenses	-	-	-	-	-	280.2
5630	Outside Services Employed	234.6	438.8	553.4	675.6	1,010.0	1,062.1
5635	Property Insurance	142.4	116.4	116.4	115.1	177.2	211.5
5655	Regulatory Expenses	148.1	148.6	167.4	153.6	163.3	157.0
5665	Miscellaneous General Expenses	-	-	-	15.3	30.0	36.5
5680	Electrical Safety Authority Fees	19.0	19.5	20.1	21.4	23.0	23.0
	Subtotal Operations	1,930.5	1,996.9	2,167.4	2,634.6	3,174.8	4,136.2
	Subtotal Maintenance	1,494.2	1,493.7	1,607.0	2,194.4	1,685.3	2,810.5
	Subtotal A&G	2,502.4	2,170.5	2,315.2	2,372.9	3,134.0	4,159.0
	Total OM&A	**$5,927.0**	**$5,661.1**	**$6,089.6**	**$7,201.9**	**$7,994.1**	**$11,105.6**

To provide the Board with context for GLPT's OM&A expenses, GLPT retained First Quartile Consulting, LLC ("FQC") to perform a benchmarking study. In performing its study, FQC performed analysis to determine how GLPT compares against a panel of utility companies with respect to transmission line, transmission substation and administrative and general expenses. Normalized on a cost per asset basis, GLPT generally falls below the average of the comparison panel, reflecting lower costs on average on per asset basis.

In considering combined administration expenses and operation and maintenance expenses, FQC found that GLPT remains below the average of the comparison panel, reflecting lower costs on average, and is within the second quartile. The second quartile is the second lowest cost tier. With only administration expenses on a per asset basis, GLPT is well below the average of the comparison panel and is primarily in the second quartile.

GLPT is also generally within the second quartile with respect to transmission lines and substation operation and maintenance costs, excluding administration costs. GLPT's costs per asset trend upwards in 2009 and 2010. This relates primarily to vegetation management expenses by GLPT, as well as GLPT expenditures that are recorded in CWIP and not yet in the asset base. As a result of the expected lower maintenance costs arising from capital expenditures in 2010 and the increment in the asset base in 2011, this upward trend is expected to lessen in 2011.

The FQC study is consistent with the view that GLPT's operation and maintenance expenditures are reasonable and that GLPT has established a corporate structure with an executive and management team that is reasonably sized. FQC's report is set out at **Appendix "A"** of this schedule.

4.1 Operations

GLPT's operating costs are driven largely by a few areas of activity, which together comprise the majority of total costs. Operating costs are made up primarily of costs incurred under Account 4810 - Load Dispatching, Account 4815 – Station Buildings and Fixtures Expenses, Account 4805 – Operation Supervision and Engineering, and from general operations activities.

Load Dispatching is the most significant cost in the operations category for GLPT. These costs are driven by the Ontario System Control Centre ("OSCC") and include costs associated with direct switching, controlling system voltages, communications services, as well as system records and report generation. The costs associated with leasing SCADA equipment are included in this account as well.

Station Buildings and Fixtures includes the costs of labour, material used and expenses incurred in operating transmission station buildings and fixtures, and in operating the office complex in which GLPT resides. Specifically, some of the expenses include lease payments, lighting, heating, telephone, and other building service expenses.

Supervision and Engineering costs are provided primarily by internal staff, with assistance provided by external consultants as needed. This includes labour costs and other expenses incurred in association with the general supervision and direction of operations for the transmission system as a whole, including engineering. More specifically, these activities include testing to determine the efficiency of equipment operation, the preparation and review of budgets, the preparation of estimates and drawings related to operations or maintenance activities, and the review and analysis of operating results.

Other general operating activity costs include labour, supplies and expenses related to transformer station equipment, overhead lines, stations and buildings, and rents. These activities and their associated costs are required to operate the business. They include testing, inspections, patrolling, switching, equipment adjustments, record keeping, compliance reporting, as well as related transportation, supplies, tools, and incidental expenses.

4.2 Maintenance

GLPT's maintenance costs are driven primarily by activities, the costs of which are under Account 4940 - Maintenance of Overhead Lines (Right of Way), and Account 4916 - Maintenance of Transformer Station Equipment.

Right of Way (ROW) maintenance costs include expenses relating to vegetation management, including the trimming of trees, clearing of brush and the maintenance of edges and buffer zones associated with ROWs. Vegetation management in ROWs is an essential component of maintaining the reliability of GLPT's transmission system. A detailed discussion of ROW maintenance can be found in section 5(a) of this schedule.

GLPT's station maintenance costs are comprised of the cost of labour with payroll burden, material, trucking and other expenses incurred in the maintenance of station equipment included in Account 1715 - Station Equipment. The majority of this maintenance is completed by internal staff. However, given the nature of corrective maintenance, GLPT may use external contractors as needed.

4.3 Administration

GLPT's administrative costs are driven primarily by activities for which costs are included under Account 5605 – Executive Salaries and Expenses, Account 5615 - General Administrative Salaries, and Account 5630 - Outside Services Employed.

Historically, General Administrative Salaries were comprised largely of salaries associated with the provision of common services shared with GLPL's distribution division. These included salaries for such areas as accounting, information technology, health and safety, and environmental. The methodology used for allocating costs up to June 30, 2009 remained consistent with GLPL's 2005 filing, EB-2005-0241. Given the development of GLPT as a stand-alone transmission business as of July 1, 2009, the cost sharing and allocation arrangements that previously existed between transmission and distribution are no longer applied.

However, although costs are no longer shared between the former divisions of GLPL, account 5615 still reflects the salaries and benefits of the employees in the administrative programs listed above. Also included in this account is GLPT's corporate cost allocation, which is described in Exhibit 4, Tab 2, Schedule 5.

Account 5605 - Executive Salaries and Expenses includes the salaries and associated expenses of GLPT's Vice President and General Manager, its Vice-President of Project Development, its Director of Legal and Regulatory, and its Director of Administration. This account also includes an allocated cost of 50% of the salary and expenses for the parent company's Chief Operating Officer responsible for North American Transmission.

With respect to Account 5630, GLPT employs external services to provide professional administrative support in a number of areas. External audit fees, as well as legal and regulatory support costs make up the bulk of the external administration support utilized by GLPT.

5.0 Variance Analysis

This section describes and discusses the key factors that have driven GLPT's OM&A cost variances over the period from 2006 up to and including the 2010 test year. These key drivers are as follows:

(a) Right-of-Way Maintenance;
(b) General Management and Executive Costs;
(c) System Control and Communications;
(d) Other Administrative Programs;

(e) GLPT's Office Complex; and

(f) Transmission Development.

The variances described in this section comprise over 80% of the total OM&A increase between 2006 and 2010. A summary of these variances is presented in *Table 4-2-1 D*, below. These drivers are further discussed and referenced, as appropriate, in the detailed year-over-year variance analyses, provided in Exhibit 4, Tab 2, Schedule 3.

Table 4-2-1 D – Variance Analysis Summary

	USofA**	($000's)	Percentage
2006 Approved OM&A	All OM&A	$5,927.0	
2010 Test Year OM&A	All OM&A	11,105.6	
Overall Variance from 2006 Approved to 2010 Test Year		**$5,178.6**	
Described in Section 5.0			
Section (a) - Right of Way Maintenance	4940 / 4945	$1,310.0	25.3%
Section (b) - Management & Executive Costs	5605 / 5615	816.9	15.8%
Section (c) - System Control & Communications	4810 / 4845	723.4	14.0%
Section (d) - Administrative Support Programs	5615 / 5620 / 5630	488.3	9.4%
Section (e) - Office Complex	4815 / 4910	475.6	9.2%
Section (f) - Transmission Development	5605 / 5620 / 5630	412.0	8.0%
Total OM&A Variance Described in this Section		**$4,226.3**	**81.6%**

**For detailed account by account variance analyses, please refer to Exhibit 4, Tab 2, Schedule 3

(a) ***Right-of-Way Maintenance (Accounts 4940 / 4945)***

The maintenance of ROWs is an ongoing challenge that is of particular importance to GLPT because of the unique character of its transmission system. As described in Exhibit 1, Tab 2, Schedule 1, GLPT's transmission system extends through two forest zones in northern Ontario that have dense vegetation throughout, and which are situated amidst the difficult terrain of the Canadian Shield. Effective ROW maintenance is required to ensure that appropriate clearances between vegetation and electrical equipment are maintained in order to mitigate risks to the reliability of GLPT's system and to the bulk electricity system in Ontario. GLPT's program is also challenged by environmental, social, ecological and economic factors that may influence the method or approach applied by GLPT.

Vegetation management in ROWs is an essential component of maintaining the reliability of GLPT's transmission system because contact between vegetation and transmission lines, such as due to weather events or growth, can result in outages. Moreover, properly maintained ROWs allow for access to transmission facilities, which is needed to carry out inspections and maintenance activities.

GLPT's vegetation management activities include brush removal along the floors of ROWs through the ground application of herbicides by work crews in accordance with applicable regulatory requirements. Brush removal is generally carried out during the summer growing season. Vegetation management also includes brush removal, tree trimming and tree removal along the edges of ROWs to prevent the encroachment of vegetation into the ROWs. This work is typically carried out during the winter and is performed by different work crews with different skills and equipment than those who do brush removal. More specifically, the work involves the trimming of branches and the removal of trees which pose a potential risk to adjacent transmission lines.

Along certain areas of GLPT's ROWs, known as buffer zones, standard methods of vegetation management are not possible for a variety of reasons. These include the presence or proximity of rivers, creeks, waterways, wetlands and lakes where, pursuant to requirements under the Pesticides Act, there may be restrictions on the use of particular herbicides or their manner of application. Other areas where standard methods of vegetation management are not possible include areas such as areas of higher elevation, areas of difficult terrain and areas where property issues restrict GLPT's ability to use standard methods. In all such buffer zones, GLPT must resort to more labour- and time-intensive processes such as hand cutting, spot spraying and the use of alternative herbicides.

GLPT relies on the use of specialized, outside contractors for the performance of the various components of this work. GLPT targets a 6-year cycle for completion of all brush removal, tree trimming and tree removal activities needed on its system's ROWs, including ROW floors and edges, as well as buffer zones.

The clearing of ROWs is a highly regulated activity as GLPT is required to comply with the IESO's reliability compliance program, which is generally aligned with NERC

Reliability Standard FAC-003-1 (Transmission Vegetation Management Program). These requirements reflect a generally greater focus on vegetation management across the electricity sector in the wake of the 2003 blackout. Moreover, GLPT must comply with the highly prescriptive licensing and approvals requirements under the *Pesticides Act* and relevant regulations. GLPT's ROW maintenance activities are also subject to requirements and restrictions under the provincial species protection legislation in respect of certain at-risk species that inhabit areas within GLPT's network of ROWs. The highly-regulated nature of this activity is a factor in driving GLPT's ROW maintenance costs.

Scope

To meet its ROW vegetation management challenges with greater effectiveness, GLPT has steadily improved its vegetation management program between 2005 and 2009. Consistent with the approach taken in the 2005 application, GLPT's ROW maintenance program operates on the basis of a 6-year cycle whereby a portion of the system's ROWs is inspected and maintained each year so that, over the course of the entire cycle, all ROWs on GLPT's system are maintained. To follow this cycle, GLPT divides its ROWs up for maintenance over 5 years and allows for 1 additional year to provide flexibility in completing the cycle.

The reasonableness of having an ROW maintenance cycle that is 6 years in duration is supported by a recent Vegetation Management Benchmarking Study prepared by an independent consultant for Hydro One Networks Inc. ("HONI") and filed in support of HONI's 2010/11 distribution rate application (EB-2009-0096).[1] This report explains at page 29 that "long cycles between treatments push the workload on an upwardly exponential curve each time it is managed. When stump re-sprouts and new trees are allowed to grow higher than the shrubs, herbs and grasses, the trees will extend their height rapidly to the height of the wire causing a need for remediation and unplanned maintenance . . . the work is the lightest and moves the quickest when it is performed before new vegetation begins the juvenile phase of growth, exponentially accumulating biomass." The report found that HONI's peer group typically used cycles of 3-5 years and that HONI made a prudent choice in seeking to reduce the length of its 10-year cycle. GLPT is therefore confident that its cycle of 5 years, plus one additional year each cycle for flexibility, is appropriate and provides a sustainable level of reliability at a reasonable cost relative to the vegetation growth.

When GLPL's transmission division submitted its EB-2005-0241 transmission rate application, GLPT's ROW maintenance activities primarily included herbicide application on the floors of the ROWs and vegetation management in buffer zones. On an as needed basis, GLPL removed danger trees. In response to (1) the significantly greater focus on vegetation management across the electricity transmission industry arising from the 2003 blackout, (2) the IESO requiring compliance with reliability standards for vegetation management and vegetation-caused outages, adopted from

[1] See Exhibit A, Tab 15, Schedule 2, Attachment 1 of HONI's pre-filed evidence in EB-2009-0096.

NERC reliability standards (Vegetation Management Standard FAC-003-01), and (3) the occurrence of vegetation-related events affecting its transmission system in 2006, GLPL’s transmission business determined that a change in its approach to vegetation management was required.

In 2006, GLPT transitioned to a fully integrated vegetation management program. As a fully integrated program, brush removal on ROW floors, tree trimming and removal along ROW edges and vegetation management in buffer zones are all carried out in a systematic and coordinated manner, within the 6-year cycle. As part of this program, beginning in 2006 a particular focus has been given to tree trimming and tree removal to address encroachment on the sides of the ROWs and to re-establish the edges of GLPT’s active ROWs. While most of the system’s lines require ROWs with a width of 30 meters, GPS mapping activities determined that in many places vegetation encroachment had reduced these ROWs to 20 or 25 meters in width. To mitigate the risk to its system, GLPT has been working to re-establish the appropriate ROW widths through tree trimming and removal, as well as brush removal.

Beginning in 2007, GLPT has also incurred additional costs associated with to its efforts to properly identify and define the sizes and locations of buffer zones situated within the ROWs, as well as to manage vegetation in those buffer zones. As indicated, buffer zones are areas near waterways where, in accordance with requirements under the *Pesticides Act* and due to the environmentally sensitive nature of these areas, traditional herbicide application cannot take place. GLPT also regards as buffer zones any areas where, due to terrain or property issues for example, standard methods of herbicide application, tree trimming and tree removal cannot be used. Because of the location of GLPT's transmission system, regulatory changes that increase the operating restrictions around buffer zones have a particularly significant impact on GLPT. In such buffer zones, GLPT must employ slower, more labour-intensive and more costly techniques using different equipment and sometimes different work crews in order to perform necessary vegetation management activities. These methods include spot-spraying, hand cutting and the use of alternative herbicides.

As part of the costs associated with the regulatory need to better manage vegetation in buffer zones, GLPL incurred expenses relating to its efforts to identify, map, define and better understand the buffer zones along its ROWs. A significant portion of this work involved crews using GPS instrumentation in the field to map buffer zone locations and characteristics. These work activities have contributed to certain efficiencies such that, while GLPT previously had difficulties in maintaining buffer zones within the 6-year cycle, it is now better able to achieve this. This is due to the enhanced ability to describe work requirements to contracted work crews, who are then better able to plan their work activities and vegetation treatment strategies. It also allows for the more efficient dispatching of crews due to reduced mobilization and demobilization time and costs. As a corollary benefit, GLPT also expects to receive better cost estimates for ROW maintenance services.

Given the success of the enhanced focus on tree trimming and tree removal activities associated with restoring and maintaining ROW edges in 2006 and 2007, GLPT expanded this part of its program so as to improve a greater portion of its ROWs in 2008. GLPT has also continued its efforts to identify, map and define buffer zones. As a result, GLPT experienced a further increase in its ROW maintenance costs in 2008. Together, these efforts will result in a more integrated, systematic, efficient and effective ROW maintenance program which will use less chemical herbicides and achieve better reliability for the GLPT transmission system.

For 2009, while GLPT maintained its level of managing vegetation on the ROW floors in accordance with its 6-year cycle, as a cost cutting measure GLPT reduced its activities associated with encroachments and buffer zones relative to 2008. It was decided that, for reliability purposes, GLPT needs to restore its prior levels of activity in these areas for 2010 and beyond.

Other Factors

In addition to the scope changes described above, there have been several other factors that have driven increases in GLPT's ROW maintenance expenses.

With respect to reliability requirements, as noted above, the IESO requires compliance with reliability standards for vegetation management and vegetation-caused outages, adopted from NERC standards. NERC's Vegetation Management Standard (FAC-003-01) came into effect in 2006, and the requirements of the standard demand more rigorous vegetation management to avoid risk to the system. Associated with the NERC standard are increased reporting and administrative requirements. Given the limited staff at GLPT, it was impossible to simply absorb the additional burden. As part of the Bulk Electricity System, this and other standards are applicable and are of particular importance for reliability. As a result, reliability requirements, and particularly this standard, have driven GLPT to incur greater costs to ensure compliance.

The additional factors driving the increase in GLPT's ROW maintenance expense also include new regulatory requirements. In particular, Ontario introduced Regulation 63/09 under the *Pesticides Act*, effective April 22, 2009. This regulation bans the cosmetic use of pesticides in Ontario. Though GLPT as a utility is exempt from the outright ban, the regulation instead requires GLPT to develop and implement an integrated pesticide management plan. GLPT has required the assistance of a contractor with the specialized expertise needed to prepare its plan, which requires approval from the Ministry of the Environment. The plan must identify the specific herbicides to be used and their manner of application with a view to minimizing the quantity and intensity of application, particularly in more environmentally sensitive areas. Once prepared, the plan must be reviewed and approved by a certified pesticide professional before submission to the Ministry. The plan must also address extensive reporting requirements, such as the preparation and maintenance of daily pesticide application logs and the preparation and filing of an annual report. In addition, the regulation establishes further restrictions on pesticide exposure for employees and the environment. This results in the requirement for additional employee training and personal protective equipment, and the potential that GLPT will no longer be able to use some otherwise valuable and cost-effective tools when applying herbicides.

The last factor driving cost fluctuations in vegetation management is species at risk legislation. On May 16, 2007, Ontario enacted the new *Endangered Species Act, 2007*, which replaced the former species protection legislation in the province. The new legislation is more comprehensive and provides broader protection for species at risk and their habitats. Some of GLPT's ROWs provide habitat for recognized species at risk. GLPT effectively treats these areas like buffer zones, where specialized vegetation management methods are required. However, there are additional constraints because GLPT must schedule its work around the "active seasons" of various species, thereby giving rise to the need to redeploy work crews to deal with the affected areas, resulting in inefficiencies. Moreover, GLPT must ensure that its work crews are appropriately trained so as to identify the species at risk and their habitats when encountered.

(b) ***General Management, Executive Costs and Corporate Allocation (Accounts 5605 / 5615)***

There are several key drivers of cost increases associated with GLPT's general management and executive services, particularly from 2008 to the 2010 test year.

General Management and Executive Costs

GLPT has established a corporate structure with an executive and management team that is reasonably sized, reflective of the overall company needs and structure, and which includes the appropriate level of experience and expertise for a stand-alone transmission utility of the size and nature of GLPT. As a stand-alone transmission company, GLPT has a wide range of needs, some of which are basic business needs and some of which are driven by GLPT's business as an electricity transmitter in Ontario, but all of which GLPT believes to be typical for any transmission utility. These include needs with respect to operations, maintenance, capital investment, regulatory, environment, health and safety, information technology, as well as management and administration, which includes such functions as legal, finance, accounting, treasury and human resources. GLPT also has obligations to its outside stakeholders which require attention. These functions require appropriate staffing, external support where needed, as well as appropriate oversight, management and leadership.

To address these wide-ranging needs, GLPT has established a relatively flat organizational structure, which is depicted by the organizational chart in Exhibit 1, Tab 1, Schedule 12. Leading the organization, on behalf of the parent company, is a Chief Operating Officer responsible for North American Transmission. This individual's duties and functions are to develop and approve GLPT's strategic plan, approve GLPT's annual budget and capital expenditure program, hire and oversee and monitor performance of GLPT's senior management team, provide executive support for regulatory initiatives including in respect of rate setting and key policy issues, provide leadership for transmission development activities, as well as to provide partner oversight over GLPT operations and quarterly reporting to the partners of GLPT. 50% of the parent company's costs associated with the Chief Operating Officer responsible for North American Transmission is allocated to GLPT to reflect these contributions.

Reporting to the parent company's Chief Operating Officer responsible for North American Transmission are GLPT's Vice President and General Manager, its Vice President of Project Development and its Director of Legal and Regulatory. Reporting to the Vice President and General Manager is GLPT's Director of Administration. The duties and functions associated with each of these positions are as follows:

- The Vice President and General Manager is responsible and accountable for planning, directing, managing and overseeing all activities and operations of GLPT. More specifically, this individual's duties include, but are not limited to, ensuring the safe, environmentally responsible and efficient operation and management of the transmission system, overseeing the management of safety and environmental performance, administration, engineering and system control, ensuring the business is organized and staffed for efficiency and effectiveness, overseeing the work of the Director of Administration and the rest of the senior management team, aligning operations with corporate goals and objectives, reviewing financial plans and budgets and recommending such plans and budgets for approval by the Chief Operating Officer, remaining informed of legislative, regulatory and policy developments that may affect the business, ensuring compliance by the business with regulatory licences, permits, codes and other requirements, and negotiating and managing collective bargaining processes.

- The functions carried out by the Vice President of Project Development arise from the circumstances discussed in section 5(f) of this schedule. The duties of this Vice President are to guide and manage GLPT's focus on transmission development needs and opportunities arising from the *Green Energy and Green Economy Act*, lead and guide GLPT in its efforts to support the province's transmission development objectives, including the development and implementation of its expansion and reinforcement plan that will require strategic decision-making and relationship-building, contribute to the planning process that will give rise to potential First Nation and Métis consultations, and pursue partnerships for transmission development with HONI;

- The Director of Legal and Regulatory provides general legal counsel, advises the company in the area of Aboriginal law (including with respect to First Nation and Métis consultations and participation in the development of transmission facilities to support renewable generation development, as further discussed under Transmission Development in section 5(f) of this schedule, below), supports the company in developing and maintaining strong relationships with relevant Aboriginal groups, as well as advises and provides legal services associated with regulatory matters, including rate applications and Board consultation processes of strategic interest to GLPT; and

- The Director of Administration is responsible and accountable for directing the finance, accounting, treasury, tax, regulatory, IT and human resource functions of the business. In particular, this individual's duties include establishing and maintaining accounting procedures and overseeing maintenance of accounting and internal controls, overseeing the preparation of forecasts, budgets and financial reports, overseeing project accounting, debt compliance reporting, preparation of management reports, working with external auditors, cash management, responsibility for tax filings and compliance, responsibility for all energy regulatory matters including overseeing applications and ensuring compliance, oversight of the IT department, and involvement in the collective bargaining process.

In addition to providing the necessary leadership, management and oversight for all areas of the business described above, as their job descriptions indicate, members of the executive team are also involved in performing many of these core business functions directly. This allows GLPT to maintain its flat and cost-effective organizational structure. GLPT believes that the functions served by each of these executive positions are essential to the effective management, operation and administration of its business.

Historically, GLPT's direct executive support was provided by a Vice President responsible for Ontario Operations, which included generation, transmission and distribution operations for a number of Ontario-based entities. By contrast, the appointment by the parent company of a Chief Operating Officer responsible for North American Transmission provides GLPT with transmission-focused leadership, oversight and executive support. While the Chief Operating Officer will have responsibility for different transmission entities across North America, GLPT believes that the focus on transmission will more effectively serve GLPT's interests in respect of its relationship with its parent company and with the industry, key stakeholders and the community at large. The incremental cost associated with the allocation of Chief Operating Officer costs to GLPT is offset, in part, by the elimination of costs related to the Vice President of Ontario Operations approved as part of EB-2005-0241.

The costs of GLPT's executive team are no longer shared with the generation business of GLPL or the distribution business now owned by Algoma Power Inc. Rather, GLPT now supports its own stand-alone executive team to provide appropriate leadership and management services.

<u>Corporate Allocation</u>

In 2010, GLPT will share certain corporate functions with its parent. As a result of this sharing, GLPT will pay a portion of the costs for certain corporate functions. These corporate costs are associated with senior executive support, tax filing preparation, as well as treasury, accounting and finance and are incremental to the functions carried out by the executive positions described above. GLPT's costs for these services and functions are determined based on the time spent by the relevant executives and the relevant staff in the finance, accounting, treasury and taxation departments of the parent company. The costs associated with these individuals are then multiplied by the relative portion of the working year that these individuals dedicate to providing support to GLPT. These costs were not budgeted in EB-2005-0241. Although these costs are now reflected as an increase in GLPT's revenue requirement, the increase is less than the expense that GLPT would have incurred if it were required to externally source these services.

(c) ***System Control and Communications (Accounts 4810 / 4845)***

The Ontario System Control Centre ("OSCC"), located at GLPT's office complex in Sault Ste. Marie, is an essential component of GLPT's business as it allows GLPT to operate its business, facilitates emergency response, allows for 24-hour contact as required by the IESO pursuant to the Market Rules, as well as serves important work protection purposes. As part of the separation of GLPL's transmission business from its generation business, the OSCC has transitioned from being a resource for which costs were shared among three business units (GLPL's transmission, distribution and generation divisions) to being a resource for which GLPT is entirely responsible.

GLPT believes that it is essential for it to have full responsibility for the operation of the OSCC. In particular, having control over its system operations enables GLPT to directly ensure its ongoing compliance with the terms and conditions of its Operating Agreement with the IESO and its Connection Facilities Agreement with HONI. Under each of these important agreements, GLPT has obligations and operational responsibilities that can only be fulfilled through the operation of the OSCC by GLPT. As such, GLPT regards system control as being strategically and operationally essential to the business.

In taking on the full responsibility for the OSCC, GLPT also felt that a stand-alone control centre fully under its control would be beneficial as it would not only relieve GLPT of any Affiliate Relationships Code issues that may have arisen as a result of the sharing, but that it would allow GLPT to retain complete control over services. This is important because it allows GLPT to be fully diligent in managing and controlling its assets. Therefore, for the benefit of its directly connected customers, and for the benefit of the reliability of the Ontario transmission grid, GLPT continues to operate the OSCC on a stand-alone basis. In GLPT's opinion, to do otherwise would not provide the utility with the level of due diligence necessary to support an operation of this type and magnitude.

In the MAAD Application submitted to the Board on March 5, 2009[2], the applicant indicated that the transmission company would experience a cost increase as a result of the transition to a stand-alone control room. This application was approved by the Board in the Decision and Order dated May 5, 2009.

In making the transition to full control and responsibility over the OSCC, GLPT has been able to reduce staffing associated with the OSCC from 16 to 9. However, as GLPT is

[2] EB-2009-0072 / EB-2009-0073 / EB-2009-0075

now responsible for the full cost of operating the OSCC, the transition to a stand-alone control room is nevertheless a significant cost driver for GLPT. Another factor driving costs has been the need for NERC certification training by all operators to enhance their skills and competency. With the OSCC employees now being focused on transmission, the activities they carry out include outage scheduling, outage documentation, as well as providing support to other GLPT departments by collecting and providing data and information that plays an important role in the operation and maintenance of GLPT's transmission system.

(d) ***Other Administrative Programs (Accounts 5615 / 5620 / 5630)***

GLPT undertakes a number of important administrative programs that are essential in supporting its core transmission operations. These programs include health and safety, environmental, as well as information technology (IT).

With respect to its health and safety program, while GLPT has been able to downsize its staffing such that the health and safety program and the environment program are now administered by a single person, rather than by two staff members, it still incurs core program costs. These core program costs include health and safety training costs, the cost of an annual safety audit to ensure that GLPT is meeting applicable legislative and regulatory requirements for health and safety, as well as internal health and safety standards.

With respect to its environmental program, as noted, while GLPT has downsized its staffing associated with the environmental program, it still incurs core program costs. These core program costs include the cost of an annual environmental audit to ensure GLPT is meeting applicable legislative and regulatory environmental protection requirements, as well as internal environmental standards. Environmental training is another significant cost associated with the environment program.

With respect to its IT program, GLPT is now responsible for the full costs of items such as licence fees, IT infrastructure costs, software costs and applicable salaries. For many of these items, because of their nature, as noted below, GLPT is responsible for the same level of costs as GLPL was when it provided IT services for the generation, transmission and distribution businesses. In addition, GLPT is experiencing incremental IT costs related to increasing cyber security requirements. The cyber security requirements are described in detail in the confidential filing at Exhibit 2, Tab 1, Schedule 3.

These important administrative programs were formerly delivered jointly for the distribution and transmission businesses. As a result of the separation of the transmission and distribution businesses, certain of these programs and their attendant costs can no longer be shared between the two businesses. Because these are programs that require the same level of program services and program costs as were incurred previously, it is not possible to simply continue with half of the resources for each of these programs at half the cost. As noted above, GLPT has taken steps to mitigate costs. However, GLPT has incurred incremental costs for purposes of supporting, as a stand-alone entity, the full costs of its health and safety program, environmental program and its information technology (IT) program.

(e) ***Office Complex (Accounts 4815 / 4910)***

The space available to the transmission-dedicated personnel of GLPL was insufficient for its needs. GLPT, as part of creating a separate transmission utility, had started to move to additional space within the office complex. To achieve this, staff were relocated within the office complex to a space that is more functional and more appropriately sized for its current and future needs. To provide improved functionality, the relocation within the complex was also needed to better reflect the distinction between GLPT and the distribution business. As a result of these changes, GLPT is now responsible for approximately 55% of the office complex costs.

Of the space now occupied by GLPT, approximately 25% is comprised of the OSCC space, which is located entirely within the portion of the building occupied by GLPT. The remainder of the space is used for GLPT's other business functions with a small proportion of space remaining available to accommodate future growth.

While the methodology of allocating building operation and maintenance costs based on square footage has been maintained, it has been determined that GLPL had previously under-allocated costs to the transmission business. This was due largely to the cost responsibility for office space used by staff performing work for both distribution and transmission generally being allocated to distribution, rather than being split between the two businesses based on hours of work done for each respective division.

Furthermore, as a division of GLPL, the business was previously not allocated any portion of the capital cost (i.e. depreciation and return on investment) of maintaining the office complex. Under the current circumstances, whereby GLPT is a stand-alone entity subleasing the office complex to Algoma Power Inc., the allocation of the cost of capital has also been revisited. As described in Exhibit 4, Tab 2, Schedule 5, GLPT pays the cost of capital in the form of an annual lease. GLPT leases the entire complex, and subleases a portion of the complex to Algoma Power Inc. All lease rates are based on square footage occupied and are charged at the median rates determined by a third party appraiser who prepared a report specifically for the complex. As a result, GLPT is now responsible for an incremental lease cost. However, as demonstrated in *Table 4-2-1 C,* the incremental cost of leasing the complex that is borne by GLPT is far lower than the incremental cost that GLPT would have borne if the relevant portion of the building were owned by GLPT and included in its rate base.

Up to and including 2008, approximately 12% of the costs related to the office complex were allocated to the transmission business. The difference between this allocation of 12% of costs and the current allocation of 55% of costs is attributable to the more accurate allocation of space as between transmission and distribution, the provision of additional space to meet GLPT's current and reasonable future needs, as well as the inclusion of the OSCC within GLPT's portion of the office complex.

In the MAAD Application submitted to the Board on March 5, 2009[3], the applicant indicated that the transmission company would experience a cost increase as a result of the cost of capital related to the office complex. Historically, none of the cost of capital was borne by transmission, and therefore the entire lease cost is incremental to GLPT. This application was approved by the Board in the Decision and Order dated May 5, 2009.

(f) ***Transmission Development (Accounts 5605 / 5620 / 5630)***

As a result of the recent amendments to the *Electricity Act* under the *Green Energy and Green Economy Act,* as well as the focused efforts by the Minister of Energy and Infrastructure to facilitate transmission development, GLPT has recognized an important need to ensure that it adequately focuses on certain aspects of transmission development.

Pursuant to section 25.36 of the *Electricity Act, 1998* (as amended) a transmitter is obliged to connect a renewable generation facility to its transmission system if the generator requests the connection in writing and meets the applicable technical, economic and other requirements prescribed by regulation, the Market Rules or by an order or code of the Board. Under section 26(1.1) a transmitter is now obliged to provide priority

[3] EB-2009-0072 / EB-2009-0073 / EB-2009-0075

access to its system to a renewable generation facility that meets the requirements prescribed by regulation.

In addition, section 70(2.1) of the *Ontario Energy Board Act* now deems, as part of each transmitter's license, that there is a condition for such transmitter to provide priority connection access to its transmission system for renewable energy generation facilities. Furthermore, section 70(2.1)(2) requires transmitters to prepare plans for the expansion or reinforcement of the transmission system to accommodate the connection of renewable energy generation facilities.

It is estimated that there is up to 1500 MW of new wind development in and around the GLPT transmission system. Preliminary conclusions suggest that any connection of wind resources above 100 MW would trigger the need for an upgrade on GLPT's system, including the construction of new network 230 kV lines. Because of this, GLPT will be focused on developing its expansion and reinforcement plan for filing anticipated to be in 2010. This plan could include plans for one or more enabler facilities. Any expansion and reinforcement plan would be expected to require consultation with First Nation and Métis communities.

In addition, based on September 2009 announcements by the Minister of Energy and Infrastructure, HONI has been asked to pursue certain transmission projects, including "East-West Tie: Nipigon by Wawa" and "Sudbury Area by Algoma Area". Both of these projects would include and would have an impact on the GLPT transmission system. The Minister has asked HONI to identify opportunities for entering into partnerships in respect of various projects, to use best efforts to enter into such partnerships, as well as to identify projects more suitably planned, developed and implemented by parties other than HONI. It is GLPT's intention to seek to partner with HONI in respect to these and other projects, including those that may not necessarily be located in close proximity to GLPT's existing transmission system.

It is also GLPT's intention to pursue designated transmitter status under the Transmission System Code in respect of various enabler transmission line projects. Such opportunities may be identified either by the OPA, the Minister or by GLPT though its expansion and reinforcement plan.

As a result of these obligations and initiatives, GLPT has identified the need to incur expenses, such as consulting and travel expenses, related to the *Green Energy and Green Economy Act* and related green energy initiatives.

APPENDIX "A"

First Quartile Consulting, LLC

Great Lakes Power Transmission Operation Cost Analysis (December 7, 2009)

Great Lakes Power Transmission operation Cost Analysis

Prepared by:
First Quartile Consulting, LLC

December 7, 2009

Introduction

Great Lakes Power Transmission LP (GLPT) is a transmission owner and operator serving a portion of northern Ontario, Canada. GLPT was established as part of a series of reorganizations of Great Lakes Power Limited (GLPL) in which GLPT became the owner and operator of GLPL's transmission business. Prior to these reorganizations GLPL ran the transmission business financially separate from its generation and distribution businesses and operationally in conjunction with the distribution business. Previously the transmission business of GLPL has been through a full cost of service review. This is the first application of GLPT as a stand-alone transmitter, i.e., both financially and operationally.

First Quartile Consulting (1QC) was engaged to analyze the costs of operation of the GLPT transmission system, in comparison with those of other transmission providers in North America. There are very few true "peers" for comparison, since GLPT is somewhat unique in terms of its size, rural geographic location, and dense vegetation. Nevertheless, it is important to gain some understanding of the relative costs of operation of the system in comparison to other transmission providers, in order to determine reasonable rates for operating the company. 1QC used the data from a panel of companies who have provided that data during detailed annual benchmark studies of North American transmission utilities as a basis for comparison against GLPT.

Analysis Approach

1QC performed a set of analyses to determine how GLPT compared against a panel of companies with regard to Transmission Line, Transmission Substation and related Administrative and General (A&G) expenses. The primary basis for the comparison was a data set of Transmission Lines & Substations O&M expenses which is gathered during the annual 1QC transmission and distribution benchmark study. That study doesn't collect A&G costs as part of the standard comparisons.

The definitions used for separation of direct O&M costs versus A&G costs in the 1QC study are those used in the FERC uniform system of accounts. Canadian utilities (some of whom are included in the comparison panel) typically capture the A&G costs together with the O&M costs, and report them as OM&A. The experience from the annual 1QC benchmark studies is that the Canadian utilities are able to separate out the A&G costs effectively, by following the definitions provided in the uniform system of accounts, so their results are directly comparable,

To address the need to include A&G costs in the comparison, we gathered 2 years of A&G expenses from available FERC reports. These A&G expenses as reported to FERC are for the whole generation, transmission and distribution operation. Therefore, it was necessary to make an allocation of A&G expenses for just transmission lines & substations. A rudimentary calculation was used to allocate A&G to transmission: (transmission O&M expense / (transmission + generation + distribution O&M expense)) * total A&G expense = transmission portion of A&G expense. While this is a very simple approach to allocating the costs, it has been tested in previous years through annual benchmark studies, and has proven accurate in determining allocations that are very close to the actual allocations for each company.

GLPT's Transmission lines & substations O&M expenses and its O&M + A&G expenses were compared against the 1QC panel. To perform a valid comparison, it was necessary to normalize the data to account for the different sizes of the companies. For the primary normalizing factor we chose total transmission lines & substations assets. Through analysis over the years, we have determined that total assets is the appropriate normalization factor for transmission spending and that it is possible to accurately predict a company's O&M expenses based upon the value of the assets they have.

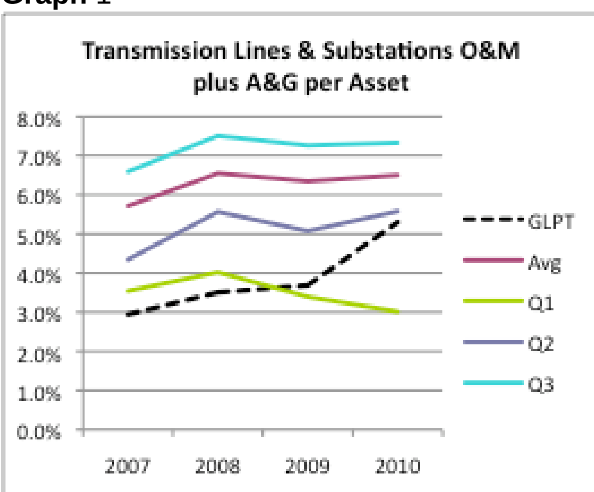
Results and Conclusions

Based upon our primary comparison, GLPT generally falls below average on a cost per asset basis. In the graphs below, the mean and quartiles are calculated without GLPT's data. They are based solely on our panel of companies, so that GLPT is being compared against a data set without influencing it.

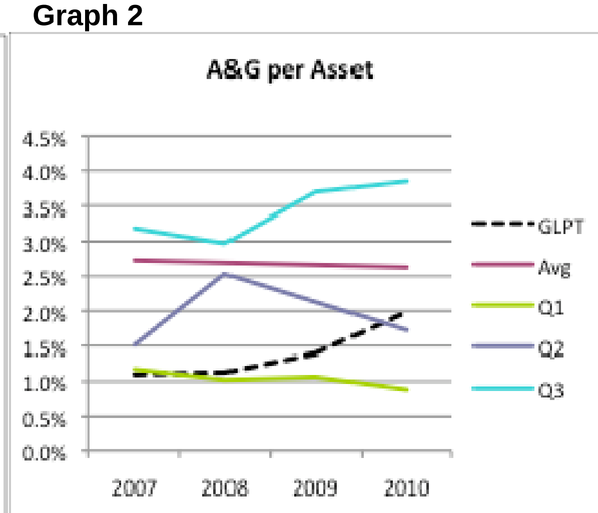
Note that in graphs 1, 2, 3, and 4, years 2009 and 2010 are projected based upon 2005 to 2008 actual data for all companies other than GLPT.

For graphs 1 and 2 below, only companies for which A&G data was available were used. GLPT compares favorably against this panel. Graph 2 shows just the A&G per asset. Clearly, while GLPT shows increasing A&G costs, the result is still very close to the median cost within the panel

Graph 1



Graph 2



Graph 3 below shows the O&M costs without the A&G costs. Despite the expected increases in costs for GLPT, the overall result in the projected period is still below average.

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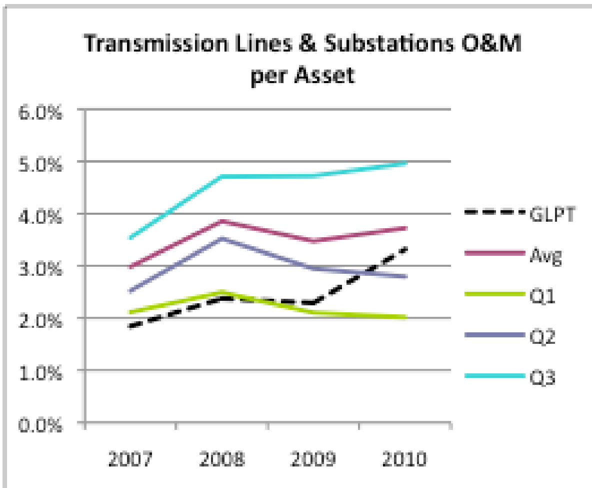
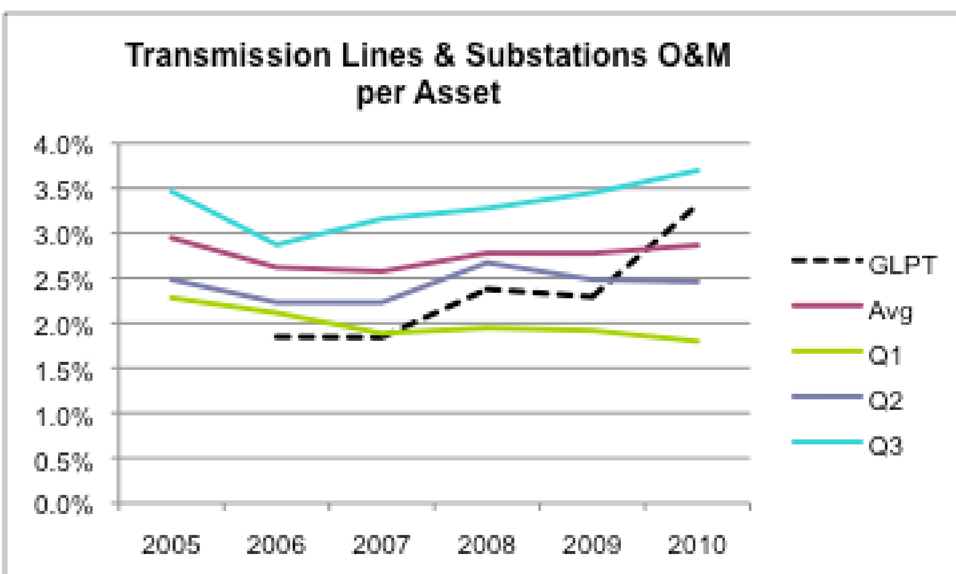
Graph 3



In Graph 4, GLPT was compared to our largest data set, which includes transmission lines and substations operations & maintenance costs and excludes A&G costs.

Graph 4:

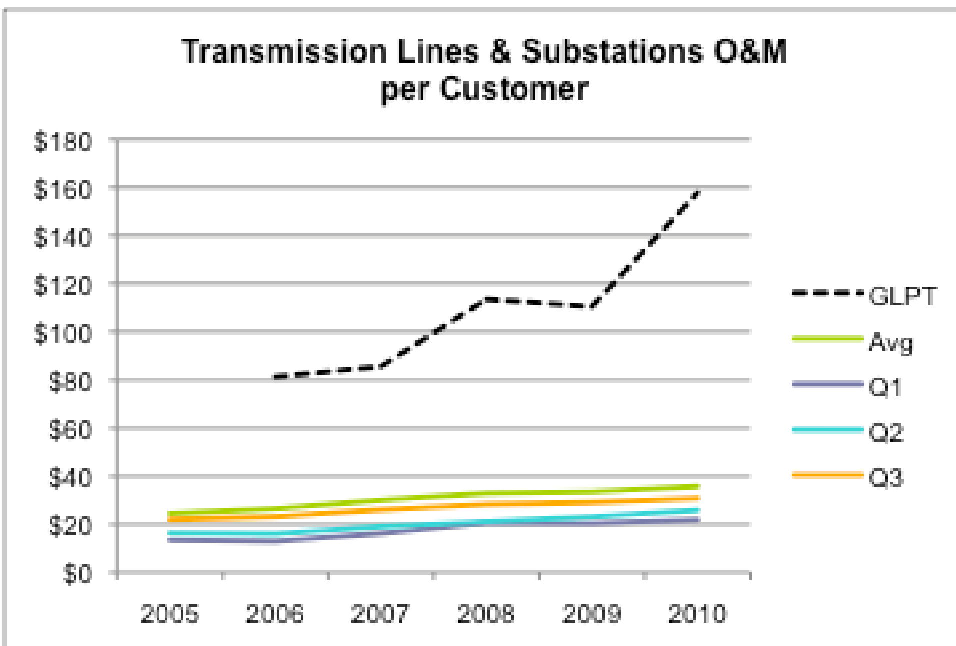


Two points of importance about the GLPT costs for 2009 and 2010 should be noted. First, GLPT is in the midst of a multi-year construction program, so the asset base will be growing. These expenditures won't be reflected in the denominator of the ratio charted until 2011, because a large portion of the expenditures will be in CWIP for the forecast period, rather than in the in-service asset base. At the same time, the new assets (primarily substation assets) will require less maintenance than the assets they are replacing. The implication is that once the new assets are placed in service after 2010, there will be a dampening effect on the increasing cost/asset shown in graph 1 above.

The second point is that the GLPT O&M costs are forecast to increase in 2010. The largest portion of the increase (33%) is focused on vegetation management improvements. The heavily-forested service territory covered by the GLPT system means that GLPT experiences greater exposure to tree-related outages than most companies, and therefore requires significant expenditures in that area.

For other comparisons, we also normalized spending based upon customers and circuit kilometers. Neither of these comparisons is recommended (see appendix) and the results are about as expected for GLPT, which is a small transmission operator.

Graph 5



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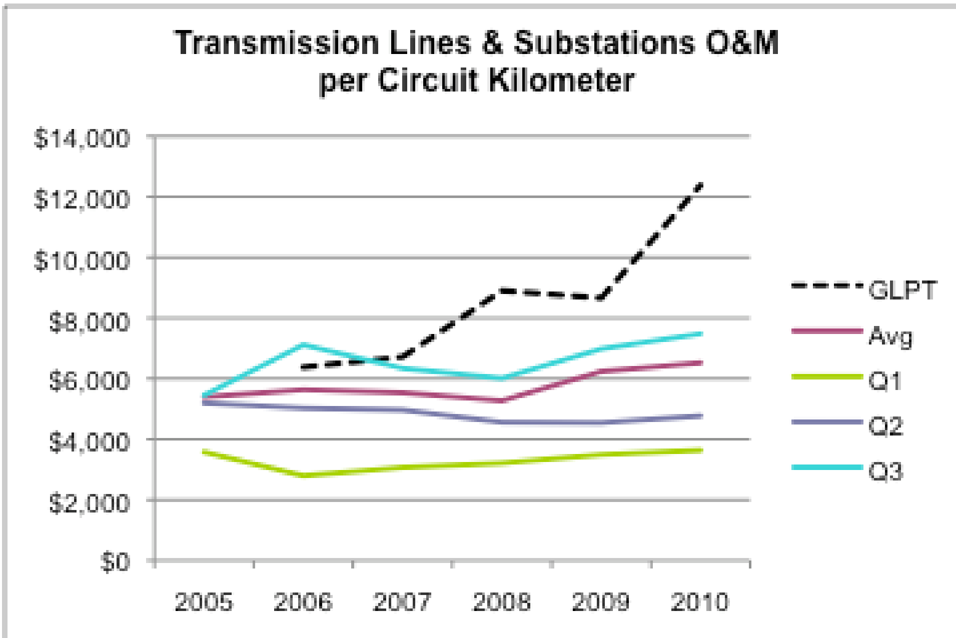
Graph 6



Two other possible normalizing factors (denominators) (kWh transmitted and megawatt miles) were excluded because of lack of data, but neither has been demonstrated to be better than assets at predicting transmission & substation O&M spending.

Appendix: Why "Assets" is the Appropriate Denominator.

Over a span of more than 20 years of executing benchmark studies of electric transmission and distribution operations in North American utilities, the consultants at 1QC have performed a variety of analyses of the resulting data. One question of enduring interest is how to normalize the data from different companies in order to make both fair and understandable comparisons. Through a number of different analyses and reporting efforts, it has become clear that with an appropriate normalizing factor, it is possible to make fair comparisons, and that it is also possible to explain the results in ways that make them useful to regulators and companies.

For many years, the studies have been consistent in terms of identifying the normalizing factor that produces the best predictor of operating costs in transmission and distribution. Given the difference in the functions of transmission and distribution, separate studies have been performed for transmission and distribution (and indeed for substation operations). The exact regression results change from year to year, but are generally the same direction.
In order to re-validate the results from previous years, the project team performed an analysis of the data from the most recently completed annual benchmark dataset. The results of that analysis are presented below.

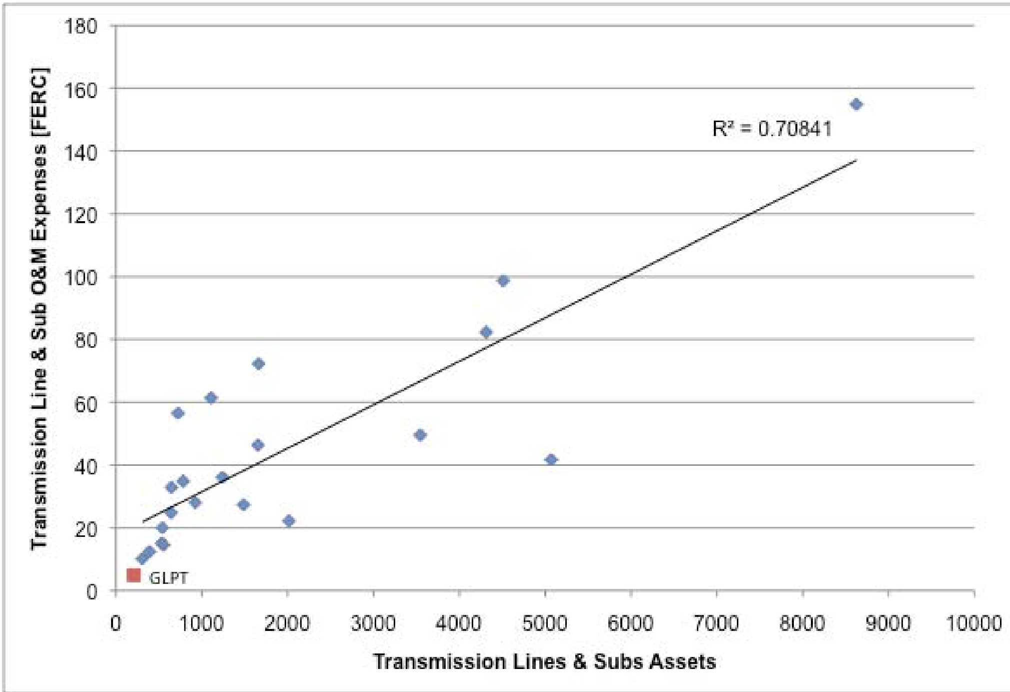
To determine the appropriate denominators (normalizing factors) to use for analysis, we compare the dependent variable, in this case O&M spending, to various independent variables: customers, circuit kilometers, and assets. We look for a strong correlation between the two variables. For transmission lines and substations O&M spending, the strongest correlation exists between spending and assets. The relationship between spending and customers or circuit km is much weaker. The table below shows R^2 correlation coefficient values for the dependent and independent variables. The table was generated without A&G expenses because of the method used for estimating A&G expenses. It was necessary to determine the correct normalizing factor from our most current valid data set.

	Transmission Lines & Subs Assets	Transmission Circuit Kilometers	Customers
Transmission Line & Sub O&M Expenses (FERC)	0.708	0.502	0.257

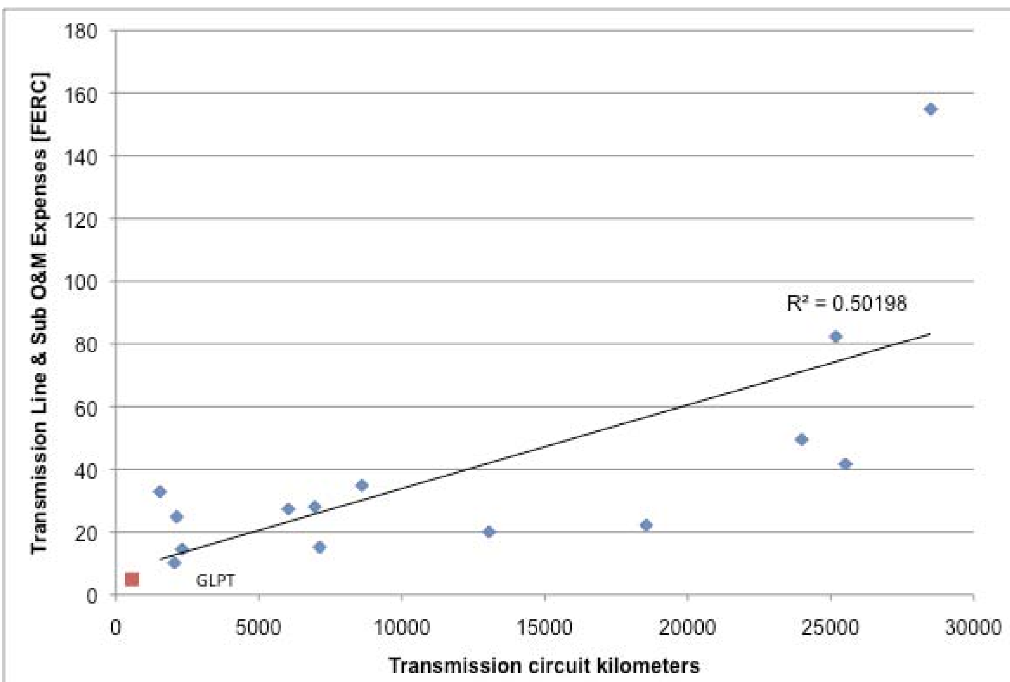
In summary, we have found assets to be the appropriate denominator because it appears to have a higher predictive value when there are big differences in customer density among the panel.

Transmission operators do not really have end-use customers, which is one reason customers is such a weak normalizing factor. Kilometers is also weak because the costs of operating substations are included in the dependent variable and substations are not accounted for when kilometers is used as a normalizing factor.

Shown below are the individual graphs from which the R^2 values are derived. In each graph, GLPT has been added to the graph to show where they fall compared to the other companies, but they are not included in the calculation of the correlation coefficient. 1QC decided that it was appropriate to determine the correlation coefficients independently of GLPT's data. By performing the analysis this way, GLPT's data isn't influencing the findings.



Other correlation charts between expenses and normalizing factors:



Note that the outlier on the circuit kilometers graph is on the regression line when assets are used. This is particularly noteworthy because this company has some of the same characteristics of GLPT, namely low customer density. The density issue is also illustrated on the graph below.

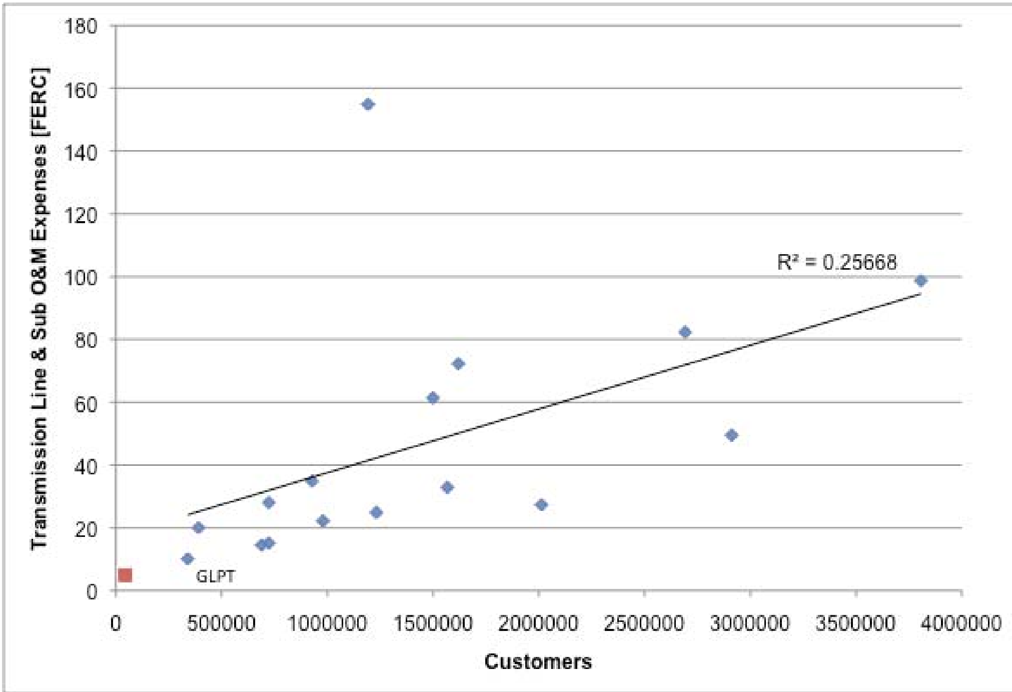


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Exhibit 4, Tab 2, Schedule 2

OM&A Variance Analysis

OM&A VARIANCE ANALYSIS

This section provides year-over-year, quantitative and qualitative analyses of GLPT's OM&A cost variances and applicable cost drivers. This analysis is provided on an account-by-account basis for the period from 2006 (approved and actual) up to and including the 2010 test year.

1.0 Key Drivers

This section highlights the key factors that are driving GLPT's OM&A cost variances from 2009 to the 2010 test year. These drivers are further discussed and referenced, as appropriate, in the detailed year-over-year variance analyses, provided throughout the remainder of this schedule. A numerical summary of these key drivers is presented in **Appendix "A"**.

GLPT will experience an increase in OM&A of $3,111,500 from 2009 to 2010. The increase in OM&A is driven by some 2010 business initiatives and, to a significant extent, by the full year impact of various 2009 initiatives. During 2009, GLPT implemented several initiatives, the financial impact of which were not fully experienced in 2009. This is because a number of the initiatives were implemented throughout the year, resulting in the 2009 OM&A reflecting only a portion of the annual impact. As a result, $1,674,800 (53.84%) of the increase in OM&A from 2009 to 2010 relates directly to items that were initiated in 2009. The remaining $1,436,700 relates to items that will be initiated in 2010. This is presented in columns 1 and 2 of Appendix "A".

Another way of considering the factors giving rise to GLPT's OM&A increase from 2009 to 2010 is to identify the respective portions of the increase that are attributable to (a) natural business growth, (b) the appropriate allocation of costs to GLPT, and (c) costs that are directly related to the separation of the transmission and distribution businesses.

Of the $3,111,500 increase in 2010 OM&A, 82% is directly attributable to the natural business growth of GLPT. This is presented in column 3 of Appendix "A".

With respect to the appropriate allocation of costs to GLPT, in 2010 GLPT will experience an increased allocation percentage relating to the office complex. The increase in the office complex cost allocation is described in Exhibit 4, Tab 2, Schedule 1. The allocation percentage increased from approximately 12% to approximately 55%. As a result, 5% of the $3,111,500 increase in 2010 OM&A relates directly to the increase in cost allocation. This is presented in column 4 of Appendix "A".

With respect to the separation of the transmission and distribution businesses associated with achieving s. 71 compliance, the reorganization eliminated the ability for GLPT to share expenses with the distribution business in respect of General Management and Executive Costs. The increase in General Management and Executive Costs is described in Exhibit 4, Tab 2, Schedule 1. GLPT's organizational structure is appropriate for an organization of its size and all personnel are fully utilized. However, the inability to share General Management and Executive Costs represents 13% of the $3,111,500 increase in 2010 OM&A. This is presented in column 5 of Appendix "A".

Account 4805 – Operations Supervision & Engineering

Table 4-2-2 A - Variance Analysis for Account 4805

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$47.000	$47.000	$404.976	$383.072	$641.536	$384.109
Cost Driver 1		357.976				
Cost Driver 2			(21.904)		(91.675)	122.592
Cost Driver 3				163.813	(201.904)	(6.660)
Cost Driver 4				109.556	11.958	
Other Minor Variances				(14.905)	24.194	(24.517)
Current Year Total	**$47.000**	**$404.976**	**$383.072**	**$641.536**	**$384.109**	**$475.524**

Cost Driver #1 – Reclassification of Costs from Account 5615

The increase in this account between 2006 Approved and 2006 Actual relates to a reclassification of costs. GLPT now classifies all asset management and engineering OM&A costs within this account instead of sharing the costs with account 5615 – General Administrative Salaries. As a result, $357,976 was reclassified from account 5615 to account 4805.

Although there is a cost increase in this account, it is offset by a cost decrease in another account and therefore does not result in incremental OM&A costs for GLPT. The offsetting decrease is reflected in Cost Driver #3 for account 5615.

GLPT believes this classification is more appropriate than the classification used in the 2006 Approved figures.

Cost Driver #2 – Staff

In 2007, GLPT lost one staff member from the engineering department in the latter part of the year, resulting in a reduction in staff costs when compared to 2006 Actual.

In 2009, GLPT lost another employee from its engineering department. Notwithstanding its recruitment efforts, GLPT has had difficulty re-filling the position. This has resulted in further cost reductions from prior historical years.

It is anticipated that, in 2010, GLPT will fill two vacant positions related to the engineering department. This will result in an increase in costs beginning in the test year. The incremental costs demonstrated in the table reflect the impact on GLPT's OM&A costs only.

Cost Driver #3 – Consulting Costs

In 2008, GLPT was forced to retain contractors and consultants for its engineering department in response to the difficulties and delays in replacing staff. These contractors were retained to deal with various day-to-day engineering requirements. In addition, GLPT incurred consulting costs in connection with the formalization of GLPT's use and occupation of First Nation reserve lands.

In 2009, these costs declined for the following reasons:

- Consulting costs related to the *Green Energy Act* and green energy initiatives are now being captured in account 5630; and
- Legal and consulting support related to GLPT's use and occupation of First Nation reserve lands has been reduced by GLPT having filled the position of Director, Legal and Regulatory. The offsetting incremental costs are found in account 5605 – Executive Salaries and Expenses.

Cost Driver #4 – Internal Engineering

In 2008, GLPT's engineering staff spent more time on operations and maintenance activities than capital activity when compared to prior years. It is anticipated that, with the addition of two engineering staff, GLPT will experience the same level of OM&A costs related to internal engineering in the 2010 test year.

<u>Account 4810 – Load Dispatching, and</u>

<u>Account 4845 – Miscellaneous Transmission Expense</u>

Table 4-2-2 B - Variance Analysis for Accounts 4810 and 4845

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$1,314.255	$1,314.255	$1,116.920	$1,201.841	$1,112.819	$1,389.173
Cost Driver 1		(197.335)	84.921	(89.022)		
Cost Driver 2					146.875	421.048
Cost Driver 3					(49.000)	49.000
Cost Driver 4					178.479	178.479
Current Year Total	**$1,314.255**	**$1,116.920**	**$1,201.841**	**$1,112.819**	**$1,389.173**	**$2,037.700**

In EB-2005-0241, GLPL divided its system control and communications costs into these two accounts. The nature of these two activities is quite similar and, therefore, in order to assist the Board in understanding the variances in these accounts, GLPT has combined them and described the variances as though they were derived in a single account.

Cost Driver #1 – Historical Variances

As described in Exhibit 4, Tab 2, Schedule 5, prior to 2009, GLPT shared the Ontario System Control Centre ("OSCC") with all divisions of GLPL. The OSCC was operated outside of the regulated divisions within GLPL and, therefore, the cost borne by the transmission division was an allocation of the overall cost of the OSCC. The methodology for allocating the costs among the divisions did not change between the time of the 2006 Approved and the 2008 Actual figures. The 2006 Approved figure of $1,314,255 was based on the transmission division's share of the 2005 budget for the OSCC. Actual costs in 2006 through 2008 were in fact lower than the budget figure and, as a result, the transmission division was allocated a smaller portion of costs than originally expected.

Cost Driver #2 – Transition to Stand-Alone

The OSCC, as discussed more fully in section 5(c) of Exhibit 4, Tab 2, Schedule 1, is an essential component of GLPT's business as it allows GLPT to operate its business, facilitates emergency response, allows for 24-hour contact as required by the IESO pursuant to the Market Rules, as well as serves important work protection purposes. As part of the separation of GLPL's transmission business from its generation business, the OSCC has transitioned from being a resource for which costs were shared among three business units (GLPL's transmission, distribution and generation divisions) to being a resource for which GLPT is entirely responsible.

GLPT believes that it is essential for it to have full responsibility for the operation of the OSCC. In particular, having control over its system operations enables GLPT to directly ensure its ongoing compliance with the terms and conditions of its Operating Agreement with the IESO and its Connection Facilities Agreement with HONI. Under each of these important agreements, GLPT has obligations and operational responsibilities that can only be fulfilled through the operation of the OSCC by GLPT. As such, GLPT regards system control as being strategically and operationally essential to the business.

In taking on the full responsibility for the OSCC, GLPT also felt that a stand-alone control centre fully under its control would be beneficial as it would not only relieve GLPT of any Affiliate Relationships Code issues that may have arisen as a result of the sharing, but that it would allow GLPT to retain complete control over services. This is important because it allows GLPT to be fully diligent in managing and controlling its assets. Therefore, for the benefit of its directly connected customers, and for the benefit of the reliability of the Ontario transmission grid, GLPT continues to operate the OSCC on a stand-alone basis. In GLPT's opinion, to do otherwise would not provide the utility with the level of due diligence necessary to support an operation of this type and magnitude.

The incremental cost of $421,000 is related to:

- Labour and labour related costs of $328,800; and
- Equipment maintenance and software licensing fees for SCADA of $92,300.

Cost Driver #3 – Staff Replacement

In 2009, an employee of the OSCC retired and the position was not filled for part of 2009. It is anticipated that the position will be filled by the start of 2010, resulting in the costs returning to their historical level.

Cost Driver #4 – Licensing Fees

As described in Exhibit 4, Tab 2, Schedule 1 and Exhibit 4, Tab 2, Schedule 5, GLPT licenses its SCADA equipment and fibre optic equipment from GLPL. Pursuant to a June 30, 2009 agreement, GLPT licenses the SCADA equipment from GLPL at a cost of 50% of the total depreciation cost of the existing equipment, with no return on capital investment. The annual depreciation cost charged to GLPT is approximately $24,500 per month ($294,000 annually). Pursuant to a June 30, 2009 agreement, GLPT licenses the use of a fibre optic network from GLPL at a cost of approximately $5,300 per month ($63,600 annually). As each of these costs are being incurred for the six months of 2009 beginning July 1 with the full twelve month cost being borne in 2010, the increases appear in a staged increment between 2009 and the 2010 test year.

The cost savings arising from licensing this equipment are described in section 3.2.2 of Exhibit 4, Tab 2, Schedule 1. As noted there, if GLPT were to own the equipment, it would bear the full depreciation cost of the equipment, plus the cost of capital. Therefore, GLPT is mitigating its costs in these accounts by licensing the equipment instead of owning it.

<u>Account 4815 – Station Buildings and Fixtures Expense, and</u>

<u>Account 4910 – Maintenance of Transformer Station Buildings and Fixtures</u>

Table 4-2-2 C - Variance Analysis for Accounts 4815 and 4910

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$442.653	$442.653	$249.262	$271.087	$276.411	$652.182
Cost Driver 1		(68.610)	(41.352)	(40.038)		50.000
Cost Driver 2		(123.771)	26.334	72.650	(0.990)	30.686
Cost Driver 3			37.975	(22.423)	42.414	96.822
Cost Driver 4		(1.710)	(1.132)	2.502	250.711	54.671
Cost Driver 5					84.878	85.726
Other Minor Variances		0.700		(7.367)	(1.241)	8.452
Current Year Total	**$442.653**	**$249.262**	**$271.087**	**$276.411**	**$652.182**	**$978.539**

The nature of the activities in these two accounts is quite similar and, therefore, in order to assist the Board in understanding the variances in these accounts, GLPT has combined them and described the variances as though they were derived in a single account.

Cost Driver #1 – Land Remediation Costs

The 2006 Board Approved figure included $150,000 related to land remediation projects at various transmission stations in GLPT's service territory. Actual land remediation expenditures in 2006 through 2009 were lower than this. In 2010, GLPT will spend $50,000 on land remediation projects.

Cost Driver #2 – Labour & Expenses

The 2006 Actual expenditures in these accounts were lower than the approved amount due to delayed staff replacements, decreases in snow removal and road maintenance, as well as a decrease in utility costs and fence and building repairs. However, as staff was added and stabilized through 2007 and 2008, the level of costs increased towards the approved level. In 2010, GLPT expects the costs to return to the level they were approved at for 2006.

Cost Driver #3 – MacKay Road Maintenance

In order to access MacKay TS, GLPT must travel approximately 14 kilometers off of Highway 17N, north of Sault Ste. Marie. The road is used only by GLPT to access the transmission station and by GLPL to access various generating stations in the area. All costs related to maintaining this road, including during both summer and winter, are shared between GLPL and GLPT.

The cost of the road maintenance contract is allocated between GLPT and GLPL based on the length of road used by each company. As a result of this means of allocation, GLPT bears 30% of the total contract costs. In 2009, the contract for maintenance of this road was re-tendered, and the cost of the maintenance has increased for 2009 (partial year impact) and 2010 (full-year impact) as a result..

Cost Driver #4 – Allocation of Building Operational Costs at 2 Sackville Rd.

Beginning in 2009, GLPT is bearing additional costs related to the office complex occupied by GLPT. Up to and including 2008, GLPT assumed approximately 12% of the costs related to the office building. GLPT has determined that this allocation was not an accurate allocation because the costs associated with the use of office space by staff who performed functions for transmission and distribution was generally allocated to the distribution business. As such, there was an historical under-allocation of building costs to the transmission business. Moreover, GLPT has required additional space to provide a functional work environment for its staff, as well as to accommodate modest staff increases in future. With the split of GLPT from GLPL's distribution division, GLPT's employees have relocated within the complex to a more appropriately sized area. GLPT occupies this space on a stand-alone basis. All employees, equipment and assets in GLPT's space are dedicated 100% to transmission. As a result of the more accurate allocation of costs, the need for increased space and the relocation of GLPT within the complex, the allocation of office complex costs to GLPT increased by 30.4%.

In addition, GLPT is responsible for the space occupied by the Ontario System Control Centre at 2 Sackville Rd. Historically, this portion of the cost was allocated to GLPL's Generation division, as they occupied the portion of the building with the Control Centre and operated the Control Centre. As a result of GLPT becoming the main operator of the

Ontario System Control Centre, the office space allocation to GLPT increased by an additional 12.6%.

As a result of these changes, GLPT is now responsible for approximately 55% of the costs of the complex, resulting in incremental costs in both 2009 and 2010.

Cost Driver #5 – Building Lease Costs at 2 Sackville Road

As described in Exhibit 4, Tab 2, Schedule 5, GLPT is now assuming costs related to leasing the office complex at 2 Sackville Road. The office complex and yard are owned by GLPL and, pursuant to a lease dated July 1, 2009, GLPT leases it in its entirety from GLPL. The lease amount was established based on the middle of the range of fair market rentals for triple net leases as assessed by an independent real estate appraiser that had been retained. Pursuant to a sublease dated July 1, 2009, GLPT subleases one of the two separately defined structures in the office complex, along with various common areas and half of the industrial space, to Algoma Power Inc. through a triple net lease at an annual rent based on the same cost per square foot as paid by GLPT. The net rental cost of the building and property to GLPT is equal to $169,755 per year, adjusted annually by increases in CPI. As the lease was effective on July 1, 2009, half the incremental amount is reflected in 2009, and the other half is reflected in 2010.

<u>Account 4820 – Transformer Station Equipment – Operation Labour,</u>

<u>Account 4825 – Transformer Station Equipment – Operations Supplies & Expenses,</u>

<u>Account 4916 – Maintenance of Transformer Station Equipment</u>

Table 4-2-2 D - Variance Analysis for Accounts 4820, 4825 and 4916

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$727.208	$727.208	$637.080	$706.498	$755.423	$932.451
Cost Driver 1		(90.128)	69.418	48.925	177.028	53.187
Cost Driver 2						75.000
Current Year Total	**$727.208**	**$637.080**	**$706.498**	**$755.423**	**$932.451**	**$1,060.638**

The nature of the activities in these three accounts is quite similar and, therefore, in order to assist the Board in understanding the variances in these accounts, GLPT has combined them and described the variances as though they were derived in a single account.

Cost Driver #1 – Program Implementation

Over the last few years, GLPT has developed a broader and more comprehensive maintenance program which enhances its ability to properly maintain its assets so as to maximize their useful life and meet all reliability requirements. As a result of completing its 2009 maintenance plan, together with the expected completion of its 2010 maintenance plan, GLPT has spent additional time and resources on operating and maintaining its transmission station equipment.

The incremental costs related to the implementation of this program are reflected in these three accounts, which relate to labour, contracts, materials and other costs.

For additional information on maintenance activities and their frequencies, please refer to Exhibit 2, Tab 5, Schedule 1.

Cost Driver #2 – Major Maintenance Project

GLPT plans to repair a leak on a transformer at Northern Avenue TS in 2010. Spill containment is currently in place at the station, mitigating any potential environmental impact in the short term. However, the repair needs to take place to avoid risks of future impacts. The cost of this repair is estimated to be $75,000 in 2010.

Account 4830 – Overhead Line Expense,

Account 4930 – Maintenance of Poles, Towers & Fixtures, and

Account 4935 – Maintenance of Overhead Conductors and Devices

Table 4-2-2 E - Variance Analysis for Accounts 4830, 4930 and 4935

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$245.565	$245.565	$234.233	$300.340	$449.525	$224.909
Cost Driver 1		(27.813)	(7.080)	35.610	(48.515)	5.717
Cost Driver 2		16.481	73.187	28.749	(91.275)	112.744
Cost Driver 3				84.826	(84.826)	60.000
Current Year Total	**$245.565**	**$234.233**	**$300.340**	**$449.525**	**$224.909**	**$403.370**

The nature of the activities in these three accounts is quite similar and, therefore, in order to assist the Board in understanding the variances in these accounts, GLPT has combined them and described the variances as though they were derived in a single account.

Cost Driver #1 – Outage Restoration

Outage restoration is a cost that fluctuates based on various factors that are beyond GLPT's control, such as weather conditions. Over the period of 2006 to 2010, GLPT's outage restoration costs have decreased by over $40,000 on an annual basis as of 2010 as a result of Right of Way maintenance and other maintenance activities, demonstrating the

(a) positive reliability impacts of such proactive maintenance measures.

Cost Driver #2 – Regular Operations and Maintenance

Regular line maintenance has progressively increased over the period of 2006 to 2010, with the exception of 2009. A reduction in spending for this program was made in response to the significant decline in actual revenues for 2009 as compared to anticipated revenues. This was a one-time reduction made in response to unique circumstances. As a result of this one-time reduction, a portion of the 2009 line maintenance work and the associated expenses have been moved forward and will be completed over the next 2-3 years. GLPT is confident that it has been able to make this one-time reduction in spending without significant impacts to the system in future years.

Cost Driver #3 – Major Maintenance Projects

The increase in 2008 is related to an insulator replacement project. In 2009, GLPT performed fewer major maintenance projects. GLPT plans to complete an infrared scan project in 2010 at a cost of $60,000.

Account 4850 – Rents

Table 4-2-2 F - Variance Analysis for Account 4850

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$48.000	$48.000	$53.209	$60.507	$89.249	$70.716
Cost Driver 1		5.209	7.298	(3.743)	(2.547)	1.672
Cost Driver 2				32.485	(15.986)	8.500
Current Year Total	**$48.000**	**$53.209**	**$60.507**	**$89.249**	**$70.716**	**$80.888**

Cost Driver #1 – Variances in Land Lease Payments

Over the past several years, GLPT's land lease costs have fluctuated. This has resulted in minor variations in this account.

Cost Driver #2 – Lease Reviews

GLPT has incurred incremental expenses in this account related to the management of its existing land leases. Also included in this cost driver are the costs associated with administering GLPT's use and occupation permits on First Nation reserve lands.

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Account 4940 – Maintenance of Overhead Lines – Right of Way

Table 4-2-2 G - Variance Analysis for Account 4940

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$600.000	$600.000	$794.905	$851.053	$1,400.829	$1,102.717
Cost Driver 1		194.905	56.148	549.776	99.171	300.000
Cost Driver 2					(397.283)	397.283
Current Year Total	**$600.000**	**$794.905**	**$851.053**	**$1,400.829**	**$1,102.717**	**$1,800.000**

Cost Driver #1 – Various Drivers

The variances in this account are described in section 5(a) of the OM&A Overview section (Exhibit 4, Tab 2, Schedule 1). As noted in that section, the cost increases are driven primarily by the following:

- New and more stringent reliability requirements from IESO and NERC, including expectations with respect to vegetation management;

- Increased program scope, including greater efforts to complete all right-of-way maintenance activities on a 6-year cycle through enhanced processes for brush removal on right-of-way floors, increased efforts to re-establish and maintain right-of-way edges and improved strategies for vegetation management in buffer zones along the rights-of way;

- New pesticide regulations affecting the spraying of the rights-of-way; and
- New species at risk legislation affecting GLPT's vegetation management activities in its rights-of-way, parts of which provide habitat for species at risk.

Cost Driver #2 – Scope Reduction

As noted in the variance analysis of the line operations and maintenance expenses, GLPT is experiencing a deficiency in revenue in 2009 and, as a result, the company has adjusted spending on various major maintenance projects. GLPT reduced spending on ROW maintenance by $397,283 in 2009 as a one-time reduction in response to this decrease. As indicated, it was decided that, for reliability purposes, GLPT needs to restore its prior level of activity in the area of ROW maintenance for 2010 and beyond.

Account 4945 – Maintenance of Overhead Lines – Roads and Trails Repairs

Table 4-2-2 H - Variance Analysis for Account 4945

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$0.000	$0.000	$0.000	$0.000	$103.243	$103.800
Cost Driver 1				103.243		
Other Minor Variances					0.557	6.200
Current Year Total	**$0.000**	**$0.000**	**$0.000**	**$103.243**	**$103.800**	**$110.000**

Cost Driver #1 – Introduction of Program

As noted in Exhibit 1, Tab 2, Schedule 1, GLPT's transmission lines run through rugged terrain in northern Ontario and many of its lines are in areas where accessibility is extremely difficult. Many of these areas are isolated and far from public roads or highways. As a result, when preparing its 2008 budget, GLPT determined that it would be beneficial and appropriate to dedicate a certain level of funding to the maintenance of access roads and trails.[1] Proper maintenance of such access routes allows GLPT more efficient access to its lines for vegetation management, visual inspections, as well as for emergency response.

GLPT has determined that dedicating funding specifically to this activity has been productive and useful, and in all respects has proven to be a worthwhile venture. As a

[1] Access roads and trails are the means by which GLPT accesses its Rights of Way and transmission lines.

(a) result, GLPT has included a provision for this maintenance in the 2010 test year.

Account 5605 – Executive Salaries and Expenses

Table 4-2-2 I - Variance Analysis for Account 5605

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$486.513	$486.513	$427.788	$401.311	$403.361	$499.711
Cost Driver 1		(154.400)	(19.000)	(79.700)	(133.400)	-
Cost Driver 2		68.000	(12.309)	44.992	146.593	346.584
Cost Driver 3		6.500	8.920	24.028	58.778	(55.919)
Cost Driver 4		21.175	(4.088)	12.730	24.379	(24.419)
Cost Driver 5						436.713
Cost Driver 6						(100.000)
Current Year Total	**$486.513**	**$427.788**	**$401.311**	**$403.361**	**$499.711**	**$1,102.670**

Cost Driver #1 – Ontario Operations

Ontario Operations represents costs related to corporate health, safety and environmental support, corporate pension and human resource management, and costs related to the Vice President responsible for Ontario Operations. All of these costs were collected at the corporate level and allocated to the transmission division of GLPL. As a stand-alone entity, GLPT no longer receives the benefit of these services from Brookfield Renewable Power's corporate level and, therefore, beginning in 2009, GLPT is no longer responsible for a share of the cost of these services.

The elimination of Ontario Operations required GLPT to add resources in other areas of the company. Specifically, some of the offsets are:

- An increase in pension administration costs described in Cost Driver #4 of account 5630;
- An increase in health and safety costs, which are now provided in-house, as described in Cost Driver #1 of account 5615 (2009-2010);
- An increase in senior management costs with the addition of a cost allocation for part of the costs associated with the parent company's Chief Operating Officer responsible for North American Transmission, as described in Cost Driver #2 of this account; and
- An increase in other labour costs with the addition of a Director of Administration and a Director of Legal and Regulatory, as described in Cost Driver #2 of this account.

Cost Driver #2 – Labour & Related Costs

This account increased in 2008 as a result of the hiring of a Director of Administration. In 2009, the costs increased as a result of the full year impact of the Director of Administration, as well as the addition of a Director of Legal and Regulatory. The incremental costs related to the addition of a Director of Legal and Regulatory are offset in part by a decrease in costs experienced in account 4805 (Cost Driver #3), and a decrease in costs experienced in account 5630 (Cost Driver #1).

As part of its management team, GLPT's Director of Administration's duties include directing the finance, accounting, treasury, tax, regulatory, IT and human resource functions of the business. GLPT's Director of Legal and Regulatory has been hired to advise the company in the area of Aboriginal law, support the company in developing and maintaining strong relationships with relevant Aboriginal groups, as well as to advise and provide legal services associated with regulatory matters, including rate applications and Board consultation processes of strategic interest to GLPT. The specific responsibilities for each of these positions are more fully described in section 5(b) of Exhibit 4, Tab 2, Schedule 1.

GLPT's 2010 costs in this account will increase due to several changes at its senior management level. The account will, in 2010, reflect 50% of the cost of the parent company's Chief Operating Officer responsible for North American Transmission. This position will generally take the place of the role formerly played by the Vice President responsible for Ontario Operations (see Cost Driver #1 for this account). The responsibilities of the Chief Operating Officer are to develop and approve GLPT's strategic plan, approve the annual budget and capital expenditure program, hire and oversee and monitor performance of GLPT's senior management team, provide executive support for regulatory initiatives, provide leadership for transmission development activities, as well as to provide partner oversight over GLPT. The duties and responsibilities of the Chief Operating Officer are more fully described in section 5(b) of Exhibit 4, Tab 2, Schedule 1.

In 2010, the costs in this account will also increase as a result of GLPT reflecting the cost of a Vice President, Project Development. Primarily as a result of the introduction of the *Green Energy and Green Economy Act* ("GEGEA") and related initiatives, GLPT has identified an important need for the business to focus on transmission development needs and opportunities. To guide GLPT in its efforts to support the province's transmission development objectives, GLPT's management team now includes a Vice President responsible for Project Development. The responsibilities associated with this position are to lead GLPT's focus on transmission development needs and opportunities arising from the *Green Energy and Green Economy Act*, to lead and guide GLPT in its efforts to support the province's transmission development objectives, including the development and implementation of its expansion and reinforcement plan, contribute to the planning process that will give rise to potential First Nation and Métis consultations, lead First Nation and Métis consultations, and pursue partnerships for transmission development with HONI. The duties associated with this position are more fully described in sections 5(b) and (f) of Exhibit 4, Tab 2, Schedule 1.

Cost Driver #3 – Travel & Conference Fees

GLPT incurred an increase in travel costs between 2007 and 2009 related primarily to the transfer of transmission assets to GLPT and the activity related to GLPT becoming a stand-alone entity. It is anticipated that these costs will decline in 2010 as the need for travel will decrease.

Cost Driver #4 – Miscellaneous Costs

Miscellaneous costs include, but are not limited to, consulting, office supplies, telephone expenses, employee recognition expenses and vehicle expenses. The increase from 2007 to 2009 relates primarily to Human Resource consulting, as well as additional telephone and supply expenses for added employees. The decrease between 2009 and 2010 relates primarily to a reduction in consulting costs that are no longer required due to the addition of the Director of Administration and the Director of Legal and Regulatory.

Cost Driver #5 – Cost Re-Allocation

As described more fully in section 5(b) of Exhibit 4, Tab 2, Schedule 1, GLPT has established a corporate structure with an executive and management team that is reasonably sized, reflective of the overall company needs and structure, and which includes the appropriate level of experience and expertise for a stand-alone transmission utility of the size and nature of GLPT. GLPT has a wide range of business needs, including obligations to outside stakeholders, operations, maintenance, capital investment, regulatory responsibilities, human resources, financial management, legal, environmental, health and safety and IT. The management team that will be in place for

2010 is appropriately structured to provide effective and efficient management for this wide range of business activities that are necessary for running an Ontario-based transmission utility that is responsible for a system that forms part of the bulk electricity system in the province.

Establishing GLPT as an owner and operator of its transmission system has resulted in a reallocation of existing costs, different from what was established in EB-2005-0241. GLPT is now responsible for the full cost of the management team related to the transmission business. This includes a management team with positions historically existing within the corporate structure, as well as with the new positions referred to in Cost Driver #2. Having a management team fully dedicated to transmission will enable GLPT on a go-forward basis to find efficiencies and synergies in addressing the foregoing needs.

Cost Driver #6 – Office Supplies and Expenses Reclassification

These executive costs were classified as a lump sum in account 5605. GLPT incurs office supplies expenses directly and therefore allocates those costs to account 5620. The costs in this account reflect a decrease. The offsetting increase is reflected in Cost Driver #1 of account 5620.

Account 5615 – General Administrative Salaries and Expenses

Table 4-2-2 J - Variance Analysis for Account 5615

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$1,471.695	$1,471.695	$1,019.374	$1,056.608	$988.574	$1,230.753
Cost Driver 1		(147.557)	19.249	73.100	258.921	43.277
Cost Driver 2		116.681				
Cost Driver 3		(357.976)				
Cost Driver 4		(63.469)	3.693	(173.544)	(1.180)	
Cost Driver 5						(105.725)
Cost Driver 6						(199.115)
Cost Driver 7						298.587
Other Minor Variances			14.292	32.410	(15.562)	18.201
Current Year Total	**$1,471.695**	**$1,019.374**	**$1,056.608**	**$988.574**	**$1,230.753**	**$1,285.978**

Cost Driver #1 – Administrative Support Programs

When discussing administrative support programs, GLPT is referring to the following programs:

- Accounting;
- Environment;
- Information Technology ("IT");

10183959.1
35306-2001

- Planning and Maintenance Services; and
- Health and Safety.

2006 Approved to 2006 Actual:

The decrease in costs in 2006 Actual compared to 2006 Approved relates primarily to organizational changes in the planning and maintenance program, and in the environmental program.

2006 Actual to 2007 Actual:

The increase between 2006 and 2007 is related primarily to consulting services in the planning and maintenance program, and an increase in IT consulting contracts. As noted below, these IT costs were one-time costs that were not experienced in 2008.

2007 Actual to 2008 Actual:

In 2008, the primary driver for the increase in costs was in the accounting department. Prior to 2008 the department was operating with a number of temporary staff. Given the increasing reporting and record keeping requirements (both regulatory and financial) driven by *Sarbanes–Oxley* driven reforms and internal reporting requirements, GLPT was required to bring in additional staff to get the department to the level it needed to be at to operate efficiently.

In addition to the change in the accounting department, costs related to health and safety increased slightly as a result of the hiring of a Health and Safety Specialist to be shared between transmission and distribution. The company required this position as it was no longer receiving support from the Ontario Operations division of GLPL. The offsetting decrease in costs is reflected in account 5605.

Another minor increase was experienced in 2008 as a result of GLPT requiring a letter of credit. The letter of credit is related to GLPT's interest payable on the outstanding third party debt, and resulted in an increase of approximately $14,000 in 2008.

These increases were offset in part by a decrease in IT consulting contract costs compared to 2007.

2008 Actual to 2009 Bridge:

In 2009, GLPT will experience a slight increase as a result of the full year impact of the staffing changes in the accounting department and in the health and safety department. This increase is fully offset by a decrease in the planning and maintenance department, which is operated on a much smaller scale in the stand-alone transmission business.

A minor increase was experienced in 2009 as a result of the full year impact of the letter of credit required by GLPT with respect to interest payable. The impact in 2009 will be approximately $15,000.

The overall increase between the 2008 actual costs and the 2009 bridge year costs relates to IT costs. As explained in section 5(d) of Exhibit 4, Tab 2, Schedule 1, there are a number of fixed costs associated with IT for which GLPT must now bear full responsibility. These include licence fees, IT infrastructure costs, software costs, as well as some employee costs. These costs are necessary to support GLPT's IT systems, which are an essential component of the business. Some of these additional IT costs are associated with the implementation of system wide cyber security requirements, the details of which are described in the confidential filing at Exhibit 2, Tab 1, Schedule 3.

2009 Bridge to 2010 Test Year:

In 2010, GLPT will experience an increase in costs related to its health and safety program as a result of the organizational changes which caused GLPT to take responsibility for all costs of the health and safety program. As an efficiency measure, this position will hold responsibility for GLPT's environmental program as well. This increase is partially offset by a decrease in costs expected in Cost Driver #1 of Account 5605.

GLPT's IT costs will also increase in 2010 as a result of the full year impact of the organizational changes that have taken place. In addition, as noted above, GLPT is subject to cyber security requirements that require additional training, software security and labour to address. The cyber security requirements are described in greater detail in the confidential filing at Exhibit 2, Tab 1, Schedule 3.

Cost Driver #2 – Consulting & Contract Costs

GLPT's 2006 Approved figure includes costs related to supervision and engineering. As a result of staffing adjustments in 2006, GLPT experienced an increase in consulting and contract costs. These costs related primarily to the engineering costs that were approved in this account.

As noted for Cost Driver #3 below, these costs were ultimately re-classified to account 4805 and any further variances in operational supervision and engineering costs are described in the analysis of that account.

Cost Driver #3 – Reclassification to Account 4805

The reason for the decrease in this account between 2006 Approved and 2006 Actual relates to the reclassification of costs by GLPL. Rather than sharing asset management and engineering OM&A costs with Account 5615, GLPL reclassified these cossts to be entirely within Account 4805. As a result, $357,976 has been reclassified from account 5615 to account 4805.

Although there was a cost decrease in this account, it was offset by a cost increase in another account and therefore did not result in a change in overall OM&A. The offsetting driver is reflected in Cost Driver #1 for Account 4805. This classification is more appropriate than the classification used in the 2006 Approved figures.

Cost Driver #4 – Meter Service Provider Costs

Costs fluctuated between 2006 Approved and 2008 as a result of variances in costs related to being a meter service provider. As of 2008, GLPL no longer acted as a meter service provider for any customer meter points and, as such, the costs related to this activity reduced to $0. Exhibit 9, Tab 1, Schedule 3 discusses the true-up of historical costs related to GLPL acting as a meter service provider.

Cost Driver #5 – Office Supplies and Expenses Reclassification

These costs were classified as a lump sum in account 5615. GLPT incurs office supplies expenses directly and, as such, allocates these costs to account 5620. The cost decrease in this account is entirely offset by a cost increase in account 5620 (Cost Driver #1).

Cost Driver #6 – Outside Services Reclassification

These costs were classified as a lump sum in account 5615. GLPT incurs outside services costs for administrative support programs directly and, as such, allocates these costs in account 5630. The cost decrease in this account is therefore offset by a cost increase in account 5630.

Cost Driver #7 – Corporate Cost Allocation

As described in section 5(b) of Exhibit 4, Tab 2, Schedule 1, beginning in 2010 GLPT will bear a corporate allocation cost. This corporate cost allocation is for the costs of certain corporate functions that GLPT's parent will share with GLPT. These functions include senior executive support, tax filing preparation, as well as treasury and financing services. These functions, it should be noted, are incremental to any such functions carried out by members of GLPT's own executive team. GLPT did not seek recovery of these costs in EB-2005-0241. The costs for these services are reasonable. The allocations reflect direct costs for shared corporate services. For services that could be sourced externally, these functions are provided at a cost that is less than if these services were sourced externally.

<u>Account 5620 – Office Supplies and Expenses</u>

Table 4-2-2 K - Variance Analysis for Account 5620

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000
Cost Driver 1						105.725
Cost Driver 2						100.000
Cost Driver 3						74.465
Current Year Total	**$0.000**	**$0.000**	**$0.000**	**$0.000**	**$0.000**	**$280.190**

Cost Driver #1 – Reclassification of General Administration Expenses

These costs were classified as a lump sum in account 5615. GLPT incurs office supplies expenses and other expenses directly and, therefore, allocates those costs to account 5620. The offsetting decrease in costs is discussed in Cost Driver #5 of account 5615.

Cost Driver #2 – Reclassification of Management & Executive Expenses

These costs were classified as a lump sum in account 5605. GLPT incurs office supplies and other expenses directly and, as such, allocates those costs to account 5620. The offsetting decrease in costs is discussed in Cost Driver #6 of account 5605.

Cost Driver #3 – Industry Relations

Travel and other costs are incurred in dealing with OPA initiatives, OEB proceedings and consultations, Canadian Electricity Association matters and government relations, First Nation and Métis community relations, as well as other industry and stakeholder relations. These costs are expected to increase in 2010 as a result of the various developments ongoing in the electricity industry in Ontario. This level of regulatory activity, relevant to GLPL's transmission business, was not present in 2005 when GLPL filed its most recent transmission rate application.

Account 5630 – Outside Services Employed

Table 4-2-2 L - Variance Analysis for Account 5630

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$234.640	$234.640	$438.762	$553.362	$675.588	$1,010.000
Cost Driver 1		204.122	(333.843)	210.786	218.598	(70.000)
Cost Driver 2			352.626	(63.763)	(128.166)	5.000
Cost Driver 3			72.154	(41.390)	174.236	(47.000)
Cost Driver 4					100.000	(50.000)
Cost Driver 5						199.115
Other Minor Variances			23.663	16.593	(30.256)	15.000
Current Year Total	**$234.640**	**$438.762**	**$553.362**	**$675.588**	**$1,010.000**	**$1,062.115**

Cost Driver #1 – Legal Fees

Legal fees in 2006 were higher than the approved amount as a result of legal work related to amendments to the Transmission System Code, wrap-up of the GLPL 2005 transmission rate proceeding, as well as the development of a MAAD application filed for the purpose of selling transformer assets to Algoma Steel Inc. In 2007, legal fees decreased as GLPL transmission was engaged in fewer activities requiring legal support. In 2008 and 2009 however, legal fees have increased primarily due to the following items:

- Preparation of this rate application;

- Filing of a licence application as a result of the expiry of GLPL's transmission licence; and
- Interpretation of Ontario legislation.

Legal fees are expected to decrease in 2010 as a result of having a Director of Legal and Regulatory on staff for the full year.

Cost Driver #2 – Audit Fees

Audit fees are the basis for the majority of the increase from 2006 Approved to 2007 Actual. GLPL's allocation of the total corporate audit fees was artificially low prior to 2007. Upon review of the allocation, it was determined that the allocation to the transmission business should be increased to reflect the actual cost incurred on behalf of the transmission business.

Audit fees during 2007 and 2008 were higher as a result of quarterly reviews completed in preparation for the transmission asset transfer on March 12, 2008. In 2009, the audit fee expense has decreased to the appropriate level.

Cost Driver #3 – OEB Proceedings & Smart Grid Development

This cost driver relates to the costs of consultants retained to assist GLPT in its participation in various OEB proceedings and consultation processes, such as the Connection Cost Responsibility Review (EB-2008-0003), the Integrated Power System

Plan ("IPSP") review (EB-2007-0707), the consultation process on the regulatory treatment of infrastructure investments (EB-2009-0152) and the consultation process on the regulatory treatment of infrastructure investments (EB-2009-0152) and the Cost of Capital proceeding (EB-2009-0084). Other 2009 costs relate to external support in investigating impacts of the *Green Energy Act* and related green energy initiatives in Ontario. The increases in 2009 are partially offset by a decrease described in Cost Driver #3 of Account 4805.

As a prudent, licenced transmitter in Ontario, GLPT has a responsibility and an obligation to participate in certain consultations and proceedings initiated by the Board. In addition, it is GLPT's responsibility to be prepared for the development of renewable generation and to allow for the timely connection of such projects as they are developed. In order to fulfill this responsibility, GLPT needs to stay abreast of relevant developments in the industry and with the plans of potential developers of renewable generation facilities. By establishing and filling the positions of Vice President for Project Development and Director of Legal and Regulatory, as well as through the transmission-focused executive management provided by the Chief Operating Officer responsible for North American Transmission, GLPT is fulfilling this obligation, and at the same time has been able to reduce external consulting costs.

Cost Driver #4 – Pension Administration

This cost driver relates to the cost of retaining Mercer Human Resources Ltd. to act as an actuary for GLPL's and GLPT's pension plan. In 2009, GLPT's costs related to the plan were higher as a result of splitting the GLPL plan into three distinct plans, one for the generation business, one for the distribution business and one for the transmission business. A new actuarial report was prepared for this purpose and there was an increase in general consulting costs as well. In 2010, it is anticipated these costs will decrease. The overall cost increase in this account is offset in part by a decrease in Ontario Operations costs as described in Cost Driver #1 of account 5605.

Cost Driver #5 – Reclassification of General Administration Contracts

These costs for outside services, to support general administrative programs, such as accounting, IT, health and safety and environmental, were classified as a lump sum in account 5615. GLPT incurs these costs directly and, therefore, allocates these costs to account 5630. The 2010 increase in this account is offset by the decrease in account 5615 (Cost Driver #6).

Account 5635 – Property Insurance

Table 4-2-2 M - Variance Analysis for Account 5635

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$142.400	$142.400	$116.430	$116.353	$115.105	$177.248
Cost Driver 1		(25.970)	(0.077)			
Cost Driver 2					50.170	13.699
Cost Driver 3					11.973	20.553
Other Minor Variances				(1.248)		
Current Year Total	**$142.400**	**$116.430**	**$116.353**	**$115.105**	**$177.248**	**$211.500**

Cost Driver #1 – Comprehensive General and Umbrella Liability

The 2006 Board Approved insurance expense was based upon the 2004 actual expense adjusted for a small increase for inflation. However, the actual insurance costs in 2006 were significantly less as a result of comprehensive general liability and umbrella liability premiums decreasing. This was offset in part by a small increase in property insurance premiums.

Cost Driver #2 – Property Insurance

In 2009, GLPT's assets were re-assessed from an insurance perspective and, as a result, GLPT's premiums increased. This was experienced for most of 2009 and all of 2010.

Cost Driver #3 – Fleet and Professional Services Insurance

GLPT acquired a fleet of transportation and work vehicles from GLPL in 2009. The total vehicle insurance premiums are expected to be approximately $20,000 in 2010, with the incremental costs experienced in both 2009 (half year) and 2010 (full year).

In addition, the total Errors and Omissions insurance premiums with respect to GLPT's professional engineering staff are expected to be approximately $12,000 in 2010.

Account 5655 – Regulatory Expenses

Table 4-2-2 N - Variance Analysis for Account 5655

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$148.120	$148.120	$148.599	$167.426	$153.595	$163.295
Cost Driver 1			18.827	(13.831)	9.700	
Other Minor Variances		0.479				(6.295)
Current Year Total	**$148.120**	**$148.599**	**$167.426**	**$153.595**	**$163.295**	**$157.000**

Cost Driver #1 – OEB Fees

Regulatory expenses include OEB fees, as well as Canadian Electricity Association fees.

GLPT has experienced minor variations in OEB fees over the past several years.

However, it is not anticipated that the 2010 regulatory expenses will vary significantly from the 2006 Approved expenses.

Account 5665 – Miscellaneous General Expense

Table 4-2-2 O - Variance Analysis for Account 5665

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$0.000	$0.000	$0.000	$0.000	$15.301	$30.000
Cost Driver 1				15.301	14.699	6.500
Current Year Total	**$0.000**	**$0.000**	**$0.000**	**$15.301**	**$30.000**	**$36.500**

Cost Driver #1 – Treasury Costs

The costs in this account are treasury costs related to GLPT's outstanding third party debt. Prior to the creation of GLPT, GLPL's non-regulated division bore the full cost related to the third party debt, thereby providing a benefit that ratepayers would not have otherwise received. On March 12, 2008, GLPT became wholly responsible for its own debt covenants and treasury costs. Although GLPT's debt comes at a small incremental cost to rate-payers, there are many benefits to having its own Deed of Trust. These benefits include, but are not limited to:

- GLPT no longer being tied to an unregulated (and therefore higher risk) entity when considering debt ratings, which affects the interest rate that GLPT is able to borrow at;

- Since GLPT is no longer tied to the unregulated entity, the company is not exposed to any potential defaults in bond covenants resulting from the unregulated business; and

- As a result of becoming wholly responsible for its own debt covenants and treasury bonds, GLPT was able to negotiate a Deed of Trust, having some covenants in the favour of GLPT.

Account 5680 – Electrical Safety Authority Fees

Table 4-2-2 P - Variance Analysis for Account 5680

OM&A	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Previous Year Total	$19.000	$19.000	$19.550	$20.136	$21.363	$23.000
Other Minor Variances		0.550	0.586	1.227	1.637	-
Current Year Total	**$19.000**	**$19.550**	**$20.136**	**$21.363**	**$23.000**	**$23.000**

GLPT is only anticipating an increase of $4,000 from the 2006 Approved amount of $19,000. This increase is outside of GLPT's control.

APPENDIX "A"

Numerical Summary of Key Drivers of 2009-2010 Variance

OM&A	2010 Test Year	2009 Decision	Natural Growth	Allocation	Split	Total
4805 - Operation Supervision & Engineering						
Cost Driver 2	122.59		122.59			122.59
Cost Driver 3	(6.66)		(6.66)			(6.66)
Other Minor Variances	(24.52)		(24.52)			(24.52)
4810 & 4845 - Load Dispatching & Communications						
Cost Driver 2	421.05	421.05	421.05			421.05
Cost Driver 3	49.00		49.00			49.00
Cost Driver 4	178.48	178.48	178.48			178.48
4815 & 4910 - Station Buildings and Fixtures Expenses and Maintenance						
Cost Driver 1	50.00		50.00			50.00
Cost Driver 2	30.69		30.69			30.69
Cost Driver 3	96.82	96.82	96.82			96.82
Cost Driver 4	54.67	54.67		54.67		54.67
Cost Driver 5	85.73	85.73		85.73		85.73
Other Minor Variances	8.45		8.45			8.45
4820 & 4825 & 4916 - Transformer Station Equipment O & M						
Cost Driver 1	53.19	53.19	53.19			53.19
Cost Driver 2	75.00		75.00			75.00
4830 & 4930 & 4935 - Overhead Line Maintenance and Expenses						
Cost Driver 1	5.72		5.72			5.72
Cost Driver 2	112.74		112.74			112.74
Cost Driver 3	60.00		60.00			60.00
4850 - Rents						
Cost Driver 1	1.67		1.67			1.67
Cost Driver 2	8.50		8.50			8.50
4940 - Maintenance of Overhead Lines - Right of Way						
Cost Driver 1	300.00	300.00	300.00			300.00
Cost Driver 2	397.28	397.28	397.28			397.28
4945 - Maintenance of Overhead Lines - Roads and Trails Repairs						
Other Minor Variances	6.20		6.20			6.20
5605 - Executive Salaries and Expenses						
Cost Driver 2	346.58	17.58	346.58			346.58
Cost Driver 3	(55.92)		(55.92)			(55.92)
Cost Driver 4	(24.42)		(24.42)			(24.42)
Cost Driver 5	436.71	70.00	70.00		366.71	436.71
Cost Driver 6	(100.00)		(100.00)			(100.00)
5615 - General Administrative Salaries and Expenses						
Cost Driver 1	43.28				43.28	43.28
Cost Driver 5	(105.73)		(105.73)			(105.73)
Cost Driver 6	(199.12)		(199.12)			(199.12)
Cost Driver 7	298.59		298.59			298.59
Other Minor Variances	18.21		18.21			18.21
5620 - Office Supplies and Expenses						
Cost Driver 1	105.73		105.73			105.73
Cost Driver 2	100.00		100.00			100.00
Cost Driver 3	74.47		74.47			74.47
5630 - Outside Services Employed						
Cost Driver 1	(70.00)		(70.00)			(70.00)
Cost Driver 2	5.00		5.00			5.00
Cost Driver 3	(47.00)		(47.00)			(47.00)
Cost Driver 4	(50.00)		(50.00)			(50.00)
Cost Driver 5	199.12		199.12			199.12
Other Minor Variances	15.00		15.00			15.00
5635 - Property Insurance						
Cost Driver 2	13.70		13.70			13.70
Cost Driver 3	20.55			20.55		20.55
5655 - Regulatory Expenses						
Other Minor Variances	(6.29)		(6.29)			(6.29)
5665 - Miscellaneous General Expense						
Cost Driver 1	6.50		6.50			6.50
	3,111.56	**1,674.80**	**2,540.62**	**160.95**	**409.99**	**3,111.56**

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Exhibit 4, Tab 2, Schedule 3

Employee Compensation Breakdown

EMPLOYEE COMPENSATION

In accordance with the Filing Requirements, GLPT has provided the following table outlining employee compensation for the period of 2006 actual to the 2010 test year. **Appendix "A"** of this schedule outlines GLPT's approach to employee incentive pay.

Table 4-2-3 A – Employee Compensation

	2006 Actual	2007 Actual	2008 Actual	2009 Forecast	2010 Test Year
Number of FTE's (Incl. Part Time)					
Union	13.0	11.1	11.9	20.8	28.9
Non-Union	13.5	12.3	13.3	19.1	25.8
Total	**26.5**	**23.4**	**25.2**	**39.9**	**54.7**
Number of Part Time Employees					
Union	0.8	0.7	0.9	0.6	1.5
Non-Union	2.7	2.4	2.4	4.3	0.8
Total	**3.5**	**3.1**	**3.3**	**4.9**	**2.2**
Total Salary & Wages ($000's)					
Union	$964.5	$776.1	$905.6	$1,508.9	$2,275.8
Non-Union (Excludes Incentive Pay)	$848.2	$773.3	$877.0	$1,392.7	$2,080.1
Total	**$1,812.7**	**$1,549.5**	**$1,782.6**	**$2,901.7**	**$4,355.9**
Total Benefits ($000's)					
Union	$292.5	$307.8	$340.4	$752.1	$778.4
Non-Union	$259.6	$262.9	$287.1	$450.7	$691.2
Total	**$552.1**	**$570.7**	**$627.5**	**$1,202.8**	**$1,469.5**
Total Compensation ($000's) (Salary, Wages & Benefits)					
Union	$1,257.0	$1,084.0	$1,246.0	$2,261.1	$3,054.2
Non-Union (Includes Incentive Pay)	$1,247.0	$1,115.4	$1,246.6	$1,981.5	$3,024.1
Total	**$2,504.0**	**$2,199.4**	**$2,492.7**	**$4,242.5**	**$6,078.3**
Compensation - Average Yearly Base Wages ($000's)					
Union	$53.0	$56.5	$59.3	$63.8	$67.8
Non-Union (Excludes Incentive Pay)	$62.8	$62.7	$65.9	$72.9	$80.5
Total	**$115.8**	**$119.2**	**$125.2**	**$136.8**	**$148.4**
Compensation - Average Yearly Overtime ($000's)					
Union	$21.2	$13.6	$17.1	$8.7	$10.9
Non-Union	$0.0	$0.0	$0.0	$0.0	$0.0
Total	**$21.2**	**$13.6**	**$17.1**	**$8.7**	**$10.9**
Compensation - Average Incentive Pay ($000's)					
Union	$0.0	$0.0	$0.0	$0.0	$0.0
Non-Union	$12.9	$8.0	$7.6	$9.3	$10.1
Total	**$12.9**	**$8.0**	**$7.6**	**$9.3**	**$10.1**
Compensation - Average Yearly Benefits ($000's)					
Union	$22.5	$27.8	$28.7	$36.2	$26.9
Non-Union	$19.2	$21.3	$21.6	$23.6	$26.8
Total	**$41.7**	**$49.1**	**$50.3**	**$59.8**	**$53.7**
Grand Total					
Total Compensation	**$2,504.0**	**$2,199.4**	**$2,492.7**	**$4,242.5**	**$6,078.3**
Total Compensation charged to OM&A	**$1,500.5**	**$1,642.9**	**$2,092.8**	**$3,892.1**	**$4,910.2**
Total Compensation Capitalized	**$1,003.5**	**$556.5**	**$399.9**	**$350.4**	**$1,168.1**

APPENDIX "A"

EMPLOYEE INCENTIVE PLAN EXPENSE

EMPLOYEE INCENTIVE PLAN EXPENSE

1.0 Description

All permanent, non-union employees with at least three months of service participate in GLPT's variable pay program. The target incentive compensation ranges from 5% to 25% of base salary. Depending on performance results, the incentive compensation paid out can range from zero to two times the target incentive compensation.

2.0 Performance Measures

The employee incentive plan is based on three key performance criteria: (a) GLPT corporate performance, (b) working group performance, and (c) individual performance.

2.1 GLPT Corporate Performance

GLPT corporate performance objectives are determined at the beginning of the year based on the annual operating plan and focus on specific financial drivers, such as Net Operating Income (NOI) or Return on Equity (ROE). The extent to which GLPT meets its corporate objectives determines the incentive to be paid under the GLPT corporate performance criterion.

2.2 Working Group Performance

Working group performance objectives are based on specific goals that are relevant to each working group. Working groups are determined based on duties and functions within the company and the duties and functions of the company as a whole. Common working group performance objectives include:

<u>Safety</u>

- Zero high-risk incidents and zero lost time injuries related to gravity, electrical and mechanical;
- Maintain an effective health & safety management system. Achieve a score in respect of a third party audit of health and safety management and implementation of at least 85%; and
- Achieve third party audit score increase in specific elements of safety planning, contractor safety, work observations and safety training.

Providing incentives for the types of behaviour associated with these objectives is to the benefit of ratepayers as accidents affect productivity and work completion and also can be costly in respect of work stoppage, investigation, legal review and rehabilitation.

<u>Environment</u>

- Maintain an effective environmental management system. Achieve a score in respect of a third party audit of environmental management and implementation of at least 80% or achieve a positive delta from previous annual score;
- Develop an action plan and implement all priority 1 recommendations from previous audit to ensure improvement;
- Zero high risk incidents (i.e. no spills, species endangerment); and
- Achieve third party audit score increase in public safety specific system element.

This benefits ratepayers by avoiding costs from spills and other environmental issues.

<u>Operations, Maintenance and Administration Costs</u>

- All planned work accomplished within established OM&A budget.

<u>Capital Budget</u>

- Ensure at least 75% of projects less than $250k are completed as per plan with respect to budget, and scope; and
- Ensure that all projects greater than $250k are completed as per plan with respect to budget and scope. Project actual spending not to exceed + or – 10% variance to budget.

This benefits ratepayers by increasing the reliability and performance of the transmission system.

2.3 Individual Performance

Individual performance measures an individual's contribution to the achievement of the objectives of their working group and GLPT. The individual's contribution is assessed in terms of results achieved by the employee against individual goals, as well as competencies demonstrated in meeting these deliverables. Key competencies include: creating value, fostering teamwork, delivering results, making a difference, and providing leadership.

Exhibit 4, Tab 2, Schedule 4

Shared Services & Corporate Cost Allocation

SHARED SERVICES & CORPORATE COST ALLOCATION

1.0 Current Shared Services

The services and assets that will be shared by GLPT with GLPL in the 2010 test year are the following:

- The office complex;
- System Control and Data Acquisition ("SCADA") equipment;
- Fibre optic systems; and
- Radio systems

The proportional cost of these shared services that is borne by GLPT is broken out in *Table 4-2-4 A* below. A discussion of how these services will be shared in the 2010 test year follows. Background information on GLPT's historical shared services is provided in **Appendix "A"**.

Table 4-2-4 A – Current Shared Services

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Office Complex						
Rent	$0.0	$0.0	$0.0	$0.0	$84.9	$171.5
Operations & Maintenance **	-	-	-	-	280.3	361.9
SCADA equipment licence	-	-	-	-	146.9	293.8
Fibre Optic System licence	-	-	-	-	31.6	63.2
Radio System costs	-	-	-	-	3.3	6.5
Total Shared	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$547.0**	**$896.8**

***These costs were not approved as shared costs in the previous application, therefore no historical actual amounts have been displayed in the table. However, these costs are not 100% incremental, as costs were incurred in each year related to these activities.*

1.1 Office Complex

The office complex utilized by GLPT is located at 2 Sackville Road in Sault Ste. Marie, Ontario. It consists of an office building and associated parking space, industrial yard, and vacant land where the transmission ROW crosses. The office building is made up of two distinct structures linked by a closed-in breezeway. The industrial yard provides a storage building, garage facility and secured fencing around the perimeter. The office complex and yard are owned by GLPL and, pursuant to a lease dated July 1, 2009, GLPT leases it in its entirety from GLPL. As part of entering into the lease, an independent real estate appraiser was retained to conduct a Commercial, Industrial and Vacant Industrial Land Lease Rate Analysis and issue a Consulting Report for 2 Sackville Road. The independent appraiser reviewed relevant available industrial space within Sault Ste. Marie and determined a range of market lease rates. In making this determination, the independent appraiser looked at three different property types: commercial/office space, industrial space, and vacant industrial land. The appraiser also conducted interviews with building owners, commercial developers, property managers, rental agents and commercial brokers.

The annual rent that GLPT pays GLPL is in the middle of the range of fair market rentals for triple net leases as assessed by this independent appraiser. Pursuant to a sublease dated July 1, 2009, GLPT subleases one of the two separately defined structures in the office building, along with various common areas and half of the industrial space, to

Algoma Power Inc. through a triple net lease at an annual rent that is the same cost per square foot as paid by GLPT.

The net rental cost of the building and property to GLPT is equal to $169,755 per year, adjusted annually by any increases in CPI. If GLPT's share of the estimated net book value of the property were included in GLPT's rate base, the overall cost to rate payers would be over $280,000[1] in 2010. Accordingly, the lease structure that GLPT utilizes in the 2010 test year is consistent with prudent planning and has resulted in demonstrable avoided costs.

1.2 SCADA Equipment

A Supervisory, Control and Data Acquisition (SCADA) system is used to monitor and control GLPT's transmission assets. The equipment operates control points and monitors alarm points throughout the transmission system and provides analog points to measure system voltages and power flows in real time. An event PC data logger records and stores all operator actions, station alarms, system loading, and metering data. The SCADA equipment forms a part of GLPT's Ontario System Control Centre, which is located in the part of the office building occupied by GLPT.

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[1] The net book value of the building and property that would be attributed to GLPT is approximately $2.6M. With annual depreciation of 2.5%, the depreciation pass-through would be approximately $65,000, and a blended cost of capital rate of 8.42% would yield an additional cost of $220,000. This analysis does not include the impacts on capital or income taxes that would also arise from the building being owned and included in rate base.

The SCADA system was formerly used by GLPL for generation, distribution and transmission functions. Currently, GLPT does not share the operation of this equipment with any other entity. Pursuant to an agreement dated June 30th, 2009, GLPT licences the equipment from GLPL for a three year term, at a cost of 50% of the total depreciation cost of the existing equipment, with no return on capital investment. The annual depreciation cost charged to GLPT is approximately $24,500 per month, or $294,000 annually. The assets are depreciated based on useful lives ranging from 5 years to 40 years, depending on the nature of the asset. However, the majority of the assets are depreciated at a rate that is 10 years or less. GLPT is fully responsible for maintenance costs of the SCADA equipment, as if it were the owner.

As noted above, GLPT only contributes 50% of the depreciation cost, and does not provide any return on investment to GLPL for owning the assets. This results in an annual benefit of $294,000 that is passed on to rate-payers in Ontario, plus the avoided cost of capital associated with these assets.

During the term of its licence agreement with GLPL, GLPT anticipates that the existing SCADA equipment will reach the end of its useful life. Before the end of the three years, GLPT will determine the most beneficial option for continuing to operate its assets through a system control centre.

1.3 Fibre Optic System

GLPT has a fibre optic communication system that is used to transmit SCADA data, telephone communications, corporate business data, protective relay signals, telemetry, truck radio voice circuits and IESO metering information. The system uses fibre optic laser technology to transmit control and voice signals between transmission stations. The fibre optic system is very reliable and mitigates the problems associated with transmitting communications and data signals through the high voltage environment of GLPT's transmission system.

The fibre optic communication system is configured as three rings of "junglemux" equipment. These rings, which cover the areas of the Montreal River, Wawa and Sault Ste. Marie, are connected by a high bandwidth, primary trunk transport system of 170 km owned by GLPL. The fibre optic cables are strung on GLPT's transmission structures so as to connect GLPT's transformer stations, as well as GLPL generating stations. Each GLPT transformer station and each GLPL generating station has a node of junglemux equipment. These nodes are the points at which the various types of data being communicated along the fibre optic cables, for GLPT, GLPL, as well as other users including the meter service provider and HONI, are separated. These nodes ensure that information of the various system users is kept confidential and that it cannot be accessed by any other party. In fact, GLPT would receive an alarm notification if there is any attempt by a party to tamper with the junglemux nodes for such purpose. The nodes of junglemux equipment are not only integral to the functioning of the system, but also serve as the demarcation points for ownership, whereby equipment beyond the nodes in GLPT's transformer stations is owned by GLPT.

The fibre optic communication system includes a total of 29 junglemux nodes. Of these, 12 are for the benefit of GLPT. Pursuant to an agreement dated June 30, 2009, GLPT has obtained a licence from GLPL to use the system for a three year term. The cost of the licence fee is based on the proportionate share of junglemux nodes dedicated to GLPT. With 12 of the 29 nodes being dedicated to GLPT, the licence fee represents approximately 41% of the total depreciation cost of the existing equipment, with no return on capital investment included. The annual depreciation cost charged to GLPT is approximately $5,300 per month, or $63,200 annually.

Under this arrangement, GLPT saves ratepayers from the full cost of capital and depreciation, as well as the additional portion of system maintenance costs that it would be responsible for if it were to be the system owner.

The network is situated in a remote area and is used by both GLPT and GLPL in the normal course of each company's business communications. Due to the remoteness of its location, it would not make economic sense for either company to duplicate the existing fibre optic network.

There is no market for fibre optic services in GLPT's service area because there is no comparable fibre optic system available. Accordingly, the formula utilized, predicated on actual costs, is equitable and consistent with the Affiliate Relationships Code. The costs incurred by GLPT are, as noted, $63,200 annually. This is competitive relative to the cost that would otherwise be incurred by GLPT if it had to install its own fibre optic system which could cost in the millions of dollars.

1.4 Radio Systems

GLPT's VHF radio system is used to transmit telephone and truck radio voice circuits. This system is essential to GLPT, particularly due to the remoteness of its service territory. The need for this system is especially pronounced in emergency situations. The system provides separate communication channels for different system users and includes towers and control buildings throughout GLPT's service territory. A zetron radio access control system ("RACS") was installed to provide various switching and cross-connecting functions. The RACS allows radio users to dial into GLPT's private telephone system as well as the public switched telephone network.

GLPT owns this system and, pursuant to an agreement dated June 30, 2009, is licensing part of the assets to GLPL for a three year term. The system is situated in a remote area and is used by both GLPT and GLPL in the normal course of each company's business communications. Due to the remoteness of location, it would not make economic sense for either company to duplicate the existing radio system.

GLPL pays GLPT a licence fee which is cost based and based on the percentage of radios in use on the overall system. The total annual depreciation cost for the radio system is approximately $6,000, of which approximately half is passed on to GLPL.

There is no market for radio services in GLPT's service area as there is no comparable system available, and accordingly, the formula utilized, predicated on actual costs, is equitable and consistent with the Affiliate Relationships Code.

2.0 Historical Shared Services

As noted, background information on GLPT's historical shared services is provided in **Appendix "A"** of this Schedule. While this information is provided as context, the historical sharing of services between the transmission, distribution and generation businesses of GLPL does not provide a useful basis for comparison to GLPT's shared services costs in the bridge and test years. This is because, as a stand-alone transmission utility, GLPT now operates its transmission system under very different circumstances as compared to when the system was operated by a division of GLPL. Historically, shared costs were allocated between the business units. Then, for the nearly 15-month period following the transfer of the transmission assets from GLPL to GLPT, GLPL operated the transmission system on behalf of GLPT pursuant to an OM&A Agreement. Effective June 30, 2009, these unique arrangements were discontinued.

3.0 Corporate Cost Allocation

In 2010, GLPT's parent will share certain corporate functions with GLPT. As a result of this sharing, GLPT will pay a portion of the costs associated with such shared corporate functions. These corporate costs are associated with senior executive support, tax filing preparation, as well as treasury, accounting and finance and are incremental to the functions carried out by the members of GLPT's executive team. GLPT's costs for these shared services and functions are determined based on the time spent by the relevant executives and the relevant staff in the finance, accounting, treasury and taxation departments of the parent company. The costs associated with these individuals are then multiplied by the relative portion of the working year that these individuals dedicate to providing support to GLPT. These costs were not budgeted in EB-2005-0241. Although these costs are now reflected as an increase in GLPT's revenue requirement, the increase is less than the expense that GLPT would have incurred if it were required to externally source these services.

With respect to finance, accounting and treasury services, which include such functions as quarterly meetings, board meetings, regulatory support, budget support and financing, $65,000 of the parent company's total costs for the relevant employees is allocated to GLPT.

With respect to executive services, which include quarterly meetings, board meetings and budget matters, $209,400 of the parent company's total costs for the relevant executives is allocated to GLPT.

With respect to taxation, which includes the preparation of GLPT tax returns, regulatory support, tax support to GLPT Inc. and GLPTLP, as well as liaising with GLPT's auditors,

$24,200 of the parent company’s total costs for the relevant employees is allocated to GLPT.

The total amount of the corporate allocation to GLPL is therefore $298,571.

APPENDIX "A"

Table 4-2-4 B below demonstrates the costs that were historically allocated to the transmission function.

Table 4-2-4 B –Historical Shared Services

($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*	-
General Manager & Admin Support	*100.0*	*195.7*	*188.2*	*269.1*	*218.8*	-
Accounting & Finance						
Payroll & Benefits	64.7	**	**	**	**	-
Accounting and Procurement	382.0	390.5	389.3	448.5	237.1	-
Stores	97.0	10.5	10.6	11.2	4.6	-
Subtotal Accounting & Finance	*543.6*	*401.1*	*399.9*	*459.7*	*241.7*	-
Planning & Maintenance and Admin Support						
Planning & Maintenance	276.4	201.3	227.9	215.6	122.5	-
Health & Safety	39.9	21.7	19.2	31.4	28.3	-
Environmental	18.8	12.4	17.5	7.2	1.6	-
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*	-
Information Technology Services	*127.3*	*165.4*	*195.8*	*175.8*	*104.3*	-
Total Shared Services	***$2,806.9***	***$2,402.2***	***$2,517.6***	***$2,462.1***	***$1,363.7***	***$0.0***

As part of the re-organization of March 12, 2008 which established GLPT as the owner of the transmission business of GLPL, an OM&A Agreement[2] was put in place that was

[2] The OM&A Agreement was an agreement between GLPL, the operator of the transmission assets, and GLPT, the owner of the transmission assets. The agreement defined the services to be provided from GLPL to GLPT as well as the compensation for those services.

effective to June 30, 2009. The OM&A Agreement contemplated the payment of GLPL's costs as an operator of the transmission system by GLPT. Included in those costs were the transmission division's share of the total costs shared between GLPL's transmission, distribution and generation divisions, using the methodology approved in EB-2005-0241. The OM&A Agreement itself had no impact on the level of cost borne by the transmission business but, rather, provided a mechanism by which the costs could be transferred to the transmission business.

Historical Services Shared with Generation

Sharing of costs with GLPL's generation division was a concern of a number of the parties in GLPL's last transmission rate application (EB-2005-0241). In order to resolve this concern, GLPL committed as part of the Settlement to:

> "retain an independent third party consultant to review and report on the accuracy of its cost allocation and transfer pricing between its transmission and generation business, the results of which will be filed at GLPL's next transmission rate application."

Navigant Consulting prepared a report on behalf of GLPT which comments on the accuracy of the shared costs between the generation and transmission businesses. Navigant Consulting was satisfied with the methodology implemented for the period in question. The report is attached as **Appendix "B"** to this schedule.

APPENDIX "B"

Navigant Report

GREAT LAKES POWER LIMITED

REVIEW OF COST ALLOCATION AND TRANSFER PRICING

June 18, 2008
www.navigantconsulting.com

Table of Contents

Executive Summary

As part of Great Lakes Power Limited's (GLPL) settlement of its 2005 Transmission Rate Application, GLPL committed to engage an independent third party to review its cost allocation and transfer pricing methodologies. The agreement called for GLPL to retain 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 would be filed at GLPL's next transmission rate application. This report from Navigant Consulting, Inc. (NCI) fulfills the third party review and reporting requirement and documents NCI's review process and findings.

GLPL does not consider its divisions affiliates because of GLPL's legal structure. NCI cannot opine on this determination; however, transfer pricing among the divisions for certain shared services does occur, and, through its review and findings, NCI has concluded that GLPL is in compliance with the spirit of the ARC based on the cost-based allocation and transfer pricing methodologies employed by GLPL. NCI's interviews with key employees involved with the cost allocation and transfer pricing and review of documentation provided by GLPL support this conclusion.

Below is NCI's detailed report including a description of the documents NCI reviewed, persons interviewed, and NCI's findings with regard to GLPL's cost allocation and transfer pricing.

1. Navigant Consulting's Review

The scope of NCI's review included: 1) review of the Affiliate Relationship Code; and, 2) review of GLPL's current cost allocation and transfer pricing methodologies.

A. *Affiliate Relationship Code*

NCI undertook a rigorous review of the OEB's Affiliate Relationships Code[1] (ARC) and other relevant OEB documents pertaining to the ARC. Following this review, NCI then narrowed the scope of the review to the sections of the ARC that pertain to cost allocation and transfer pricing; namely, *Section 2.3, Transfer Pricing*. In summary, Section 2.3 stipulates three requirements related to transfer pricing[2]:

1) That the utility provide services, resources, or products (to an affiliate) at a price that is no less than fair market value,

2) That the affiliate provide services, resources, or products (to the utility) at a price that is no more than fair market value, confirmed either by a tendering process or through cost-based pricing; and,

3) That the utility did not sell assets (to an affiliate) at less than the net book value of the asset.

GLPL stated that its Transmission division (a regulated utility) did not provide any services and did not transfer or sell assets to or from any other GLPL divisions. Therefore, NCI's review focused on the second requirement pertaining to services provided to GLPL's Transmission division.

B. *GLPL Interviews and Documents*

NCI performed a portion of its review through interviews of key GLPL employees familiar with the transfer pricing and cost allocation processes, including GLPL's Business Controller and Regulatory Accounting Analyst. The scope of NCI's interviews and review of GLPL documents was limited to certain areas where transfer pricing and cost allocation activities occur between GLPL's various divisions. These areas represent the totality of NCI's review and include:

1) Ontario System Control Centre Dispatch Operations
2) Integrated Communications Network

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[1] Affiliate Relationships Code for Electricity Transmitters and Distributors, Revised November 24, 2003.

[2] NCI has paraphrased the Affiliate Relationship Code requirements. For full text, refer to the Affiliate Relationship Code, Section 2.3, Transfer Pricing, p. 6-7.

3) Meter Service Provider
4) Ontario Operations Administration

In addition, NCI examined numerous documents provided by GLPL. These documents included:

- GLPL's 2005 interrogatory answers provided to the OEB regarding shared services
- 2006 Budget and Actual costs for the Ontario Systems Control Centre (OSCC)
- 2007 Budget and Actual costs for the OSCC
- Invoices and the allocation of costs from the OSCC to T&D for the months of April, May, and September 2006 and May, October, and November 2007
- Ontario Operations cost allocations for June 2007 and December 2007
- Written explanation of cost allocations for the OSCC and services provided by GLPL's Regulatory Accounting Analyst

2. GLPL's Cost Allocation and Transfer Pricing

GLPL does not consider its divisions (OSCC, Generation, and Transmission and Distribution) affiliates due to GLPL's legal structure; therefore, GLPL does not have service agreements, as required in Section 2.2.1 of the ARC. However, as mentioned above, and further detailed below, cost allocation and transfer pricing does occur between GLPL's divisions. Where cost allocation and transfer pricing does occur, NCI has examined the cost allocation and transfer pricing methodologies for adherence to the standards set forth in the ARC. Further, NCI assessed the accuracy, consistency, and fairness of GLPL's cost allocation and transfer pricing methodologies in these circumstances.

NCI's analysis applies to four GLPL areas that require cost allocation or transfer pricing to the Transmission and Distribution division (Ontario System Control Centre Dispatch Operations, Integrated Communications Network, Meter Service Provider, and the Ontario Operations Administration).

In summary, GLPL's transfer pricing and cost allocations are based on actual costs (i.e., cost-based pricing) as explained below.

A. Ontario System Control Centre Dispatch Operations

GLPL's Ontario System Control Centre (OSCC) provides continuous operating (control & monitoring) services for the Transmission and Distribution division. This includes acting as the Controlling Authority for all GLPL owned transformers, breakers, switches, capacitors, reactor, and transmission circuits. Along with these services, the OSCC provides dispatch and scheduling services for the Generation division. Accordingly, GLPL has developed a process to allocate the cost for OSCC services to the Transmission and Distribution division. On a monthly basis, GLPL allocates 40% of the OSCC costs to the Transmission and Distribution division and bills the division for the allocated cost of the OSCC services.

Key OSCC activities undertaken for the Transmission and Distribution division include:

- Operating and monitoring the transmission equipment and systems
- Communicating with customers directly connected to the transmission system
- Outage scheduling
- Maintaining the OSCC equipment, servers, SCADA, screens, alarms, and other equipment

The Transmission and Distribution Division's allocated costs have been determined to be 40% of the total OSCC costs based on: 1) the number of operators required for the Transmission and

Distribution division out of the total number of operators at the OSCC; and, 2) the number of facilities operated for the Transmission and Distribution division. When totaled, GLPL determined that approximately 40% of the operators are required for the Transmission and Distribution division and approximately 40% of the facilities are operated for the Transmission and Distribution division.

OSCC services are provided by NERC-certified operating personnel who interact continuously with the IESO and interconnected transmitters (Hydro One), LDCs (PUC, GLPD) and transmission customers). GLPL has 15 dedicated operators, six of whom are required for transmission and distribution functions. Day to day operator activities 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, customer coordination, and outage coordination. In addition, the OSCC operates and monitors approximately 35 stations, 14 of which are transmission and distribution stations.

Based on NCI's review of GLPL's cost allocation methodology, NCI concludes that allocating 40% of the OSCC costs (based on the actual number of dedicated personnel and facilities operated by the OSCC for the Transmission and Distribution division) is fair, because it is proportional to a major cost driver, and therefore cost-causal or cost-based. In addition, through NCI's review of invoices for OSCC services to the Transmission and Distribution division, NCI determined that this allocation has been consistent for the years of 2006 and 2007.

B. Integrated Communications Network

To control the generation, transmission, and distribution systems, GLPL maintains and operates its own integrated communications network. GLPL allocates the cost of operating and maintaining this system based on the number of circuits utilized by each division's specific network applications and services that utilize the communications network. On average, GLPL determined that the Transmission and Distribution division utilizes 47% of the available circuits; therefore, Transmission and Distribution is allocated 47% of the costs for the communications network. For cost tracking purposes, GLPL has assigned the costs associated with the communications network to the OSCC and these costs are included in the same invoice as OSCC services.

The communications network consists of fiber optic and radio communications systems for use by all GLPL stations and staff. Three dedicated technicians provide continuous technical support for and maintenance of the network. In addition, other major costs include the maintenance, overhauls, and testing of the fibre optics and station equipment.

Based on NCI's review of GLPL's cost allocation methodology, NCI concludes that allocating 47% of the communications network costs (based on the actual number of circuits utilized by the Transmission and Distribution division) is fair. In addition, through NCI's review of invoices for the communications network to the Transmission and Distribution division, NCI determined that this allocation has been consistent for the years of 2006 and 2007.

C. Meter Service Provider

GLPL maintains, operates, and supports the wholesale metering points for the Transmission and Distribution division. This includes ensuring wholesale meters are operating correctly and comply with the IESO market rules. MSP costs are divided equally among each metering point and the costs are allocated based on the number of metering points each division owns. On average, the Transmission and Distribution division utilizes 51% of the MSP points and, therefore, 51% of the MSP costs are allocated to Transmission and Distribution. Like the communications network costs, MSP costs are assigned to the OSCC for cost tracking purposes and included in the same invoice as OSCC services.

Based on NCI's review of GLPL's cost allocation methodology, NCI concludes that allocating 51% of the MSP costs (based on the actual number of metering points by the Transmission and Distribution division) is fair. In addition, through NCI's review of invoices for the MSP service to the Transmission and Distribution division, NCI determined that this allocation has been consistent for the years of 2006 and 2007.

D. Ontario Operations Administration

GLPL's Ontario Operations Administration allocates costs that are common to all divisions of GLPL. These costs include: V.P. responsible for Ontario, Environmental and Health & Safety, Pension Administration, and other miscellaneous costs. Costs associated with the V.P. responsible for Ontario, Environmental and Health & Safety, and any miscellaneous costs are allocated proportionately among the four divisions of GLPL and three divisions of Brookfield Power Corporation. Therefore one seventh of the costs are allocated to the Transmission and Distribution division. One fourth of the Pension Administration costs are allocated to the Transmission and Distribution division because the pension plan is for the four divisions of GLPL only.

Based on NCI's review of GLPL's cost allocation methodology, NCI concludes that a proportional allocation of the Ontario Operations Administration costs among its divisions is fair because it spreads these expenses equally among the beneficiaries/recipients of the services. In addition, through NCI's review of GLPL journal entries, NCI determined that this allocation has been consistent throughout 2007.

3. Conclusion

Based on the above findings, NCI believes that GLPL utilizes procedures that allocate costs fairly and accurately to each division and uses cost-based pricing to perform its cost allocation and transfer pricing. Because of GLPL's transfer pricing and cost allocation methodologies, NCI concludes that GLPL is in compliance with the spirit of Section 2.3 of the ARC.

Exhibit 4, Tab 2, Schedule 5

Purchase of Non-Affiliate Services

PURCHASE OF NON-AFFILIATE SERVICES

1.0 Overview

In the course of operating its transmission business, GLPT relies on the purchase of services from non-affiliated companies. The actual aggregate dollar amounts for each of 2006 through 2008, and the forecasted amount for 2009 are as follows:

- 2006: $1,784,400,
- 2007: $2,061,300,
- 2008: $1,837,800, and
- 2009 Forecast: $1,798,600

Of the non-affiliated companies that transact with GLPT, six companies have been close to or over GLPT's materiality threshold[1] for at least one year between 2006 and 2008. A summary of the transactions with these three companies is provided in *Table 4-2-5 A* below.

Table 4-2-5 A – Non-Affiliate Purchases Over GLPT's Materiality Threshold

Identity of Company	Nature of Activity	2006 Actual	2007 Actual	2008 Actual	2009 Forecast
ABB Inc.	Transmission Equipment Work	$0	$195,114	$10,482	$8,256
Deloitte & Touche LLP	Audit	10,600	196,055	192,399	180,000
Golder Associates Ltd.	Environmental Activities	558,913	473,489	-	-
Ogilvy Renault LLP	Legal	295,309	269,641	221,446	53,216
Torys LLP	Legal	-	-	-	350,000
Wilderness Vegetation Management	Forestry	556,748	515,331	656,516	577,570
		$1,421,570	**$1,649,630**	**$1,080,843**	**$1,169,042**

[1] GLPT's materiality threshold is $196,825, as defined in Exhibit 1, Tab 4, Schedule 1.

2.0 Methodology

In determining vendors for purchasing services, GLPT considers a number of different factors. The first and most important factor is pre-qualification, which is discussed in further detail below. The other key measure used is Request for Proposals ("RFPs"), which assess cost, scope of work and availability of potential vendors.

2.1 Contractor Pre-Qualification

Depending upon the nature of the services to be provided, GLPT may carry out a contractor pre-qualification process. A safe and healthy workplace is an important part of GLPT's work environment. As such, GLPT takes a number of steps to ensure that contractors, particularly those carrying out physical work on behalf of the company, demonstrate a level of dedication to health and safety that is consistent with GLPT's own commitment to health and safety. This process, which GLPT refers to as its contractor pre-qualification process, is described in detail below:

1. Interested contractors are sent an application form,

2. The contractor completes the application form and returns it to GLPT along with any additional information requested. Information requested includes business history, safe work performance, health and safety policies and information, and environmental policies and information.

3. GLPT evaluates the information supplied and requests additional information as required. GLPT determines whether the contractor is qualified to work for GLPT, depending on the level of risk that is associated with the work sought by the contractor.

4. Annually, contractors are requested to update certain information in the application form. Some examples of information requiring updates include Workplace Safety & Insurance Board experience ratings, training completed, and Ministry of Labour orders.

2.2 Requests for Proposals

Subject to pre-qualification of contractors on safety and environmental standards, and where practical, GLPT will seek the optimal service provider through an RFP process. An RFP is sent to each of the pre-qualified contractors in the relevant field. The responses to the RFP are assessed and evaluated by GLPT on the basis of considerations such as price, health and safety, environment, value added, past experience and reliability. A successful contractor is asked to provide an itemized estimate of the costs to conduct the work. Based upon the estimate, efforts are made to negotiate the price and terms on a fixed price contract basis.

Exhibit 4, Tab 2, Schedule 6

Depreciation and Amortization

DEPRECIATION AND AMORTIZATION

GLPT uses straight-line depreciation calculations based on the depreciable gross book value of each asset class. The rates utilized by GLPT, shown in the table below, are the same as those approved in EB-2005-0241. GLPT has made no changes to assumptions in calculating depreciation expense since that application.

Table 4-2-6 A – Depreciation Rates

USofA	Description	Depr. Rate
1705	Land	0.00%
1715	Station Equipment	2.50%
1720	Towers and Fixtures	2.50%
1725	Poles and Fixtures	2.50%
1730	Overhead Conductors & Devices	2.50%
1740	Underground Conductors & Devices	4.00%
1745	Road and Trails	2.50%
1908	Buildings and Fixtures	4.00%
1915	Office Furniture & Equipment	10.00%
1920	Computer Equipment - Hardware	20.00%
1925	Computer Software	20.00%
1930	Transportation Equipment	20.00%
1940	Tools, Shop and Garage Equipment	10.00%
1955	Communication Equipment	10.00%
1960	Miscellaneous Equipment	10.00%
1990	Other Tangible Property	2.50%

Table 4-2-6 B below outlines GLPT's depreciation expense by asset class.

Table 4-2-6 C demonstrates continuity for depreciation amounts for each of the years 2006 (actual) through 2010 (forecast). For additional details on GLPT's asset continuity, please refer to Exhibit 2, Tab 2, Schedule 1.

Table 4-2-6 B – Depreciation Expense Asset Class

($000's) USofA	Description	Depr. Rate	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
1705	Land	0.00%	-	-	-	-	-	-
1715	Station Equipment	2.50%	$3,092.5	$2,644.0	$2,966.4	$3,387.8	$3,605.4	$3,766.8
1720	Towers and Fixtures	2.50%	578.7	580.9	592.1	592.1	590.7	589.2
1725	Poles and Fixtures	2.50%	1,477.2	1,214.9	1,404.2	1,450.0	1,463.5	1,456.2
1730	Overhead Conductors & Devices	2.50%	739.0	983.9	1,060.1	1,046.7	1,046.9	1,047.0
1740	Underground Conductors & Devices	4.00%	6.4	6.4	3.2	-	-	-
1745	Road and Trails	2.50%	9.8	9.8	9.8	9.8	9.6	15.5
1908	Buildings and Fixtures	4.00%	0.2	1.4	1.3	1.3	2.5	19.2
1915	Office Furniture & Equipment	10.00%	-	-	-	-	9.9	19.8
1920	Computer Equipment - Hardware	20.00%	1.9	1.9	-	0.1	127.4	235.7
1925	Computer Software	20.00%	5.7	5.7	3.7	2.0	32.2	159.1
1930	Transportation Equipment	20.00%	-	-	-	-	59.1	117.0
1940	Tools, Shop and Garage Equipment	10.00%	-	-	-	-	0.8	1.5
1955	Communication Equipment	10.00%	124.7	79.1	80.0	57.2	24.2	15.3
1960	Miscellaneous Equipment	10.00%	1.5	1.6	1.7	1.7	1.7	1.7
1990	Other Tangible Property	2.50%	-	-	-	-	-	-
	Less: Disallowed 2005 Addition		(36.7)	(37.1)	(37.1)	(37.1)	(37.1)	(37.1)
	Total Annual Depreciation:		**$6,000.8**	**$5,492.4**	**$6,085.3**	**$6,511.6**	**$6,936.6**	**$7,406.9**

Table 4-2-6 C – Continuity of Accumulated Depreciation

($000's) USofA	Description	2006 Opening Accumulated Depreciation	2006 Annual Depreciation	2006 Disposals	2006 Closing Accumulated Depreciation	2007 Annual Depreciation	2007 Disposals	2007 Closing Accumulated Depreciation	2008 Annual Depreciation	2008 Disposals	2008 Closing Accumulated Depreciation
1705	Land	-	-	-	-	-	-	-	-	-	-
1715	Station Equipment	$26,548.6	$2,644.0	$412.0	$28,780.6	$2,966.4	$34.1	$31,713.0	3,387.8	$179.3	$34,921.5
1720	Towers and Fixtures	6,436.2	580.9	-	7,017.1	592.1	-	7,609.2	592.1	-	8,201.3
1725	Poles and Fixtures	7,624.9	1,214.9	-	8,839.8	1,404.2	-	10,243.9	1,450.0	-	11,694.0
1730	Overhead Conductors & Devices	5,596.7	983.9	-	6,580.6	1,060.1	-	7,640.7	1,046.7	-	8,687.4
1740	Underground Conductors & Devices	150.8	6.4	-	157.2	3.2	-	160.4	-	-	160.4
1745	Road and Trails	383.5	9.8	-	393.2	9.8	-	403.0	9.8	-	412.8
1908	Buildings and Fixtures	3.2	1.4	-	4.5	1.3	-	5.9	1.3	-	7.2
1915	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	-
1920	Computer Equipment - Hardware	17.2	1.9	-	19.1	-	-	19.1	0.1	-	19.2
1925	Computer Software	19.9	5.7	-	25.5	3.7	-	29.2	2.0	-	31.2
1930	Transportation Equipment	-	-	-	-	-	-	-	-	-	-
1940	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	-	-
1955	Communication Equipment	1,157.3	79.1	-	1,236.4	80.0	-	1,316.4	57.2	-	1,373.6
1960	Miscellaneous Equipment	3.9	1.6	-	5.5	1.7	-	7.2	1.7	-	8.9
1990	Other Tangible Property	757.0	-	-	757.0	-	-	757.0	-	-	757.0
	Less: Disallowed 2005 Addition	(18.6)	(37.1)	-	(55.7)	(37.1)	-	(92.9)	(37.1)	-	(130.0)
	Totals	**$48,680.5**	**$5,492.4**	**$412.0**	**$53,760.8**	**$6,085.3**	**$34.1**	**$59,812.1**	**$6,511.6**	**$179.3**	**$66,144.4**

Table 4-2-6 C – Continuity of Accumulated Depreciation (cont'd)

($000's) USofA	Description	2009 Opening Accumulated Depreciation	Forecasted 2009 Annual Depreciation	Forecasted 2009 Disposals	2009 Closing Accumulated Depreciation	Forecasted 2010 Annual Depreciation	Forecasted 2010 Disposals	2010 Closing Accumulated Depreciation
1705	Land	-	-	-	-	-	-	-
1715	Station Equipment	$34,921.5	3,605.4	$0.0	$38,526.9	$3,766.8	$0.0	$42,293.7
1720	Towers and Fixtures	8,201.3	590.7	-	8,792.0	589.2	-	9,381.2
1725	Poles and Fixtures	11,694.0	1,463.5	-	13,157.4	1,456.2	-	14,613.6
1730	Overhead Conductors & Devices	8,687.4	1,046.9	-	9,734.3	1,047.0	-	10,781.3
1740	Underground Conductors & Devices	160.4	-	-	160.4	-	-	160.4
1745	Road and Trails	412.8	9.6	-	422.3	15.5	-	437.9
1908	Buildings and Fixtures	7.2	2.5	-	9.7	19.2	-	28.9
1915	Office Furniture & Equipment	-	9.9	-	9.9	19.8	-	29.7
1920	Computer Equipment - Hardware	19.2	127.4	-	146.5	235.7	-	382.2
1925	Computer Software	31.2	32.2	-	63.5	159.1	-	222.5
1930	Transportation Equipment	-	59.1	-	59.1	117.0	-	176.2
1940	Tools, Shop and Garage Equipment	-	0.8	-	0.8	1.5	-	2.3
1955	Communication Equipment	1,373.6	24.2	-	1,397.7	15.3	-	1,413.0
1960	Miscellaneous Equipment	8.9	1.7	-	10.6	1.7	-	12.2
1990	Other Tangible Property	757.0	-	-	757.0	-	-	757.0
	Less: Disallowed 2005 Addition	(130.0)	(37.1)	-	(167.1)	(37.1)	-	(204.3)
	Totals	**$66,144.4**	**$6,936.6**	**$0.0**	**$73,081.0**	**$7,406.9**	**$0.0**	**$80,487.8**

Exhibit 4, Tab 3, Schedule 1

Tax Overview

TAX OVERVIEW

Income tax for regulatory purposes for the years 2006 to 2010, inclusive, is discussed in Exhibit 4, Tab 3, Schedule 2 and summarized in *Table 4-3-1 A*, below.

Capital tax expenses for regulatory purposes for the years 2006 to 2010, inclusive, are discussed in Exhibit 4, Tab 3, Schedule 3 and summarized in *Table 4-3-1 A*, below.

Property tax expenses for the years 2006 to 2010, inclusive, are discussed in Exhibit 4, Tab 3, Schedule 3 and summarized in *Table 4-3-1 A*, below.

Table 4-3-1 A – Summary of Income, Capital and Property Taxes

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Income Tax	$5,360.7	$5,390.4	$4,590.8	$3,229.9	$1,798.1	$2,861.5
Capital Tax	598.4	503.5	423.8	436.6	436.4	145.5
Property Tax	268.1	195.1	202.4	195.5	236.8	258.2
Total Tax	**$6,227.2**	**$6,089.0**	**$5,216.9**	**$3,862.1**	**$2,471.4**	**$3,265.2**

Exhibit 4, Tab 3, Schedule 2

Income Tax

INCOME TAX

1.0 Introduction

Income tax for regulatory purposes for the years 2006 to 2010, inclusive, are as calculated in *Table 4-3-2 E* below, and summarized in *Table 4-3-2 A* below.

Table 4-3-2 A - Summary of Income Tax Expense

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Federal Corporate Tax	$3,205.6	$3,301.1	$2,811.4	$1,880.1	$1,035.3	$1,661.5
Provincial Corporate Tax	2,155.1	2,089.3	1,779.4	1,349.8	762.9	1,200.0
Total Income Tax	**$5,360.7**	**$5,390.4**	**$4,590.8**	**$3,229.9**	**$1,798.1**	**$2,861.5**

The facts and assumptions underlying the calculation of income tax are,

(a) Applicable income tax rates are set out in *Table 4-3-2 B* below;

(b) Tax expense is calculated using the standalone principle; and

(c) Capital cost allowance for regulatory purposes is calculated without regard to non-arm’s length transactions that affect actual balances for income tax purposes.

Each of these facts and assumptions is discussed below.

2.0 Tax Rates

GLPT has used the relevant tax rates described in *Table 4-3-2 B* to calculate income tax for the purposes of this application.

Table 4-3-2 B - Summary of Income Tax Rates

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Federal Corporate Tax	22.12%	22.12%	22.12%	19.50%	19.00%	18.00%
Provincial Corporate Tax *	14.00%	14.00%	14.00%	14.00%	14.00%	13.00%
Total Income Tax	**36.12%**	**36.12%**	**36.12%**	**33.50%**	**33.00%**	**31.00%**

* Ontario corporate tax rate in 2010 is scheduled to be 14% through June 30 and 12% for the remainder of the year, therefore GLPT has assumed an average rate of 13%, consistent with the Tax Model provided by the Board.

3.0 Responsibility for Tax Cost

GLPT was formed as a limited partnership in 2007 and commenced operations on March 12, 2008 when it acquired the Ontario transmission assets and related working capital of Great Lakes Power Limited ("GLPL") for $90.4 million in cash and the assumption of $120 million of debt relating to the transmission assets. Brookfield Infrastructure Holdings (Canada) Inc. ("BIH") is the 99.99% limited partner of GLPT. Great Lakes Power Transmission Inc. ("Transmission Inc."), which is a wholly owned subsidiary of BIH, is the 0.01% general partner.

Since GLPT's operations are located in Ontario, its income is subject to taxation in Canada at both federal and provincial levels. As a partnership, however, GLPT is not itself a taxpayer. Unlike individuals, corporations or trusts, partnerships under Canadian tax law are not viewed as separate "persons" subject to tax. The *Income Tax Act (Canada)* addresses this fact by requiring each partnership to calculate its annual taxable income *as though* it were a taxpayer, but then to allocate that income (or loss, as the case may be) to its partners. In the case at hand, GLPT will allocate 99.99% of its taxable income to BIH and 0.01% to Transmission Inc. As a result, there is a tax cost that arises from the regulated activity of GLPT.

The two partners of GLPT are each taxable Canadian corporations and their respective allocations of partnership income will be subject to federal and provincial taxation. The partners are responsible for the tax cost. As a result, the tax liability for the transmission business that is allocated to the partners is representative of the applicable regulatory tax allowance.[1] A tax allowance is therefore included in rates. Accordingly, income tax for purposes of this rate application is calculated on a stand-alone basis as though GLPT was a corporate entity operating in Canada within the Province of Ontario.

4.0 Capital Cost Allowance

Capital Cost Allowance ("CCA") used for calculating income tax for regulatory purposes is set out in Exhibit 4, Tab 3, Schedule 6 and can be summarized as follows:

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[1] The Alberta Energy and Utilities Board ("AEUB") considered such a case in the hearings for AltaLink Management Ltd. and TransAlta Utilities Corporation's transmission tariff for 2002 through 2004. AltaLink was the first application for which the AEUB had to consider ownership and operation of a transmission business by a limited partnership. It was found that it was a reasonable deviation from the traditional stand-alone principle to recognize the tax payable by partners that are taxable entities. The AEUB accepted the partners as tax paying entities in Canada and that there was a "reasonable expectation" that income taxes would be incurred.

Table 4-3-2 C - Summary of Annual CCA Claims

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Capital Cost Allowance (CCA)	$5,645.5	$6,946.0	$8,714.9	$9,035.5	$9,619.1	$9,725.8

Due to the differences between the accounting and tax treatments of the transmission assets (as described below), GLPT's calculation of CCA for regulatory purposes disregards the income tax effect of the 2008 non-arm's length sale of the transmission assets by GLPL to GLPT and treats CCA for regulatory purposes as though the assets were acquired by GLPT at "tax book value" (i.e., historic undepreciated capital cost ("UCC")). This approach is reflected in the CCA claims summarized in *Table 4-3-2 C*, above.

The opening NBV of the transmission assets for GLPT upon acquisition in March 2008 is the same as the closing NBV of the assets to GLPL at the time of sale.

There is no analogous continuity of interest principle for tax purposes. The sale transaction was fully taxable and therefore had income tax ramifications for both GLPL and GLPT despite the fact that the transaction was essentially 'break-even' for accounting and regulatory purposes. GLPL realized taxable recapture of previously deducted CCA on the sale of the transmission assets because the UCC of the assets for tax purposes was less than the mandated sale proceeds. This is because of the declining balance method of depreciation under the CCA regime for tax purposes. While the total depreciation taken under the accounting (straight line) methodology and the tax (declining balance) methodology will be the same in the long run, the year-to-year amounts will vary. The tax method's declining balance approach tends to have faster early-year amortization than the straight line equivalent, but then slows appreciably for the remaining years. For example, using an 8% declining balance rate (such as used for certain transmission assets), 50% of the cost of an asset is depreciated within the first 9 years or so, but the remaining portion would require more than 40 additional years to be fully depreciated. The NBV of the transmission assets as at December 31, 2007 was approximately $210 million. The corresponding UCC of those assets at that time was approximately $140 million. The $70 million variance can be explained by the different depreciation methodologies employed for accounting purposes (straight line) versus tax purposes (declining balance).

Because of the use of the straight line approach for accounting purposes, ratepayers have already realized the benefit of the $70 million UCC deduction.

The flipside to GLPL's recapture is that NBV also becomes the starting point for determining new opening UCC balances for the transmission assets in the hands of GLPT. The result is that the tax value of the assets to GLPT going forward is higher than GLPL's closing balance. GLPT in effect gets to reclaim CCA on amounts that GLPL previously claimed (but subsequently recaptured). Therefore, taxable asset sales, such as the case at hand, generate tax liabilities to the vendor (from the disposition of assets) and generally reciprocal tax benefits to the purchaser (in the form of a step-up in opening UCC balances as compared to the vendor's UCC balance).

In the context of the rate application, the ratepayers should be indifferent to the movement of assets between related parties. Since the tax consequences of the recapture realized by GLPL in 2008 were borne by GLPL—not the Ontario ratepayers—it stands to reason that the ratepayers should not benefit from the corresponding step-up in GLPT's opening UCC balances either. Applying the principle that benefits should follow the costs, the ratepayers incurred no costs to entitle ratepayers to receive the benefit of a higher UCC. In fact, as noted, ratepayers have already received that benefit through the straight line methodology applied for regulatory purposes. If ratepayers were provided the benefit of the higher UCC, then the ratepayers would effectively receive the same benefit twice.

Just as the sale transaction took place at historical cost values for both accounting and regulatory purposes, the most expedient way of ensuring symmetrical treatment of the Ontario ratepayers in respect of taxes is to treat GLPT's CCA claims in 2008 and onward as though they were based on historical GLPL UCC values. That is, to roll forward the UCC continuity schedule for transmission assets established in the 2005 transmission rate submission. This would therefore use $140 million as the opening UCC value for 2008 rather than a number based on the higher transaction value. With this approach there is neither cost to the Ontario ratepayers on the sale of the transmission assets by GLPL, nor any incremental benefit to them from the acquisition of those same assets by GLPT. The transaction is effectively neutral for both accounting and tax purposes in the eyes of the ratepayer.

5.0 Financing Fees

Financing fees incurred by GLPT in 2007 and 2008 are deductible for tax purposes over a five-year period. This deduction is reflected in the calculation of income taxes payable.

6.0 Interest

Table 4-3-2 D below outlines the total interest expense deducted in GLPT's tax calculation. For additional details on the interest cost used, please refer to Exhibit 4, Tab 3, Schedule 5.

Table 4-3-2 D – Interest Expense

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Deemed Interest Expense	$7,141.5	$6,366.0	$7,186.7	$7,467.0	$7,584.3	$8,260.8

7.0 Income Tax Calculation

GLPT's income taxes are calculated in *Table 4-3-2 E* below.

Table 4-3-2 E – Income Tax Calculation

($000's)	Reference (Ex-Tab-Sch)	2006 Approved	2006	2007	2008	2009 Bridge	2010 Test Year - Revenue Forecast	2010 Test Year - Revenue Requirement
Total Revenue		$34,785.4	$34,686.2	$35,567.6	$35,073.4	$31,958.2	$34,696.2	$39,365.1
Less:								
Operation, mtce and admin	4-2-1	5,927.0	5,752.0	6,184.6	7,663.5	7,994.1	11,105.6	11,105.6
Capital Taxes	4-3-3	410.0	503.5	536.8	436.6	436.4	145.5	145.5
Property Taxes	4-3-4	268.1	195.1	202.4	195.5	236.8	258.2	258.2
Sub-Total		28,180.3	28,235.6	28,643.8	26,777.7	23,290.9	23,186.9	27,855.8
Deduct:								
Interest	4-3-5	7,141.5	6,366.0	7,186.7	7,467.0	7,584.3	8,260.8	8,260.8
Financing fees		-	-	32.4	633.7	638.6	638.6	638.6
Capital cost allowance	4-3-6	5,645.5	6,946.0	8,714.9	9,035.5	9,619.1	9,725.8	9,725.8
Taxable Income		15,393.4	14,923.6	12,709.9	9,641.5	5,448.9	4,561.7	9,230.6
Federal Corporate Tax		3,205.6	3,301.1	2,811.4	1,880.1	1,035.3	821.1	1,661.5
Provincial Corporate Tax		2,155.1	2,089.3	1,779.4	1,349.8	762.9	593.0	1,200.0
Total Income Tax		**$5,360.7**	**$5,390.4**	**$4,590.8**	**$3,229.9**	**$1,798.1**	**$1,414.1**	**$2,861.5**
Statutory rates			**36.12%**	**36.12%**	**33.50%**	**33.00%**	**31.00%**	**31.00%**

Exhibit 4, Tab 3, Schedule 3

Capital Tax

CAPITAL TAX

Capital tax expenses for regulatory purposes are calculated in *Table 4-3-3 D,* and summarized in *Table 4-3-3 A* below.

Table 4-3-3 A - Summary of Capital Tax Expense

($000's) Tax Category	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Federal LCT Tax	188.4	-	-	-	-	-
Provincial Capital Tax	410.0	503.5	423.8	436.6	436.4	145.5
Total Capital & Property Taxes	**$598.4**	**$503.5**	**$423.8**	**$436.6**	**$436.4**	**$145.5**

The facts and assumptions underlying the calculation of capital tax are,

(a) Applicable capital tax rates are as set out in *Table 4-3-3 B* below;

(b) Capital tax expenses are calculated using the stand-alone principle; and

(c) GLPT's share of the capital exemption is prorated in years where there are other regulated entities in the larger corporate group.

Each of these facts and assumptions is discussed below.

1. Capital Tax Rates

GLPT has used the relevant Ontario capital tax rates displayed in *Table 4-3-3 B* to calculate capital tax for the purposes of this application.

Table 4-3-3 B - Summary of Ontario Capital Tax Rates

(%)	**2006**	**2007**	**2008**	**2009**	**2010**
Capital Tax Rate*	0.30%	0.225%	0.225%	0.225%	0.075%

* Ontario capital taxes are scheduled to be eliminated on July 1, 2010. The 0.075% tax rate used for 2010 is the prorated effective tax rate since the actual rate will be 0.15% through June 30 and nil for the balance of the year.

2. Responsibility for Tax Cost

Since GLPT's operations are located in Ontario, its operations are subject to Ontario capital tax. Similar to the income tax treatment of the partnership's operations, the taxable capital of the partnership is determined as though it is a corporation, but is allocated to GLPT's two corporate partners in the same proportions as partnership income is allocated. As a result, a capital tax allowance is included in rates.

This approach is consistent with the stand-alone principle discussed at Exhibit 4, Tab 3, Schedule 2. That is, Ontario capital tax is calculated on a stand-alone basis as though GLPT was a corporate entity operating only in the Province of Ontario.

3. Capital Exemption

Capital exemptions are usually prorated among all associated corporations resident in Canada, regulated and unregulated alike. For the purposes of this submission, however, and consistent with Board guidance on the application of capital tax exemptions,[1] the statutory exemptions from paid-up capital are prorated only among regulated entities in the larger corporate group.

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[1] 2006 Electricity Distribution Rate Handbook, subsection 7.2.2

Specifically, for 2005 through 2008, GLPT and related party GLPL are allocated proportionate shares of the relevant capital exemptions based on their respective rate base balances. As GLPL's electricity distribution business was sold to a third party in 2009, GLPT is allocated the full amount of the capital exemption in 2009 and 2010.

Table 4-3-3 C - Summary of Capital Exemptions

($000's)	**2006**	**2007**	**2008**	**2009**	**2010**
Available Capital Exemption	$10,000	$12,500	$15,000	$15,000	$15,000
GLPT Allocation	$7,668	$9,672	$11,705	$15,000	$15,000

4. Capital Tax Calculation

GLPT's required capital tax provision is calculated in *Table 4-3-3 D* below. In this application, GLPT is requesting a provision of $145,500 for Ontario Capital Tax.

Table 4-3-3 D – Calculation of Ontario Capital Tax

($000's) **Tax Category**	**2006 Approved**	**2006 Actual**	**2007 Actual**	**2008 Actual**	**2009 Bridge**	**2010 Test Year**
Federal LCT Tax	188.4	-	-	-	-	-
Provincial Capital Tax	410.0	503.5	423.8	436.6	436.4	145.5
Total Capital & Property Taxes	**$598.4**	**$503.5**	**$423.8**	**$436.6**	**$436.4**	**$145.5**
Provincial Capital Tax Details						
Rate Base (Taxable Capital Estimate)		175,490.1	198,023.9	205,765.1	208,974.4	208,999.2
- Capital Exemption		7,668.0	9,671.5	11,705.5	15,000.0	15,000.0
= Deemed Taxable Capital		167,822.1	188,352.4	194,059.6	193,974.4	193,999.2
x Tax Rate		0.30%	0.225%	0.225%	0.225%	0.075%
= Provincial Capital Tax		**$503.5**	**$423.8**	**$436.6**	**$436.4**	**$145.5**

Exhibit 4, Tab 3, Schedule 4

Property Tax

PROPERTY TAX

1.0 Overview

GLPT is forecasting total property taxes for the 2010 test year to be $258,200. Property taxes are driven by two distinct cost drivers:

1. Payments in Lieu of Taxes to First Nations, and
2. Payments for other municipal taxes.

Table 4-3-4 A below outlines the total property taxes from 2006 approved – 2010 test year.

Table 4-3-4 A – Payments in Lieu of Taxes & Property Taxes

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Payments to First Nations	$134.8	$133.1	$133.2	$129.1	$128.8	$133.2
Other Municipal Taxes	133.3	62.0	69.2	66.4	108.0	125.0
Total Property Taxes	**$268.1**	**$195.1**	**$202.4**	**$195.5**	**$236.8**	**$258.2**

2.0 Payments in Lieu of Taxes to First Nations

GLPT utilizes property located on two different First Nations properties. The aggregate amount of payments to First Nations in lieu of taxes is forecasted to be $133,200 in 2010.

As discussed in Exhibit 9, Tab 2, Schedule 1, GLPT is requesting the Board approve a variance account to track any variances between the approved payments in lieu of taxes and any new payments to First Nations in lieu of taxes that may be negotiated before GLPT's next rate application.

3.0 Payments for Other Municipal Taxes

GLPT property is subject to municipal taxes. The municipal taxes for 2010 are forecasted to be $125,000. The increase in property tax costs relates to property taxes on the office complex occupied by both GLPT and Algoma Power Inc. For historical years up to 2008, the office complex was occupied by the generation, transmission and distribution divisions of GLPL. This allowed the property tax costs related to the building to be split among the three parties. In 2009, GLPL's generation business vacated the complex. The property tax as of July 1, 2009 and for the 2010 test year was split according to the respective portions of the building leased and occupied by GLPT (55%) and Algoma Power Inc. (45%).[1]

[1] Changes to GLPT's building arrangements are described in detail at Exhibit 4, Tab 2, Schedule 4, Section 1.1.

Exhibit 4, Tab 3, Schedule 5

Interest Expense

INTEREST EXPENSE

In *Table 4-3-5 A* below, GLPT calculates the total deemed interest expense to be deducted from income in calculating income tax payable.

Table 4-3-5 A – Interest Expense Calculation

($000's)	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Bridge	2010 Test Year
Rate Base	196,734.2	175,370.7	197,980.6	205,702.0	208,934.3	208,999.2
Portion Deemed as Debt	55.0%	55.0%	55.0%	55.0%	55.0%	57.5%
Deemed Debt	108,203.8	96,453.9	108,889.3	113,136.1	114,913.8	120,174.5
Long Term Debt Rate	6.60%	6.60%	6.60%	6.60%	6.60%	6.87%
1) Deemed Interest Expense (Sch 5-1-1)	**7,141.5**	**6,366.0**	**7,186.7**	**7,467.0**	**7,584.3**	**8,260.8**

GLPT currently holds $120 million in long term debt in the form of third party, series 1 bonds, with interest payable at a rate of 6.60%. Interest is paid semi-annually on June 16th and December 16th of each year. Principal will be reimbursed on maturity in June 2023. In Exhibit 5, Tab 1, Schedule 1, GLPT proposes a rate of interest on debt equal to the effective interest rate on its debt, which incorporates both interest payments and recovery of financing fees related to the issuance of additional debt and the establishment of a new Deed of Trust specific to GLPT. GLPT's actual effective rate of interest is 6.874%, which is approximately 0.746% lower than the current deemed rate for long term debt of 7.62%.

In the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* dated December 20, 2006, the Board determined that short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors. The Board also states that many distributors (utilities) are using short-term debt to finance their operations. GLPT is not one of those utilities, as it does not use short-term debt to finance operations. This is demonstrated in GLPT's historical and pro-forma financial statements, found at Exhibit 1, Tab 3, Schedules 1 and 2. The primary reason that GLPT does not use short-term debt to finance its operations is that the Deed of Trust under which the current bonds are held allows for no additional short-term indebtedness. This limitation on additional short-term indebtedness provides GLPT with a lower rate of interest on the existing bonds, the benefit of which is passed through to ratepayers through the use of the effective rate of interest on GLPT's debt.

Therefore, GLPT has calculated interest expense under the assumption that all of the deemed debt is long term debt, with no part deemed as short term. As a result the interest expense used in the calculation of income taxes is $8,260,800.

Exhibit 4, Tab 3, Schedule 6

CCA Calculation

CAPITAL COST ALLOWANCE ("CCA")

Table 4-3-6 A – CCA – 2006

		U.C.C. DEC 31, 2005	ADDITIONS 2006	DISPOSALS 2006	INTEREST CAPITALIZED 2006	TOTAL 2006 ADDITIONS NET	C.C.A. On Opening	C.C.A. On Additions	TOTAL C.C.A. CLAIMED	U.C.C. DEC 31, 2006
CLASS 1	4%	67,717,968	0	(250,000)	0	(250,000)	2,708,719	(5,000)	2,703,719	64,764,249
CLASS 8	20%	122,368	103,047	0	0	103,047	24,474	10,305	34,778	190,637
CLASS 10	30%	3,896	0	0	0	0	1,169	0	1,169	2,728
CLASS 47	8%	33,299,081	39,664,336	0	(1,104,265)	38,560,071	2,663,927	1,542,403	4,206,329	67,652,823
		101,143,313	**39,767,383**	**(250,000)**	**(1,104,265)**	**38,413,118**	**5,398,288**	**1,547,708**	**6,945,995**	**132,610,436**

1 *Table 4-3-6 B – CCA – 2007*

		U.C.C. DEC 31, 2006	ADDITIONS 2007	DISPOSALS 2007	INTEREST CAPITALIZED 2007	TOTAL 2007 ADDITIONS NET	C.C.A. On Opening	C.C.A. On Additions	TOTAL C.C.A. CLAIMED	U.C.C. DEC 31, 2007
CLASS 1	4%	64,764,249	0	(108,142)	0	(108,142)	2,590,570	(2,163)	2,588,407	62,067,700
CLASS 8	20%	190,637	5,189	0	0	5,189	38,127	519	38,646	157,179
CLASS 10	30%	2,728	0	0	0	0	818	0	818	1,909
CLASS 47	8%	67,652,823	17,169,669	0	(300,581)	16,869,088	5,412,226	674,764	6,086,989	78,434,921
		132,610,436	**17,174,858**	**(108,142)**	**(300,581)**	**16,766,135**	**8,041,741**	**673,120**	**8,714,861**	**140,661,709**

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Table 4-3-6 C – CCA – 2008

		U.C.C. DEC 31, 2008	ADDITIONS 2009	DISPOSALS 2009	INTEREST CAPITALIZED 2009	TOTAL 2009 ADDITIONS NET	C.C.A. On Opening	C.C.A. On Additions	TOTAL C.C.A. CLAIMED	U.C.C. DEC 31, 2009
CLASS 1	4%	62,067,700	0	(6,696)	0	(6,696)	2,467,015	(108)	2,466,908	59,594,097
CLASS 8	20%	157,179	13,412	0	0	13,412	30,442	1,077	31,520	139,072
CLASS 10	30%	1,909	0	0	0	0	546	0	546	1,364
CLASS 47	8%	78,434,921	11,045,237	0	(343,133)	10,702,104	6,190,956	345,588	6,536,544	82,600,481
		140,661,709	**11,058,649**	**(6,696)**	**(343,133)**	**10,708,821**	**8,688,959**	**346,558**	**9,035,517**	**142,335,013**

Table 4-3-6 D – CCA – 2009

		U.C.C. DEC 31, 2008	ADDITIONS 2009	DISPOSALS 2009	INTEREST CAPITALIZED 2009	TOTAL 2009 ADDITIONS NET	C.C.A. On Opening	C.C.A. On Additions	TOTAL C.C.A. CLAIMED	U.C.C. DEC 31, 2009
CLASS 1	4%	59,594,097	0	0	0	0	2,383,764	0	2,383,764	57,210,333
CLASS 8	20%	139,072	285,045	(2,100)	(25,000)	257,945	27,814	25,795	53,609	343,408
CLASS 10	30%	1,364	1,009,977	0	0	1,009,977	409	151,497	151,906	859,435
CLASS 47	8%	82,600,481	6,675,672	0	(150,000)	6,525,672	6,608,038	261,027	6,869,065	82,257,087
CLASS 50	55%	0	584,441	0	0	584,441	0	160,721	160,721	423,720
		142,335,013	**8,555,135**	**(2,100)**	**(175,000)**	**8,378,035**	**9,020,026**	**599,039**	**9,619,065**	**141,093,983**

1 *Table 4-3-6 E – CCA – 2010*

		U.C.C. DEC 31, 2009	ADDITIONS 2010	DISPOSALS 2010	INTEREST CAPITALIZED 2010	TOTAL 2010 ADDITIONS NET	C.C.A. On Opening	C.C.A. On Additions	TOTAL C.C.A. CLAIMED	U.C.C. DEC 31, 2010
CLASS 1	4%	57,210,333	0	0	0	0	2,288,413	0	2,288,413	54,921,920
CLASS 8	20%	343,408	0	0	0	0	68,682	0	68,682	274,726
CLASS 10	30%	859,435	378,000	0	0	378,000	257,831	56,700	314,531	922,905
CLASS 47	8%	82,257,087	4,368,288	0	(413,400)	3,954,888	6,580,567	158,196	6,738,763	79,473,213
CLASS 50	55%	423,720	299,587	0	0	299,587	233,046	82,386	315,432	407,874
		141,093,983	**5,045,875**	**0**	**(413,400)**	**4,632,475**	**9,428,538**	**297,282**	**9,725,820**	**136,000,638**

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EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE

Exhibit 5, Tab 1, Schedule 1

Cost of Capital

COST OF CAPITAL AND RATE OF RETURN

1.0 Cost of Capital

GLPT's proposed cost of capital is $17,587,400, as set out in *Table 5-1-1 A* below.

2.0 Capital Structure

GLPT recognizes that the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Cost of Capital Report") dated December 20, 2006 states that all electricity distributors should have a deemed capital structure of 60% debt and 40% equity. GLPT has used the Cost of Capital Report as a guide.

In the Cost of Capital Report, the Board allowed a transition period for utilities moving from any structure that was not already 60% debt and 40% equity. GLPT's most recently approved capital structure is 55% debt and 45% equity. For distributors with this structure, the Board allowed a two year transition period. Therefore, GLPT is proposing the same two year transition period as a part of this application, whereby the target capital structure of 60% debt and 40% equity will be achieved in 2011. As a result, in accordance with the Board's two-year phase in approach, GLPT is proposing a capital structure of 57.5% debt, and 42.5% equity for the 2010 test year.

Table 5-1-1 A – Cost of Capital and Rate of Return

2010 Test Year	Capital Component ($000's)	Capital Component (%)	Deemed Rates (%)	Return Component (%)	Return Component ($000's)
Deemed Debt	$ 120,174.5	57.50%	6.87%	3.95%	$ 8,260.8
Deemed Equity	$ 88,824.7	42.50%	10.50%	4.46%	$ 9,326.6
Rate Base:	$ 208,999.2	100.00%		8.42%	$ 17,587.4

3.0 Cost of Debt

GLPT currently holds $120 million in long term debt in the form of third party, series 1 bonds, with interest payable at a rate of 6.60%. Interest is paid semi-annually on June 16th and December 16th of each year. Principal will be reimbursed on maturity in June 2023. GLPT proposes a rate of interest on debt equal to the effective interest rate on its debt, which incorporates both interest payments and recovery of financing fees related to the issuance of additional debt and the establishment of a new Deed of Trust specific to GLPT. GLPT's effective rate of interest is 6.874%, which is approximately 0.746% lower than the current deemed rate for long term debt of 7.62%.[1]

In the Cost of Capital Report, the Board determined that short-term debt should be factored into rate setting, and that a deemed amount should be included in the capital structures of electricity distributors. The Board also states that many distributors

[1] Based on a rate base of $210 million where 57.5% is deemed as long-term debt, the net cost savings to ratepayers as a result of the use of the effective rate is approximately $900,000.

(utilities) are using short-term debt to finance their operations. GLPT is not one of those utilities, as it does not use short-term debt to finance operations. This is demonstrated in GLPT's historical and pro-forma financial statements, found at Exhibit 1, Tab 3, Schedules 1 and 2. The primary reason that GLPT does not use short-term debt to finance its operations is that the Deed of Trust under which the current bonds are held allows for no additional short-term indebtedness. This limitation on additional short-term indebtedness provides GLPT with a lower rate of interest on the existing bonds, the benefit of which is passed through to ratepayers through the use of the effective rate of interest on GLPT's debt.

Therefore, GLPT has calculated the cost of debt under the assumption that all of the deemed debt is long term debt, with no part deemed as short term. As a result the cost of debt for GLPT is $8,260,800.

4.0 Cost of Equity

GLPT's currently approved return on equity ("ROE") is 8.62%.

At the time of this filing, the Board is conducting its "Consultation Process on Cost of Capital Review" EB-2009-0084 (the "Consultation") in which the Board is consulting with stakeholders on possible changes in the methodology and approach for the determination of the ROE used as part of the determination of rates.

It is GLPT's understanding that the Board intends to advise as to its resolution of how to proceed with the determination of the ROE before the end of 2009 and implement any revision to its cost of capital guidelines for rates effective in 2010. Based upon GLPT's position in the Consultation, and because of the uncertainty as to the intended approach by the Board, for purposes of calculating revenue requirement and establishing rates, GLPT has used an ROE of 10.5% for its 2010 test year. This is consistent with the reports filed by experts in the Consultation and with the reports filed by GLPT's expert, Power Advisory LLC, in the Consultation. Attached as **Appendix "A"** is the report filed by GLPT dated September 8, 2009. As a result, the cost of equity for GLPT is $9,326,600.

GLPT notes that the ROE sought above relates to the carrying on of the transmission business in the ordinary course. This request is without prejudice to GLPT's submissions (attached in **Appendix "B"**) in the Board's consultation process on the regulatory treatment of infrastructure investments (EB-2009-0152), in which GLPT requested the Board move expeditiously to establish incentive cost recovery mechanisms and adders to ROE in respect of infrastructure investments. This is essential to attaining the infrastructure investments necessary for Ontario to achieve its transmission goals.

APPENDIX "A"

GLPT Submission in EB-2009-0084

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September 8, 2009

VIA RESS and COURIER

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

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli,

Re: Consultation on Cost of Capital - Board File No. EB-2009-0084

We are counsel to Great Lakes Power Transmission LP ("GLPT"). In respect of the above-noted matter, attached are the responses of GLPT prepared in conjunction with Power Advisory LLC relating to the Board's prescribed issues in this matter. Also attached for the Board's consideration is a report prepared by Power Advisory LLC on behalf of GLPT setting out in greater depth an analysis of the application of the ERP formula and the need to change from the current approach.

GLPT has made this submission using RESS and has sent three hard copies to the Board via courier.

Yours truly,

Charles Keizer

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IN THE MATTER OF a consultation by the Ontario Energy Board on the Cost of Capital for Electricity Distribution Companies

Issues for Discussion at Stakeholder Conference

1. **What method(s)/test(s) might the Board formally consider to determine whether the return on capital meets: (i) the comparable investment standard; (ii) the financial integrity standard; and (iii) the capital attraction standard?**

a) Methods for calculating return on equity

A range of different approaches have been employed across North America to establish the appropriate return on equity ("ROE"); the National Energy Board ("NEB") has recently proposed and accepted a different methodology for calculating the cost of capital. Each of these methods has advantages and disadvantages in setting the ROE. The appropriateness and reliability of these methods will vary depending on economic and capital market conditions. We briefly review them here.

The three methods most commonly employed are

1. The Discounted Cash Flow (DCF) model
2. The Capital Asset Pricing Model (CAPM)
3. The Equity Risk Premium (ERP) model.

The National Energy Board recently accepted the After-Tax Weighted Average Cost of Capital (ATWACC) methodology in its decision (RH-1-2008) on the appropriate cost of capital for the Trans Quebec & Maritimes Pipeline, Inc. (TQM).

In addition to their ability to meet the Fair Return Standard outlined in the question, criteria often applied to models for the determination of ROE are ease and transparency of application, sensitivity to cross-entity variations like risk, and ability to respond readily to changes in financial and economic market conditions which affect the regulated entities. The National Energy Board also discussed the ability of the ATWACC to allow comparisons across different financial structures.

i) DCF

The DCF methodology sets the ROE as that discount rate which will make the expected future cash flows (dividends plus share price appreciation) equal to the current value of the equity. The ROE is therefore set at the rate of return which is already implicit in the value of the company's stock. To account for normal stock price fluctuations, the calculation is averaged over some period. The advantage of this methodology is that it is entirely market-oriented, letting the ROE reflect the market's valuation. Difficulties include potential variability in the ROE as the stock price and expectations fluctuate and, for Ontario, the fact that most electricity distribution and transmission utilities are not publicly traded and hence have no open market valuation. This method meets the comparable investment standard by virtue of its market orientation and use of a peer group of similarly situated utilities. It meets the financial integrity standard by setting ROE at the level expected by shareholders, and the capital attraction standard similarly by setting the ROE at a rate that attracts capital.

ii) CAPM

The CAPM model's structure is similar to the ERP approach, but it relies on market valuations by looking specifically at the relationship between the subject stock and the market. It calculates the ROE as an underlying risk-free rate plus a factor that measures the degree to which changes in the value of the utility stock are correlated with changes in the overall market. The formula for the CAPM is

$$K_e = r_f + \beta(r_m - r_f),$$

where r_f is the risk-free market rate of return and r_m is the rate of return for the market. β is the covariance between the company's return and the market; that is, it measures the extent to which the company's returns are influenced by the same factors as the market as a whole. With this model, the ROE is determined by current market interest rates and the historical relationship between the company's returns and those of the market. The advantage of this methodology is that it reflects the market's historical perception of the risk of a specific company. Disadvantages for Ontario include that, like the DCF model, it relies for its value on the performance of the stock in the market, while Ontario most distributors and transmitters are not publicly traded and therefore have no readily discoverable relationship between their returns and those of the market.

iii) ERP

The ERP model assumes that equity is more risky than debt, since the equity owners share in the residual profits, not in the interest (which is paid before profit is calculated.) To compensate for this risk, they expect a higher rate of return than the interest rate the firm is paying to lenders. The ERP model therefore adds an equity risk premium to a risk-free (market-based) rate of interest. The model used by the Board is expressed as

$$K_e = K_0 + \gamma(r_{forecast} - r_f)$$

Where K_0 is the original ROE in the first year of the program, r_f is the risk-free rate (the yield on long-term government bonds) at the time the formula was established, $r_{forecast}$ is the current forecast of the long-term government bond rate. γ is a parameter that represents the responsiveness (or elasticity) of ROE to changes in the long-term government bond interest rate forecast. For Ontario electricity distributors, k_0 is 9.35%, r_f is 5.5% and γ is .75. The advantage of this method is that it is transparent and, having been in use for over a decade in Ontario, familiar and understandable to everyone. Its disadvantages include its inability to respond to changing conditions either of the market or of the relative risks of one or more of the regulated entities. In addition, changes in ROE are based solely on changes in the long-term government bond rate. Therefore, it is insensitive to changes in other financial market conditions. It also provides the same ROE to all distribution utilities, which does not recognize their varying degrees of risk.

b) Tests for determining whether the return meets the three standards

We would suggest three sets of empirical tests to determine whether each of the standards is being met:

(i) comparisons of the ROE to those of other utilities, such as those in the United States (which the NEB recognized as a valid comparator group in its recent TQM decision);

(ii) financial market measures for financial integrity, such as times interest coverage; and

(iii) actual cost of capital to utilities, such as the credit spread relative to a benchmark debt.

A simple and simplistic measure of whether returns are fair is to observe whether new investors are seeking to invest. The Ontario transmission market should be attractive due both to the anticipation that it will need significant capital investment to expand in the near future, and the flexibility of the regulatory framework to accept new transmitters. It is instructive to compare the number of transmission investors looking to invest in Ontario with the recent experience in the regulated Texas electricity market, where in excess of a dozen investors both from within and outside Texas competed to participate in the $5 billion transmission investments mandated by the state's Competitive Renewable Energy Zone initiative.

2. **That new firms have not entered and do not appear to be seeking to enter is one indication that the market is not attracting interest, which could be due to the inability of firms to earn returns commensurate with risks, which means that it is not meeting the capital attraction part of the FRS. Is the current deemed capital structure appropriate? If not, what alternative(s) might the Board consider?**

The critical issue for this stakeholder consultation is the ERP formula. This should be the focus of this investigation. GLPTLP is not proposing to take a position on the appropriate debt/equity ratio for electric transmission or distribution companies in Ontario at this time.

3. **Should the approach to setting cost of capital parameter values differ depending on whether a distributor finances its business through the capital markets or through government lending such as Infrastructure Ontario or through bank lending? If so, what would be the implications, if any, of doing so?**

The approach to setting the cost of debt should reflect the underlying cost of the debt to which the utility has access. If the utility has access to lower cost debt from Infrastructure Ontario then the utility's cost of debt assumptions should reflect this.

However, the same approach should be used to establish the ROE for all utilities regardless of whether the utility must access equity from public markets or from a government entity. In both instances, the ROE must provide the owners of the company with returns sufficient to attract capital, and for utilities reliant on capital markets, the return have to meet the expectations of the capital markets. Government-owned utilities should not be discriminated against (and have lower regulated ROEs) because of their public ownership and lack of need to access the capital markets.

Furthermore, there are risks associated with government-owned utilities that are not adequately recognized. With the taxpayer effectively the equity owner, taxpayers bear the risks associated with insolvency of the utility and this is at a time when provincial and municipal budgets are stressed by the financial downturn. This is the same risk faced by equity in investor-owned utilities and the compensation should be similar.

Government-owned utilities should receive the same market-based ROE as investor-owned utilities to ensure that capital is efficiently allocated. If they receive a lower ROE than investor-owned utilities then this may contribute to over investment in distribution and transmission infrastructure recognizing that the generation sector can be a "competitor for investment" and it relies on private capital which must earn a market-based return over the long run. Demand side management and conservation can also be competitors for investment. Where capital intensive transmission or distribution investment competes with less capital intensive demand side management and conservation measures, the allocation of investment between transmission and distribution assets and conservation will be based on the respective costs of these investments. Therefore, if the costs of capital for transmitters and distributors are understated by setting an ROE which is too low, there will be too much transmission and distribution investment. .

4. **Does the analysis in the Concentric Report provide a reasonable foundation for satisfying the comparable investment test standard?**

Yes. The Concentric Report performed significant analysis to construct a comparable group of utilities in the United States. First, they considered the criteria that bond rating services apply to determine risk.[1] Then, they considered a set of screening criteria to establish similarity. Ultimately, they concluded that the gas distributors in Ontario are largely comparable to those in the United States.[2] In addition, Concentric narrowed its sample to eight US utilities which could, by the criteria, be considered most comparable to those in Ontario. Again, they concluded that there remains a clear difference in allowed ROEs between Ontario utilities and comparable utilities in the United States. This analysis developed and considered reasonable criteria to measure comparability, gathered the available data, and applied the criteria. The study therefore forms a reasonable foundation for satisfying the comparable investment test standard.

A similar evaluation by NERA concluded "that the regulatory environments in Canada and the US are highly similar and directly comparable." (Allowed Return on Equity in Canada and the United States – An Economic, Financial and institutional Analysis, National Economic

[1] Concentric Energy Advisors, "A Comparative Analysis of Return on Equity for Natural Gas Distributors", June 14, 2007, prepared for the Ontario Energy Board, pg. 27.

[2] Concentric Energy Advisors, pg. 32.

Research Associates, Inc., Kenneth Gordon, Ph.D. and Jeff D. Makholm, Ph.D., February 2008, p. 6).

5. **If not, what might the Board use as a comparator group?**

Based on the Concentric and NERA analyses, US utilities can represent a reasonable comparator group. Since most regulators in Canada now use the ERP formula, comparing returns in Ontario to returns elsewhere in Canada does not allow for a test of the ERP formula itself. There is circularity in that comparison, given that the other jurisdictions in Canada employ the same basic approach for establishing ROEs.

The Concentric Report notes that returns to utilities in Canada were about equal to those in the United States before the widespread adoption by Canadian regulators of the ERP formula. Since then, as the Concentric Report also shows, ROEs in Canada have fallen relative to those in the United States.

6. **Were the Board to only consider the use of Canadian utilities as a comparator group, is there an issue with circularity, given that the ROEs of these utilities are, and have been established by a mechanism similar to currently used by the Board?**

Yes, there is a circularity issue with the use of Canadian utilities as a comparator group. This is supported by the high correlation coefficient (0.88) between Canadian utility ROEs and Long Canada Bond rates.

The Concentric study established that the disparity in ROEs between gas distribution utilities in Canada and the United States extends throughout Canada. They noted, for example, that the range of ROEs in Canada does not overlap at all with those in the United States.[3] Since a common factor among the Canadian utilities – the use of the ERP formula – is at issue here, it is not possible to use Canadian utilities to compare the results of the formula to those with some other approach to setting ROE.

7. **Should the ERP approach be reset given that when the formula was first established the reference bond rate was 8.75%?**

Yes. If the current ERP formula is retained in its present form, it must be reset in light of significant changes in Canadian and North American economies and capital markets. These changes and current financial market conditions are delineated in more detail in the Power Advisory Report filed with this response.

Briefly, financial market conditions and utility risks have changed dramatically since the ERP formula was first established. In 1997, the Government of Canada had reduced, but not yet

[3] Concentric Energy Advisors, pg. 24.

eliminated, its budget deficit. The deficit was not forecast for elimination for two more years[4]. The inflation rate had stayed below 5% for about five years. The inflationary expectations built into the markets had not yet fully been removed, but the influence began to be felt in 1997.

For the first five months of 1997, the monthly average yield on 30-year Government of Canada benchmark bonds was above 7%. It has not reached that level again. Yields began to drop from the middle of 1997 on, finishing the year just below 6% and with an annual average of the monthly averages of 6.66%. The following year, yields had dropped further to average 5.59%. So conditions in Canadian financial markets were changing in 1997 and have continued to change. As the Report pointed out, the monthly average yield on the 30-year benchmark bonds had not been below 4% until 2008, and only for one month before November of 2008. Since November of 2008, the yield has been consistently below 4%.

This low yield reflects the current monetary policy which is aimed at stimulating the economy through expanding the money supply and reducing interest rates. Government of Canada bond yields are therefore at lows not seen in more than 30 years. At the same time, the recession has worsened corporate performance and raised investors' perceptions of risk in corporate equities. Investors have therefore demanded higher risk premiums for corporate (including utility) equities.

Directionally, the yields on long-term Canadian government bonds and corporate returns on equity have diverged. Any relationship that held in 1997 no longer holds.

8. Should the ERP approach be reset on a regular basis (e.g., every 4 or 5 years) to mitigate the issues described in the 1997 Compendium?

Yes, if the ERP approach is retained, at a minimum it should be reset every 4 or 5 years. While the Power Advisory Report outlines two alternative ERP formulas that should be more robust and the ROE estimates that they generate less subject to bias and distortions from market events than the Board's current ERP formula, a regular reset of the ERP formula is appropriate given the potential for bias being compounded in the ROEs. The *Compendium to Draft Guidelines* acknowledged that "over time these parameters and adjustment factors will have a cumulative or compounding effect on the results of the formulaic ROE mechanism. The use of an inappropriate initial ROE will either inflate or understate subsequent rate determinations."[5] Therefore, with this compounding effect a small mis-specification of the formula can result in significant bias in the ROE determination over time. To a large degree using the ERP formula to establish the ROE for utilities is akin to driving using the rear view mirror. The relationship embedded in the ERP formula is based on the past performance of the financial and credit markets and in no way reflects changes in this relationship that could occur in the future. This argues for re-evaluating the appropriateness of the ERP formula on a regular basis. This potential for compounding bias

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[4] Government of Canada, Department of Finance, Economic and Fiscal Update, October 1997.

[5] p. 6.

in the ERP approach is another reason for a thorough review of the Cost of Capital methodology used by the Board.

9. How might the Board address the potential issues arising from the application of the current methodology as a single, point-in-time calculation?

One strategy for reducing the weight given to current conditions which might not be representative of future conditions is to use averages for parameter values that are used in the model. Whether averaging is appropriate depends on whether it neglects current information that might better reflect anticipated future market conditions. Exponential smoothing techniques could be used to weight more heavily the historical lagged data that has proven to be the best predictor of the future. The use of consensus forecasts for the future bond yields is valuable given that it better reflects anticipated future market conditions and that consensus forecasts have been shown to be more accurate than individual forecasts.

10. How should the Board establish the initial ROE for the purposes of resetting the methodology?

To properly and fairly review such a central aspect of the regulation of electricity and gas distributors in Ontario as the initial ROE , the Board should conduct a formal proceeding with evidence from all stakeholders. The proceeding should focus on both the methodology for setting the ROE and the level of the initial ROE.

In such a proceeding, all stakeholders would be able to present evidence on such matters as the degree to which the ERP formula meets the Fair Return Standard; what alternative methodologies they would prefer to the current ERP formula, and the initial level of ROE they believe meets the criteria. The issues list for this proceeding should be broad enough to allow a thorough discussion of these various methodologies and testing of the evidence supporting or opposing them.

After hearing the evidence and the submissions of the participants in the hearing, the Board would decide on a new (or revised) methodology. It would also determine the initial level of ROEs to be set under the new methodology. As the first application, the initial ROE should be a result of the application of the methodology to the then current conditions.

Since, as we and others have argued in these responses, the current conditions of the financial markets are not typical of the immediate past and will probably change as the economic and financial situation of Canada changes, the Board will need to take particular care to ensure that the initial ROE that it sets meets the FRS criteria and that it will not set a biased level that the ongoing methodology (like the ERP methodology) will only magnify.

11. Is the government (of Canada) bond yield the appropriate base upon which to begin the return on equity calculation.

Not necessarily. Long Canada Bonds are a distinctly different financial instrument than utility equities, with different risks and different determinants of prices and value. Long Canada Bonds are low risk. Long Canada Bond rates are driven by monetary and fiscal policy and reflect investor expectations regarding future inflation and the real cost of capital. Long Canada Bonds have little credit or return risk. Utility equities have all these risks and bear greater return and credit risk than Long Canada Bonds. Therefore, it is inappropriate to attempt to forecast utility ROEs by only considering Long Canada Bond rates.

Power Advisory proposed two alternative models in the attached report prepared for GLPTLP. The first model established utility ROEs based on BAA corporate bond yields with a 6 month lag. This model specification would be relatively easy to implement. The second model established utility ROEs based on the 30 year government bond yield with a six month lag and market expectations regarding near term volatility of a stock market index with a six month lag. Both models performed better in terms of standard econometric measures than just using the government bond yield as the sole explanatory variable.

12. What is the relationship between corporate bond yields and the corporate cost of equity? Is this relationship sustainable?

This relationship is more stable than that between Long Canada Bond and corporate cost of equity. Regression analysis results indicate that corporate bond yields are a better predictor of utility ROEs than Long Canada Bond rates. The adjusted r^2 for a regression where Long Canada Bonds is the sole explanatory variable (along with a constant) is 0.864 versus 0.889 where a BAA corporate bond is the sole explanatory variable (along with a constant).

As discussed in the attached report prepared for GLPTLP by Power Advisory, corporate bonds will better reflect the impact of changes in credit risks. Such changes aren't likely to affect the rates for Long Canada Bonds, but would affect the rates for corporate bonds and utility ROEs.

13. Does the current approach used by the Board to calculate the ERP remain appropriate? If not, how should the ERP be calculated?

The current approach used by the Board to calculate the ERP isn't appropriate. As discussed further in Power Advisory's September 8th report, the Board's ERP formula overstates the relationship between Long Canada Bond rates and utility ROEs and as a result understates the required ROE to satisfy the Fair Return Standard. In the short-term the ERP formula should be revised by replacing the "0.75" coefficient with a value of from "0.45" to "0.50". Longer term the ERP formula should be revised and based on the relationship between corporate debt rates and utility ROEs or alternatively an additional variable should be added to the ERP formula to better reflect equity risks. Power Advisory evaluated an explanatory model which in addition to long term government bonds used the VIX which measures near-term volatility of the Standard and Poor's 500 Index. This model performed considerably better than the Board's existing ERP formula in terms of goodness of fit.

14. **Should the Board adopt a dead band? If so, what should the range of the dead band be?**

For administrative ease, the Board could adopt a narrow dead band, say ±10 bp. The value of such a dead band depends on whether it would avoid having utilities restate rates. However, given that ROE is just one element of utility rates, even if the ROE were not to change, other elements of the ratemaking process are likely to change which would require the utility to restate rates. Therefore, it isn't clear that a dead band would result in significant savings in the costs of administering rates.

15. **Should the Board adopt trigger mechanism(s)? If so, how should the Board review the methodology?**

A trigger mechanism would be useful for review of the cost of capital mechanism. If the mechanism is formulaic, one set of criteria could trigger a review of the formula's parameters and more severe criteria could trigger a review of the formula or of the approach itself.

Trigger mechanisms could monitor for breaks in historical relationships among financial market variables and for other conditions such as changes in equity market volatility through market volatility indices like VIX or VMX.

16. **What is the appropriate test(s) to ensure the FRS is met (e.g., corroborating results for reasonableness relative to other benchmarks or through other methods?)**

See the empirical tests reviewed in the response to Question 1.

17. **What information might the Board need to definitively determine that market conditions are having an effect on the variables used by the Board's cost of capital methodology?**

GLPTLP believes that the critical question is whether market conditions are being adequately reflected by the variables used in the Board's cost of capital methodology. One measure of the degree to which market conditions effect on these variables is appropriate and within norms, are the values produced by the Board's cost of capital methodology. To the degree that the relationships between these values (e.g., the ROE and long-term debt rate) change significantly then the Board should evaluate the reasonableness of these changes in light of market conditions.

GLPTLP believes that there are no simple tests that can be applied to evaluate the reasonableness of the results produced by the Board's cost of capital methodology. The reasonableness of the results produced by the Board's cost of capital methodology can be assessed by applying judgment regarding whether the results produced are generally consistent with financial and credit market conditions. For example, when the ROE decreases from the previous year, it is appropriate to consider whether conditions in the financial and credit market are consistent with such a decline, i.e., do they indicate lower interest rates for a comparable credit risk and lower risks for equities in general.

18. Should the Board consider monitoring indicators like these on an on-going basis to test the reasonableness of the results of its cost of capital methodology?

Yes but from time-to-time rather than continuously. It is not necessary to monitor these indicators on an on-going basis because the Board's cost of capital methodology is only applied at specific time periods. However, when the Board's cost of capital methodology is being applied, it is important to assess financial market conditions because these conditions change constantly: the Board's FRS ROE also changes and in ways not always related to underlying market fundamentals.

19. What other key metrics used by financial market participants to determine whether financial markets conditions are or are not "normal" might the Board consider?

The key metrics that should be considered by the Board are those that will offer insights regarding the reasonableness of the relationships embedded within the Board's ERP formula and cost of capital methodology. These metrics include spreads between "risk free" bonds like Government of Canada bonds and corporate bonds, the shape of the yield curve, and investor expectations regarding volatility of stock market indices including MVX and VIX.

Evaluation of the Ontario Energy Board's Equity Risk Premium Formula

Prepared for:

Great Lakes Power Transmission LP

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Power Advisory LLC

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Contents

Executive Summary

The equity risk premium (ERP) formula used by the Ontario Energy Board (OEB or Board) to set the Return on Equity (ROE) allowed for gas and electricity distributors and electricity transmitters under the Board's jurisdiction does not meet the Fair Return Standard (FRS). While current financial market conditions exacerbate its shortcomings, the formula has proven to provide inadequate returns over much of the time that it has been in use. Therefore, the Board cannot assume that the current perverse results produced by the ERP formula will be remedied when the credit markets heal. The deficiencies of the current ERP formula are more systemic. The Board should undertake a formal proceeding to review its ROE methodology and the reasonableness of the results it produces.

The fact that the Board's ERP formula is broken and doesn't meet the Fair Return Standard is demonstrated by:

1. The unrealistic ROE values that it has produced. The most recent ROE that it produced provides a mere 39 basis point premium over long-term debt and this premium must compensate investors for the considerably greater risks of equity. Furthermore, this ROE declined by 24 basis points relative to the previous ROE value at a time when equities (including utility stocks) have been subjected to unprecedented volatility.

2. The ERP formula assumes that utility ROEs can be explained solely by changes in Long Canada Bond rates which are a distinctly different financial instrument with different risks and different determinants of prices and value than utility equities. The net result is that the Board's ERP formula is missing critical variables that influence the required returns for utility equities.

3. Failing to include these critical variables in the ERP formula causes the formula to overstate the relationship between Long Canada Bond rates and utility ROEs. The net effect is that the ".75" coefficient in the ERP formula is too high. As a result, the significant declines in Long Canada Bond rates since 1997 have resulted in declines in utility ROEs produced by the ERP formula which cause these ROEs to be below the Fair Return Standard.

4. The factors that have led to declines in Long Canada Bonds do not all result in declines in the required ROEs for utilities, causing the ERP formula to understate the ROE needed to meet the Fair Return Standard.

5. The amount of risk faced by regulated utilities has increased significantly since the ERP formula was first adopted. Conservation and demand management programs and unprecedented declines in several of Ontario's major electricity consuming industries pose increased demand risks, with attendant risks to revenues. The capital and phasing required for major new transmission facilities required to implement the *Green Energy and Green Economy Act* present increased financial risks. These increased risks are not reflected in the ROEs produced by the ERP formula.

1. Introduction and Purpose

Power Advisory LLC (Power Advisory) was engaged by Great Lakes Power Transmission LP (GLPT) to provide an independent assessment of the Ontario Energy Board's (OEB's or Board's) Equity Risk Premium (ERP) formula. Specifically, Power Advisory was asked to assess whether the existing ERP formula and parameters provide a proper basis for establishing a required return on equity (ROE) for an electricity distribution or transmission company in Ontario that meets the Fair Return Standard (FRS) and, if the formula does not do so, to propose an alternative formula that would provide a reasonable estimate and satisfy the Fair Return Standard.

The OEB issued a letter on March 16, 2009 to establish a consultative process to consider whether current economic and financial market conditions warrant an adjustment to any of the Cost of Capital values identified in the Board's in its February 24, 2009 letter. On June 18, 2009, the Board issued a letter announcing a review of its policy regarding the cost of capital and a stakeholder conference to provide a discussion of issues regarding its ERP formula.

The *Issues for Discussion at Stakeholder Conference* document noted that

> "the Board has found the Equity Risk Premium ("ERP") approach to be pragmatic and efficient given the Ontario market structure and the number of utilities that the Board regulates. These factors remain unchanged and the Board has concluded that an ERP approach remains the most appropriate in the current circumstances. However, the Board will review the application and the derivation of the current ERP approach to determine if it is sufficiently robust to guide the Board's discretion in applying the FRS."[1]

This report provides Power Advisory's assessment of the ability of the ROE produced by the current ERP formula to meet the FRS and discusses alternative formulas that would provide a long-term fix.

1.1 Summary of Power Advisory's April 17th Report

On March 16, 2009, the OEB issued a letter to establish a consultative process to consider whether current economic and financial market conditions warrant an adjustment to the Cost of Capital parameter values, but not to consider the Cost of Capital methodology itself. In response to this letter, GLPT asked Power Advisory for an independent opinion on these parameters. A report from Power Advisory was filed with the Board on April 17, 2009.[2] This section summarizes that report, which was confined to the issue of whether current market conditions warrant a change in the parameters of the ERP formula.

The Report noted that the ERP formula used by the OEB assumes a fixed relationship between the equity risk premium and long-term Government debt yields. However, the OEB acknowledged that opinions differ on the relationship itself and that the relationship may change as financial market conditions

[1] Attachment B: Issues for Discussion at Stakeholder Conference, p. 1.

[2] Power Advisory LLC, "Comments on the Cost of Capital in Current Economic and Financial Market Conditions," April 17, 2009, prepared for GLPT.

change.[3] The equity risk premium must compensate investors for the additional risks associated with equity relative to debt. The Power Advisory report gave evidence that the ROE resulting from the OEB's formula does not adequately compensate investors for the additional risks associated with equity under current financial market conditions.[4]

There are three aspects of the current economic and financial markets that suggest any fixed relationship between long-term Government debt and equity risk premiums is unlikely to be maintained:

(1) Worsening economic conditions and subprime mortgage exposure resulted in a flight to quality which has reduced yields on Government Bonds and increased those for other investments, such as utility equities;

(2) The bankruptcies and forced sales of major financial intermediaries and the deleveraging and unwinding of positions led to reduced liquidity and a collapse in credit availability for corporate borrowers. This increased Corporate debt yields and required stock ROEs; and

(3) In response to these conditions and a deepening recession, central banks coordinated efforts to reduce interest rates. The net effect has been a dramatic decline in government interest rates, with increased spreads between government and corporate debt.[5]

The net effect of these developments was that any fixed relationship that had existed between changes in Long Canada Bonds and utility ROEs assumed by the ERP formula no longer held. This report expands on this analysis and extends it to the broader question of the validity of the ERP formula under the full range of economic and credit market conditions.

1.2 Contents of this Report

This report contains four chapters, the first of which is this introduction. The second provides a critical assessment of the ERP methodology focusing first on the current formula and the resulting 2009 ROE estimate in light of the current financial market conditions and then on the systemic deficiencies of the formula that apply to the full range of economic and credit market conditions. The third chapter responds to comments offered in various April 17th submissions to the OEB that suggested that the ERP formula continues to produce reasonable results. The final chapter recommends alternative ERP formulas. A long term fix for the ERP formula is proposed. These changes should be made to the ERP formula to better allow it to reflect a diverse range of economic and financial market conditions such as have recently occurred.

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[3] Ibid., pp. 4-5.

[4] Ibid., pp. 8-9.

[5] Ibid., pg. 2.

2. Review of the Equity Risk Premium Formula Results

In a 2004 Decision the OEB outlined: "two reasons which would justify a review of the formula. The first justification would be significant changes in market conditions. The second justification would be significant changes in the utility risk."[6] Power Advisory believes that both of these conditions have been satisfied. We first review the changes in financial market conditions and evidence regarding how the results of the ERP formula are inconsistent with these conditions. We then review changes in utility risk since the ERP formula was implemented by the OEB in 1997.

2.1 ERP Formula Results Inconsistent with Financial Market Conditions

The clearest indication that the Board's ERP formula must be revised is the most recent ROE that it yielded. This ROE provides a mere 39 basis point premium over the equivalent long-term debt rate. This is relative to a 247 basis point spread provided by the OEB's 2008 cost of capital parameters.[7] In the OEB's words, the equity risk premium methodology "relies on the assumption that common equity is riskier than debt and that investors will demand a higher return on shares, relative to the return required on bonds, to compensate for that risk."[8] This premium must compensate investors for these greater equity risks at a time when equities have been subjected to unprecedented volatility. While there is evidence that credit spreads and relationships in the financial and credit markets are beginning to return to more normal conditions, it is likely that the recent financial crisis will have a lasting effect on investor perceptions of risk and as a consequence the price of risk.

Another indication that the ERP formula is producing results that are out of line with economic fundamentals is that the 2009 ROE declined by 24 basis points.[9] This decline in the ROE suggests a lower risk environment; whereas in fact market risks increased.

Equity markets recently have experienced unprecedented volatility. This is demonstrated by the MVX and VIX which are the volatility indices published by the Montreal Exchange and the Chicago Board of Options Exchange.[10] An increase in the MVX and VIX signals investor expectations of greater share price volatility. The VIX reached an all time high in October 2008 and remained high for several months.[11] A

[6] RP-2002-0158 Decision and Order, para. 114

[7] Ontario Energy Board, *The Cost of Capital in Current Economic and Financial Market Conditions*, EB-2009-0084, p. 1.

[8] *Compendium to Draft Guidelines on a Formula-based Return on Common Equity for Regulated Utilities (Compendium to Draft Guidelines)*, March 1997, p. 6.

[9] The ROE produced by the ERP formula is 8.01% relative to the 8.35% ROE allowed in 2008.

[10] MVX measures the expected volatility over the next month of the Canadian Standard and Poor's/Toronto Stock Exchange 60 Index. VIX measures market expectations regarding the near-term volatility of the Standard and Poor's 500 Index, a broad-based market index.

[11] The MVX reflected a corresponding increase as investors expected increased stock market index volatility. Utility shares have also experienced increased volatility.

fundamental precept of finance is that investors require higher returns to compensate for higher risk. As the expectation of increased volatility affects investor perceptions, investors will require an increase in ROE as compensation for this increased volatility. The discounted cash flow model results presented in Power Advisory's April 17th report, which was filed with the OEB, indicated that utility ROEs increased from 11% to 12.5% from the first quarter of 2007 to the first quarter of 2009.[12] Therefore, expected utility ROEs actually increased during this period rather than declined as implied by the ERP formula.

2.2 Failure of ERP Formula to Produce Fair ROEs not Surprising

The inability of the ERP formula to provide a reasonable ROE under these economic and financial market conditions isn't surprising. The ERP formula assumes that changes in utility ROEs can be explained solely by changes in Long Canada Bond rates. This is unrealistic. Long Canada Bonds are a distinctly different financial instrument than utility equities, with different risks and different determinants of prices and value. Long Canada Bonds are low risk. Long Canada Bond rates are driven by monetary and fiscal policy and reflect investor expectations regarding future inflation and the real cost of capital. Long Canada Bonds have little credit or return risk. Utility equities have all these risks and bear greater return and credit risk than Long Canada Bonds.

Government and corporate bond yields (and by extension utility ROEs under most conditions) are likely to be highly correlated as long as credit risks don't materially change. However, this relationship would not necessarily hold under financial market conditions as extreme as have been experienced or in other situations where the factors affecting these two financial variables diverge. For example, with a change in credit risks such as occurred in 2008 with the Lehman Brothers bankruptcy this relationship will break down and the predictive power of the ERP formula with it. Similarly, expansionary monetary policy drives down the yields on government debt while not necessarily impacting corporate rates of return to the same degree. When implementing the ERP formula the OEB acknowledged this: "[a] disadvantage of using the ERP approach is that ...historical-average risk premium calculations are time sensitive and subject to considerable volatility from period to period."[13]

This is particularly relevant given the investor flight to quality and use of monetary policy to reduce interest rates to promote economic activity. In these circumstances, any historical relationship between Long Canada Bonds and equity risk premiums is unlikely to be maintained. Finally, a relationship that was appropriate in the early 1990s may no longer be appropriate in 2009 given changes in financial markets. When this formula was initially set Long Canada Bond yields were 8.75% and had recently been close to 10%.[14] That the apparent relationship between Long Canada Bond yields and utility ROEs no longer holds at these levels supports the fact that these financial variables respond to different market factors. In sum, it is unreasonable to assume that changes in Long Canada Bond rates will fully reflect required changes in utility ROEs, particularly under recent financial market conditions.

[12] *Comments on the Cost of Capital in Current Economic and Financial Market Conditions*, prepared for Great Lakes Power Transmission LP

[13] *Compendium to Draft Guidelines*, p. 6.

[14] OEB, Issues for Discussion at Stakeholder Conference, July 30, 2009, p. 4.

Econometrics indicates that if a variable is omitted from the "correct model" specification the parameter estimates for the remaining variables will be biased if the omitted variable is correlated with these variables. To the degree that these variables (i.e., the omitted and those in the model) are positively correlated the coefficient of the remaining variables will take on the effect of the omitted variable(s).[15,16] Therefore, the coefficient(s) for the variables in the regression equation overstate the effect of changes in these variables on the dependent variable. Specifically, the coefficient for the explanatory variable will be higher than it should be. In terms of the ERP formula employed by the OEB this suggests that the .75 coefficient is too high.[17] In our April 17th report we estimated a regression coefficient for the ERP formula for changes in Long Canada Bond rates of .472.

Therefore, the significant decline in Long Canada Bond rates since 1997 has resulted in too large a decline in the utility ROEs produced by the ERP formula such that these ROEs do not satisfy the Fair Return Standard. Furthermore, the deficiencies in the ERP formula are systemic and not just a consequence or reflection of recent economic and credit market conditions.

This potential for the compounding effect of a small mis-specification of the formula which results in significant bias in the ROE determination over time was acknowledged by the OEB in its *Compendium to Draft Guidelines:* "over time these parameters and adjustment factors will have a cumulative or compounding effect on the results of the formulaic ROE mechanism. The use of an inappropriate initial ROE will either inflate or understate subsequent rate determinations."[18]

Given the prevalence of the ERP for setting utility ROEs in Canada and its limited application in the US, this compounding effect explains why Canadian ROEs are considerably below those of US utilities even though others have found that there are no appreciable differences in regulatory or financial risks, operating characteristics, or tax environment that justify the differences in ROE allowed in the US and Ontario.[19]

2.3 Changes in the Canadian Economy and Financial Markets Since the ERP was Specified

The situation of the Canadian economy and financial markets is very different now from that in 1994, when first the British Columbia Utilities Commission, then (in 1995) the National Energy Board, and the

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15 Robert S. Pindyck and Daniel L. Rubinfeld, *Econometric Models and Econometric Forecasts*, Second Edition, 1981, p. 129.

16 As discussed further below, one possible additional explanatory variable is corporate bond yields which are highly correlated with government bond yields.

17 $ROE_t = 9.35\% + 0.75 \times (\text{Long Canada Bond Forecast}_t - 5.50\%)$

18 p. 6.

19 Concentric Energy Advisors, A Comparative Analysis of Return on Equity For Electric Utilities, June 2008.

OEB in 1997 initiated the ERP formula-based methodology for determining ROEs for regulated utilities. The formula makes the changes to allowed ROEs dependent only on changes in the rate of interest on long-term Government of Canada bonds. To be valid, therefore, the formula had to reflect a stable relationship between the interest rate on long-term Government of Canada bonds and the rate of return on equity for utility shares. This section shows how these variables have diverged because they do not respond in the same way to financial market events.

This chapter analyzes the factors that drove government bond rates over the last 20 years and the impacts on the variables which drive the ERP formula and discusses their current dynamics versus those that prevailed in the mid 1990s. As outlined below, these dynamics show that these variables now respond to much different economic drivers.

2.3.1 Long-term Government of Canada Bonds

The interest rate on sovereign lending from a stable government, such as that of Canada, is cited as a "risk-free rate". Such bonds are felt to have no risk of default or of failure of the borrower to meet all of its obligations.[20] Furthermore, if the bonds are held to maturity then the holder is guaranteed to earn the coupon rate and bears little return risk.

However, while there is no risk of default of the nominal amount of the bond and its interest, lenders do still bear risk. If there is unanticipated inflation in the currency in which the bond is denominated, then the repayments of both principal and interest will have a lower real value (that is, a lower value in terms of their ability to purchase goods and services) than was anticipated when the bond was purchased. Lenders therefore look at a nominal interest rate as a combination of a real rate of interest and compensation for expected inflation. If the actual inflation rate is higher than expected, the real return will be lower than expected once the nominal interest rate is set.

The first application of the ERP formula in Canada was made at an atypical time in Canadian economic and financial history. In the early 1980s, Canada had endured a period of very high inflation (above 8% per year from 1975 to 1983, except for a dip to about 6.5% in 1976). Canada had been running large fiscal deficits during that time. The result was that interest rates on Canadian government securities became quite high. Even though inflation had started to come down by the mid 1990s as a result of a determined effort by the central bank, the government continued to run very large fiscal deficits. These forced the government to be a very active borrower, driving up interest rates in order to attract needed capital. In addition, investors demanded a premium on these bonds given the expectation that the consequence of the continued high fiscal deficits would be increasing inflation as a way to mitigate the cost of the debt repayments. These conditions changed dramatically after the mid 1990s. Canada's fiscal deficit not only declined but turned into a large surplus, taking the Canadian government out of the business of issuing net new securities and taking pressure off the financial markets. The reduction in government borrowing left greater room for private borrowing.

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[20] While governments can go bankrupt, the market expects that the circumstances under which a stable government like Canada's would go bankrupt would be so extraordinary that it is likely that no investments would be safe.

The inflation rate stayed firmly within the Bank of Canada's target range of 1-3% per year. Finally, this good performance on both the fiscal and the inflation fronts led investors to trust the performance of the Canadian government and to reduce the implicit inflation risk premium in Canadian government bonds.

An easy way to see this reduction is to look at the Canadian government's real interest rate bond. This is an indexed bond with the principal linked to the rate of inflation and a real interest rate representing the real net return. It was introduced in the 1990s to allow Canada to borrow without having to pay a large inflation risk premium. In the early 1990s the yield on these bonds was over 4%; by January of 2008 it was 1.94%[21] and the current rate is about 1.80%.[22] Since January of 2008, forces have acted to drive Canadian interest rates even lower. The economic crisis originating in the US sub-prime lending markets has resulted in a recession in Canada and most other developed countries. Monetary authorities in Canada, like those in other countries, have adopted monetary policies intended to stimulate the economy. These have meant increasing the money supply, driving Canadian government bond rates and other short term rates to unusually low levels in order to stimulate consumer and business spending.

The average rate on the Canadian government benchmark long-term bond rate for the last 10 years (1999-2008) was just over 5%. That is a significant drop from its previous 10 year average of almost 8.4%, when the rate was under pressure both from government borrowing and from investor fears of future inflation. But the rate has now fallen further. Prior to November 2008 it had been under 4% for only one month; since then, it has been under 4% for every month, but one.[23] Clearly, current conditions have reduced interest rates on Canadian government bonds. At issue is whether the factors that reduced those interest rates would also have reduced the expected ROEs for Canadian utilities.

The long-term decline in interest rates on long-term Government of Canada bonds can be attributed to three factors: the reduction in inflation, the reduction in inflation risk premiums (to cover the uncertainty regarding the rate of inflation), and the reduction in Government bond interest premiums required to induce investors to hold bonds as a result of reduced borrowing due to the improvement in the Government's fiscal position. Of these, only the reduction in inflation can be expected to influence the equity risk premium that corporate owners expect.[24] The forces driving down long-term government bonds rates would therefore not be expected to drive down investor expectations of corporate rates of

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[21] Laurence Booth and Sean Cleary, "Capital Market Developments in the Post-October 1987 Period: A Canadian

Perspective", October 2008

[22] Bank of Canada.

[23] Data from the Bank of Canada.

[24] Kathleen McShane, "Capital Structure and Fair Return on Equity," prepared for Terasen Gas, May, 2009. Equity owners do not require the same inflation hedge as bondholders because they expect that corporate profits will grow with inflation.

return on equity in the same way. A closer look at the forces affecting Canadian corporate financial performance and ROEs is in the next section.

2.3.2 Recent Corporate Financial Performance

Current market conditions have put stress on corporate borrowers and investors. As the financial crisis continued, lenders reacted by a flight to quality, preferring government bonds and their lack of default risk to corporate issues, especially equity issues. The recession threatened corporate rates of return and drove stock prices down to compensate for the increased risk. This suggests that corporate equity risk is being driven by a very different dynamic from that affecting long-term government bonds.

This can also be seen in simple correlations. The correlation coefficient between long-term Government of Canada bonds and the S&P/TSX composite index from February 1998 to July 2008 was -0.02; in effect, they were statistically not related at all.[25] At the same time, the correlation between long-term Government of Canada bonds and long-term US Government bonds was .79, indicating that they are highly correlated.[26]

When the depth of the recession became more fully known in the latter part of 2008, corporate bond rates and the spreads between corporate and government bond rates rose dramatically in both the United States and Canada.[27] While government bond rates are driven down by the flight to quality, corporate bond rates are driven up because the flight is away from them.

If the equity risk premium is to represent the amount that investors require to compensate them for taking the additional risk of equity compared to the risk-free government bond rate, then the formula does not produce an adequate result. The analysis has shown that the equity risk demanded by investors can in fact move in opposite directions from the rate of interest on government bonds, or at best be wholly uncorrelated with it.

As Roland Priddle, the former chair of the NEB, observed,

> It's now hard for me to see that long-term bond yields, driven by factors as disparate as governments' efforts to get budgetary deficits in hand, central bank' concerns (or not) about inflation...are somehow going to provide a continuing, reliable proxy for returns

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[25] The correlation coefficient is a number between -1 and +1 which indicates how closely related two series are to each other. If the series are identical, the correlation coefficient is +1; if they are exactly opposite, the correlation coefficient is -1. A correlation coefficient of 0 means that the two series are not statistically related . (Thomas H. Woonnacott and Ronald J. Wonnacott, Introductory Statistics for Business and Economics, Second Edition, 1977, pg 124-125.) A correlation coefficient of -.02 is effectively zero.

[26] Booth and Cleary, op. cit., pg. 18.

[27] Concentric Energy Advisors, Inc., "Comments on the OEB Consultative Process", pg. 11 (filed by Enbridge Gas Distribution Inc.)

available in businesses presenting degrees of risk similar to gas pipelines and distribution enterprises.[28]

2.4 Changes in Utility Risks

The amount of risk faced by regulated electricity utilities in Ontario has increased significantly since the ERP formula was first adopted. For example, current economic conditions have led to greatly increased demand risk for both transmission and distribution utilities whose revenues depend on system usage (peak demand for the transmitters and both peak and energy demand for the distributors). In the current economic climate, both peak demand and energy use have both fallen for virtually all utilities. The declines in electricity demand have been deeper than in previous economic downturns and may reflect fundamental changes in the Ontario economy. The economic futures of two major electricity consuming industries in Ontario – pulp and paper and automotive manufacturing – are very uncertain. Adding to these demand risks are programs of conservation and demand management, which aim to reduce peak demand both through targeted programs, sometimes implemented by the distributors, and through such provincial programs as appliance standards. Therefore, there is increased uncertainty regarding future electricity demands and this greater uncertainty represents an increased revenue risk for Ontario distribution and transmission electric utilities.

Other government policies, particularly environmental policies, have added to risk for these utilities. The *Green Energy and Green Economy Act* places new obligations on distributors to carry out conservation programs and to expand their systems to connect renewable generation. Transmitters also will be required to expand their systems both to enable integration of planned renewable generation and to allow its transmission to markets. The construction of these facilities will place risks on the utilities due to their sheer size relative to the existing capital asset base as well as due to the need for accelerated construction schedules. For example, the Integrated Power System Supply Plan (IPSP) identified $4 billion in transmission expenditures compared to a total rate base for the licensed transmitters of approximately $6.5 billion. They also will have increased risk that the renewable generation for which the facilities were built will not itself be completed and the unused transmission cannot be charged to the network pool.

Ontario electricity distribution utilities also face significant political and associated regulatory risk. The Ontario electricity industry has been restructured three times since 1998, and each restructuring has affected the transmission, distribution and generation industries. There is little to reassure investors that the industry will not be further restructured as Ontario continues to adapt to changing economic conditions and new technologies.

As the risk to the regulated entities increases, the amount of equity risk premium that investors will demand can be expected also to increase. Clearly, utility risks have increased since the ERP formula was implemented by the OEB in 1997.

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[28]Roland Priddle, "It's Time for the Next Evolution in Regulation," in The Gas Journal of Canada (2007): A9. Cited in Canadian Gas Association, "Natural Gas Utility Return Determination in Canada: A New Approach", April 2008. Filed by Enbridge Gas Distribution, Inc.

3. Comments on Assertions that ERP Formula Results Reasonable

This chapter addresses the arguments that have been put forward by various consumer groups in their April 17th comments to the OEB. In general these parties assert that the OEB's ERP formula continues to provide reasonable results. A wide range of assertions were made. They were perhaps most clearly articulated by the Canadian Manufacturers and Exporters (CME) who asserted that: (1) there is no increase in the perceived risk of utilities and the decline in utility share prices has been 50% of the decline in the value of the market as a whole; (2) there is no evidence that the values are causing any immediate and material threat to the financial integrity of any electricity distribution utilities that the Board regulates; (3) there is no evidence to indicate that any electricity utilities the Board regulates are having any difficulty accessing capital; and (4) the capital markets do not perceive utilities to be any riskier than they were when the Board's adjustment formula was established.[29] Each of these arguments is addressed below, except for the last which was addressed in the previous chapter.

3.1 No Increase in the Perceived Risk of Utilities

Consumer groups have argued that in spite of the financial turmoil experienced in the international financial and credit markets there is no increase in the perceived risk of utilities. They assert that this is demonstrated by the fact that the decline in utility share prices have been 50% of the decline in the value of the market as a whole.[30] They note that utility shares are a safe harbor and the flight to quality also results in utility shares being a preferred investment.

This argument fails to consider the tangible evidence provided by the capital markets which indicates that risk has been repriced at a higher level by investors as a result of the financial crisis. As discussed in the previous chapter, a spread of 39 basis points between utility debt and equity doesn't provide adequate compensation to equity investors for the additional risks that they bear. Specifically, equity investors are subordinate to debt in terms of their claims on utility assets and furthermore, dividends are paid only after debt obligations have been discharged. Therefore, as the economy stalls and both electricity demand and transmission income, which is a function of demand, fall, there is an increased risk regarding the earnings for transmitters.[31] Bondholders returns are threatened if the transmitter defaults, whereas shareholders are at risk for any revenue loss. Clearly, equity investors face greater risks with respect to the returns that they earn and require additional compensation for this risk. At a time of increased business and financial risks (i.e., when these returns are more uncertain), it doesn't make sense that the compensation that equity investors demand would decline.[32,33]

[29] Comments of the Canadian Manufacturers and Exporters, April 16, 2009, p. 9.

[30] Comments of the Canadian Manufacturers and Exporters, p. 5.

[31] While this risk can be mitigated over the long term by the utility filing rate application that contains a new revenue forecast, the utility is at risk for the period prior to which new rates are established and bears the risk regarding the reasonableness of the revenue forecast used to establish these rates.

[32] Recall that the spread was 247 basis points under the OEB's 2008 cost of capital parameters.

As earnings yields increase, the cost of equity increases. Figure 1 shows the dramatic decline in utility share prices. Declining share prices shown in Figure 1 reflect in part investor requirements for higher earnings and dividend yields. Earnings yield indicates a stock's return.

Figure 1 also contrasts the performance of the Dow Jones Utility Average (DJUA)[34] (darker, blue line) with the S&P 500 index[35] (lighter, red line) over the last twelve months. While the S&P 500 had a lower low (with a decline of about 48%) than the DJUA (decline of 39%), utility share prices have clearly be hard hit.[36] The magnitude of the drop in utility share prices challenges the assertion that there is no increase in the perceived risk of utilities. More significantly, the standard deviation of the DJUA average over the last 12 months relative to the previous 12 months increased by almost twice the rate experienced by the S&P 500, calling into question the assertion that there is no increase in the perceived risk of utilities.[37]

Figure 1: Dow Jones Utility Average vs S&P 500 over the last 12 Months

Source: Yahoo Finance

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[33] A financial analyst engaged by the Edison Electric Institute, characterized the 230 basis point spread between bond yields and allowed ROEs as "modest" and "suggests that equity investors need additional compensation to encourage their investment in utility common stocks." (J.M. Cannell, Inc., The Financial Crisis and Its Impact On the Electric Utility Industry, Prepared for: Edison Electric Institute, February 2009, p. 7)

[34] The DJUA is a price-weighted average of 15 utility stocks traded in the United States. The DJUA was started in 1929. Source:www.investopedia.com

[35] The S&P 500 index published by Standard & Poor's is widely regarded as the best single gauge of the U.S. equities market and includes 500 leading companies in leading industries of the U.S. economy. Source: Standard and Poor's

[36] Interestingly, the S&P 500 has rebounded more than the DJUA.

[37] The standard deviation of the DJUA over the most recent 12-months relative to the previous 12-months increased by 68%, whereas the SP 500 increased by 39%.

The increase in required utility ROEs was indicated by the previously discussed discounted cash flow (DCF) analysis which was a part of our April 17th filing with the OEB. Recall that this DCF analysis indicated that utility ROEs increased from 11.0% in the first quarter of 2007 to 12.5% in the first quarter of 2009. The primary contributor to this increase was the increase in dividend yield from declining share prices.

Another perspective on the increase in risk and how this has been priced into bond and equity prices is provided by a White Paper conducted for the Edison Electric Institute.[38]

> One of the most important characteristics of the current environment is a dramatic rise in risk levels. Bond yields and spreads clearly reflect that reality in terms of debt securities. Declining stock prices and attendant rising yields convey the same message relative to equities. The impact on debt and equity financing from mounting risk is that it is now more difficult and costly to access the public markets. Because the ratemaking process is intended to help foster capital attraction for utilities, this new risk paradigm needs to be incorporated accurately into regulatory deliberations.

This increase in ROE is very real when utilities are required to issue additional equity with these lower share prices. Consumer groups claim that Ontario utilities continue to have access to the equity markets. While these utilities can issue equity, the important question is at what cost. Our analysis indicates that this access is at an effectively higher required ROE.

3.2 No Evidence of an Immediate and Material Threat to Financial Integrity of Utilities

The consumer groups also argue that there is no evidence that the values (cost of capital values produced by the OEB formulas) are causing any immediate and material threat to the financial integrity of any electricity distribution utilities that the Board regulates.

While there has been clear evidence that the ERP formula has caused utility allowed ROEs to be below the true cost of capital for a number of years, it is the recent declines in allowed ROEs that have threatened their financial integrity. The impact on utility financial integrity is insidious. The resulting reduced cash flows can threaten utilities' credit ratings; the rating agencies indicate that one of their rating criteria is the severity of the regulator. Lower cash flows make utilities more susceptible to the business cycles. The signs of financial distress may become apparent only after the utility is downgraded. In the current credit environment which is characterized by wide credit spreads, the impact of a downgrade can be very significant on both the cost of debt and equity and this is at a time when the capital budgets for a number of Ontario utilities are significantly greater than available cash flow and require access to capital markets. Where downgrades are in part a response to a perception of an adverse regulatory climate, the consumer cost impacts of higher debt costs and reduced reliance on leverage can be sustained for years.

Utility capital budgets are developed for long time horizons. Planning and permitting requirements result in a lag between committing to an investment and spending the funds.[39] Therefore, the effect of an

[38] J.M. Cannell, Inc., The Financial Crisis and Its Impact On the Electric Utility Industry, Prepared for: Edison Electric Institute, February 2009, p. 9.

inadequate ROE will be felt in the future as investments are deferred. Furthermore, utilities have an obligation to ensure that the service they offer is reliable and their systems can be operated safely. These investments are unlikely to be deferred except in the direst circumstances. Other investments which might offer long term savings or service quality enhancements to customers in the form of efficiency improvements or new services are more likely to be deferred under such conditions. Another area where investments are likely to be deferred is with respect to infrastructure replacement. These investments are important for service quality and offer benefits to customers, but are not essential for system operation.

The nature and structure of the Ontario electricity sector makes the consequences of low ROE on the financial health and performance of the firm particularly difficult to identify. Most Ontario LDCs and transmission companies are not publicly traded, so there is no market in which to see the actual rates of return to their owners.

3.3 No Evidence that Utilities are Having Difficulty Accessing Capital

Utilities have been able to access the debt markets, but they have had to pay increased credit spreads in the last twelve months. There has been some evidence of easing in the last several months. Accessing the equity markets has been more difficult. While utilities have been able to access these markets the question is at what cost.

A report by the Edison Electric Institute calls into question the consumer groups' assertion regarding access to equity markets.

> Equity financing also has been difficult to secure, and utility deals have been scarce. The equity markets have been characterized by unprecedented and sustained volatility, driven in part by hedge funds being forced to undo billions of dollars worth of investments due to investor withdrawals. In the current environment, few companies have been eager to try to price a stock offering. At the same time, stock prices hovering near 52-week lows have made selling new common stock unattractive, if not unpalatable. Issuing stock at prices below book value—where some electric utilities are currently trading—is not a financially astute course of action, as it serves to undermine shareholder value.[40]

An alternative perspective on whether utilities are having difficulty accessing capital is to compare the ROEs yielded by the ERP formula with those that pipeline companies are negotiating for new pipeline investments. As discussed, above it is difficult for utilities to eliminate all investment if the allowed ROE is below their required cost of capital. Furthermore, when the allowed ROE is below the actual cost if essential, utilities can issue additional equity, but only by further diluting the returns earned.

New pipelines are one utility investment that is fully discretionary and as such a better indication regarding the required cost of equity for utilities. John C. Major (former Justice Canadian Supreme

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[39] Also these effects may not be visible for some time because the utility can use the existing infrastructure, but eventually the quality or efficiency of the utility's service will suffer.

[40] J.M. Cannell, Inc., p. 7.

Court) and Roland Priddle (former Chair of the National Energy Board) note that "in the "generic ROE era" it has become the practice for new pipelines subject to NEB jurisdiction to apply for tolls that have been the subject of prior negotiation with shippers. Typically, these tolls reflect ROEs about 300 or more basis points higher than incumbent pipelines, such as Foothills, TCPL, TQM and Westcoast, receive under the generic ROE."[41] This indicates that the NEB's ERP formula which is similar to the OEB's has yielded ROEs that are insufficient to attract capital to greenfield gas pipeline projects and suggests that the ROEs produced by these ERP formula may impair utilities ability to attract capital over the long term.[42]

3.4 Spread between Long Term Debt Rate and ROE isn't Unprecedented

The consumer groups have argued that the spread between long term debt rate and ROE produced by the ERP formula isn't unprecedented and shouldn't be viewed as evidence that the ERP Formula is broken.[43]

The preceding chapter has reviewed at length how the relationship between the Long Canada Bonds (which is reflective of the risk free rate) and utility ROEs doesn't hold and how it is unrealistic to expect an equation as simple as the ERP formula to provide reasonable results regarding the cost of utility equity in financial markets where relationships between the risk free rate and equity returns have fundamentally changed given changes in investor attitudes and perceptions of risk and fundamental changes in credit markets. In addition, current monetary and fiscal policy has influenced the rates for Long Canada Bonds and resulted in a further decoupling of the relationship with utility ROEs.

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[41] John C. Major and Roland Priddle, *The Fair Return Standard for Return on Investment by Canadian Gas Utilities: Meaning, Application, Results, Implications*, March 2008, p. 21.

[42] Major and Priddle, p. 5.

[43] The Canadian Manufacturers and Exporters asserts that the spread was even negative during the early 1980s when short and long term interest rates were very high. (CME Comments, p. 7). However, inflation during this period exceeded 10% and this along with regulatory lags caused some utility share prices to drop below book value, a clear indication of the poor financial health of the sector. As such, it isn't reasonable to reference these credit and financial market conditions as an appropriate financial benchmark.

4. Proposed Revisions to the ERP Formula

The preceding discussion suggests that the OEB's current ERP formula yields an unreliable estimate of the required ROE for an electric distribution or transmission company. The major deficiencies of the formula are that it is based solely on the relationship between changes in the rates for Long Canada Bonds and required utility ROEs and omits other critical explanatory variables. As discussed, by omitting other important explanatory variables the formula overstates the relationship between Long Canada Bonds and required utility ROEs. Specifically, the ".75" coefficient in the formula is too high. Therefore, the Board cannot assume that the deficiencies in the ERP formula will be remedied when credit markets heal.

Given the OEB's desire to continue to use the ERP approach, to address these deficiencies the ERP formula needs to be respecified and reflect additional explanatory variables that capture the determinants of required utility ROEs. Two obvious types of data series are: (1) rates for long-term utility bonds to better reflect changes in credit spreads for higher risk securities than Long Canada Bonds; and (2) investor expectations regarding stock price index volatility to better reflect changes in equity market conditions. The VIX or MVX represent possible data series to consider equity market conditions.[44]

Alternative model specifications which could replace the current ERP formula are reviewed below to provide the Board with an indication regarding what an alternative formula could look like.

4.1 Proposed Revision to the ERP Formula

Power Advisory evaluated a range of different model specifications in an effort to come up with a formula that will yield more reasonable results than the existing formula under a range of different credit and financial market conditions. The different explanatory variables that were evaluated include: Long Government Bond Rates, Corporate AAA Debt, Corporate BAA Debt, and the VIX. Different lags were considered to recognize the length of time required to conduct cost of capital proceedings causing utility ROEs to be established under earlier credit and financial market conditions.

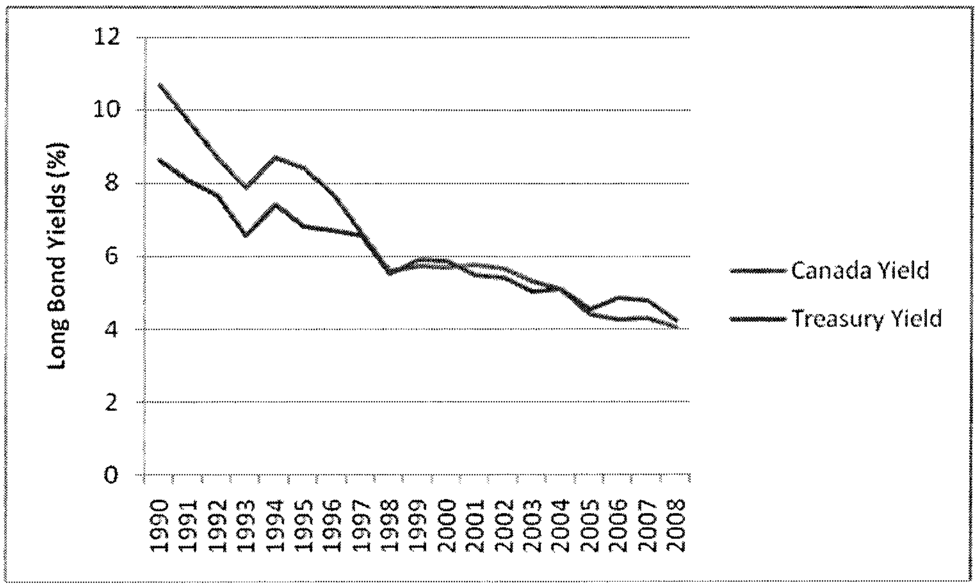
Because ERP formulas have been used to establish utility ROEs in the vast majority of Canadian jurisdictions with investor owned utilities (all except Nova Scotia – Nova Scotia Power currently receives 9.35%[45]), Canadian utility ROEs cannot be used to evaluate the reasonableness of these relationships. If these values were used then Long Canada Bonds would clearly be shown to have the strongest statistical relationship with utility ROEs because they were used to establish these ROEs. Therefore, the various models evaluated were all based on U.S. utility ROEs along with U.S. financial data. As indicated in

[44] One issue with the use of the VIX is that it measures the implied investor expectations regarding 30-day forward volatility. CBOE has developed a 3-month volatility index (VMX) which helps address this issue. Therefore, it doesn't necessarily reflect investor expectations for the term of the rate period. However, with investor expectations regarding future volatility likely to be based largely on recent volatility and few reliable tools to forecast future changes in stock market volatility while imperfect such an index might be preferred over a model specification which doesn't consider this variable.

[45] FAM Settlement Agreement, UARB Decision, NSUARB – NSPI – P-887, December 10, 2007, paragraph 13.

Figure 2 which contrasts U.S. and Canada long-term bond yields and more fully evaluated in our April 17th filing, U.S. and Canadian financial markets are highly integrated. Furthermore, others have found that there are no appreciable differences in regulatory or financial risks, operating characteristics, tax environment that justify the differences in ROE allowed in the US and Ontario.[46,47]

Figure 2: Comparison of Long Bond Yields



Two models performed the best in terms of standard econometric considerations (i.e., goodness of fit, highly significant parameter values, and plausible statistical relationships). The first was also relatively straight forward which should make it relatively easy to implement. The second was a multi-variable model which should make it more robust and better able to reflect financial and credit market conditions similar to those recently experienced. Interestingly, both models performed better than just using the Government Bond yield as the sole explanatory variable.[48]

The first model is: ROE = 7.008% + (US Corp BAA Bond yield with 6 month lag x 0.5356)[49]

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[46] Such findings were made by Concentric Energy Advisors and NERA in two separate reports. Concentric Energy Advisors, A Comparative Analysis of Return on Equity For Electric Utilities, June 2008. Allowed Return on Equity in Canada and the United States – An Economic, Financial and institutional Analysis, National Economic Research Associates, Inc., Kenneth Gordon, Ph.D. and Jeff D. Makholm, Ph.D., February 2008.

[47] The National Energy Board in its recent Trans Quebec Maritimes Pipeline, Inc. Decision found that US pipelines represented an appropriate point of reference relative to Canadian pipelines. (RH-1-2008) The NEB found that although there are some differences in U.S. and Canadian regulatory frameworks, the similarities outweigh the differences. The NEB noted that both countries have similar regulatory models, similar regulatory goals and policies, and operate within a common market for commodities.

[48] The adjusted r^2, or coefficient of determination, indicating goodness of fit for this model is .864.

The second model is: = 7.451% + (US Gov 30 Year Bond yield with 6 month lag x 0.5122)
+ (VIX index value with 6 month lag x .0077)[50]

Using current values for these variables produces ROE estimates of 10.5% to 11.3%. However, when implementing these models Canadian values should be used for these variables.[51] When these are employed the ROE estimates range from 10.3% to 11.1%. These ROE estimates provide an indication regarding the magnitude of the bias in the ROE estimate produced by the OEB's current ERP formula and the importance of addressing this issue expeditiously.

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[49] The t-statistics and confidence levels regarding the statistical significance of the constant are 27.899 (t-stat) and 0.00000 (confidence level) and US Gov Bond yield are for constant and 15.267 (t-stat), and 0.00000 (confidence level) for VIX 4.118 (t-stat) and 0.00080 confidence level. The adjusted r^2 indicating goodness of fit is .889.

[50] The t-statistics and confidence levels regarding the statistical significance of the constant and US Corp BAA Bond yield are 19.823 (t-stat), 0.00000 (confidence level) for constant and 12.0525 (t-stat), and 0.00000 (confidence level) for US Corp BAA Bond yield. The adjusted r^2, coefficient of determination, indicating goodness of fit is .930.

[51] For example, a comparison of current Long Canada Bond rates with those for US treasuries indicates that Canadian bonds are offering a 27 basis point discount relative to Treasuries.

APPENDIX "B"

GLPT Submission in EB-2009-0152

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July 8, 2009

RESS & COURIER

Ontario Energy Board
P.O. Box 2319
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Attention: Ms. K. Walli, Board Secretary

Dear Ms. Walli:

Re: The Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors (EB-2009-0152) - Comments from Great Lakes Power Transmission LP

On behalf of Great Lakes Power Transmission LP ("GLPTLP") and in connection with the above-noted proceeding, please find attached two copies of GLPTLP's comments on Board Staff's June 5, 2009 Discussion Paper on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors, along with confirmation of electronic filing on the RESS system.

Yours truly,

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Submissions of Great Lakes Power Transmission LP to Staff Discussion Paper on The Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors

A. Introduction

These are the submissions of Great Lakes Power Transmission LP (GLPTLP) to the *Staff Discussion Paper on The Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors ("Staff Discussion Paper")*. As a licensed transmitter, GLPTLP's submissions are from the transmission perspective only.

GLPTLP believes that the *Staff Discussion Paper* represents a major step towards providing a workable framework for approval of investment in infrastructure by electricity transmitters and distributors.

From a transmission perspective, currently Ontario faces a number of transmission challenges and needs. Further to the Ontario Power Authority's Integrated Power System Plan ("IPSP") and the planning aspects set out in the *Green Energy and Green Economy Act, 2009* ("GEGEA"), transmission initiatives will include transmission expansion plans to permit the connection of renewable energy facilities, enabler lines and significant and new network projects such as the North/South Transmission Reinforcement. All these investments are out of the ordinary course of the transmission investments typically related to load or generator connections or reliability. All of these projects will need to attract public and private capital in competition with other opportunities.

It is within this context which the Board must consider the application of the cost recovery and return on equity ("ROE") mechanisms discussed in the *Staff Discussion Paper* and in more detail below.

In working within this context the Board must consider the added complexity of the stages of transmission investment and how that will affect the application of any mechanism. Broadly, the stages could be described as: planning and development (includes aspects of route assessment, stakeholding, system analysis, environmental review, permitting etc.), financing, construction and operation.

Depending on the scope and timeframe associated with the project and the degree of risk, the extent to which such risk presents impediments will vary from project to project. As well, approval of the mechanisms may need to be considered at different points at or in the regulatory process. Siting major new transmission lines is extraordinarily difficult given the environmental, stakeholder, First Nations/Métis and land-use concerns with obtaining and permitting new lines on new rights-of-way or reinforced systems on existing rights-of-way. In addition, there will be long lead times (with a significant portion of project costs attributable to long lead time equipment orders), regulatory and political risks, and financing and cash flow challenges. The key is that transmission investment is varied and complex and as such, a singular approach is not sufficient. Flexibility in the Board's approach will be key to facilitate transmission investment that balances the goals of the GEGEA and the public interest.

Under the GEGEA, the Board has as an objective the "***timely reinforcement and expansion of transmission systems ... to accommodate the connection of renewable energy generation facilities***". In this circumstance, as an economic regulatory authority the Board's role in approving cost recovery and ROE mechanisms (whether those of a conventional or unconventional nature) affects the allocation of capital to transmission investments. Capital, as a mobile and limited financial resource, is allocated by a business entity between competing needs within and between jurisdictions. The Board's role is to encourage new investment through incentives that work to facilitate the investment. If the Board does not recognize the diverse nature of projects that could arise under the GEGEA and applies a one size fits all approach or no incentives at all, then sufficient capital will not be dedicated to transmission investment. As noted, the extraordinary nature of transmission projects that will arise requires a flexible approach in which the Board sends the appropriate signals to allocate capital investment to permit the timely expansion and reinforcement of transmission systems in the public interest.

B. FERC Criteria Under Order 679

The *Staff Discussion Paper* appropriately draws upon the work done by the U.S. Federal Energy Regulatory Commission (FERC) in its Final Rule, Promoting Transmission Investment through Pricing Reform (Order No. 679). The commonality between Ontario's needs under the GEGEA and those of the US electricity sector stems from similar circumstances. FERC's rule was intended to: (1) promote capital investment in transmission facilities; (2) provide an ROE that attracts new investment in transmission; and (3) encourage deployment of new transmission technologies. The GEGEA requires additional transmission investment to promote the development of renewable energy projects and mandates increased investment in the smart grid. Given these common objectives, GLPTLP also references the framework employed by FERC to provide context and assist the OEB in developing the details of the framework for the regulatory treatment of major transmission and distribution investment in Ontario.

In Order 679 and subsequent decisions reviewing transmitter requests for incentive-based rate treatment for transmission investment, FERC developed a framework for establishing when applicants will be provided with incentive-based rates. FERC established as a rebuttable presumption that a project satisfies these criteria and would be eligible for incentive ROE if: (1) it is the result of a fair and open regional planning process; and (2) receives construction approval from a state commission. Furthermore, the applicant was required to demonstrate that the incentives are "tailored to address the demonstrable risks or challenges faced by the applicant." [1] This is referred to as the "nexus requirement". Subsequently, FERC has evaluated this based on whether the project is "routine" which was in turn assessed based on: (1) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (2) the effect of the project (e.g., ensuring reliability or reducing congestion costs); and (3) the challenges or risks faced by the project (e.g., siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, and other impediments).

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[1] *Baltimore Gas and Electric Company,* 120 FERC ¶ 61,084, at P 52-55 (2007).

FERC also found that an applicant must provide sufficient explanation and support to allow the Commission to evaluate the incentives. However, applicants do not have to show that "but for" the incentives, expansion would not occur.

The FERC rejected this test because it created an evidentiary hurdle that could only, in very rare cases, be satisfied. The FERC stated that:

> "There are many impediments to investing in new transmission, including siting concerns, financing challenges, rate recovery concerns, etc. It is therefore unreasonable to expect or require an applicant to show that a facility could not be constructed "but for" the removal of a single impediment - e.g., increased cash flow through 100 percent construction work-in-progress (CWIP) or an enhanced ROE. This test could rarely, if every, be satisfied, particularly given that incentives are ordinarily sought before investment decisions are made and, hence, before any siting impediments are even confronted."

C. Review of the Mechanisms Identified in the Discussion Paper

The *Staff Discussion Paper* identified five mechanisms that could be used "to encourage appropriate infrastructure investment" and noted that "[t]hese mechanisms are intended to address the unique challenges that may be associated with those investments, and to facilitate the timely development of infrastructure that is expected to be needed to accommodate increased renewable generation and to establish the smart grid…"[2] These are: (1) recovery of costs of abandoned facilities; (2) contract-term (i.e., accelerated) depreciation; (3) construction work in progress; (4) project ROE incentives; and (5) project-specific capital structure. Each of these mechanisms is reviewed below.

A critical issue is when these mechanisms should be applied. In this regard it is important to make a distinction between "routine" and "non-routine" investments. A routine investment is that forming part of the typical capital plan of a utility based on forecasted load growth, generation connections and reliability. At page 8 of the *Staff Discussion Paper*, it indicates that a non-routine incremental investment differs from a routine investment where it can be demonstrated that the investment is extraordinary and an unanticipated capital spending requirement, i.e. something other than the normal course of business.

To some extent, GLPTLP agrees with this distinction and the characterization of "non-routine" subject to the fact that the non-routine nature of the investment does not just relate to the level of spending, but also includes a risk profile that is greater than that associated with investments made in the ordinary course of business. Outside the ordinary course of business is fact dependent determined on a case-by-case basis by considering the project's scope (e.g. dollar investment, increase in transfer capability, involvement of multiple proponents (acting separately or together), size, land mass used, affect on region); its affect (e.g. improving reliability on reducing congestion); and unique challenges or risks (e.g. siting, internal competition for

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[2] Ontario Energy Board, *Staff Discussion Paper on The Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors (Staff Discussion Paper)*, p. 15

financial resources, long lead times, regulator and political risks, specific financing challenges, etc.). For example, the constructing of an enabler line to connect a renewable cluster is not undertaken in the ordinary course of business for a transmission entity.

It is in this context that GLPTLP uses the term "non-routine" investments in these submissions.

(i) Recovery of Costs of Abandoned Facilities

The recovery of prudently incurred abandonment costs is appropriate. For example, the development stage for transmission investments under the GEGEA will require significant time, resources and money. The uncertainties related to stakeholders, land, and permitting can be significant and present many variables outside of a proponent's control. The certainty of recovering those costs before expenditures are made will facilitate this initial investment. Furthermore, for projects required to access renewable generation facilities through enabler lines there are significantly greater risks from factors that are beyond transmitters' and distributors' control such as generation developers' decisions to terminate the development of renewable energy resources.[3] In addition, extended construction periods and long level time ordering for major equipment further increase exposure to non-completion risks because of factors outside the proponents' control.

Criteria: It would be unfair for a proponent to pursue a project the proponent had reason to believe was in the public interest and be left exposed for costs incurred beyond the proponent's control. For routine investments, the recovery of any abandonment costs would be considered by the Board after the event. Where the investment is non-routine the regulatory certainty of the prospect of cost recovery at the outset would eliminate an impediment to a decision to proceed with the investment. This should not be viewed as a new mechanism that is being made available only to non-routine investments, but is already an element of the regulatory construct. Therefore, GLPTLP does not believe that discrete criteria are necessary to establish when utilities should be able to recover the costs of prudently incurred abandonment costs.

(ii) Accelerated Depreciation

Depending on the circumstances, a broader consideration of accelerated depreciation may be appropriate. From a financial perspective, accelerated depreciation could provide increased cash flows which may be needed to fund increased levels of investment arising under the GEGEA.

Criteria: Instances may arise that have need for non-traditional treatment of depreciation and should be considered based on the facts presented and the relief sought.

(iii) Construction Work in Progress (CWIP)

The magnitude of required investment supports the application of advance recovery of CWIP in rate base to reduce financing requirements and financial burdens, particularly for large capital investments. The importance of advance recovery of CWIP is increased by the long lead times

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[3] FERC Order 679, p. 88.

required to plan and construct new major transmission facilities.[4] This is a critical issue given the magnitude of transmission investment anticipated by the IPSP and, in particular, the GEGEA, which calls for accelerated development of renewable energy projects. Furthermore, a considerable portion of investment is likely to be undertaken by publicly-owned distribution and transmission companies which in the current economic climate are less able to secure additional equity investment and as a result are more reliant on cash flow from operations. Given the magnitude of transmission and distribution investment required by the GEGEA, without increases in available cash flow and retained earnings, the required capital investment can lead to increasing debt ratios which will in turn lead to higher financing costs. In addition, because transmission rates in Ontario are based on a uniform rate that combines all transmitters under one rate, it is possible, that with projects potentially proceeding in parallel, rate impacts could be mitigated with CWIP brought into rate base over time.

Criteria: Transmission and distribution companies should be eligible for advance recovery of CWIP based on a variety of factors considered on a case-by-case basis.

(iv) Project ROE Adders

The level of ROE reflects two aspects. The first relates the ability to attract capital to an investment relative to competing investments. The second relates to the compensation for risks associated with the investment over and above the return needed to attract capital away from competing alternatives.

Risks giving rise to ROE adders could include: (1) the size of the investment relative to the existing rate base so that the proponent's financial performance is significantly affected (as indicated by reduced cash flows and coverage ratios) by the development, construction and operation of the investment;[5] (2) increased reliance on capital markets and uncertainty regarding the ability to access equity and debt under reasonable terms given current financial market volatility and risks aversity; (3) unanticipated increases in project costs from escalating equipment costs and project delays; (4) the need to commit capital for equipment (including pre-ordering long lead time and stockpiling components) to the project prior to securing all regulatory approvals given accelerated project development schedules; (5) the difficulty of sequencing construction as a result of heavy utilization of existing facilities and limited periods during which necessary outages can be scheduled;[6] (6) risks arising from operating a new transmission line over new and potentially varied topography extending over long distances; (7) regulatory risk given that facility need is driven by the GEGEA and uncertainties regarding generation project development; (8) risks associated with public policy changes; (9) the performance and suitability of any innovative technologies that are employed; and (10) the challenges in securing permits and siting approvals under the terms envisioned, with these risks influenced by the broad scope of the project and numerous overlapping permitting approvals and siting constraints from the need to cross sensitive areas.

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[4] FERC Order 679, p. 60.

[5] This also increases the potential for internal competition for funds which makes the obtaining an adequate ROE critical.

[6] This includes First Nations' consultations.

Criteria: Higher ROEs should be applied where applicants can demonstrate that the risks of their projects are higher than routine investments. The ten risk considerations outlined above could represent a starting point for evaluating project risks. The criteria for determining when this mechanism is appropriate will likely be the most subjective of the various available mechanisms.

(v) Project Specific Capital Structure

As noted above, the application of mechanisms requires a flexible approach from the Board. As noted in the *Staff Discussion Paper*, the Board must recognize that unique projects may require capital structures that are also unique. In addition, the proponent of the project may be a combination of entities that does not fit the traditional structure of regulated utilities.

Criteria: It is reasonable for the Board to allow for a project specific capital structure based upon a request by an applicant and the applicants specific circumstances.

D. Consideration of Interaction Among Mechanisms

The mechanisms identified in the *Staff Discussion Paper* should not be viewed as separate from each other. GLPTLP believes that the Board should consider these mechanisms to constitute a menu from which proponents can choose in order to facilitate their proposed investments. Proponents can also choose the implementation details they wish to propose. The Board can then rule on the particular proposed package by accepting any, all or none of the proposal, and by setting the implementation details. For example, the proponent could propose a level of incentive ROE, a rate of accelerated depreciation, and a formula for inclusion of CWIP in rates. The Board can then set conditions that it accepts.

In its Order 679, FERC stated "An applicant may request any combination of the incentives listed in the Final Rule"[7] but it must make its case that the incentives are applicable to the proposed investment.

The objective of these mechanisms is to recognize, and where appropriate, to mitigate the risks of these "non-routine" transmission investments. As a result when these mechanisms are implemented they will reduce the risk of the underlying investment to which they apply and aid in causing a proponent to proceed with the investment. This raises the question as to whether the resulting reduction in risk would eliminate the need for ROE adders for specific projects, another mechanism that the *Staff Discussion Paper* considers. While GLPTLP believes that this should be assessed on a project-by-project basis, the following table indicates that these mechanisms do not necessarily reduce risks of these investments so that they are less than or equal to a "routine" investment. Therefore, it is not appropriate to assume that these mechanisms obviate the need for an ROE adder for some projects. In the table below, this is illustrated by the first financing risk identified - "Large investment relative to rate base". Allowing the recovery of prudently incurred abandonment costs (if abandonment is for reasons beyond the control of the utility),

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[7] Federal Electric Regulatory Commission, Order 679, *Promoting Transmission Investment Through Pricing Reform*, 116 FERC 61,057, issued July 20, 2006. para. 55, pg. 23.

construction work in progress, and accelerated depreciation all serve to reduce financing risk. Nonetheless, there would continue to be greater risks associated with this investment than a "routine" investment. If the investment required by these new facilities is large relative to the proponent's existing rate base, then the residual risks to the proponent can still be greater than a routine investment. Under these conditions, the proponent should receive a higher ROE than provided for routine investments.

In addition, GLPT expects that by reducing risks these mechanisms will result in a lower cost of capital (likely through reduced debt costs) than otherwise would be realized. This will reduce the rate impacts of these facilities and is a benefit realized by customers from these mechanisms.

	Risk Mitigants			
Risk	**Recovery of Abandonment Costs**	**CWIP**	**Accelerated Depreciation**	**Residual Risk Greater than Routine Investment**
Financing Risks				
Large investment relative to rate base	Reduces	Reduces	Reduces	Yes
Access to Capital given Current Financial Market	Reduces	Reduces	NA	Yes
Increasing project costs & ability to manage impact	NA	Reduces	NA	Yes
Scheduling Risks				
Accelerated Development puts Investment at Risk	Significantly Reduces	NA	NA	Yes
Ability to achieve schedule given Outage needs	Reduces	NA	NA	Yes
Regulatory Risks				
Permitting and Siting Risks	Reduces	NA	NA	Yes
Need for investments driven by GEGEA	Reduces	NA	NA	Yes
Technology Risk				
Performance & Suitability of Innovative Technology	Reduces	NA	NA	Considerably
Operating Risk				
Operating Performance of the Project	NA	NA	NA	Marginally

(Table prepared by Power Advisory LLC)

E. Board Staff Specific Questions.

1. Should the framework and mechanisms identified in the *Staff Discussion Paper* apply to other rate-regulated entities? If so, why and for what types of projects?

Yes, to the extent there are non-routine investments as contemplated herein and the mechanisms provide an appropriate balance of risk and return. For purposes of answering this question it would be helpful to better understand the industry under consideration.

2. **Are there other broad classifications for investment, beyond "routine", "non-routine incremental", and/or "GEGEA-related" that should be considered? If so, what are they and what are the specific underlying drivers for such investment?**

No, as noted in Part C of this submission (p. 3), "non-routine" investment is a reasonable criterion for determining when the various mechanisms should be applied. However, the definition of non-routine proposed by the OEB staff focuses on the level of investment. Non-routine incremental investment differs from routine investment in that it causes utilities to face extraordinary and unanticipated capital spending requirements with **a risk profile that is different than experienced in the ordinary course of investment**.

The mechanisms in the *Staff Discussion Paper* should apply to the recovery of costs incurred by electricity transmitters or distributors for investments to accommodate renewable generation and develop the smart grid. However, the Board should apply a flexible approach to establish the non-routine nature of the project and the applicable mechanisms. It is GLPTLP's view that the mechanisms put in place must reflect prudently incurred costs and be reasonable such that just and reasonable rates can be put in place. However, it believes that a generic test is not necessary or applicable as the mechanisms proposed are a basket of alternatives that may be applied in a variety of ways depending on the facts. As a result, the assessment by the Board must be fact specific applied on a case-by-case basis.

Transmission investment is critical to the success of the GEGEA. As a result, central to the consideration of alternative mechanisms is a desire to increase the likelihood of projects and investments to occur in order to achieve the objectives of the GEGEA while at the same time protecting the interests of customers.

The OEB should establish criteria for a rebuttable presumption that qualifies an investment for incentive mechanisms. GLPTLP believes that an investment would qualify for the incentive mechanisms if the investment is: (1) arising by virtue of an approved expansion plan under the GEGEA, (2) an enabler line, (3) a major network project to further the GEGEA or (4) a part of a Ministerial directive.

Once qualifying pursuant to the rebuttable presumption, then the Board would establish the appropriate combination of mechanisms.

3. **Should the mechanisms in the *Staff Discussion Paper* apply to the recovery of costs incurred by electricity transmitters or distributors for investments to accommodate renewable generation or to develop the smart grid, or both? Why or why not?**

Please see response to #2 above.

4. **Should the mechanisms set out in the *Staff Discussion Paper* be applied to infrastructure investment if the cost of the investment is potentially recoverable through a Province-wide recovery mechanism? Why or why not?**

These mechanisms relate to the timing or amount of the cost recovery, not to its source. The function of the mechanisms is to provide incentives to encourage investments that are non-routine. The characteristics of the investment are independent of cost responsibility.

As discussed, the application of these mechanisms should be based on specific criteria and not be affected by whether the costs of the investment are potentially recoverable through a Province-wide recovery mechanism.

5. **Should the mechanisms set out in the *Staff Discussion Paper* be applied to infrastructure investment in smart grid technology while it is at an early stage of development and where governing standards are yet to be developed? Why or why not?**

GLPTLP has limited its submissions to transmission investment only.

6. **Should "routine" investment made by a transmitter or distributor be eligible for one or more of the alternative treatments identified in the *Staff Discussion Paper*? Why or why not?**

Yes, but the rebuttable presumption may not apply. If the project meets the criteria proposed (i.e., risk profile) for establishing the applicability of these investments, the Board can agree to their use. However, GLPT LP believes that in general "routine" investment will be unable to satisfy these criteria.

Even for routine investment, GLPTLP believes that transmission and distribution utilities should recover all prudently incurred abandonment costs if the abandonment is for reasons beyond the control of the utility.

7. **Should the mechanisms identified in the *Staff Discussion Paper* be presumed to apply to certain types of investments (for example, to accommodate renewable generation)? Why or why not? If so, to which investments?**

Yes. As noted in response #2 above, the approach of a "rebuttable presumption" (i.e., projects that satisfy these conditions are viewed as eligible for the various mechanisms) should also be employed.

8. **Should the Board be more prescriptive as to which type of investment may qualify and which will not? If so, what criteria might the Board use to make a determination on which type of investment would qualify?**

Yes. Please also see response #6 above. The criteria are outlined above in Part C and as set out in response #2.

9. **Should the Board permit applications to request confirmation from the Board that prudently-incurred costs associated with any abandoned projects will be recoverable in rates if such abandonment is outside the control of management? Why or why not?**

Yes. This should be allowed whenever the applicant can demonstrate that the costs were prudently incurred and beyond its reasonable control. Please see Part C(i), above.

10. Should the Board allow for full or partial CWIP to be placed in rate base during the construction of transmission facilities to accommodate the connection of renewable generation and/or develop the smart grid? Why or why not? Should the Board allow this particular treatment for distribution investment? If so, on what basis?

Yes, advanced recovery of CWIP should apply to non-routine investments. Ability to place CWIP in rate base, and the fraction of CWIP to be collected, should be part of the menu of options.

11. Should the Board allow depreciation to be adjusted to match a contract term or the useful life of the connecting renewable generation facility? Why or why not?

Yes. Depending on the circumstances, it may be appropriate to tie cost recovery to the useful life of the facilities that determine the need for the investments.

12. In light of a legislative context in which the Board may mandate infrastructure investments, are incentives necessary or appropriate in Ontario?

The Board Staff construes the incentive mechanism of an increment to ROE as " 'cost plus' compensation to a regulated entity for its investment". This asserts that such an incentive is a bonus or a payment for which there is no corresponding cost. This is an incorrect assertion.

An appropriate ROE is not just representative of a shareholder dividend. A ROE reflects compensation for the risks taken and for the opportunities forgone, i.e. opportunity costs. An appropriate ROE also permits the utility to repay the principal of its debt obligations and to reinvest in capital upgrades and improvements.

It is incorrect for the Board to consider the current established ROE as the "true" ROE and any increment is a bonus only. As indicated by Board Staff in its paper, investments arising because of the GEGEA are those out of the normal course for a licensed transmitter or distributor. As a result the consideration of the current ROE is irrelevant as a comparator. At most it is the base to which the incremental return related to the unique risks associated with infrastructure investment under the GEGEA and opportunity costs related to competing investments are to be added.

For example, in some circumstances, transmitters and distributors could face financial risks as a result of escalating construction costs over the lengthy planning and construction period necessary for expansion and reinforcement. As well, there are risks associated with any accelerated development and construction schedule in order to meet the objectives of the GEGEA. Other risks are set out above at Part C(iv).

With respect to competing capital needs, investor owned utilities will be confronted with an internal competition for funds, with projects providing returns commensurate with the risks (both financially and from a regulatory perspective) receiving funding. Without regulatory change, these projects may not be in Ontario.

For utilities owned by the public sector, if the proper investment signal is not given, public resources may be allocated between public policy initiatives in a manner that does not strike the proper balance.

To finance capital investments contemplated by the GEA, publicly-owned transmitters and distributors will be required to obtain the capital resources either from debt financing, new equity, retained earnings or a reduction in dividends. For municipally controlled LDCs, equity may not be available from municipal shareholders because of the impacts of the current economic conditions on municipal budgets. As noted by Hydro One Inc. in its Annual Consolidated Financial Statements, 2008 at page 20: "Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures".

Based on the forgoing, any incremental ROE provided for infrastructure investment under the GEGEA will have corresponding risks and opportunity cost. As such, the establishment of an ROE reflecting a fair rate of return for the transmitter's shareholder is part of establishing just and reasonable rates. To merely compel a transmitter to undertake infrastructure investment in return for an ROE that does not reflect the corresponding risks or opportunity cost for capital would result in rates that do not provide for a fair return, and that are not just and reasonable. By the Board Staff's very acknowledgement the investments considered are not routine and therefore do not fit the established ROE. To impose the rate of return without due consideration of all the relevant facts would be arbitrary.

13. If the Board were to provide for incentives, should it allow project-specific ROE? If so, should the Board consider adopting a range rather than a specific adder? Further, how might the Board determine an appropriate range or ROE adder?

The Board should allow for project specific ROE. For transmission, some of the lines will require significant investment over a specific time frame. Because of the nature of the project, a consortium of parties could pursue the project. As a result, the capital needs of the project may be dictated by its particular aspects. In addition, the Board as part of its rates assessment could distinguish between the routine and non-routine investments arising from the GEGEA.

As each project is unique the Board should adopt a range rather than a specific adder.

14. If the Board were to provide for incentives, should it allow project-specific capital structures?

GLPTLP agrees with Board Staff's comments related to this issue.

15. What other alternative mechanisms, if any, might the Board consider be made available to applicants?

The Board should establish the allowed ROE for qualifying investments up front. This is essential to providing the desired regulatory certainty and mitigating the financial risks associated with these large infrastructure investments. Also transmitters and distributors should be able to expense prudently incurred project development costs given the long lead times, particularly for development costs of large transmission projects. In addition, clarity regarding the rules and procedures for reviewing and approving these investments would reduce development time frames and permitting risks. GLPT recognizes that the OEB is working to provide such clarity for its rules and procedures.

16. In addition to the potential considerations identified, are there any other matters that the Board might consider in making decisions on requests for alternative treatment?

ROE for investment must be known up-front for it to mitigate financing risks. With the ROE known then the transmitter better able to attract capital and manage the various financial risks associated with undertaking transmission investments of this magnitude.

17. What performance conditions, if any, should be established?

GLPTLP recognizes that there is a need for performance conditions associated with incentive mechanisms. It is GLPTLP's view that the performance conditions are best related to the stages of a project, such as development, construction and operation. In each of these areas, the issues confronting a transmitter and the nature of costs incurred by a transmitter will be different. In addition, the alternative mechanisms are best applied to the stages. For example, certain level of permitting is required before recovery of development costs; or certain indicia are required before the project is abandoned at the development stage and the associated costs are recovered. Similarly, the recovery of construction costs at an earlier stage could be related to a percentage of completion. Conditions may also depend on where in the process the approval occurs. For example, with a leave to construct approval it is possible to approve advance recovery of CWIP up to a certain percentage of project costs since the project, if granted leave, would be in the public interest and the project costs were part of establishing that finding. The costs incurred (and thus recovered) would be prudent. In this circumstance, at a subsequent rate case, the question of reasonableness only extends to costs above those already considered in a leave to construct to establish the determination of public interest in granting leave.

18. Are the reporting requirements suggested appropriate and adequate?

Although the format is acceptable, given the limited number of investments expected to be eligible for an alternative treatment and the anticipated large dollar value of each investment, the actual milestones and the corresponding schedule should be proposed by the proponent and established by the Board on a case-by-case basis.

19. Are there any other conditions that the Board might need to establish in relation to an approved alternative mechanism referred to in the *Staff Discussion Paper* to protect ratepayer interests?

Not with respect to the criteria for establishing when proponents would be eligible for the various mechanisms being considered by Board Staff. Rates associated with these incentives continue to be "just and reasonable" so no additional conditions would be required. The Board must strike a balance between the protection of ratepayers and the realization of the benefits offered by these mechanisms. For example, as noted in Part B above, FERC established that proponents do not need to demonstrate that without the incentives the investment would not occur.

20. Beyond those already reflected in the Board's existing filing guidelines (e.g., the Z-factor test of causation, materiality, and prudence) and in the Board's jurisprudence, is there a specific test that successful applicants should be required to meet in order to be granted an alternative treatment?

Please see response to #2 above.

21. Are the Board's existing filing guidelines for electricity transmitters and distributors sufficient to support the case-by-case approach discussed in the *Staff Discussion Paper*? If not, what additional information should an applicant provide?

The filing requirements contemplate a very different scenario from a rates perspective, especially on a project specific basis. The suitability of the requirements will depend on the proceeding (leave to construct or rates) in which the alternative mechanisms are to be considered. The filing requirements do not consider the nexus between the GEGEA objectives and the implementation of the incentive mechanisms to further those objectives. In addition, the filing guidelines do not set out parameters for the nature of non-routine investments or the assorted risks or impediments for the project.

22. Should the process for applying for the regulatory treatment of infrastructure investment discussed in the *Staff Discussion Paper* be more prescriptive (e.g., the timing, sequencing, and/or combining of applications)? Should it be combined with the process for approving infrastructure investment plans? If so, why and in what way?

See response to #23 below.

23. Should the Board permit applicants to seek approval prior to construction of the facilities to determine whether the facilities qualify for the requested alternative treatment(s)? Why or why not?

GLPTLP takes the position that a transmitter should qualify for alternative treatment not just before construction but also before any development expenditures are incurred. For projects requiring leave to construct, development expenditures can be significant and unpredictable because of environmental matters, stakeholders and permitting concerns.

GLPTLP notes that for transmission projects there are three areas of regulatory approval that are of concern: (1) approval of infrastructure investment plans; (2) potentially a transmitter designation process and approval of development funding for new lines; and (3) leave to construct.

Each of these three approvals will result in costs being incurred. For regulatory efficiency, regulatory approvals should occur in parallel and not sequentially. As a result, incentive mechanism should be established coincident to the applicable approval. For example, if the incentive mechanism is required to implement the approved infrastructure investment plan, then evidence should be lead and the mechanism sought considered. Likewise in respect to a leave to construct, there is no prohibition in the *Ontario Energy Board Act* to making a leave to construct filing and a rate application at the same time. It is possible for the Board both to establish that the construction of the transmission line is in the public interest and to decide on the applicable rate treatment for the project. Please see response to #17 above.

24. What are the implications, if any, of using the single-issue rate review process?

GLPTLP does not believe there are any specific negative implications for a single-issue rate review process. Where possible, proceedings relating to a project or projects should be grouped for regulatory efficiency.

25. Is the use of rate riders an appropriate approach for implementing rate adjustments associated with the alternate treatments identified in the *Staff Discussion Paper*? Alternatively, should the adjustments be made directly to base rates?

The Board should not make a conclusion on whether the adjustment should be a rate rider or to base rates. The rate treatment may vary depending on the mechanism or group of mechanisms employed. The Board should adopt a flexible approach.

26. Should the Board allow applicants to seek approval of multi-year rate riders or should the applicant be required to apply every year to adjust its rate riders to reflect any changes in project costs?

See response to #25 above.

EXHIBIT 6 - CALCULATION OF REVENUE DEFICIENCY

Exhibit 6, Tab 1, Schedule 1

Calculation of Revenue Deficiency

CALCULATION OF REVENUE DEFICIENCY

Table 6-1-1 A – Schedule of Overall Revenue Deficiency

($000's)		2006 Approved	2006 Actual	2007 Actual	2008 Actual	Bridge 2009	2010 Test Year - Revenue Forecast	2010 Test Year - Revenue Requirement
Operating Revenue *		$34,785.4	$34,686.2	$35,567.6	$35,073.4	$31,958.2	$34,696.2	$39,365.1
Operation, Maintenance & Admin.		5,927.0	5,661.1	6,089.6	7,201.9	7,994.1	11,105.6	11,105.6
Depreciation & Amortization		6,000.8	5,492.4	6,085.3	6,511.6	6,936.6	7,406.9	7,406.9
Retirement of Readily Identifiable Assets		1,855.8	1,649.1	1,649.1	1,649.1	1,649.1	0.0	0.0
Property Taxes		133.3	62.0	69.2	66.4	108.0	125.0	125.0
Payments in Lieu of Taxes to First Nations		134.8	133.1	133.2	129.1	128.8	133.2	133.2
Provincial Capital Tax		410.0	503.1	423.7	436.5	436.4	145.5	145.5
Total Costs & Expenses		14,461.7	13,500.8	14,450.1	15,994.7	17,252.9	18,916.2	18,916.2
Utility Income Before Taxes		20,323.7	21,185.4	21,117.5	19,078.7	14,705.3	15,780.0	20,448.9
LCT Tax		188.4	0.0	0.0	0.0	0.0	0.0	0.0
Income Taxes		5,360.7	5,390.4	4,590.8	3,229.9	1,798.1	1,414.1	2,861.5
Utility Income	**[A]**	14,774.6	15,794.9	16,526.7	15,848.8	12,907.1	14,365.9	17,587.4
Utility Rate Base	**[B]**	196,734.2	175,370.7	197,980.6	205,702.0	208,934.3	208,999.2	208,999.2
Indicated Rate of Return	**[C]** = [A] / [B]	7.51%	9.01%	8.35%	7.70%	6.18%	6.87%	8.42%
Approved/Requested Rate of Return	**[D]**	7.51%	7.51%	7.51%	7.49%	7.49%	8.42%	8.42%
(Deficiency)/Sufficiency in Return	**[E]** = [C] - [D]	0.00%	1.50%	0.84%	0.22%	-1.31%	-1.54%	0.00%
Revenue (Deficiency)/Sufficiency	**[F]** = [B] * [E]	(0.1)	2,624.6	1,660.4	448.9	(2,734.7)	(3,221.5)	0.0
Provision for Income Taxes		(0.1)	1,540.4	995.2	280.3	(1,323.5)	(1,447.4)	0.0
Gross Revenue (Deficiency)/Sufficiency		(0.2)	4,165.0	2,655.5	729.1	(4,058.2)	(4,668.9)	0.0
Service Revenue Requirement:		**34,785.6**	**30,521.2**	**32,912.0**	**34,344.2**	**36,016.4**	**39,365.1**	**39,365.1**
Less: Revenue from Other Sources		0.0	349.0	34.9	(128.4)	(51.9)	7.2	7.2
Base Revenue Requirement:		**$34,785.6**	**$30,172.2**	**$32,877.2**	**$34,472.7**	**$36,068.3**	**$39,357.9**	**$39,357.9**

* For 2010, Operating Revenue includes Transmission Services Revenue and Interest and Dividend Income

Table 6-1-1 B – Numerical Description of Revenue Deficiency

Cost of Capital	($000's)	($000's)
Rate Base	$208,999.2	
Requested Rate of Return	8.42%	$17,587.4
Cost of Service		
Operations, Maintenance & Admin	11,105.6	
Depreciation & Amortization	7,406.9	
Property Taxes	258.2	
Capital Taxes	145.5	
Income Taxes	1,414.1	20,330.3
Operating Revenue		
Transmission Services Revenue	34,696.2	
Net Revenues from Merchandising, Jobbing, Etc.	0.0	(34,696.2)
Gross (Deficiency)/Sufficiency		(3,221.5)
Income Taxes on (Deficiency)/Sufficiency		(1,447.4)
Gross Revenue (Deficiency)/Sufficiency		**($4,668.9)**

EXHIBIT 7 - COST ALLOCATION

Exhibit 7, Tab 1, Schedule 1

Cost Allocation to Rate Pools

COST ALLOCATION TO RATE POOLS

1.0 Cost Allocation

Hydro One Networks Inc. ("HONI") filed an application[1] with the Board on September 30, 2008 for approval of a revenue requirement and load forecast for 2009 and 2010 Test Years. As a part of that application, HONI provided an update to the allocation of costs among the Uniform Transmission Rate pools. As a result of the approved cost allocation, GLPT's approved revenue requirement was allocated as follows:

Table 7-1-1 A – EB-2008-0272 Approved Figures

EB-2008-0272 Approved Figures	Network	Line Connection	Transformation Connection	Total
Revenue Requirement	$19,959,065	$5,037,863	$9,788,494	$34,785,422

2.0 2010 Revenue Requirement Allocation

As described in Exhibit 9, Tab 3, Schedule 1, GLPT is requesting disbursal of several deferral and variance accounts. The collective impact of this disbursal is expected to decrease GLPT's revenue requirement by $987,600 per year over a three year period. As a result, GLPT's revenue required from Uniform Transmission Rates is the total base revenue requirement of $39,357,900 less $987,600, or $38,370,300. As a result, GLPT has allocated $38,370,300 to the Uniform Transmission Rate pools.

[1] EB-2008-0272

As in EB-2001-0034 and in EB-2005-0241, GLPT has allocated its incremental revenue requirement to the transmission cost pools by applying the same proportions as was determined by the Board in EB-2008-0272. The resulting allocation of revenue requirement to each of the pools is summarized below.

Table 7-1-1 B – 2010 Revenue Requirement by Transmission Pool

2010 Application	**Network**	**Line Connection**	**Transformation Connection**	**Total**
Revenue Requirement less Regulatory Liability Disbursal	$22,015,990	$5,557,051	$10,797,269	$38,370,310

EXHIBIT 8 - RATE DESIGN

Exhibit 8, Tab 1, Schedule 1

Charge Determinant Forecast

CHARGE DETERMINANT FORECAST

1.0 Methodology

GLPT has developed a methodology for developing a charge determinant forecast for directly connected customers. As shown in Exhibit 8, Tab 2, Schedule 1, this forecasting methodology is combined with the approved charge determinant for Ontario's other three electricity transmitters in order to derive the Uniform Transmission Rate in Ontario (the "UTR").

1.1 Communication with Direct Customers

As a licensed transmitter in Ontario, GLPT has seven customers who are directly connected to it's system that have peak demands that can be considered material. Because there are only seven customers, GLPT determined that the most effective method for developing a forward-looking forecast would be through direct communication with those customers. Statistical modeling or forecasting techniques used without direct communication with customers (where that communication is readily available) could produce inaccurate results if there are foreseeable changes known to the customer, but not factored into consumer loads in the test year. Therefore, GLPT utilized both direct communication and historical information to develop its load forecast for 2010.

In preparation for this application, GLPT has engaged in communication with the seven directly connected customers referred to above in order to gather information on forward-looking load expectations. Information has also been gathered through stakeholder sessions, customer impact assessments and direct discussions. No information has been presented to GLPT to suggest that peak loads will vary significantly, from recent history, in 2010. Therefore, GLPT's load forecast should not anticipate any significant variations from the status quo.

1.2 Use of Historical Information

As a result of the status quo input received from directly connected customers, GLPT uses an historical average methodology. The results of applying the methodology are used as a forecast of charge determinants. The forecasted charge determinants are used in calculating the UTR. The historical average methodology is reasonable given the input from customers, as the customers anticipate no significant variance from the recent past. The historical information used to develop this forecast is published by the IESO for Ontario's transmitters, and is described below.

Each month, the IESO makes available a number of reports that provide information on loads and peaks for each of the transmitters in Ontario. One particular report named the *Transmitter Reconciliation Final Data File* is created on a monthly basis, and details the monthly peaks and the total revenue generated by asset pool.[1] GLPT has analyzed this report for each of the months in the period January 2004 to June 2009, extracted the monthly peaks by asset pool, and developed a forward-looking forecast based on the historical information. The results are as follows:

[1] The three asset pools are Network, Line Connection, and Transformation Connection.

Network Pool:

For over five years, the peak loads in GLPT's Network pool have been very consistent. Therefore, GLPT estimated a charge determinant using the average annual peak loads for the five year period of July 1, 2004 to June 30, 2009. This calculation produces an estimated value for a charge determinant for the Network pool which is similar to the approved figure from 2001.

Line Connection Pool:

The peak loads in the Line Connection pool have also been very consistent for over five years. Therefore, GLPT estimated a charge determinant using the average annual peak loads for the same five year period of July 1, 2004 to June 30, 2009. This calculation produces an estimated value for a charge determinant for the Line Connection pool which is also similar to the approved figure from 2001.

Transformation Connection Pool:

In the fourth quarter of 2006, GLPT entered into a transaction with one of it's largest directly connected transmission customers and sold to that customer the transformers and associated equipment.[2] As a result of this transaction, beginning in December 2006, the peak demands in the Transformation Connection pool have decreased significantly. Therefore, in order to incorporate this reduction, GLPT estimated a charge determinant

[2] Approved in EB-2006-0151.

using the average annual peak loads for the two year period of July 1, 2007 to June 30, 2009.

2.0 Proposed Charge Determinants

GLPT has utilized the information from both the forward-looking customer input, as well as the historical trends to forecast the charge determinants in the table below. The table outlines GLPT's currently approved charge determinants and compares them to the GLPT charge determinants proposed in this Application.

Table 8-1-1 B – Charge Determinants – Actual vs. Proposed

	Annual Charge Determinants (MW)		
	Network	**Line Connection**	**Transformation Connection**
Approved GLPT per EB-2008-0272	4,150.498	2,847.032	2,777.933
GLPT proposal	4,019.797	2,939.425	1,057.605
Variance	(130.701)	92.393	(1,720.328)

Exhibit 8, Tab 2, Schedule 1

Calculation of Uniform Transmission Rates

CALCULATION OF UNIFORM TRANSMISSION RATES

1.0 Overview

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002 as per RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044. The current Ontario Transmission Rate Schedules, which were issued on July 3, 2009 as part of the Board's EB-2008-0272 Decision and Order, are filed at Exhibit 8, Tab 2, Schedule 2.

Since rates are established on a uniform basis for the province, the revenue requirement of the four transmitters in the province, HONI, Canadian Niagara Power Inc., Five Nations Energy Inc., and GLPT, must be aggregated in order to calculate the total transmission revenue requirement for the province for a test year. Therefore, any change to the revenue requirement or charge determinant of any transmitter contributes to a change in the overall provincial transmission tariffs.

The overall revenue requirement must be allocated to the three Uniform Transmission Rate Pools in order for uniform rates by pool to be established.[1] The revenue requirement by Rate Pool for all transmitters is based on the shares established by HONI's Cost Allocation process.[2] Once the revenue requirement by rate pool has been established, then rates need to be established by the Board by applying the appropriate provincial charge determinants for each pool to the associated total revenue requirement for each

[1] GLPT's revenue is allocated to the Rate Pools in Exhibit 7, Tab 1, Schedule 1.
[2] Approved in EB-2008-0272.

pool. The provincial charge determinants are the sum of all charge determinants for the four transmitters by Rate Pool.

2.0 Calculation of Uniform Transmission Rates

Table 8-2-1 A below demonstrates the calculation of the proposed UTR with the inclusion of GLPT's proposed revenue requirement and provincial charge determinants. In calculating the rates in the table, GLPT has not incorporated any changes that may be driven by other transmitters in Ontario. The variances in the rates calculated in *Table 8-2-1 A* compared to the currently approved rates are driven only by GLPT's updated charge determinant forecast and revenue requirement.

Table 8-2-1 A – Proposed 2010 Uniform Transmission Rates

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$2,971,016	$749,913	$1,457,071	$5,178,000
CNPI	$2,646,512	$668,006	$1,297,925	$4,612,443
GLPT	$22,015,990	$5,557,051	$10,797,269	$38,370,310
H1N	$652,352,000	$164,660,000	$319,932,000	$1,136,944,000
All Transmitters	$679,985,518	$171,634,970	$333,484,265	$1,185,104,753

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI	44.915	44.915	44.915	
CNPI	583.420	668.600	668.600	
GLPT	4,019.797	2,939.425	1,057.605	
H1N	250,100.712	241,200.708	208,517.964	
All Transmitters	254,748.844	244,853.648	210,289.084	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**2.67**	**0.70**	**1.59**	
	↓	↓	↓	
FNEI	0.00437	0.00437	0.00437	
CNPI	0.00389	0.00389	0.00389	
GLPT	0.03238	0.03238	0.03238	
H1N	0.95936	0.95936	0.95936	
All Transmitters	1.00000	1.00000	1.00000	

GLPT has also prepared *Table 8-2-1 B* which is a replica of *Table 8-2-1 A,* but shows only the variances in comparison to the currently approved UTR.

Table 8-2-1 B – Variance in UTR Calculation Driven by GLPT

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$0	$0	$0	$0
CNPI	$0	$0	$0	$0
GLPT	$2,056,925	$519,188	$1,008,775	$3,584,888
H1N	$0	$0	$0	$0
All Transmitters	$2,056,925	$519,188	$1,008,775	$3,584,888

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI	-	-	-	
CNPI	-	-	-	
GLPT	(130.701)	92.393	(1,720.328)	
H1N	-	-	-	
All Transmitters	(130.701)	92.393	(1,720.328)	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**0.01**	**0.00**	**0.02**	
	↓	↓	↓	
FNEI	(0.00001)	(0.00001)	(0.00001)	
CNPI	(0.00001)	(0.00001)	(0.00001)	
GLPT	0.00294	0.00294	0.00294	
H1N	(0.00292)	(0.00292)	(0.00292)	
All Transmitters	0.00000	0.00000	0.00000	

3.0 Rate Impacts

As demonstrated in the table, the impact of this application on Ontario rate-payers is a $0.01 increase in the rate for the Network pool, and a $0.02 increase in the rate for the Transformation Connection pool. Overall, GLPT's request results in a 0.30% increase in Ontario's transmission revenue requirement pool.

The rate impact on an average residential customer in Ontario is 0.015%, or approximately $0.01 per month, as calculated in *Table 8-2-1 C* below. For the purposes of this analysis, an average residential customer is one who consumes 1,000 kWh per month. The rates in the analysis are the rates for PUC Distribution Inc., effective November 1, 2009.

Table 8-2-1 C – Bill Impact on Average Residential Customer

		Per Unit	Per Month
Monthly Consumption	1,000	kWh	
Electricity	per kWh	$0.058	$58.00
Monthly Service Charge	per month	9.72	9.72
Distribution Charge	per kWh	0.0157	15.70
Transmission Network Charge	***per kWh***	***0.0048***	***4.80***
RPP Admin	per month	0.25	0.25
Wholesale Market Services	per kWh	0.0065	6.50
Debt Retirement Charge	per kWh	0.0020	2.00
Total Monthly Bill			**$96.97**
Amount of Bill Related to Transmission Rates			4.80
Percentage Increase in Transmission Rates			0.30%
$ Increase Resulting from Transmission Rate Change			**$0.01**
% Bill Increase Resulting from Transmission Rate Change			**0.015%**

Exhibit 8, Tab 2, Schedule 2

Uniform Transmission Rate Reconciliation

UNIFORM TRANSMISSION RATE RECONCILIATION

Table 8-2-2 A below applies the provincial charge determinant forecast to the proposed rates and then to GLPT's allocation factor to reconcile the revenue forecast for GLPT. As anticipated, the proposed UTR and Allocation Factors will eliminate GLPT's expected deficiency in 2010.

Table 8-2-2 A – 2010 Rate Proof Calculation

	Network	Line Connection	Transformation Connection	
2010 Annual Charge Determinants (MW)	254,748,844	244,853,648	210,289,084	
2009 Approved Uniform Rates ($kW-Month)	2.66	0.70	1.57	
2009 GLPTLP Allocation Factor	0.02944	0.02944	0.02944	
2009 GLPTLP Revenue Forecast	19,947,983	5,039,550	9,708,654	34,696,188
2010 Test Year Revenue Requirement				38,370,310
Gross Revenue Deficiency/(Sufficiency)				3,674,122
2010 Proposed Uniform Rates ($kW-Month)	2.67	0.70	1.59	
2010 Proposed GLPT Allocation Factor	0.03238	0.03238	0.03238	
2010 Test Year GLPT Revenue Forecast	22,017,931	5,557,540	10,798,220	38,373,692
2010 Test Year Service Revenue Requirement				38,370,310
Gross Revenue Deficiency/(Sufficiency)				(3,382)

Exhibit 8, Tab 2, Schedule 3

Ontario Transmission Rate Schedule

ONTARIO TRANSMISSION RATE SCHEDULE

Attached in **Appendix "A"** is the current Transmission Rate Schedule approved under EB-2008-0272, and issued on July 3, 2009.

APPENDIX "A"

Ontario Transmission Rate Schedule

APPENDIX B

ONTARIO TRANSMISSION RATE SCHEDULES
EB-2008-0272

The rate schedules contained herein shall be effective July 1, 2009.

Issued: July 3, 2009
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY

The rate schedules contained herein pertain to the transmission service applicable to:

- The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario.
- The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules.

These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE

The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT

The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act.*

The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS

The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool.

All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS.

The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns, or has fully contributed toward the costs of, all transformation connection assets associated with that transmission delivery point.

The PTS customers that utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS-L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns, or has fully contributed toward the costs of, all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES

The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS

In accordance with the Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers.

Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered energy market may be used for the settlement of transmission service charges.

The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS.

The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point.

The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION

The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water.

Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission

Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT

In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point.

In above situations:

- The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO-administered market.

- The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	
$ Per kW of Network Billing Demand [1,2]	2.66
Line Connection Service Rate (PTS-L):	
$ Per kW of Line Connection Billing Demand [1,3]	0.70
Transformation Connection Service Rate (PTS-T):	
$ Per kW of Transformation Connection Billing Demand [1,3,4]	1.57

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3 The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by embedded generation for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4 The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.00 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

Appendix “C” to

ONTARIO UNIFORM RATE ORDER

EB-2008-0272

July 3, 2009

EB-2008-0272
Appendix C

ONTARIO UNIFORM RATE ORDER

REVENUE ALLOCATORS

Effective July 1, 2009

Transmitter	Network	Line Connection	Transformation Connection
Five Nations Energy Inc.	0.00438	0.00438	0.00438
Canadian Niagara Power Inc.	0.00390	0.00390	0.00390
Great Lakes Power Ltd.	0.02944	0.02944	0.02944
Hydro One Networks Inc.	0.96228	0.96228	0.96228
Total	1.00000	1.00000	1.00000

EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS

Exhibit 9, Tab 1, Schedule 1

Deferral and Variance Accounts Overview

DEFERRAL AND VARIANCE ACCOUNTS OVERVIEW

1.0 Existing Deferral and Variance Accounts

GLPT is applying to disburse its December 31, 2008 audited balances in its existing deferral and variance accounts, along with forecasted accruals and carrying charges to December 31, 2009.

GLPT has calculated balances in accounts 1505, 1508, 1572, 1574, 1562 and 1592 of the Uniform System of Accounts. GLPT has provided additional details and calculations in:

- Exhibit 9, Tab 1, Schedule 2—Account 1505;
- Exhibit 9, Tab 1, Schedule 3—Account 1508;
- Exhibit 9, Tab 1, Schedule 4—Account 1574;
- Exhibit 9, Tab 1, Schedule 5—Accounts 1562 & 1592; and,
- Exhibit 9, Tab 1, Schedule 6—Account 1572.

2.0 New Deferral and Variance Account Requests and Request for Direction

GLPT is requesting approval to establish the following new deferral/variance accounts:

- Pension Cost Variance Account;
- OEB Cost Variance Account;

- Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Deferral Account;
- Property Taxes and Use and Occupation Permit Fees Variance Account; and
- IFRS Transition Deferral Account.

GLPT is also requesting the Board's direction on how to treat expenditures arising from an outstanding claim by Comstock Canada Ltd. ("Comstock") in respect of the Transmission Reinforcement Project.

The need for the new accounts, the background to the Comstock claim and the accounting and control process is described in further detail at Exhibit 9, Tab 2, Schedule 1.

Exhibit 9, Tab 1, Schedule 2

Account 1505 - Unrecovered Plant

ACCOUNT 1505 - UNRECOVERED PLANT

1.0 Background

As a result of GLPL's Reinforcement Project, "readily identifiable" assets that were used and useful were retired. A net book value of $9.2791 million was retired in 2005, and in order to mitigate rates, GLPT proposed collecting this amount over a 5-year period instead of collecting the total amount in 2005 alone. This treatment was incorporated in GLPL's Settlement Proposal dated September 15, 2005 (See Exhibit 1, Tab 1, Schedule 13, Appendix "A") and was subsequently approved by the Board.

As a result of the Board's decision, GLPL debited account 1505 – Unrecovered Plant and Regulatory Study Costs for $9.2791 million. The amortization of the balance in account 1505 was charged to account 5730 – Amortization of Unrecovered Plant and Regulatory Study Costs. Through the Uniform Transmission Rates, GLPT has collected $1.8558 million per year beginning April 1, 2005.

2.0 Post-Decision Adjustment

As a result of further analysis subsequent to the Board's decision in EB-2005-0241, GLPL determined that the remaining readily identifiable assets were in fact valued at a net book value of $8.2457 million, not $9.2791 million, the balance of which is being written off equally over five years. Accordingly, GLPL made an adjustment to account 1505 to reflect the appropriate balance in the account. The adjustment also impacted the approved rate base from that proceeding. As a result of the adjustment, the approved rate base was $1,033,378 lower than it would have been had the original write-off amount been correct. Therefore GLPT proposes to offset the over-collected amounts with the lost revenue resulting from rate base being lower than it should have been. *Table 9-1-2 A* demonstrates the calculation of the lost revenue for 2005 through 2009.

Table 9-1-2 A – Calculation of Lost Revenue

Lost Revenue	2005	2006	2007	2008	2009	Total
Unrecovered Depreciation Expense (2.5% per year)	$17,223	$25,834	$25,834	$25,834	$25,834	**$120,561**
Unearned Cost of Capital (2005=7.79%, 2006=7.51%)	53,667	77,607	77,607	77,607	77,607	**364,094**
Unrecovered Ontario Capital Tax Expense	2,067	3,100	2,945	2,945	2,325	**13,382**
Total GLPT Lost Revenue	**$72,956**	**$106,541**	**$106,386**	**$106,386**	**$105,766**	**$498,037**

By removing the full value of $9.2791 million from rate base and only collecting $8.2457 million, GLPT essentially lost the earning potential of that variance for 2005-2009. It would be unfair to GLPT if it was denied this earning potential, and at the same time disallowed recovery of the variance. Therefore, in order to maintain GLPT's fair and equitable recovery, GLPT proposes to include the lost revenue amounts in the final calculation of account 1505.

Table 9-1-2 B below outlines the calculation of the recovered amounts, and the projected balances at each year end.

Table 9-1-2 B – Account 1505 Balance:

Year	**Opening**	**Lost Revenue**	**Write-off Collections**	**Closing Balance**
2005	$8,245,740	$72,956	($1,391,865)	$6,926,831
2006	6,926,831	106,541	(1,855,820)	5,177,553
2007	5,177,553	106,386	(1,855,820)	3,428,119
2008	3,428,119	106,386	(1,855,820)	1,678,685
2009	1,678,685	105,766	(1,855,820)	(71,368)

The table above calculates the closing balance for this account in each year for the period of 2005 through 2009. Each year, the opening balance is reduced by the amount of the regulatory asset that was collected via rates, and increased by the lost revenue as calculated and described above.

GLPT did not intend, nor did it receive direction to collect carrying charges on the outstanding balances in account 1505, and therefore carrying charges have not been recorded.

Therefore, at December 31, 2009 GLPT is forecasting a balance payable to ratepayers of $71,368. GLPT proposes to credit this balance to the benefit of ratepayers in this proceeding, in accordance with the methodology outlined in Exhibit 9, Tab 3, Schedule 1.

Exhibit 9, Tab 1, Schedule 3

Account 1508 - Other Regulatory Assets

ACCOUNT 1508 – OTHER REGULATORY ASSETS

1.0 Preamble

For purposes of describing historical impacts on this account, GLPT has included information on activities undertaken by GLPL in 2007 and by GLPT in 2008-2010. As a result, throughout this section, reference to GLPT will encompass both GLPL and GLPT, unless otherwise specified.

2.0 Summary

GLPT has recorded balances in two sub-accounts of Account 1508 – Other Regulatory Assets. The two sub-accounts are related to:

i) Wholesale Meter Services Rebates, and

ii) Stakeholder Related Costs.

The net balance of Account 1508 is forecasted to be $105,401 at December 31, 2009. This is made up of $122,102 related to the Wholesale Meter Services Rebates sub-account (payable to ratepayers), and $16,701 related to the Stakeholder Related Costs sub-account (receivable from rate payers).

3.0 Wholesale Meter Services Rebates

As described below, the transactions discussed in this section relate to the Board's Decision and Order in EB-2004-0505, a copy of which is provided in Exhibit 1, Tab 1, Schedule 8. At December 31, 2009, GLPT forecasts a principle balance of $122,102 in Account 1508 related to wholesale meter services rebates (the "Rebates"). This includes the total Rebates paid of $465,500, plus carrying charges of $6,099[1] less avoided costs of $593,701.

3.1 Background

Pursuant to Section 3.2 of Chapter 6 of the Market Rules, GLPL, as part of its transmission business, and Hydro One Networks Inc. ("HONI") were required to continue acting as meter service providers ("MSPs") for metered market participants[2] ("MMPs") after market opening until the earlier of the MMP electing to retain its own MSP or the expiry of the first meter seal of the metering installation (the "Transitional Arrangement"). However, MMPs who exited the Transitional Arrangement, and new load-consuming MMPs who retained their own MSPs, paid for HONI's wholesale meter service through the Network service charge in addition to paying their own MSP. As a result, these customers were subject to duplicate charges.

To address this, the Board issued an order (RP-2003-0188/EB-2003-0233) amending HONI's transmission rate order by prescribing rebates and charges related to wholesale meter service. In addition, the Board issued an order (EB-2004-0505) amending GLPL's transmission rate schedule to include a *Rebate And Exit Fee Schedule For Wholesale Meter Service***.** GLPL's rate schedule was adjusted not because it was recovering GLPL's

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[1] Carrying charges are calculated using the OEB's quarterly prescribed interest rates.
[2] Defined at Chapter 11 of the Market Rules for the Ontario Electricity Market.

costs for meter service, but rather because its transmission customers were paying Uniform Transmission Rates, which included a recovery of HONI's revenue requirement relating to meter service.

The Order issued in EB-2004-0505 directed GLPL to provide a rebate in the amount of $5,700 per metering point, per year to MMPs who made alternative arrangements for the provision of wholesale metering services, and to charge an exit fee equivalent to the net book value of the meter assets. GLPL was permitted to set up a deferral account so that the variance between the Rebates and the avoided costs of not providing wholesale metering services would be recorded for later disposition.

GLPL followed the direction in the rate order amendments, as set out in Appendix "A" of the Decision and Order in EB-2004-0505 (see Exhibit 1, Tab 1, Schedule 8). *Table 9-1-3 A* below demonstrates the calculation of the balance in Account 1508 that is related to the Rebates.

Table 9-1-3 A – Wholesale Meter Services Rebates

Year	Opening Balance	Carrying Charges	Carrying Charge Balance	Accruals	Avoided Costs	Accrual Balance	Closing Balance
2005	-	(80)	(80)	-	(2,634)	(2,634)	(2,714)
2006	(2,714)	(1,507)	(1,587)	-	(63,469)	(66,104)	(67,690)
2007	(67,690)	(2,457)	(4,044)	465,500	(59,776)	339,620	335,576
2008	335,576	9,705	5,661	-	(233,321)	106,299	111,961
2009	111,961	437	6,099	-	(234,500)	(128,201)	(122,102)
			$6,099	**465,500**	**(593,701)**	**($128,201)**	**($122,102)**

3.2 The Rebates

The total payments related to the Rebates were $465,500, and were made in November of 2007. After November 1, 2007, GLPL ceased payment of the Rebates. This was as a result of the Board's Decision and Order in EB-2006-0501, which reset the Uniform Transmission Rates in the province and ultimately discontinued the requirement for GLPL to provide the Rebates to customers who were making alternative arrangements. In that proceeding, the Board approved the creation of a separate Wholesale Meter Pool that captured HONI's revenue requirement related to providing MSP services to customers who remained on the Transitional Arrangement from market opening. This removed that portion of the revenue requirement from the Network pool. Any customers who remained on the Transitional Arrangement would have paid a rate specifically for the use of a transmitter as a MSP, and would no longer pay for the services through the Network rate. GLPL did not have any MMPs remaining on the Transitional Arrangement as of November 1, 2007 and, as a result, GLPL did not seek an amendment to the Board's Order to allow GLPL to charge MMPs through the Wholesale Meter Pool.

In summary, since GLPL's MMPs were no longer paying MSP costs through the transmission Network rate, the duplicate payment scenario was eliminated.

3.3 Avoided Costs

Although GLPL did not record the avoided costs as incurred,[3] for purposes of calculating the balance to be disbursed from Account 1508 GLPT has assumed that all avoided costs were recorded as incurred. With respect to the avoided costs, GLPT has recorded the avoided cost of providing MSP services to MMPs for the period beginning at the effective date of GLPL's most recently approved revenue requirement.[4] GLPT has continued to record the avoided costs and forecast avoided costs of providing MSP services up to December 31, 2009 because GLPT has continued to collect funds from the IESO related to the MSP costs. These costs were included in GLPL's approved revenue requirement from EB-2005-0241 and, therefore, GLPT has an obligation (based on the Board's Order in EB-2004-0505) to offset the balance in the deferral account by those avoided costs and to return those funds to ratepayers. In this Application, GLPT is seeking rates that will be effective January 1, 2010. If approved, this will eliminate the avoided cost scenario by removing the provision in GLPT's revenue requirement for the recovery of MSP costs.

3.4 Proposed Disbursal

GLPT is proposing to disburse the forecasted accrual balance, together with the forecasted carrying charges, as of December 31, 2009. By disbursing the forecasted

[3] GLPT has recorded the collective avoided costs in the fourth quarter of 2009. This has been done in order to true up the balance in Account 1508 to align with the balance sought for disposition.
[4] The effective date of GLPL's revenue requirement approved in EB-2005-0241 was April 1, 2005. GLPT has calculated the avoided costs beginning on this date, but has not recorded any avoided cost for any period prior to April 1, 2005.

balances at December 31, 2009, the Board would be clearing the account in full. Moreover, because the calculation of the accrual amount is a mathematical exercise, the forecast balance will not vary from the actual balance as at December 31, 2009.

Also as a part of this Application, GLPT requests that the Board amend GLPT's rate order to remove the *Rebate and Exit Fee Schedule for Wholesale Meter Service*. As noted above, the Board's Decision and Order in EB-2006-0501 reset the Uniform Transmission Rates in Ontario, thus eliminating the requirement to provide the Rebates. The change in the rates removed HONI's metering costs from the Network pool of the Uniform Transmission Rates and, ultimately, eliminated the double-payment issue that drove the requirement to provide the Rebates.

4.0 Stakeholder Related Costs

Under the Settlement in EB-2005-0241, dated September 15, 2005 and accepted by the Board, section 3.1.1 required GLPL to retain an independent third party consultant to review and report on the accuracy of its cost allocation and transfer pricing. As a part of the Settlement, GLPL and all interested parties agreed that a deferral account would be appropriate to track the costs of this consultant's review. Accordingly, GLPT incurred total costs of $16,125 in 2008, plus carrying charges at OEB prescribed rates, as outlined in *Table 5-1-3 B* below.

Table 5-1-3 B – Transfer Pricing Review Costs

Year	Opening Balance	Carrying Charges	Carrying Charge Balance	Accruals	Accrual Balance	Closing Balance
2008	-	392	392	16,125	16,125	16,517
2009	16,517	183	576	-	16,125	16,701
			$576	**16,125**	**$16,125**	**$16,701**

5.0 Balance for Disbursal

GLPT proposes to disburse the balance of Account 1508 in accordance with the methodology described in Exhibit 9, Tab 3, Schedule 1. For ease of reference, the table below outlines the total balance in Account 1508, including both sub-accounts.

Table 5-1-3 C – Account 1508 Balance for Disbursal

Year	Opening Balance	Carrying Charges	Carrying Charge Balance	Accruals	Avoided Costs	Accrual Balance	Closing Balance
2007	-	(80)	(80)	-	(2,634)	(2,634)	(2,714)
2007	(2,714)	(1,507)	(1,587)	-	(63,469)	(66,104)	(67,690)
2007	(67,690)	(2,457)	(4,044)	465,500	(59,776)	339,620	335,576
2008	335,576	10,098	6,054	16,125	(233,321)	122,424	128,478
2009	128,478	621	6,675	-	(234,500)	(112,076)	(105,401)
			$6,675	**481,625**	**(593,701)**	**($112,076)**	**($105,401)**

Exhibit 9, Tab 1, Schedule 4

Account 1574 - Deferred Rate Impact Amounts

ACCOUNT 1574 – DEFERRED RATE IMPACT AMOUNTS

1.0 Background

1.1 Recording the Deficiency

In a Partial Decision and Order related to EB-2005-0241 dated March 22, 2005, which is provided in **Appendix "A"**, the Board ordered that GLPT establish a deferral account in which to record the revenue deficiency incurred by GLPT, plus carrying charges, under currently approved transmission rates beginning January 1, 2005.

Subsequently, the Board approved GLPT's revenue requirement and revenue deficiency on September 15, 2005 through its acceptance of a settlement agreement reached among the parties to the proceeding. The settlement agreement proposed setting the commencement date for recording the revenue deficiency to April 1, 2005.

In an Order dated November 14, 2005,[1] the Board outlined specific guidance for recording the revenue deficiency, and GLPT followed the specific guidance in recording the deficiency in account 1574. For the purposes of that Order, the 1574 account definition was amended to include the following:

> The Company shall record the revenue deficiency based upon the difference between the approved monthly revenue requirement and the monthly revenue forecast as calculated using currently approved rates as directed by the Ontario

[1] Please attached Order for Board File No. EB-2005-0241, Dated November 14, 2005 at Appendix A

Energy Board in its partial decision (EB-2005-0241) dated March 22, 2005 and approved accounting order.

At the end of the deficiency period (December 31, 2005), GLPT had recorded a total deficiency of $3.3211 million, plus carrying charges, to be recovered beginning January 1, 2006.

1.2 Collection of the Deficiency

As a part of the aforementioned settlement agreement, GLPT agreed to file as part of that proceeding a proposal for the disposition of the deferral account. The proposal would seek recovery of the deferral account balance as part of the 2006 Uniform Transmission Rates ("UTR"). The proposal would also provide for the tracking of any potential over-recovery of the deferral account balance such that any outstanding balance can be credited to the benefit of ratepayers in GLPT's next rate proceeding.

From the implementation of the 2006 UTR on January 1, 2006 to the implementation of the 2007/2008 UTR on November 1, 2007, GLPT had collected amounts in relation to the deficiency recorded in account 1574. The over-collections that GLPT was experiencing ended with the implementation of the 2007/2008 UTR on November 1, 2007. The UTR implemented on that date included GLPT's base revenue requirement only, and did not include a gross-up for collection of the deficiency that was required in the 2006 UTR. Therefore, GLPT stopped recording principal balances in this account.

At October 31, 2007, GLPT had recorded a principle balance in account 1574 of $2.4529 million, plus applicable carrying charges, to the credit of ratepayers. *Table 9-1-4 A* below outlines the evolution of account 1574 from April 1, 2005 to December 31, 2009.

As agreed upon in the settlement agreement, GLPT calculated carrying charges on the opening monthly balance of account 1574 at a rate of interest of prime minus 50 basis points, adjusted annually on April 1.

GLPT proposes to credit this balance to the benefit of ratepayers in this proceeding, in accordance with the methodology outlined in Exhibit 9, Tab 2, Schedule 1.

Table 9-1-4 A – Deferred Rate Impact Accruals

Month	Opening Balance	Carrying Charges	Carrying Charge Balance	Accruals	Accrual Balance	Closing Balance
2005	0	44,845	44,845	3,321,112	3,321,112	3,365,958
2006	3,365,958	85,273	130,118	(3,118,145)	202,967	333,085
2007	333,085	(67,849)	62,269	(2,655,867)	(2,452,900)	(2,390,631)
2008	(2,390,631)	(121,112)	(58,843)	0	(2,452,900)	(2,511,743)
2009	(2,511,743)	(65,922)	(124,764)	0	(2,452,900)	(2,577,664)

APPENDIX "A"

Board Order in (EB-2005-0241)

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2005-0241

IN THE MATTER OF the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B;

AND IN THE MATTER OF the Accounting Procedures Handbook for Electricity Distributors as amended for the purposes of this Order;

AND IN THE MATTER OF a request by Great Lakes Power Limited, for an Accounting Order to establish a deferral account in its books of account to capture the revenues that would have been collected had their current rate application been effective April 1, 2005.

O R D E R

In a partial decision and order dated March 22, 2005, the Ontario Energy Board ordered that Great Lakes Power Limited (the "Company") establish a deferral account in which to record the revenue deficiency incurred by the Company, plus carrying charges, under currently approved transmission rates beginning January 1, 2005. The Board assigned file number EB-2005-0241 to the partial decision and order. The Board stated that the Company must prepare and submit a draft accounting order reflecting this order. Subsequently, the Board approved the Company's revenue requirement and revenue deficiency on September 15, 2005 through its acceptance of a settlement agreement reached between the parties to the proceeding. In addition, the proposal in the settlement agreement that the commencement date for recording the revenue deficiency be changed to April 1, 2005, was accepted by the Board.

The Board has reviewed all the evidence and Board staff's recommendation to approve the Accounting Order.

THE BOARD ORDERS THAT:

1. The Company is hereby authorized to establish a deferral account, Deferred Rate Impact Amounts account ("DRIAA"), to capture the associated revenue deficiency arising had the amounts collected in rates, effective April 1, 2005,

been implemented as approved under EB-2005-0241. This is with respect to the revenue requirement and deficiency and effective date approved by the Board on September 15, 2005. Also, the natural volume variability will be reflected in the Company's revenues received during the period. The recording of this revenue deficiency will cease when a new transmission rate approved by the Board is implemented.

The actual provincial charge determinants will differ from the approved determinants. Accordingly there will be a natural variance. Under normal circumstances, the Company would accept the risk/reward of this variance; therefore, the Board will allow the Company to earn revenues on this basis while ensuring that the approved revenue deficiency is accrued.

For each month commencing April 1, 2005, the Company will record the revenue deficiency based upon the difference between the approved monthly revenue requirement and the monthly revenue forecast at current rates. The forecasted revenue requirement will be calculated based on the charge determinants and IESO 18-month forecast included in the settlement agreement accepted by the Board on September 15, 2005 and use current approved rates. The approved monthly revenue requirement will be calculated using the approved revenue requirement as accepted by the Board on September 15, 2005.

2. Details of the accounting entries hereby authorized shall be in accordance with Appendix "A" attached hereto.

3. The Company shall dispose of the DRIAA balance over the authorized collection period in accordance with the recovery methodology to be approved by the Board in Phase II of the proceeding. Any over recovery of the deferral account balance will be tracked, such that any such balance will be credited to the deferral account and will be included in the rate recovery in the Company's s next rate proceeding so that the benefits will be accrued to the benefit of the rate payers.

DATED at Toronto, November 14, 2005

ONTARIO ENERGY BOARD

Original signed by

John Zych
Board Secretary

APPENDIX "A" TO

ORDER

BOARD FILE NO. EB-2005-0241

DATED: NOVEMBER 14, 2005

EB-2005-0241
Appendix "A"

GREAT LAKES POWER LIMITED

Accounting Entries to Recognize Revenues That Would have Been Collected Had the Rates Been Effective April 1, 2005
(Deferred Rate Impact Amounts Account - "DRIAA")

1. To record the difference between the approved monthly revenue requirement and the actual monthly revenue requirement in rates.

   Debit Account 1574, DRIAA

   Credit Account 4110, Transmission Services Revenue

   For the purposes of this entry, the DRIAA shall be calculated as follows:

   DRIAA = approved monthly revenue requirement (network revenues + line connection revenues + transformation connection revenues) – monthly revenue forecast at currently approved rates

2. To record simple interest on the opening monthly balance of the DRIAA account at a rate of interest of prime minus 50 basis points[1].

   Debit Account 1574, DRIAA, Sub-account Carrying Charges

   Credit Account 4405, Interest and Dividend Income

3. To drawn down the account balance for recoveries in rates over the collection period authorized by the Board.

   Debit Account 4110, Transmission Services Revenue

   Credit Account 1574, DRIAA

[1] Posted by CIBC on April 1, 2005 and adjusted annually, per EB-2005-0241 Receipt of Settlement Proposal dated September 15, 2005, as approved by the Board.

The accounts in this order are prescribed by the Board for use under the Accounting Procedures Handbook (“APH”) for Distribution Utilities.

For the purposes of this order, the 1574 account definition has been amended to include the following:

> The Company shall record the revenue deficiency based upon the difference between the approved monthly revenue requirement and the monthly revenue forecast as calculated using currently approved rates as directed by the Ontario Energy Board in its partial decision (EB-2005-0241) dated March 22, 2005 and approved accounting order.

Exhibit 9, Tab 1, Schedule 5

Accounts 1562 & 1592 - Changes in Large Corporations Tax

<u>ACCOUNTS 1562 & 1592 – CHANGES IN TAX LEGISLATION</u>

1.0 Background

The Board has created accounts 1562 and 1592 to deal with changes in tax legislation and tax rules with respect to PILs and taxes. Account 1562 applies to entries up to and including April 30, 2006, while account 1592 relates to tax changes that affect the period after April 30, 2006.

2.0 Large Corporations Tax

The Federal Large Corporations Tax ("LCT") was repealed in the Federal Government's 2006 Budget and the repeal was retroactive to January 1, 2006. Since there has been no LCT cost to GLPT since 2005, no cost recovery is required from ratepayers. Accordingly, both accounts have been used to record adjusting entries for LCT in the applicable periods indicated above.

With respect to recording the accruals in the account, GLPT is unable to accurately identify the amount of LCT that has been collected from the IESO through the Uniform Transmission Rates. Therefore, GLPT has used the provision included in rates from its approved 2006 revenue requirement.[1] Included in GLPT's approved revenue requirement is a proxy of $188,400 for LCT. For the entire period of 2006 to 2008, the monthly accruals in the accounts were one twelfth of $188,400, or $15,700.

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[1] EB-2005-0241

3.0 Income Tax Rates

GLPT's currently approved revenue requirement includes a provision for recovery of income taxes, calculated using a combined federal and provincial tax rate of 35%. However, the tax rates for all years have been different from the approved rate of 35%. In 2006 and 2007, not enough income tax was recovered, and in 2008 and 2009, there was an over-recovery. Therefore, GLPT has calculated and recorded the variance between the approved income tax recovery, based on a 35% rate, and the required income tax recovery, based on the actual rates in each year. As a result, GLPT has recorded accrual balances for each year of 2006 through 2009, as calculated in *Table 9-1-5 A* below. Negative balances in the table below denote amounts payable to rate-payers.

Table 9-1-5 A – Calculation of Income Tax Variances

($000's)	**2006**	**2007**	**2008**	**2009**	
Income tax per OEB decision	5,360.7	5,360.7	5,360.7	5,360.7	(a)
Rate - per filing	35.00%	35.00%	35.00%	35.00%	(b)
Rate - effective rate	36.12%	36.12%	33.50%	33.00%	(c)
Revised income tax (before gross up)	5,532.2	5,532.2	5,131.0	5,054.4	(d) = (a) x (c) / (b)
Change (before gross up)	171.5	171.5	(229.7)	(306.3)	(e) = (d) - (a)
Change (after gross up)	**268.5**	**268.5**	**(345.5)**	**(457.2)**	(f) = (e) / (1 - (c))

4.0 Ontario Capital Tax

In addition to the changes in LCT and income taxes, there have been changes to the rules around Ontario Capital Tax ("OCT") since GLPT's last application. The OCT rate has declined over the period of 2006 to 2009, resulting in GLPT recovering more than required with respect to OCT. As a result, GLPT has recorded total accrual balances in each of 2007, 2008 and 2009, as calculated in *Table 9-1-5 B* below. Negative balances in the table below denote amounts payable to rate-payers.

Table 9-1-5 B – Calculation of Ontario Capital Tax Variances

($000's)	**2006**	**2007**	**2008**	**2009**	
Capital tax per OEB decision	410.0	410.0	410.0	410.0	(a)
Rate - per filing	0.300%	0.300%	0.300%	0.300%	(b)
Rate - effective rate	0.300%	0.285%	0.225%	0.225%	(c)
Revised Capital Tax	410.0	389.5	307.5	307.5	(d) = (a) x (c) / (b)
Change	**-**	**(20.5)**	**(102.5)**	**(102.5)**	(e) = (d) - (a)

5.0 Calculation of Amounts

The balances proposed for disbursal are the forecasted principal balances at December 31, 2009, plus forecasted carrying charges up to December 31, 2009. By disbursing the forecasted balances at December 31, 2009, the Board would be clearing the account in full, and would not leave behind amounts that will carry into GLPT's next transmission rate application. In addition, the calculation of the accrual amounts is a mathematical exercise, and the forecasted balance will not vary from the actual balance at December 31, 2009.

Carrying charges were applied using GLPT's actual debt rate of 6.6% up to and including April 30, 2006, and using the Board's prescribed interest rates for the period after April 30, 2006. Negative balances in the tables below denote amounts payable to rate-payers.

Table 9-1-5 C – Calculation of Account 1562

Year	Opening Balance	Carrying Charges	Carrying Charge Balance	Accruals	Accrual Balance	Closing Balance
2006	-	$1,018	$1,018	$26,713	$26,713	$27,731
2007	$27,731	1,263	2,281	-	26,713	28,993
2008	28,993	1,063	3,344	-	26,713	30,057
2009	30,057	304	3,648	-	26,713	30,360
			$3,648		**$26,713**	**$30,360**

Table 9-1-5 D – Calculation of Account 1592

Year	Opening Balance	Carrying Charges	Carrying Charge Balance	Accruals	Accrual Balance	Closing Balance
2006	-	$713	$713	$53,426	$53,426	$54,138
2007	$54,138	4,928	5,641	59,639	113,065	118,706
2008	118,706	(5,895)	(255)	(636,376)	(523,311)	(523,565)
2009	(523,565)	(8,415)	(8,670)	(748,098)	(1,271,409)	(1,280,078)
			($8,670)		**($1,271,409)**	**($1,280,078)**

GLPT proposes to credit the net balance of $1,249,718 ($1,280,078 - $30,360) indicated in the tables above to the benefit of ratepayers in this proceeding in accordance with the methodology outlined in Exhibit 9, Tab 3, Schedule 1. In addition, GLPT proposes to continue use of account 1592 in the test year as required.

Exhibit 9, Tab 1, Schedule 6

Account 1572 - Extraordinary Event Costs

ACCOUNT 1572 - EXTRAORDINARY EVENT COSTS

GLPT is an electricity transmission company that is solely in the business of owning and operating its electricity transmission system in accordance with Section 71 of the Ontario Energy Board Act (the "OEB Act"). GLPT is the successor of GLPL's transmission business. Up to and including March 2008, GLPL operated the transmission system as a division, financially separate from its distribution and generation businesses. Under Section 5(4) of Ontario Regulation 161/99, GLPL was exempt from Section 71 of the OEB Act until December 31, 2008 and, as a result, was permitted to carry on the activities of transmission and distribution, together with generation, within the same corporation until such date.

In early 2007 in anticipation of the expiry of the Section 71 exemption, a reorganization began in which the transmission assets of GLPL were transferred to GLPT in March 2008. This was approved by a Decision and Order of the Board issued on December 24, 2007 (EB-2007-0647). GLPT became a licensed transmitter (ET-2007-0649) in respect of ownership only. GLPL also remained a licensed transmitter, as the operator of the GLPT transmission system. This completed the first phase of completing the compliance with Section 71. Full compliance with Section 71 occurred when the distribution business was transferred to Great Lakes Power Distribution Inc. ("GLPDI") and the transmission and distribution activity was carried on in two stand alone entities - GLPT and GLPDI, respectively.

As part of acquiring the transmission assets, GLPT incurred costs in the amount of $995,007. The projected balance as of December 31, 2009 in Account 1572 of $1,041,454 which includes $46,448 of carrying charges, as calculated in *Table 9-1-6 A* below.

Table 9-1-6 A – Calculation of Extraordinary Event Costs

Year	Opening Balance	Carrying Charges	Carrying Charge Balance	Accruals	Accrual Balance	Closing Balance
2007	$0	0	-	647,000	647,000	647,000
2008	647,000	35,129	35,129	348,007	995,007	1,030,136
2009	1,030,136	11,318	46,448	0	995,007	1,041,454
			$46,448		**$995,007**	**$1,041,454**

GLPT proposes to recover this balance from ratepayers in accordance with the methodology outlined in Exhibit 9, Tab 3, Schedule 1.

The costs in question arose because of the unique circumstance of Section 71 and the expiration of the legislative exemption to it. Unlike nearly all utilities in Ontario, GLPL was corporately organized prior to the existence of Section 71 of the OEB Act. As a result, Section 71 was not an issue of compliance for most utilities since they could organize with it in mind. For GLPL and any successor to it, Section 71 presented a compliance issue. The Section 71 exemption regulation granted time to prepare for compliance, but nevertheless, compliance could not be avoided in the long term. As a result, the unwinding of a long-standing corporation was both a unique and an extraordinary event not contemplated in the ordinary course of utility business at the time GLPL was created. In the event of non-compliance, the ability to operate the transmission business would have been affected and there would have been a possibility of legal consequences against the business. In particular, under the OEB Act, the Board has the power to suspend or revoke a licence and to issue administrative penalties. Moreover, where convicted of an offence, such as for contravening a provision of the OEB Act or a regulation made under the OEB Act, there is a possibility of substantial fines being issued.

The costs incurred are material as they represent more than 0.25% of GLPT's net assets.

The circumstance giving rise to the costs was not within management's control as it arose from a statutory requirement that was implemented notwithstanding that the integrated structure of GLPL was known and long standing.

The costs have been prudently incurred. The transaction in question was complicated and time consuming since it involved:

- extensive land transfers and land registrations;
- renegotiation of material contracts;
- statutory filings;
- tax considerations; and
- a detailed omnibus application to the Board seeking multiple forms of relief.

As a result, GLPT satisfies the four requirements of causation, materiality, inability of management control, and prudence.

Therefore, GLPT proposes to recover the December 31, 2009 balance for this account of $1,041,454 from ratepayers, in accordance with the methodology outlined in Exhibit 9, Tab 3, Schedule 1.

Exhibit 9, Tab 1, Schedule 7

Reconciliation to Financial Statements

RECONCILIATION OF REGULATORY ACCOUNTS
TO FINANCIAL STATEMENTS

GLPT has provided *Table 9-1-7 A* which reconciles the total regulatory assets and liabilities from GLPT's historical actual and pro-forma financial statements to the total regulatory assets and liabilities provided in Exhibit 9 of this application. The 'Net Regulatory Accounts' line is equal to the 'Current portion of regulatory assets' line, plus the 'Regulatory assets' line, minus the 'Regulatory liabilities' line from GLPT's financial statements.

Table 9-1-7 A – Reconciliation of Regulatory Accounts to Financial Statements

($000's)	Ref	2006	2007	2008	2009
Current portion of regulatory assets		$1,649.0	$1,649.0	$1,649.0	$0.0
Regulatory assets		3,299.0	2,762.0	4,044.0	870.7
Regulatory liabilities		-	(2,391.0)	(2,512.0)	(3,827.4)
Total per FS		**4,948.0**	**2,020.0**	**3,181.0**	**(2,956.7)**
Unrecovered Plant Variance	A	230.2	129.8	29.1	-
Avoided Meter Costs Variance	B	(66.1)	(125.9)	(359.2)	-
Account 1508 Carrying Charges	C	(1.5)	(4.0)	5.6	-
Account 1574 in A/R	D	333.1	-	-	-
PILs Variances	E	81.8	147.7	(493.5)	-
Financing Fee Variance	F	-	-	(2,531.9)	-
IFRS Costs Variance	G	-	-	-	(6.0)
Other (rounding)		(0.7)	0.2	0.4	-
Adjusted Total per FS		**5,524.8**	**2,167.8**	**(168.5)**	**(2,962.7)**
Account 1505	9-1-2	5,177.6	3,428.1	1,678.1	(71.4)
Account 1508	9-1-3	(67.7)	335.6	128.5	(105.4)
Account 1574	9-1-4	333.1	(2,390.6)	(2,511.7)	(2,577.7)
Account 1562	9-1-5	27.7	29.0	30.1	30.4
Account 1592	9-1-5	54.1	118.7	(523.6)	(1,280.1)
Account 1572	9-1-6	-	647.0	1,030.1	1,041.5
Total per Application		**5,524.8**	**2,167.8**	**(168.5)**	**(2,962.7)**

The reconciling items reflected in the table are described below:

A - 1505 – Unrecovered Plant Variance relates to a variation in the method used by GLPT to record the collection of the deferred loss and the recording of the associated lost revenue.

B - 1508 – Avoided Meter Costs Variance relates to unrecorded avoided meter point costs. Prior to 2009, GLPT had not recorded the avoided costs in its financial statements.

C - 1508 – Carrying Charges relates to unrecorded carrying charges on the balance in account 1508. Prior to 2009, GLPT had not recorded the carrying charges in its financial statements.

D - 1574 – Accounts Receivable relates to the classification of the balance of account 1574 in 2006. At December 31, 2006, the total in the account was recorded in GLPT's accounts receivable balance on its Balance Sheet.

E - 1562/1592 – PILs Variances relates to unrecorded PILs variances. Prior to 2009, GLPT had not recorded any variances derived from changes in tax legislation.

F - Financing Fees Variance relates to two items. The first item represents financing costs that are being accounted for as an offset to GLPT's long-term debt. In 2008, the costs were classified as a regulatory asset. The second item represents costs incurred in securing and formalizing GLPT's land assets. In 2008, these costs were recorded as a regulatory asset, but have been added to rate base in 2009 as an addition to GLPT's land value. Subsequent to preparing the audited financial statements, a further review of the regulatory asset accounts was undertaken, and the amounts were re-classified in accordance with Generally Accepted Accounting Principles.

G – 1508 – IFRS Costs Variance relates to one-time administrative incremental IFRS transition costs that GLPT has recorded in its financial statements. GLPT is not requesting disposition of this sub-account in this proceeding and therefore has not included the balance in Account 1508 in Exhibit 9 of this application.

Exhibit 9, Tab 2, Schedule 1

Proposed Deferral and Variance Accounts and Request for Direction

PROPOSED DEFERRAL & VARIANCE ACCOUNTS AND REQUEST FOR DIRECTION

1.0 Deferral and Variance Account Requests

GLPT is requesting approval to establish the following new deferral/variance accounts:

- Pension Cost Variance Account;
- OEB Cost Assessment Variance Account;
- Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Deferral Account;
- Property Taxes and Use and Occupation Fee Variance Account; and
- IFRS Transition Deferral Account**.**

The need for these accounts and the accounting and control process is described in further detail below.

GLPT further requests an accounting order to establish a deferral account to record revenue requirement deficiencies incurred from January 1, 2010 until GLPT's proposed 2010 rates are implemented.

In addition, GLPT is asking the Board to provide direction on how to treat expenditures arising from an outstanding claim related to the Transmission Reinforcement Project, as described in section 3.0 below.

2.1 Pension Cost Variance Account

GLPT proposes that a variance account be established to track the difference between the estimated pension costs for 2010, which will be included in GLPT's approved revenue requirement, and the actual pension costs incurred. To the extent that there are material variances between approved pension costs and actual pension costs, this account will provide a mechanism to protect both ratepayers and GLPT.

The pension cost estimates for 2010 are based on actuarial assessments prepared by Mercer Human Resource Consulting.

The proposed account meets the four prerequisites for the establishment of a variance account, as set out by the Board: causation, materiality, inability of management to control and prudence. The driver behind the request for this account is market forces. The pension cost estimate for 2010 is $660,145, which is a material expense for GLPT. GLPT management does not and cannot control market forces or fluctuations, the cause of the potential variance.

The Board's decision on Hydro One's Transmission Rate Application for 2007 and 2008 (EB-2006-0501) accepted the establishment of the Pension Cost Differential Account for that licensed transmitter.

2.2 OEB Cost Assessment Variance Account

GLPT proposes that a variance account be established to capture incremental OEB cost assessments relating to transmission. The intent of this account is to record future amounts of OEB cost assessments that are incremental to the 2010 base costs embedded in the revenue requirement approved in this proceeding.

The Board's decision on Hydro One's Transmission Rate Application for 2007 and 2008 (EB-2006-0501) accepted the establishment of an OEB Cost Assessment Differential Account for that licensed transmitter. With regard to distributors, in December of 2004 the Board announced that it was amending the Accounting Procedures Handbook and the Uniform System of Accounts to establish a deferral account to allow LDCs to record their OEB cost assessments for the Board's fiscal year of 2004 and subsequent fiscal year(s). Accordingly, for that purpose, the Board approved account 1508, Other Regulatory Assets—sub-account "OEB Cost Assessments".

The allowance for OEB Cost Assessments sought by GLPT in this application is $105,000, and is included in account 5655 – Regulatory Expenses.

2.3 Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Deferral Account

GLPT's transmission system is a fundamental part of Ontario's bulk transmission system and represents a critical link in that part of the IESO-Controlled Grid that extends from the Manitoba border to Sudbury, Ontario. For further details of GLPT's transmission system, see Exhibit 1, Tab 2, Schedule 1.

In addition to GLPT's current role in respect of the Ontario power system, GLPT's role has been enhanced by the *Green Energy and Green Economy Act* and initiatives arising from Ontario's green energy policy. Pursuant to Section 25.36 of the *Electricity Act,* 1998 (as amended) a transmitter is obliged to connect a renewable generation facility to its transmission system if the generator requests the connection in writing and makes the applicable technical, economical and other requirements prescribed by regulation, the Market Rules or by an order or code of the Board. Under Section 26(1.1), a transmitter is obliged to provide priority access through its system to a renewable generation facility that meets the requirement prescribed by regulation.

In addition, Section 70(2.1) of the *Ontario Energy Board Act* deems as part of a transmitter's licence the requirement to provide priority connection access to its transmission system for renewable energy generation facilities. Furthermore, Section 70(2.1)(2) requires transmitters to prepare plans for the expansion or reinforcement of the transmission system to accommodate the connection of renewable energy generation facilities.

It is estimated that there is up to 630 MW of new wind development in and around the GLPT transmission system. Preliminary conclusions suggest that any connection of wind resources between 40-60 MW would trigger the need for an upgrade on GLPT's transmission system, including the construction of new network 230 kV lines.

In addition, based on recent announcements by the Minister of Energy and Infrastructure (the "Minister"), HONI has been asked to pursue certain transmission projects, including "East-West Tie: Nipigon by Wawa" and "Sudbury Area by Algoma Area". These projects include and have an impact on the GLPT transmission system. The Minister has encouraged HONI to pursue partnerships in respect of various projects. It is GLPT's intention to seek to partner with HONI in respect of these and other projects, including projects that may not necessarily be located in the proximity of GLPT's current transmission system.

The Transmission System Code has recently been amended to clarify the means by which connection facilities associated with renewable energy resources may be designated as enabler lines. As such, GLPT may be required to explore the development and construction of enabler lines for renewable resource clusters or enabler facilities that are identified (a) in an approved Integrated Power System Plan, (b) in a direction from the Minister of Energy and Infrastructure, (c) by the Ontario Power Authority through implementation of the Feed-in Tariff Program, or (d) by GLPT in a Board-approved transmission system expansion and reinforcement plan filed in accordance with the deemed condition of GLPT's licence.

This work will be comprised primarily of preliminary engineering, data collection, options assessments, cost estimating, stakeholder and other consultations and other related activities required to prepare project submissions for Environmental Assessment and Leave to Construct Approvals. The planned expenditures are material.

At this time, GLPT has no assurance that capital assets will in fact materialize as a result of such expenditures. Accordingly, GLPT faces the risk of not recovering its investment.

GLPT believes that it satisfies the Board's criteria of causation, materiality, management inability to control and prudence articulated by the Board as the basis for establishing such an account. GLPT's activities are clearly driven by current Ontario energy policy as set out within the amended *Electricity Act*, OEB Act and the OPA's Feed-in Tariff Program. GLPT is not the driver behind these expenditures. As an integral part of Ontario's bulk power system, GLPT will have to respond to the statutory and regulatory directives established as part of Ontario's energy policy.

The Board's decision on Hydro One's Transmission Rate Application for 2009 and 2010 (EB-2008-0272) accepted the establishment of such an account for that licensed transmitter. In the decision, the Board observed that deferral of these costs protects ratepayers from determinations (based on incomplete and inadequate information involved in treating such expenses as OM&A costs and expensing them in the test year) that may be proved wrong. It also, appropriately, protects the transmitter from the risk of non-recovery of pre-engineering expenditures which could not be capitalized if projects do not materialize.

In addition, the Board recognized the need to establish a similar account for distribution utilities as described in the Board's guidelines for "deemed conditions of licence: distribution system planning" (G-2009-0087) dated June 16, 2009.

2.5 Property Taxes and Use and Occupation Permit Fee Variance Account

GLPT has installations on First Nation reserve lands in certain locations. For the use and occupation of such lands, GLPT makes payments in lieu of taxes, as well as pays permit fees under the *Indian Act.* GLPT is in the process of: a) ensuring that there is consistency and uniformity in its payments-in-lieu of taxes payments; and b) formalizing new terms for s.28(2) *Indian Act* permit(s), as required. GLPT has put forward proposals to effectuate this and is awaiting response from at least one affected First Nation. Accordingly, due to the present uncertainty resulting from the fact that agreements have not been formalized, GLPT is requesting the establishment of a variance account to track these payments-in-lieu of taxes and permit fee amounts that are incremental to the amounts in rates.

2.6 IFRS Transition

As indicated in the July 28, 2009 *Report of the Board on International Financial Reporting Standards,* the Board has established a deferral account to record all incremental one-time administrative costs related to the transition to International Financial Reporting Standards ("IFRS"). While this not a new account being proposed by GLPT, GLPT does intend to record costs in this account. However, disbursal of this account will be sought in a future application. GLPT recognizes that the amounts in this account will be subject to review before disposition, with consideration of the criteria of materiality, causation and prudence.

3.0 Request for Direction - Comstock Claim

As noted in GLPL's Section 86 application in EB-2007-0647 and in GLPL's rate application EB-2005-0241**,** there is an outstanding claim by Comstock Canada Ltd. ("Comstock") in respect of the Transmission Reinforcement Project. As described in Exhibit 2, Tab 1, Schedule 1, Comstock claimed additional costs under the Design-Build Contract with GLPL. It was noted in EB-2007-0647 that the claim would be adjudicated by the Ontario Superior Court or pursuant to alternative dispute resolution provisions agreed to by the parties. As this claim remains outstanding, GLPT is not able to comment on any details of the proceeding. However, as there is uncertainty associated with this outstanding claim, including with respect to the costs and legal fees associated with the claim and uncertainty with respect to the amount of any award or settlement that may arise from the claim, GLPT believes these costs are capital expenditures that form part of the project and that, once the claim is resolved, those capital costs will be added to rate base. GLPT seeks direction as to whether the Board would prefer GLPT to include these costs in Construction Work in Progress (as is currently being done), or record these costs in a designated deferral account, which the Board would consider at the time of the account's disbursal.

4.0 Accounting and Control Process

The deferral and variance accounts requested above will be managed in the same manner as existing GLPT deferral and variance accounts. They will be updated monthly and interest will be applied consistent with Board-approved rates**.** Balances will be reported to the Board as part of the quarterly reporting process. The outstanding balances, whether in debit or credit position, will be submitted for approval by the Board as part of a future filing.

Exhibit 9, Tab 3, Schedule 1

Disbursal of Existing Deferral and Variance Accounts

DISBURSAL OF EXISTING DEFERRAL AND VARIANCE ACCOUNTS

1.0 Introduction

The purpose of this Schedule is to outline GLPT's proposed methodology for disbursing approved deferral and variance accounts.

2.0 Proposed Methodology for Disbursal

GLPT proposes to disburse the aggregate balance of the existing deferral and variance accounts over a three-year period. GLPT proposes to reduce its 2010 revenue required from Uniform Transmission Rates by $987,600, or one third of the aggregate balance of $2,962,700, calculated in *Table 9-3-1 A* below. GLPT chose a three-year period for disbursal as it is a reasonable period of time to disburse a balance of this magnitude.

GLPT is proposing to disburse account balances up to December 31, 2009. Balances as of December 31, 2009 are reasonably predictable. Disbursing balances up to December 31, 2009 is more efficient as it provides the opportunity to close out a number of GLPT's deferral and variance accounts. GLPT chose this date because it reflects a fiscal year end, and GLPT is requesting its revenue requirement to be effective January 1, 2010.

Table 9-3-1 A below outlines the calculation of the existing deferral account balances, where a negative amount represents an amount payable to rate-payers.

1 *Table 9-3-1 A – Aggregation of Deferral and Variance Accounts*

($000's)			
USofA Account	**Reference**	**Description**	**Balance for Disbursal**
1505	9-1-2	Unrecovered Plant Costs	($71.4)
1508	9-1-3	Other Regulatory Assets	(105.4)
1574	9-1-4	Deferred Rate Impact Amounts	(2,577.7)
1562	9-1-5	Deferred Payments in Lieu of Taxes	30.4
1592	9-1-5	PILs and Tax Variance for 2006 and subsequent	(1,280.1)
1572	9-1-6	Extraordinary Event Costs	1,041.5
		Total	**(2,962.7)**
		Annual Disbursal	**($987.6)**

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