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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 Oshawa PUC Networks Inc. for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2008 distribution rates and related matters.

APPLICATION

1. The Applicant is Oshawa PUC Networks Inc. ("OPUCN"). OPUCN is a licensed electricity distributor operating pursuant to license ED-2002-0560. OPUCN distributes electricity to approximately 52,000 customers within the corporate boundaries of the City of Oshawa, Ontario.

2. OPUCN 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 distribution of electricity based on a 2008 test year.

3. Specifically, OPUCN hereby applies for an order or orders granting approval of:

   a. its forecasted distribution revenue requirement of $20.44 million;

   b. distribution rates that allow OPUCN to recover its forecasted distribution revenue requirement, effective May 1, 2008;

   c. the dispersal of Regulatory Asset, deferral and variance account balances and the recovery of those balances with a rate adder;

d. OPUCN's current distribution rates becoming interim effective May 1, 2008; and a rate adder for recovery of any deferred revenue requirement from May 1, 2008 until a new rate order issued by the Board becomes effective;

e. Recovery of amounts related to a Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM);

4. As indicated by OPUCN's pre-filed evidence, based on current distribution rates and forecasted load, OPUCN forecasts a revenue deficiency in the amount of $3.98 million.

5. The distribution rates proposed by OPUCN will result in overall bill increases for each class as follows: Residential = 2.3%; General Service < 50 kW = 2.8%; General Service > 50 kW < 1000 kW = 1.2%; General Service > 1000 kW < 5000 kW = 2.1%; General Service > 5000 kW = 1.5%; Unmetered Scattered Load = 1.4%; Sentinel Lightings = 5.9%; Street Lighting = 5.8%.

6. This Application is made in accordance with the Board's *Filing Requirements for Transmission and Distribution Applications* dated November 14, 2006.

7. 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.

8. 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.

9. 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:

Oshawa PUC Networks Inc.
100 Simcoe Street South
Oshawa, ON L1H 7M7

Attention:

Mr. Michael Chase, Corporate Controller
mchase@opuc.on.ca
(905) 723-4626 ext 5246
Fax: (905) 743-5222

Ms Vivian Leppard, Regulatory Analyst
vleppard@opuc.on.ca
(905) 723-4626 ext 5243
Fax: (905) 743-5222

The Applicant's Counsel:

Ogilvy Renault LLP
Suite 3800
Royal Bank Plaza, South Tower
200 Bay Street
P.O. Box 84
Toronto, Ontario M5J 2Z4

Attention:

Mr. Andrew Taylor
ataylor@ogilvyrenault.com
Telephone: (416) 216-4771
Fax: (416) 216-3930

DATED at Toronto, Ontario, this 3rd day of October, 2007.

OSHAWA PUC NETWORKS INC.
By its counsel,

Andrew Taylor
Ogilvy Renault LLP

DISTRIBUTION LICENSE

Oshawa PUC Networks Inc.

ED-2002-0560

Ontario

Electricity Distribution Licence

ED-2002-0560

Oshawa PUC Networks Inc.

Valid Until

March 31, 2023

Mark C. Garner
Director of Licensing
Ontario Energy Board

Date of Issuance: June 10, 2003

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th. Floor
Toronto, ON M4P 1E4

Commission de l'Énergie de l'Ontario
C.P. 2319 2300, rue Yonge 26e étage
Toronto ON M4P 1E4

Electricity Distribution Licence

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1 Definitions 3

In this Licence: 4

"**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; 5

"**Act**" means the Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Schedule B, as amended; 6

"**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; 7

"**Board**"means the Ontario Energy Board; 8

"**Director**" means the Director of Licensing appointed under section 5 of the *Act*; 9

"**distribution services**"means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the *Act*, for which a charge or rate has been established in the Rate Order; 10

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems; 11

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A, as amended; 12

"**Licensee**" means Oshawa PUC Networks Inc.; 13

"**Market Rules**" means the rules made under section 32 of the *Electricity Act*; 14

"**Performance Standards**" means the performance targets for the distribution and connection activities of 15 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; 16

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers; 17

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity; 18

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the *Electricity Act*; 19

"**wholesaler**" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person other than a consumer. 20

2 Interpretation 21

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 and where the time for doing an act expires on a holiday, the act may be done on the next day. 22

3 Authorization Granted under this Licence 23

3.1 The Licensee is authorized, under Part V of the *Act* and subject to the terms and conditions set out in this Licence: 24

a) To own and operate a distribution system in the service area described in Schedule 1 of this Licence; 25

b) To retail electricity for the purposes of fulfilling its obligation under section 29 of the *Electricity Act* in the manner specified in Schedule 2 of this Licence; and , 26

c) To act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the *Electricity Act*. 27

4 Obligation to Comply with Legislation, Regulations and Market Rules 28

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. 29

4.2 The Licensee shall comply with all applicable Market Rules. 30

5 Obligation to Comply with Codes 31

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 to this requirement are set out in Schedule 3 of this Licence: 32

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters; 33

b) the Distribution System Code; 34

c) the Retail Settlement Code, and; 35

d) the Standard Supply Service Code. 36

5.2 The Licensee shall: 37

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; 38

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. 39

40

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence. 41

7 Obligation to Connect 42

7.1 The Licensee shall connect a building to its distribution system if: 43

a) The building lies along any of the lines of the distributor's distribution system, and 44

b) The owner, occupant or other person in charge of the building requests the connection in writing. 45

7.2 The Licensee shall make an offer to connect a building to its distribution system if: 46

a) The building is within the Licensee's service area as described in Schedule 1, and 47

b) The owner, occupant or other person in charge of the building requests the connection in writing. 48

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board. 49

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the *Act* or any Codes to which the Licensee is obligated to comply with as a condition of this Licence. 50

8 Obligation to Sell Electricity 51

8.1 The Licensee shall fulfill its obligation under section 29 of the *Electricity Act* to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail 52

Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity 53

9.1 The Licensee shall maintain its distribution system to the standards established in the Distribution System Code, Market Rules and have regard to any other recognized industry operating or planning standards adopted by the Board. 54

10 Market Power Mitigation Rebates 55

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence. 56

11 Distribution Rates 57

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the *Electricity Act* except in accordance with a Rate Order of the Board. 58

12 Separation of Business Activities 59

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board. 60

13 Expansion of Distribution System 61

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make and interconnection except in accordance with the *Act* and Regulations, the Distribution System Code and applicable provisions of the Market Rules. 62

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine. 63

64

14 Provision of Information to the Board and Director of Licensing

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board or the Director, such information as the Board or the Director may require from time to time. 65

14.2 Without limiting the generality of condition 14.1 the Licensee shall notify the Director 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) days past the date upon which such change occurs. 66

15 Restrictions on Provision of Information 67

15.1 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. 68

15.2 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: 69

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence; 70

b) for billing, settlement or market operations purposes; 71

c) for law enforcement purposes; or 72

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator. 73

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified. 74

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions 75 under which their information may be released to a third party without their consent.

76

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

77

16 Customer Complaint and Dispute Resolution

78

16.1 The Licensee shall:

79

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

80

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

81

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

82

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

83

e) refer unresolved complaints and subscribe to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Director. The Director will provide reasonable notice to the Licensee of the date this condition becomes effective.

84

17 Term of Licence

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17.1 This Licence shall take effect on June 10, 2003 and terminate on March 31, 2023.

86

18 Transfer of Licence

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

88

19 Amendment of Licence

19.1 The Board may amend this Licence in accordance with section 74 of the *Act* or section 38 of the *Electricity Act.* 89

20 Fees and Assessments 90

20.1 The Licensee shall pay all fees charged and amounts assessed by the Board. 91

21 Communication 92

21.1 The Licensee shall designate a person that will act as a primary contact with the Director of Licensing on matters related to this Licence. The Licensee shall notify the Director promptly should the contact details change. 93

21.2 All official communication relating to this Licence shall be in writing. 94

21.3 All written communication is to be regarded as having been given by the sender and received by the addressee: 95

a) when delivered in person to the addressee by hand, by registered mail or by courier; 96

b) seven (7) business days after the date of posting if the communication is sent by regular mail; and, 97

c) when received by facsimile transmission by the addressee, according to the sender's transmission report. 98

22 Copies of the Licence 99

22.1 The Licensee shall: 100

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; 101

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

Schedule 1 Definition of Distribution Service Area 103

104
This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with condition 8 of this Licence.

105
The City of Oshawa as established by the Durham Municipal Hydro-Electric Service Act, 1979 and as continued by the Regional Municipality of Durham Act R.S.O. 1990, C.R. 9.

Schedule 2 Provision of Standard Supply Service 106

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the *Electricity Act*. 107

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with condition 8 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders. 108

Schedule 3 List of Code Exemptions 109

This Schedule specifies any specific Code requirements from which the Licensee has been exempt. 110

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it. 111

Appendix A Market Power Mitigation Rebates 112

1 Definitions and Interpretation 113

In this Licence, 114

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor 115
distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is 116
connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to 117
another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IMO includes interim payments 118
made by the IMO.

2 Information Given to IMO 119

a Prior to the payment of a rebate amount by the IMO to a distributor, the distributor shall provide 120
the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with information in respect of the volumes of electricity withdrawn by the distributor from the IMO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail 121
Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed 122
price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity 123
consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IMO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of

any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and 124

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* 125

c Prior to the payment of a rebate amount by the IMO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IMO, in the form specified by the IMO and before the expiry of the period specified by the IMO, with the information provided to the host distributor by the embedded distributor in accordance with section 2. 126

The IMO may issue instructions or directions providing for any information to be given under this section. The IMO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment. 127

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IMO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IMO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period. 128

3 **Pass Through of Rebate** 129

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IMO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to: 130

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented; 131

b consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the 132

Ontario Energy Board Act, 1998 and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity. 133

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor. 134

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement: 135

"ONTARIO POWER GENERATION INC. rebate" 136

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IMO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt. 137

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party. 138

Pending pass-through or return to the IMO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account. 139

CONTACT INFORMATION

The Applicant:

Oshawa PUC Networks Inc.
100 Simcoe Street South
Oshawa, ON L1H 7M7

Attention:

Mr. Michael Chase, Corporate Controller
mchase@opuc.on.ca
(905) 723-4626 ext 5246
Fax: (905) 743-5222

Ms Vivian Leppard, Regulatory Analyst
vleppard@opuc.on.ca
(905) 723-4626 ext 5243
Fax: (905) 743-5222

The Applicant's Counsel:

Ogilvy Renault LLP
Suite 3800
Royal Bank Plaza, South Tower
200 Bay Street
P.O. Box 84
Toronto, Ontario M5J 2Z4

Attention:

Mr. Andrew Taylor
ataylor@ogilvyrenault.com
Telephone: (416) 216-4771
Fax: (416) 216-3930

LIST OF SPECIFIC APPROVALS REQUESTED

OPUCN hereby applies for an order or orders granting approval of:

a. its forecasted distribution revenue requirement of $20.44 million;

b. distribution rates that allow OPUCN to recover its forecasted distribution revenue requirement, effective May 1, 2008;

c. the dispersal of Regulatory Asset, deferral and variance account balances and the recovery of those balances with a rate adder;

d. OPUCN's current distribution rates becoming interim effective May 1, 2008; and a rate adder for recovery of any deferred revenue requirement from May 1, 2008 until a new rate order issued by the Board becomes effective;

e. Recovery of amounts related to a Lost Revenue Adjustment Mechanism (LRAM) and Shared Savings Mechanism (SSM);

DRAFT ISSUES LIST

1. Are the distribution rates proposed by OPUCN just and reasonable?

PROCEDURAL ORDERS/CORRESPONDENCE/NOTICES

There are no current procedural orders, motions or notices at this time.

ACCOUNTING ORDERS

OPUCN does not request any accounting orders at the time of submission.

LIST OF NON-COMPLIANCE WITH THE US of A

OPUCN is in compliance with the Uniform System of Accounts (US of A).

MAP OF OPUCN'S DISTRIBUTION SYSTEM

A map that illustrates the Applicant's distribution system is at:

http://www.opuc.on.ca/conditions-of-service/

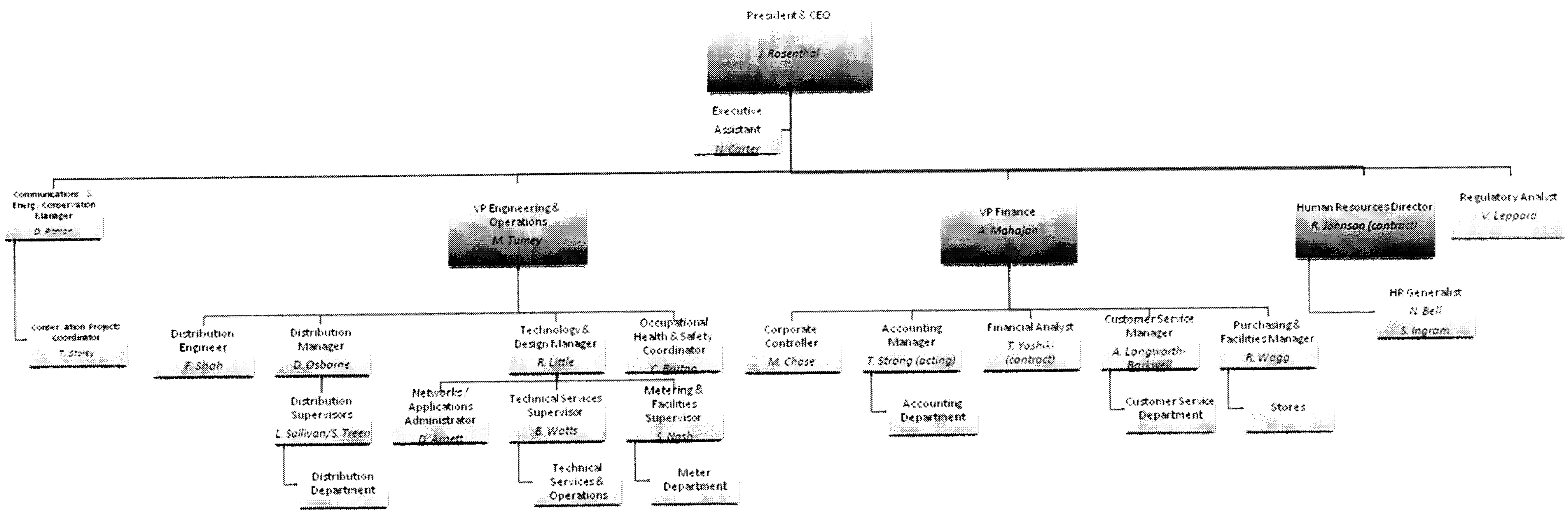
LIST OF NEIGHBORING UTILITIES

Whitby Hydro Electric Corp 100 Taunton Rd. E. Whitby, ON L1N 5R8	Direct line: (905) 668-5878 Direct Fax: (905) 668-6598 E-mail: whitbyhydro@whitbyhydro.on.ca
Veridian Connections Inc 55 Taunton Rd. E. Ajax, ON L1T 3V3	Direct line: (888) 445-2881 Direct Fax: E-mail: service@veridian.on.ca
Hydro One Networks 483 Bay St. North Tower, 15th floor Reception Toronto, ON M5G 2P5	Direct line: (888) 955-1155 Direct Fax: (416) 345-5866 E-mail: regulatory@HydroOne.com

EXPLANATION OF ANY HOST OR EMBEDDED UTILITIES

An affiliate of OPUCN is currently building a CHP generation project behind the meter at one of OPUCN's customer's premises. For the electricity generation expected to begin in 2008, OPUCN will make settlements with the Generator for the commodity payments. However, OPUCN will continue billing its end customer. Since the generator is not expected to replace existing distribution load it will have no effect on OPUCN's revenue forecast.

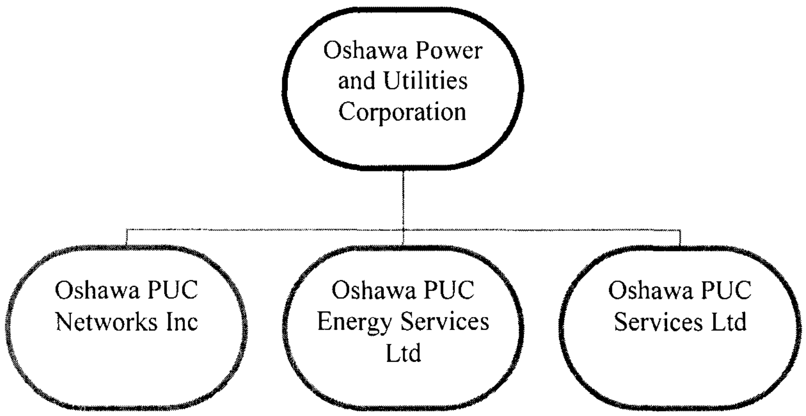
UTILITY ORGANIZATIONAL CHART


President & CEO
J. Rosenthal
Executive Assistant
N. Carter
Communications & Energy Conservation Manager
Conservation Projects Coordinator
VP Engineering & Operations
M. Turney
Distribution Engineer
F. Shah
Distribution Manager
D. Osborne
Distribution Supervisors
L. Sullivan/S. Treen
Distribution Department
Technology & Design Manager
R. Little
Networks / Applications Administrator
D. Arnett
Technical Services Supervisor
B. Watts
Technical Services & Operations
Metering & Facilities Supervisor
S. Nash
Meter Department
Occupational Health & Safety Coordinator
C. Burton
VP Finance
A. Mahajan
Corporate Controller
M. Chase
Accounting Manager
T. Strong (acting)
Accounting Department
Financial Analyst
T. Yoshiki (contract)
Customer Service Manager
A. Longworth-Barkwell
Customer Service Department
Purchasing & Facilities Manager
R. Wagg
Stores
Human Resources Director
R. Johnson (contract)
HR Generalist
N. Bell
S. Ingram
Regulatory Analyst
V. Leppard

CORPORATE ENTITIES RELATIONSHIPS CHART

1.0 Overview

The parent company of OPUCN is Oshawa Power and Utilities Corporation ("OPUC"). OPUC is the sole shareholder of the three subsidiaries: OPUCN, Oshawa PUC Services Inc. ("OPUC Services"), and Oshawa PUC Energy Services Inc. ("OPUC Energy Services"), as illustrated by the following diagram:



OPUC, incorporated under the Ontario Business Corporation Act, was formed to conduct electricity distribution and non-regulated service ventures. OPUC is wholly owned by the Corporation of the City of Oshawa.

OPUC Services provides dark fibre-optic network connections to various MUSH (Municipalities, Universities, Schools and Hospitals), enterprise and carrier customers. OPUC Services also provides electric meter installation, verification and maintenance services within Ontario.

OPUC Energy Services is currently in the process of constructing a 2.4 MWcombined heat and power generating unit to be located at Durham College, Oshawa and is expected to commence operations in 2008.

2.0 Boards of Directors

The Board of Directors of OPUC has three members. These three members also sit on the Boards of Directors of OPUCN, OPUC Energy Services, and OPUC Services. The Board of Directors of OPUCN has an additional two independent members in compliance with the Affiliate Relationships Code.

3.0 Shared and Contracted Services

3.1 Between OPUCN and OPUC

OPUC provides corporate governance services to OPUCN. This includes activities to support its board of directors, board committees, legal and consulting services and executive management. The CEO and CFO of OPUCN are employees of the parent company. OPUCN pays a monthly management fee to the parent company for these corporate governance services, as described at Exhibit 4, Tab 2, Schedule 4.

3.2 Between OPUCN and OPUC Services and OPUC Energy Services

OPUCN provides a variety of services which are invoiced by OPUCN monthly. The fee charged by OPUCN for these services is based on the fully allocated cost incurred by OPUCN to provide these services.

All inter-affiliate transactions including installation and maintenance services are processed through job costing system using charges and rates that do not provide cross subsidization between the Affiliates.

OPUCN also receives wholesale metering services from OPUC Services. OPUCN pays a standard market based fee for these services and it is ensured that such fee is at the same rates as those charged to OPUC Services' "arms length" customers.

PLANNED CHANGES IN CORPORATE OR OPERATIONAL STRUCTURE

There are no planned changes to the corporate or operational structure of OPUCN at this time.

STATUS OF BOARD DIRECTIVES

There are no specific Board directives active for OPUCN at this time.

COMPANY POLICIES AND REGULATIONS/SERVICE CHARGES

OPUCN uses the following standard service charges approved by the Board:

Customer Administration	Rate
Arrears Certificate	$15.00
Easement Letter	$15.00
Account History	$15.00
Change of Occupancy (Account Setup)	$30.00
Legal Letter charge	$15.00
Credit Check (plus credit agency charges)	$15.00
Meter Dispute Charge (if meter found to be correct)	$30.00
Credit Reference Letter	$15.00
Returned Cheque Charge (plus bank charges)	$15.00
Special Meter Reads	$30.00
Non-Payment of Account	
Late Payment - per month	1.50%
Late Payment - per annum	19.56%
Collection of account charge - no disconnection	$30.00
Disconnect/Reconnect at meter during regular hours including Load Limiters	$65.00
Disconnect/Reconnect at meter after regular hours including Load Limiters	$185.00
Disconnect/Reconnect at pole during regular hours	$185.00
Disconnect/Reconnect at pole after regular hours	$415.00
Access to the Power Poles - per pole/year	$22.35
Allowances	
Transformer Allowance for Ownership - per kW of billing demand/month	($0.60)

OPUCN's Conditions of Service can be viewed at http://www.opuc.on.ca/conditions-of-service.

CHANGES IN POLICIES AND REGULATIONS

OPUCN's Conditions of Service were filed with the Board in June 2007. Since that time there have been no changes.

LIST OF WITNESSES AND THEIR CURRICULUM VITAE

A list of witnesses and their curriculum vitae will be provided as required.

SUMMARY OF THE APPLICATION

1.0 Introduction

Oshawa PUC Networks Inc. ("OPUCN") is applying to the Ontario Energy Board (the "Board") for distribution rates to be effective from May 1, 2008 to April 30, 2009 (the "2008 rate year"). As illustrated by Table 1 below, the proposed rates will recover OPUCN's forecasted revenue requirement of approximately $20.44 million. OPUCN's proposed distribution rates are necessary to avoid a forecasted revenue deficiency in the amount of $3.98 million during the 2008 rate year (Exhibit 1, Tab 2, Schedule 2).

The following table summarizes the general components of OPUCN's 2008 distribution revenue requirement.

Table 1 – Summary of Revenue Requirement:

	($000's)	Reference
Cost of Capital		
Rate Base	$64,758.2	Ex 2, Tab 1, Sch 1
Requested Rate of Return	7.60%	Ex 6, Tab 1, Sch 1
	4,920.6	
Cost of Service		
Operations, Maintenance & Admin.	10,446.6	Ex 4, Tab 2, Sch 1
Depreciation	4,395.4	Ex 4, Tab 2, Sch 7
Municipal & Capital Taxes	345.5	Ex 4, Tab 3, Sch 1
Income Taxes	1,935.9	Ex 4, Tab 3, Sch 1
Service Revenue Requirement	22,044.0	
Other Revenue	(1,601.6)	Ex 3, Tab 3, Sch 1
Base Revenue Requirement	**$20,442.4**	

The major components of Table 1 are described below.

2.0 Rate Base

As set out at Exhibit 2, Tab 1, Schedule 1, OPUCN's rate base from 2006 to 2008 can be numerically summarized as follows:

Table 2 – Rate Base Summary

($000's)	2006 Actual	2007 Bridge	2008 Test
Net Fixed Assets	$41,788.5	$43,870.5	$49,510.7
Working Capital Allowance	12,474.8	14,854.4	15,247.5
Rate Base	**54,263.3**	**58,724.9**	**64,758.2**

OPUCN's forecasted revenue deficiency can be primarily attributed to its proposed rate base additions. The last full rebasing of OPUCN's distribution rates took place prior to the 2004 rate year. Capital expenditures since that time are not reflected in OPUCN's rate base, although capital expenditures have increased since 2004 and the need for more capital improvements will continue over the next three years. These improvements are necessary due to the age of the system and the expansion of large development in the City of Oshawa during the last three to five years. 2006 was a record year for development in Oshawa and the forecast for the amount of new plant needed made prior to that year was based on historic trend analysis and did not reflect this record. As a consequence, full recovery of the increased capital investment needed to meet that growth has not been possible to this point.

Since 2004, Oshawa has experienced significant growth. Much of this growth has been in areas of the municipality which were formerly underused and unserviced land. This growth has required the building of new infrastructure. Growth in the northern region of the City of Oshawa has created a requirement for other major investments as well, including an imminent need for a Municipal Substation (MS) to provide load without negatively impacting the rest of the system.

3.0 Operating Revenue

OPUCN's operating revenue forecast for 2008 is described at Exhibit 3. As indicated by the Table 4 below, a numerical summary of OPUCN's operating revenues from 2006 to 2008, operating revenues are forecasted to increase in the 2008 Test year.

Table 4 – Operating Revenue Summary

($000's)	2006 Actual	2007 Bridge	2008 Test
Total Operating Revenue	19,928.3	19,626.6	22,044.0

OPUCN determined its load forecast by applying Hydro One's weather normalization factor to the most recent five year (2002-2006) volumes for each class (Exhibit 3, Tab 2, Schedule 5). These normalized average loads were applied to forecasted customer counts (Exhibit 3, Tab 2, Schedule 2) to establish loads for both the 2007 Bridge year and the 2008 Test year.

4.0 Operating Costs

OPUCN's operating costs include: operations, maintenance & administration ("OM&A"); depreciation & amortization; capital & property taxes; and income taxes. A summary of OPUCN's operating costs for 2006 through 2008 are set out in the following table:

Table 4 – Operating Costs Summary:

($000's)	**2006 Actual**	**2007 Bridge**	**2008 Test**
Operations, Maintenance & Administration	$8,237.0	$9,192.2	$10,446.6
Depreciation & Amortization	3,659.1	3,892.0	4,395.5
Capital & Property Taxes	387.7	393.0	345.5
Income Taxes	2,171.7	2,100.5	1,935.9
Total Operating Costs	**14,455.5**	**15,577.7**	**17,123.5**

As illustrated by Table 4, OPUCN's OM&A costs have increased from 2006 to 2008 due primarily to workforce related circumstances:

- Succession planning to deal with the large number of retirements expected during the next few years. These employees must ideally be hired ahead of the retirements since the long training times are required to ensure appropriate knowledge transfer for the maintenance of safety and system reliability standards;
- The collective agreement in place for the next two years contains a provision for 3% wage increases during that time.
- Based on the results of the AON study of future benefit liabilities (available at Appendix C.1 and C.2), OPUCN increased the accrual for future benefits by approximately $173,000.

More information on OPUCN's operating costs is at Exhibit 4.

5.0 Cost Of Capital

OPUCN's cost of capital can be numerically summarized as follows:

Table 5 – Cost of Capital Summary:

($000's)	2006 Actual	2007 Bridge	2008 Test
Rate Base	$54,263.3	$58,725.0	$64,758.2
Rate of Return	8.13%	8.13%	7.60%
Total Cost of Capital	**$4,408.9**	**$4,771.4**	**$4,920.6**

OPUCN has followed the Board's *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* in determining its cost of capital.

More information on OPUCN's cost of capital is at Exhibit 6, Tab 1, Schedule 1.

6.0 Rates and Rate Impacts

OPUCN has proposed distribution rates based on its current Board-approved cost allocation methodology.

The distribution rates proposed by OPUCN are set out at Exhibit 9, Tab 1, Schedule 6.

The rate impacts associated with the proposed rates are not significant, and will result in minor overall bill increases for each class as follows: Residential = 2.3%; General Service < 50 kW = 2.8%; General Service > 50 kW < 1000 kW = 1.2%; General Service

> 1000 kW < 5000 kW = 2.1%; General Service > 5000 kW = 1.5%; Unmetered Scattered Load = 1.4%; Sentinel Lightings = 5.9%; Street Lighting = 5.8%. (Exhibit 9, Tab 1, Schedule 12)

7.0 Other Matters

OPUCN intends to install smart meters when direction is received from the Board. OPUCN will apply to increase its existing smart meter rate adder as a separate application to implement the Government's smart meter plans.

SCHEDULE OF OVERALL REVENUE DEFICIENCY/SUFFICIENCY

Revenue	
Distribution Revenue	17,905,146
Other Operating Revenue (Net)	1,601,656
Total Revenue	19,506,802
Distribution Costs	
Operation, Maintenance, and Administration	10,446,613
Depreciation & Amortization	4,395,489
Property & Capital Taxes	345,450
Payment in Lieu of Taxes (PILS)	1,935,917
Total Costs and Expenses	17,123,469
Sufficiency/ Deficiency	
Revenue before Interest Expense	2,383,333
Proposed Rate Base	64,780,648
Achieve Return on Rate Base	3.68%
Required Return on Rate Base	7.60%
Sufficiency/ Deficiency Rate of Return	-3.92%
Net Deficiency	(2,539,996)
Income Tax Rate	36.12%
Gross Deficiency	(3,976,199)

AUDITED FINANCIAL STATEMENT (2006)

Oshawa PUC Networks Inc.
December 31, 2006

AUDITORS' REPORT

To the Shareholder of
Oshawa PUC Networks Inc.

We have audited the balance sheet of **Oshawa PUC Networks Inc.** as at December 31, 2006 and the statements of income and retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation'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 Corporation as at December 31, 2006 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Toronto, Canada,
March 27, 2007.

Oshawa PUC Networks Inc.

BALANCE SHEET

[in thousands of dollars]

As at December 31

	2006 $	2005 $
ASSETS		
Current		
Cash and cash equivalents [including customer deposits [2006 - $3,456; 2005 - $3,790]	**12,880**	14,883
Restricted cash	**—**	7,000
Treasury bill – Government of Canada 4.10% *[note 17]*	**5,901**	6,001
Accounts receivable	**8,207**	4,230
Unbilled revenue	**7,903**	9,330
Due from affiliates *[note 14]*	**—**	644
Inventory	**743**	590
Prepaid expenses	**412**	285
Current portion of regulatory assets *[note 4]*	**1,384**	1,136
Total current assets	**37,430**	44,099
Property, plant and equipment, net *[note 3]*	**45,493**	44,757
Regulatory assets, net *[note 4]*	**1,607**	3,191
Other assets *[note 5]*	**41**	42
Total non-current assets	**47,141**	47,990
	84,571	92,089
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current		
Accounts payable – IESO *[note 18]*	**7,130**	9,300
Accounts payable and accrued liabilities	**5,233**	6,004
Payments in lieu of corporate income taxes	**293**	345
Advance payments	**1,974**	1,697
Deferred revenue *[note 19]*	**235**	345
Current portion of regulatory liabilities *[note 4]*	**—**	590
Current portion of long-term liabilities *[note 6]*	**794**	1,306
Total current liabilities	**15,659**	19,587
Note payable to shareholder *[note 11]*	**23,064**	23,064
Long-term debt *[note 12]*	**7,000**	7,000
Customers' advance deposits	**3,097**	2,865
Deferred revenue	**11**	24
Post-employment non-pension benefits *[note 10]*	**8,176**	7,797
Regulatory liabilities *[note 4]*	**121**	21
Employee sick leave benefits *[note 7]*	**128**	229
Total long-term liabilities	**41,597**	41,000
Total liabilities	**57,256**	60,587
Shareholder's equity		
Capital stock *[note 13]*	**23,064**	23,064
Retained earnings	**4,251**	8,438
Total shareholder's equity	**27,315**	31,502
	84,571	92,089

Contingencies and commitments *[notes 15 and 16]*
See accompanying notes

Oshawa PUC Networks Inc.

STATEMENT OF INCOME AND RETAINED EARNINGS

[in thousands of dollars]

Year ended December 31

	2006 $	2005 $
REVENUE		
Sale of electrical energy	**92,454**	122,729
Cost of electrical energy	**74,541**	105,316
Net revenue from sale of electrical energy	**17,913**	17,413
Other revenue	**1,240**	712
Net revenue	**19,153**	18,125
EXPENSES		
Operations, maintenance and administrative	**13,024**	12,718
Less amount allocated to property, plant and equipment and billable jobs	**(4,464)**	(4,182)
Net operations, maintenance and administrative expenses	**8,560**	8,536
Income before the following	**10,593**	9,589
Depreciation	**(3,659)**	(3,545)
Gain on disposal of property, plant and equipment	**48**	35
Interest income	**775**	498
Interest improvement on regulatory accounts	**160**	390
Interest expense *[note 11]*	**(1,943)**	(1,534)
Income before payments in lieu of corporate income taxes	**5,974**	5,433
Provision for payments in lieu of corporate income taxes *[note 8]*	**2,125**	2,330
Net income for the year	**3,849**	3,103
Retained earnings, beginning of year	**8,438**	6,055
Dividends paid *[note 13]*	**(8,036)**	(720)
Retained earnings, end of year	**4,251**	8,438

See accompanying notes

Oshawa PUC Networks Inc.

STATEMENT OF CASH FLOWS

[in thousands of dollars]

Year ended December 31

	2006 $	2005 $
OPERATING ACTIVITIES		
Net income for the year	**3,849**	3,103
Add (deduct) items not involving cash		
Depreciation	**3,659**	3,545
Gain on disposal of property, plant and equipment	**(48)**	(35)
Regulatory assets	**1,336**	(787)
Other assets	**1**	(42)
Regulatory liabilities	**(490)**	611
Employee sick leave benefits	**(48)**	(30)
Advance payments	**277**	(445)
Deferred revenue	**(110)**	345
Post-employment health benefits	**379**	353
	8,805	6,618
Changes in non-cash working capital balances related to operations		
Decrease (increase) in accounts receivable	**(3,977)**	2,481
Decrease (increase) in unbilled revenue	**1,427**	(1,074)
Decrease (increase) in due from affiliates	**644**	(154)
Increase in inventory	**(153)**	(147)
Increase in prepaid expenses	**(127)**	(76)
Increase (decrease) in accounts payable – IESO	**(2,170)**	3,618
Increase (decrease) in accounts payable and accrued liabilities	**(771)**	1,693
Decrease in provision for environmental costs	**—**	(100)
Decrease in payments in lieu of corporate income taxes	**(52)**	(284)
Increase (decrease) in deferred revenue	**(13)**	24
Cash provided by operating activities	**3,613**	12,599
INVESTING ACTIVITIES		
Additions to property, plant and equipment, net	**(10,773)**	(11,444)
Contributions in aid of construction	**6,362**	5,300
Proceeds from disposal of property, plant and equipment	**64**	35
Treasury bill – Government of Canada 4.10%	**100**	(1)
Decrease in upstream capital improvement funds	**—**	(706)
Cash used in investing activities	**(4,247)**	(6,816)
FINANCING ACTIVITIES		
Dividends paid	**(8,036)**	(720)
Decrease in customers' advance deposits	**(333)**	(755)
Increase in long-term debt	**—**	7,000
Cash provided by (used in) financing activities	**(8,369)**	5,525
Net increase (decrease) in cash and cash equivalents during the year	**(9,003)**	11,308
Cash and cash equivalents, beginning of year	**21,883**	10,575
Cash and cash equivalents, end of year	**12,880**	21,883

Supplemental cash flow information

Interest paid [prior to capitalization of interest]	**1,678**	1,672

Payments in lieu of corporate income taxes	**2,330**	2,233

See accompanying notes

1. INCORPORATION

Oshawa PUC Networks Inc. (the "Corporation") was incorporated under the *Ontario Business Corporations Act* (Ontario) on October 18, 2000. The incorporation was required in accordance with the provincial government's *Electricity Act, 1998*. The Corporation operates in one business segment, providing electricity distribution services to businesses and residences in the service area of Oshawa, Ontario.

The Corporation is a wholly-owned subsidiary of Oshawa Power and Utilities Corporation, which is wholly owned by the Corporation of the City of Oshawa.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The Corporation's financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"), including accounting principles prescribed by the Ontario Energy Board (the "OEB") in the handbook "Accounting Procedures Handbook for Electric Distribution Utilities" ("AP Handbook"), and reflect the significant accounting policies summarized below:

Rate setting and regulation

The *Energy Competition Act, 1998* (the "Act") was given Royal Assent on October 30, 1998. The Act provides for a competitive market in the sale of electricity and the regulation of the monopoly electricity delivery system in the Province of Ontario (the "Province") by the OEB. On May 1, 2002, the competitive market opened in Ontario.

The OEB has regulatory oversight of electricity matters in the Province. The *Ontario Energy Board Act, 1998* sets out the OEB's powers to issue a distribution licence which must be obtained by any person owning or operating a distribution system under the *Ontario Energy Board Act, 1998*. The OEB is charged with the responsibility of approving or setting rates for the transmission and distribution of electricity and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers.

On May 11, 2006, for rates effective May 2006, the OEB approved the Corporation filed Rate Application EDR 2006 by issuing a Decision and Order. In the Decision and Order, the distribution rates increased by 1.0% for Residential and Commercial customer classes. Industrial class customers generally reflected decreases of between 1% and 9%. The recovery of regulatory assets, for balances as at December 31, 2004, was approved in the EDR Decision and Order. The recovery of these balances is expected to be collected over a three-year period. In February 2007, the Corporation filed a Rate Application to the OEB for rates effective May 1, 2007. The decision is not expected until April 2007.

Revenue includes regulated distribution income for the Corporation and the flow-through revenue that is collected on behalf of others. The flow-through revenue includes cost of electricity, transmission and wholesale charges. Due to a decline in the wholesale cost of electricity in 2006, the total revenue including flow-through revenue has decreased by $30,275.

In order to achieve a proper matching of revenue and expenses, the timing of recognition of certain revenue and expenses for the distribution of electricity may differ from that otherwise expected under Canadian GAAP. The following regulatory treatments have resulted in accounting treatments which differ from Canadian GAAP for enterprises operating in a non-regulated environment:

[a] Regulatory assets and liabilities

Certain costs and variance account balances are deemed to be "regulatory assets" or "regulatory liabilities" and are reflected in the Local Distribution Company's ("LDC") balance sheet until the manner and timing of disposition is determined by the OEB *[note 4]*.

The principal regulatory assets and liabilities of the Corporation are comprised of the following:

[i] Retail settlement variances: The Corporation has recognized settlement variances for the period from January 1, 2005 to December 31, 2006 in accordance with criteria set out in the AP Handbook. Specifically, these amounts include variances between the amounts charged by the Independent Electricity System Operator ("IESO") for the operation of the markets and the grid, as well as various wholesale market settlement charges and transmission charges as compared to the amount billed to consumers based on the OEB approved wholesale market service rates. Under such regulation, the variances are allowed to be deferred, which would be recorded as revenue when incurred under Canadian GAAP. The deferred balance for settlement variances yet to be approved by the regulator continues to be calculated and attract carrying charges in accordance with the OEB's direction.

[ii] Regulatory Asset Recovery Account ("RARA"): Effective May 2006, the setup of RARA was approved by the OEB. Included in RARA are retail settlement variances, pre-market opening energy variances, qualifying transition costs and carrying charges, less recoveries accumulated to April 30, 2006. Permission was granted by the OEB to include a regulatory rate rider, which is charged to each customer class effective May 1, 2006, for the collection of RARA balances over three years.

[iii] Capitalized interest: The Corporation has capitalized interest on the regulatory assets and also the deferred payments in lieu of corporate income taxes ("PILs") in the rate base, as prescribed by the OEB.

[iv] In accordance with Bill 100, the IESO implemented a price adjustment mechanism called "Global Adjustment" which represents a difference between the spot price charged by the IESO to various market participants, including the Corporation, and the blended price paid by the IESO under the various contracts with electricity generators/suppliers.

The Global Adjustment came into effect January 1, 2005 and in accordance with Bill 100, the IESO calculates a "preliminary" difference in terms of $/kWh at the beginning of each month to be credited or charged back by the distribution companies, such as the Corporation, to their various customers other than low volume designated customers. The difference between these amounts credited or charged back by the distribution companies and the "final" amounts credited or billed by the IESO is to be tracked in a variance account which is currently reflected in the financial statements as a part of regulatory liabilities.

[b] Payments in lieu of corporate income taxes

The Corporation provides for PILs using the taxes payable method for its regulated activities as permitted by The Canadian Institute of Chartered Accountants ("CICA") and the OEB.

Inventory

Inventory, which consists of parts and supplies acquired for internal maintenance or construction, is valued at the lower of cost and replacement cost, with cost being determined on a weighted average basis.

Property, plant and equipment

Property, plant and equipment purchased or constructed by the Corporation are stated at historic cost and include contracted services, material, labour, engineering costs and overhead. Furthermore, constructed property, plant and equipment include deemed interest during the period of construction.

Property, plant and equipment also include the cost of certain capital assets partially funded by developers as a contribution in aid of construction to the Corporation. The OEB requires that such contributions, whether in cash or in-kind, be offset against the related asset cost.

When identifiable capital assets are retired or otherwise disposed of, their original cost and accumulated depreciation are removed from the accounts and the related gain or loss is included in the determination of income or loss for the year. Repairs and maintenance expenditures are charged to operations as incurred.

Depreciation is provided on a straight-line basis over estimated service lives as follows:

Buildings	1.67% - 3.33%
Transmission, distribution system and meters	2.86% - 4%
Equipment and furniture	10%
Computer hardware	20%
Vehicle fleet	12.5% - 20%

Construction in progress comprises capital assets under construction, capital assets not yet placed into service and pre-construction activities related to specific projects expected to be constructed. These assets are not depreciated until placed into service.

Customers' advance deposits

Customers' advance deposits represent cash collections from customers that are available to offset the payment of energy bills or other services. Customers may be required to post security to obtain electricity or other services. Where the security posted is in the form of securities, these amounts are recorded in the accounts as securities held in respect of customer deposits. Interest is paid on customer balances at rates established by the Corporation in accordance with OEB guidelines. Deposits expected to be refunded to customers within the next fiscal year are classified as a current liability.

Pension and other post-employment benefits

The Corporation accounts for its participation in the Ontario Municipal Employees Retirement Fund ("OMERS"), a multi-employer public sector pension fund, as a defined benefit plan. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The Corporation recognizes the expense related to this plan as contributions are due.

Employee future benefits, other than pensions provided by the Corporation through OMERS, include supplemental health insurance, dental and life insurance. These plans provide benefits to retired employees, their spouses and surviving spouses when they are no longer providing active service.

Employee future benefits expense is recognized in the period in which the employees render services.

Employee future benefits other than pensions are recorded on an accrual basis. The Corporation actuarially determines the cost of post-employment benefits offered to employees and retirees including their spouses and surviving spouses using the projected benefit method, pro rated on service and based on management's best estimate assumptions. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the employee's years of service in the attribution period commencing at date of hire, and ending at the earliest age the employee could retire and qualify for benefits.

The current service cost for a period is equal to the actuarial present value of benefits attributed to employees' services rendered during the period. Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment. The excess of the net actuarial gains (losses) over 10% of the accrued benefit obligation is amortized as an expense on a straight-line basis over the average remaining service period of active employees to full eligibility. The effect of a curtailment (reduction in post-employment benefits) gain or loss is recognized in the period of the event giving rise to the curtailment as a charge or credit to operations. The effect of a settlement (post-employment benefits) gain or loss is recognized in the period in which a settlement occurs.

Cash and cash equivalents

Cash and cash equivalents are defined as cash and bank deposits, or equivalent financial instruments, with maturities upon issue of less than 90 days.

Hedging relationships

The Corporation's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified debt instrument and document relationships between hedging instruments and associated hedged items. The documentation includes: identification of the specific asset, liability or forecasted transaction being hedged; the nature of the risk being hedged; the hedge objective; the method of assessing hedge effectiveness; and the method of accounting for the hedging relationship. Hedge effectiveness is formally assessed, both at the inception and on an ongoing basis, to determine whether the derivative used in hedging transactions is highly effective in offsetting changes in the interest rate risk of the hedged item. Hedge accounting is applied only if there is reasonable assurance that the hedging relationship will be effective.

The Corporation enters into interest rate swaps in order to reduce the impact of fluctuating interest rates on its long-term debt. These swap agreements require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. The Corporation does not enter into derivatives for speculative purposes. The Corporation designates its interest rate hedge agreements as hedges of the underlying debt. Interest expense on the debt is adjusted to include the payments made or received under the interest rate swaps and, accordingly, follows hedge accounting.

Investments

Investments consist of a Government of Canada treasury bill amounting to $5,901 (2005 - $6,001). The interest rate on the treasury bill is 4.10% per annum (maturing on November 1, 2007). This treasury bill is pledged to the IESO as collateral support for energy amounts payable to the IESO.

Advance payments

Advance payments consist of both the Equal Payment Plan ("EPP") and Customer Advance Payments.

Deferred debt issue costs

The Corporation defers and amortizes on a straight-line basis costs related to obtaining new financing over the term of the debt.

Revenue recognition

Revenue from the sale of electrical energy represents actual revenue attributable to the sale and delivery of electricity. Revenue includes an estimate of unbilled revenue, which represents electricity delivered and consumed by customers since the date of each customer's last meter reading.

Other revenue and interest are recognized as services are rendered, projects completed or when interest is earned.

Measurement uncertainty

The preparation of financial statements in conformity with Canadian GAAP 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 financial statements and the reported amounts of revenue and expenses during the reporting period. Certain estimates are necessary since the regulatory environment in which the Corporation operates requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions, or other regulatory proceedings. Due to inherent uncertainty involved in making such estimates, actual results could differ from those estimates, including changes as a result of future decisions made by the OEB, the Minister of Energy or the Minister of Finance.

Corporate income taxes and capital taxes

Under the *Electricity Act, 1998* and effective October 1, 2001, the Corporation is required to make payments in lieu of corporate income taxes and capital taxes to the Ministry of Finance, commencing October 1, 2001. These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998* and related regulations. In theory, payments remitted to Ontario Electricity Financial Corporation are applied against the stranded debt of Ontario Hydro.

The regulated electricity distribution business of the Corporation provides for PILs using the taxes payable method. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax bases of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the Corporation at that time.

The OEB's Electricity Distribution Rate Handbook provides for the recovery of PILs by local distribution companies through annual distribution rate adjustments as permitted by the OEB.

The method that has been used to set the PILs portion of the Corporation's rates for 2006 is consistent with the approach used in past periods.

Upstream capital improvement funds

Upstream capital improvement funds, collected under the *Development Charges Act, 1997* or predecessor legislation, are earmarked for specific property, plant and equipment related to growth that will occur in the future. Upstream capital improvement fund balances are reduced as expenditures occur.

Asset retirement obligations

The Corporation follows the CICA's Handbook which requires the recording of the fair value of the future expenditures required to settle legal obligations associated with asset retirements. The Corporation has determined that there are asset retirement obligations ["AROs"] associated with some parts of its transmission, distribution and generation systems.

On April 1, 2006, the Corporation retroactively adopted EIC 159, Conditional Asset Retirement Obligations ("EIC 159"). EIC 159 requires an entity to recognize a liability for the fair value of an ARO even though the timing and/or method of settlement are conditional on future events.

3. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following:

	2006			2005		
	Cost $	Accumulated depreciation $	Net book value $	Cost $	Accumulated depreciation $	Net book value $
Transmission and distribution						
Underground distribution	**46,305**	**19,700**	**26,605**	42,745	17,940	24,805
Overhead distribution	**38,274**	**19,177**	**19,097**	33,358	17,965	15,393
Transformers	**15,483**	**11,864**	**3,619**	15,550	11,447	4,103
Station equipment	**10,179**	**6,520**	**3,659**	9,945	6,240	3,705
Meters	**8,130**	**4,519**	**3,611**	7,856	4,273	3,583
Total transmission and distribution	**118,371**	**61,780**	**56,591**	109,454	57,865	51,589
Construction in progress	**3,964**	**—**	**3,964**	2,654	—	2,654
Vehicle fleet	**3,229**	**2,364**	**865**	3,624	2,618	1,006
Equipment and furniture	**2,971**	**2,470**	**501**	2,804	2,375	429
Computer hardware	**2,063**	**1,899**	**164**	2,007	1,747	260
Buildings	**528**	**268**	**260**	528	259	269
Land	**294**	**—**	**294**	111	—	111
Property, plant and equipment before contributions in aid of construction	**131,420**	**68,781**	**62,639**	121,182	64,864	56,318
Contributions in aid of construction from developers and others	**(19,425)**	**(2,279)**	**(17,146)**	(13,063)	(1,502)	(11,561)
	111,995	**66,502**	**45,493**	108,119	63,362	44,757

4. REGULATORY ASSETS AND LIABILITIES

Regulatory assets (liabilities) consist of the following:

	2006			2005
	Total regulatory assets $	**Current** $	**Non-current** $	**Total** $
Regulatory assets				
Regulatory Asset Recovery Account	**1,893**	**1,173**	**720**	3,804
Retail settlement variances	**656**	—	**656**	409
Global Adjustment variance	**211**	**211**	—	—
Regulatory accrued interest	**231**	—	**231**	114
Net regulatory assets	**2,991**	**1,384**	**1,607**	4,327
Less current portion	**1,384**	**1,384**	—	1,136
Net long-term regulatory assets recognized	**1,607**	—	**1,607**	3,191

	2006 $	**2005** $
Regulatory liabilities		
Global Adjustment variance	—	590
Smart Meter Liability	**100**	—
Acsys deferral	**21**	21
Net regulatory liabilities	**121**	611
Less current portion	—	590
Net long-term regulatory liabilities recognized	**121**	21

On May 1, 2006, the Corporation complied with OEB guidelines and established a new account called Regulatory Asset Recovery Account or RARA. The account transfers regulatory asset accounts as of December 31, 2004, the recoveries up to April 30, 2006 and carrying charges as of April 30, 2006. Only balances as approved by the OEB in its 2006 EDR Decision and Order can be applied to the account. RARA includes recoveries since May 1, 2006, based on approved OEB regulatory rate riders.

The OEB approved distribution rates for PILs recovery based on estimated consumption volumes. The difference between actual billings that relate to the recovery of PILs and the OEB approved PILs amount is tracked by the Corporation as a deferred tax amount in accordance with OEB guidelines for regulatory assets and with the criteria set out in the AP Handbook. The Corporation has recorded a deferred PILs asset in the amount of $1,106 (2005 - $349), which is offset by a deferred PILs liability, as required by the OEB, in an equivalent amount.

5. OTHER ASSETS

Other assets consist of the following:

	2006 $	2005 $
Deferred debt issue costs	**30**	35
Other costs	**8**	—
Securities held as customer deposit	**3**	7
	41	42

6. CURRENT PORTION OF LONG-TERM LIABILITIES

The current portion of long-term liabilities consists of the following:

	2006 $	2005 $
Deferred revenue	**14**	14
Customers' advance deposits	**360**	925
Upstream capital improvement funds *[note 9]*	**351**	351
Employee sick leave benefits *[note 7]*	**69**	16
	794	1,306

7. EMPLOYEE SICK LEAVE BENEFITS

Under the sick leave benefit plan, unused sick leave can accumulate and employees on the regular staff prior to August 1, 1979 may become entitled to cash payments after termination of service, for which they may receive payment for 50% of their unused sick leave credits up to a maximum of six months' pay. During the year, $57 was paid (2005 - $39) towards sick leave credits. The liability recorded in the accounts for these accumulated benefits, to the extent that they have vested, amounted to $197 (2005 - $245). In 2006, the current portion of long-term liabilities for employee sick leave benefits otaled $69, and long-term liability for employee sick leave benefits otaled $128.

8. CORPORATE INCOME TAXES

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

Statement of income

	2006 $	2005 $
Income before PILs	**5,974**	5,433
Statutory Canadian federal and Ontario income tax rate	**36.12%**	36.12%
Expected income tax provision at statutory tax rate	**2,158**	1,963
Tax reassessment (2001 and 2002)	**124**	—
Refund on 2005 income tax	**(388)**	—
Other temporary differences:		
Property, plant and equipment	**263**	85
Post-employment non-pension benefits	**137**	127
Deferred revenue	**(53)**	125
Other	**(32)**	30
Cost allocations	**(84)**	—
Provision for PILs	**2,125**	2,330
Effective tax rate	**35.57%**	42.89%
Components of income tax provision		
Current income taxes	**2,125**	2,330
Provision for PILs	**2,125**	2,330

Balance sheet

Future income taxes relating to the regulated business have not been recorded in the accounts as they are expected to be recovered through future electricity rate revenue. As at December 31, 2005, future income tax assets are in the amount of approximately $8,000 (2005 - $9,500).

9. UPSTREAM CAPITAL IMPROVEMENT FUNDS

Upstream capital improvement funds represent amounts received from developers for improvements to system capacity.

	2006 $	**2005** $
Current portion balance	**351**	351

10. EMPLOYEE BENEFITS

[a] Pension costs

The Corporation makes contributions to OMERS, which is a multi-employer plan. The plan is a defined benefit plan which specifies the amount of retirement benefits to be received by the employees based on length of service and rates of pay. Future contributions are dependent upon the results of the OMERS plan as actuarially determined.

The Corporation incurred current service pension costs for the year ended December 31, 2006 of $379 (2005 - $353) as prescribed by OMERS.

[b] Non-pension retirement (post-employment) benefits

The Corporation provides post-employment benefits, principally supplemental health and dental coverage, for employees who retire from active employment.

	2006 $	2005 $
Change in accrued non-pension benefit obligations		
Accrued benefit obligations, beginning of year	**7,797**	7,444
Net periodic benefit cost accrued	**789**	734
Benefits paid by the Corporation in the year	**(410)**	(381)
Accrued benefit obligations, end of year	**8,176**	7,797
Components of net periodic benefit cost accrual		
Current service cost	**250**	200
Imputed interest cost	**520**	512
Amortization of actuarial gains	**19**	22
Net periodic benefit cost accrued for the year	**789**	734

An actuarial study was completed in 2004 and updated in 2006 to estimate the Corporation's obligations under the non-pension post-employment benefits. The significant actuarial assumptions adopted in measuring the Corporation's accrued non-pension benefit obligations as at December 31 are as follows:

	2006 %	2005 %
Discount rate applied to the calculation of future benefits	**5.25**	6.0
Rate of compound compensation increase used in determining future costs	**3.0**	3.0

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects for 2006:

	Increase $	Decrease $
Total service and interest cost	**135**	**(113)**

Benefit obligations	**1,357**	**(1,097)**

11. NOTE PAYABLE

The note payable to the shareholder of $23,064 (2005 - $23,064) bears an interest rate of 7.25% per annum and is due on demand.

The Corporation does not anticipate that the note will be called upon within one year, accordingly, the note remains classified as a long-term liability.

In 2006, the Corporation made interest payments of $1,672 (2005 - $1,672) to the shareholder.

12. DEBT

The Corporation's long-term and short-term borrowing facilities are as follows:

Long-term facilities

The Corporation incurred new debt in 2005 in the amount of $7,000 due in one repayment obligation at maturity in December 2012. This facility was drawn down in December 2005 and structured with a seven-year interest rate swap agreement with the bank, effectively converting the Corporation's obligations to a fixed interest rate, approximately 4.9%. Subject to payment of any unwinding costs or receipt of benefits for unwinding the interest rate swap agreement, the Corporation has the flexibility of pre-paying the debt at its option.

Short-term facilities

The Corporation has an operating line in the maximum amount of $10,000 to assist with its working capital requirements. During 2006, no amounts were drawn under this facility.

The above borrowing facilities are subject to financial tests and other covenants. The principal financial covenants require a consolidated debt to capital ratio of less than or equal to 0.65:1 and a consolidated Interest Coverage Ratio of no less than 1.4. These financial covenants are to be tested quarterly for the Corporation. In addition, these facilities are subject to other customary covenants and events of default, including an event of Cross-Default (for non-payment of other debts) of amounts in excess of $5,000. Non-compliance with such covenants could result in accelerated payment of amounts due under the facilities, and their termination. The Corporation was in compliance with the above-mentioned covenants at December 31, 2006.

13. CAPITAL STOCK

Capital stock consists of the following:

	2006 $	2005 $
Authorized		
Unlimited common shares		
Issued		
1,000 common shares	**23,064**	23,064

14. RELATED PARTY TRANSACTIONS

The Corporation transacts business with the City of Oshawa and its affiliates in the normal course of business at commercial rates. These transactions are summarized below:

	2006 $	2005 $
REVENUE – Electricity sold to the City of Oshawa		
Facilities	**2,467**	1,715
Streetlights	**1,011**	859
	3,478	2,574
Streetlight maintenance and construction services	**1,488**	404
EXPENSES		
Net rent – 100 Simcoe Street	**264**	264
Property taxes	**146**	151
ACCOUNTS RECEIVABLE		
Facilities and Streetlights	**337**	155
Streetlight maintenance and construction services	**224**	36

The Corporation receives management support from its parent, Oshawa Power and Utilities Corporation. During the year, the Corporation paid $480 (2005 - $480) to its parent.

As at December 31, 2006, the parent owed the Corporation nil (2005 - $246), which is included in due from affiliates. The amounts owed to the Corporation from affiliated companies include nil from Oshawa PUC Services Inc. (2005 - $392) and nil from Oshawa PUC Energy Services Inc. (2005 - $6).

15. LEASE COMMITMENTS

The Corporation leases its premises under a net operating lease, which expired November 1, 2005, from the Corporation of the City of Oshawa. The Corporation and the City of Oshawa are in discussions to renew the lease. The Corporation is currently leasing on a month-to-month basis.

16. CONTINGENCIES

[i] Insurance claims

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE"), which was created on January 1, 1987. A reciprocal insurance exchange is an Ontario-based group formed for the purpose of exchanging reciprocal contracts of indemnity of inter-insurance with each other. MEARIE provides general liability insurance to its member utilities.

Insurance premiums charged to each Municipal Electric Utility consist of a levy per thousand dollars of service revenue subject to a credit or surcharge based on each electric utility's claims experience.

The Corporation refers any claims received to MEARIE under the provisions of this plan. No provision has been recorded in these financial statements in respect of these matters as the Corporation has not received any material claim that is not adequately covered by its insurance.

[ii] Income taxes

The tax returns filed by the Corporation are subject to review and reassessment by the Ministry of Finance for a period of five years from the date of filing. Any reassessment may result in a revision to previously determined tax obligations.

[iii] Excessive late penalty charges

In the period prior to the incorporation of the Corporation, its predecessor organization, Oshawa Public Utilities Commission, had charged late payment levies on overdue utility bills. A class action was brought under the *Class Proceedings Act, 1992*, wherein the plaintiff class seeks $500 million in restitution for amounts paid to Toronto Hydro-Electric Commission and to other Ontario municipal electric utilities ("LDCs") who received late payment penalties which constitute interest at an effective rate in excess of 60% per year, contrary to section 347 of the *Criminal Code*. Pleadings have closed in this action. The action has not yet been certified as a class action and no discoveries have been held, as the parties were awaiting the outcome of similar proceedings brought against Enbridge Gas Distribution Inc. (formerly Consumers Gas).

On April 22, 2004, the Supreme Court of Canada released a decision in the Consumers Gas case rejecting all of the defences which had been raised by Enbridge, although the Court did not permit the Plaintiff class to recover damages for any period prior to the issuance of the Statement of Claim in 1994 challenging the validity of late payment penalties. The Supreme Court remitted the matter back to the Ontario Superior Court of Justice for determination of the damages. At the end of 2006, a mediation process resulted in the settlement of the damages payable by Enbridge.

After the release by the Supreme Court of Canada of its 2004 decision in the Consumers Gas case, the plaintiffs in the LDC late payment penalties class action indicated their intention to proceed with their litigation against the LDCs. To date, no formal steps have been taken to move the action forward. The electric utilities intend to respond to the action if and when it proceeds on the basis that the LDCs' situation may be distinguishable from that of Consumers Gas. At this time it is not possible to quantify the effect, if any, and no amount has been accrued in the financial statements of the Corporation.

17. FAIR VALUES OF FINANCIAL INSTRUMENTS

The carrying values of cash and cash equivalents, accounts receivable, unbilled revenue, accounts payable and accrued liabilities approximate their fair values because of the short period to maturity of these financial instruments.

Financial assets held by the Corporation expose it to credit risk. The Corporation provides for an allowance for doubtful accounts to absorb credit losses. As at December 31, 2006, there is no significant concentration of credit risk with respect to any financial assets.

Investments consist of a Government of Canada treasury bill amounting to $5,901 (2005 - $6,001). The treasury bill matures on November 1, 2007 and bears interest at a rate of 4.10% per annum.

18. COLLATERAL

As part of its energy purchase agreement with the IESO, the Corporation has pledged its treasury bill in the amount of $5,901 to the IESO as support for its energy purchase obligations.

19. CONSERVATION AND DEMAND MANAGEMENT INITIATIVES

In March 2005, the Corporation received approval from the OEB to increase distribution rates to recover an amount of $1,477 in its rates effective April 1, 2005 to April 30, 2006 to achieve the allowable return on equity (MBRR) of 9.88%. The Corporation must spend an equivalent amount on OEB approved Conservation and Demand Management Initiatives ("CDM") until September 2007. Depending upon the nature of these approved CDM expenditures, they will be either charged to the Corporation's operations or capitalized in the period up to and including September 2007. At each reporting date, on a cumulative basis, to the extent the CDM operating expenditure commitment exceeds the CDM items charged to operations, the difference is recorded as deferred revenue. The deferred revenue as at December 31, 2006 amounted to $235. The cumulative CDM operating expenditure as at December 31, 2006 amounted to $442 (2005 - $219) and the CDM cumulative capital expenditures amounted to $348 (2005 - $227). The CDM capital amount available to spend until September 30, 2007 is $452.

Oshawa PUC Networks Inc.

SCHEDULE OF SUMMARY OF NET INCOME

[in thousands of dollars]

Five-year period ended December 31, 2006

	2006 $	2005 $	2004 $	2003 $	2002 $
REVENUE					
Sale of electrical energy	**92,454**	122,729	98,308	93,250	104,185
Cost of electrical energy	**74,541**	105,316	81,987	77,012	88,821
Net revenue from sale of electrical energy	**17,913**	17,413	16,321	16,238	15,364
Other revenue	**1,240**	712	1,288	1,103	1,471
Net revenue	**19,153**	18,125	17,609	17,341	16,835
EXPENSES					
Operations, maintenance and administrative	**13,024**	12,718	12,175	12,281	12,029
Less amount allocated to property, plant and equipment and billable jobs	**(4,464)**	(4,182)	(3,736)	(2,629)	(2,423)
Net operations, maintenance and administrative expenses	**8,560**	8,536	8,439	9,652	9,606
Income before the following:	**10,593**	9,589	9,170	7,689	7,229
Recovery of non-collectible regulatory assets	—	—	—	1,500	—
Depreciation	**(3,659)**	(3,545)	(3,339)	(2,922)	(3,079)
Gain on disposal of property, plant and equipment	**48**	35	—	—	—
Interest income	**775**	498	393	439	—
Interest improvement on regulatory accounts	**160**	390	329	—	—
Interest expense	**(1,943)**	(1,534)	(1,485)	(1,505)	(1,114)
Interest before payments in lieu of corporate income taxes	**5,974**	5,433	5,068	5,201	3,036
Provision for payments in lieu of corporate income taxes	**2,125**	2,330	1,999	1,941	110
Net income for the year	**3,849**	3,103	3,069	3,260	2,926

INCOME STATEMENT FOR 2007 (PROFORMA)

Group Description	Account Description	Total
3000-Sales of Electricity	4006-Residential Energy Sales	(22,079,259)
	4010-Commercial Energy Sales	(6,337,136)
	4015-Industrial Energy Sales	(16,005,018)
	4020-Energy Sales to Large Users	(3,195,413)
	4025-Street Lighting Energy Sales	(442,430)
	4035-General Energy Sales	(2,822,180)
	4050-Revenue Adjustment	(9,405,882)
	4055-Energy Sales for Resale	(10,897,781)
	4062-Billed WMS	(7,194,752)
	4066-Billed NW	(4,908,144)
	4068-Billed CN	(6,156,290)
3000-Sales of Electricity Total		(89,444,285)
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(17,618,141)
	4084-Service Transaction Requests (STR) Revenues	(4,502)
3050-Revenues From Services - Distribution Total		(17,622,643)
3100-Other Operating Revenues	4210-Rent from Electric Property	(107,038)
	4225-Late Payment Charges	(198,734)
	4235-Miscellaneous Service Revenues	(613,356)
3100-Other Operating Revenues Total		(919,128)
3150-Other Income & Deductions	4310-Regulatory Credits	0
	4325-Revenues from Merchandise, Jobbing, Etc.	(2,240,445)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	2,183,447
	4355-Gain on Disposition of Utility and Other Property	0
	4390-Miscellaneous Non-Operating Income	(253,310)
3150-Other Income & Deductions Total		(310,308)
3200-Investment Income	4405-Interest and Dividend Income	(774,546)
3200-Investment Income Total		(774,546)
3350-Power Supply Expenses	4705-Power Purchased	69,989,454
	4708-Charges-WMS	7,230,646
	4712-Charges-One-Time	0
	4714-Charges-NW	6,591,473
	4716-Charges-CN	5,632,713
3350-Power Supply Expenses Total		89,444,286
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	372,516
	5020-Overhead Distribution Lines and Feeders - Operation Labour	(81,483)
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	(182,304)

	5040-Underground Distribution Lines and Feeders - Operation Labour	7,751
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	193
	5065-Meter Expense	52,211
	5085-Miscellaneous Distribution Expense	(127,912)
3500-Distribution Expenses - Operation Total		40,972
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	218,220
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	19,891
	5114-Maintenance of Distribution Station Equipment	129,470
	5120-Maintenance of Poles, Towers and Fixtures	477,847
	5145-Maintenance of Underground Conduit	122,982
	5155-Maintenance of Underground Services	30,000
3550-Distribution Expenses - Maintenance Total		998,410
3650-Billing and Collecting	5305-Supervision	212,111
	5310-Meter Reading Expense	406,158
	5315-Customer Billing	886,869
	5320-Collecting	395,466
	5335-Bad Debt Expense	282,000
3650-Billing and Collecting Total		2,182,604
3700-Community Relations	5405-Supervision	105,594
	5410-Community Relations - Sundry	23,200
	5415-Energy Conservation	0
	5420-Community Safety Program	276,902
	5425-Miscellaneous Customer Service and Informational Expenses	478,470
3700-Community Relations Total		884,166
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	480,000
	5610-Management Salaries and Expenses	726,591
	5615-General Administrative Salaries and Expenses	2,009,560
	5620-Office Supplies and Expenses	165,149
	5625-Administrative Expense Transferred Credit	(638,000)
	5630-Outside Services Employed	373,008
	5635-Property Insurance	104,669
	5640-Injuries and Damages	153,531
	5645-Employee Pensions and Benefits	455,253
	5655-Regulatory Expenses	429,818
	5660-General Advertising Expenses	1,579
	5665-Miscellaneous General Expenses	64,325
	5670-Rent	264,000
	5675-Maintenance of General Plant	496,560

3800-Administrative and General Expenses Total		5,086,043
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	3,891,960
	5710-Amortization of Limited Term Electric Plant	0
	5715-Amortization of Intangibles and Other Electric Plant	0
3850-Amortization Expense Total		3,891,960
3900-Interest Expense	6005-Interest on Long Term Debt	2,010,480
	6035-Other Interest Expense	138,000
	6040-Allowance for Borrowed Funds Used During Construction--Credit	(67,603)
	6042-Allowance For Other Funds Used During Construction	(47,706)
3900-Interest Expense Total		2,033,171
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	393,000
3950-Taxes Other Than Income Taxes Total		393,000
4000-Income Taxes	6110-Income Taxes	1,646,520
4000-Income Taxes Total		1,646,520
4100-Extraordinary & Other Items	6205-Donations	4,000
	6225-Other Deductions	0
	6315-Income Taxes, Extraordinary Items	0
4100-Extraordinary & Other Items Total		4,000
Grand Total		(2,465,779)

INCOME STATEMENT FOR 2008 (PROFORMA)

Group Description	Account Description	Total
3000-Sales of Electricity	4006-Residential Energy Sales	(30,366,923)
	4010-Commercial Energy Sales	(8,771,029)
	4015-Industrial Energy Sales	(26,799,141)
	4020-Energy Sales to Large Users	(4,410,893)
	4025-Street Lighting Energy Sales	(609,274)
	4035-General Energy Sales	(138,615)
	4050-Revenue Adjustment	0
	4055-Energy Sales for Resale	0
	4062-Billed WMS	(7,344,951)
	4066-Billed NW	(6,695,673)
	4068-Billed CN	(5,721,757)
3000-Sales of Electricity Total		(90,858,257)
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	(20,442,367)
	4084-Service Transaction Requests (STR) Revenues	(4,502)
3050-Revenues From Services - Distribution Total		(20,446,869)
3100-Other Operating Revenues	4210-Rent from Electric Property	(107,038)
	4225-Late Payment Charges	(198,734)
	4235-Miscellaneous Service Revenues	(592,607)
3100-Other Operating Revenues Total		(898,379)
3150-Other Income & Deductions	4310-Regulatory Credits	0
	4325-Revenues from Merchandise, Jobbing, Etc.	(2,240,445)
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	2,183,447
	4355-Gain on Disposition of Utility and Other Property	0
	4390-Miscellaneous Non-Operating Income	(463,778)
3150-Other Income & Deductions Total		(520,776)
3200-Investment Income	4405-Interest and Dividend Income	(178,000)
3200-Investment Income Total		(178,000)
3350-Power Supply Expenses	4705-Power Purchased	71,095,876
	4708-Charges-WMS	7,344,951
	4712-Charges-One-Time	0
	4714-Charges-NW	6,695,673
	4716-Charges-CN	5,721,757
3350-Power Supply Expenses Total		90,858,257
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	384,274
	5020-Overhead Distribution Lines and Feeders - Operation Labour	109,267

	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	(165,705)
	5040-Underground Distribution Lines and Feeders - Operation Labour	7,984
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	199
	5065-Meter Expense	127,559
	5085-Miscellaneous Distribution Expense	(20,840)
3500-Distribution Expenses - Operation Total		442,737
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	225,076
	5110-Maintenance of Buildings and Fixtures - Distribution Stations	20,487
	5114-Maintenance of Distribution Station Equipment	133,354
	5120-Maintenance of Poles, Towers and Fixtures	492,183
	5145-Maintenance of Underground Conduit	126,671
	5155-Maintenance of Underground Services	30,900
3550-Distribution Expenses - Maintenance Total		1,028,671
3650-Billing and Collecting	5305-Supervision	218,582
	5310-Meter Reading Expense	417,950
	5315-Customer Billing	913,569
	5320-Collecting	407,783
	5335-Bad Debt Expense	290,460
3650-Billing and Collecting Total		2,248,345
3700-Community Relations	5405-Supervision	169,589
	5410-Community Relations - Sundry	23,896
	5415-Energy Conservation	0
	5420-Community Safety Program	285,376
	5425-Miscellaneous Customer Service and Informational Expenses	521,354
3700-Community Relations Total		1,000,216
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	480,000
	5610-Management Salaries and Expenses	1,002,599
	5615-General Administrative Salaries and Expenses	2,127,341
	5620-Office Supplies and Expenses	170,103
	5625-Administrative Expense Transferred Credit	(638,000)
	5630-Outside Services Employed	530,198
	5635-Property Insurance	116,766
	5640-Injuries and Damages	175,190
	5645-Employee Pensions and Benefits	476,312

	5655-Regulatory Expenses	442,713
	5660-General Advertising Expenses	1,626
	5665-Miscellaneous General Expenses	66,255
	5670-Rent	264,000
	5675-Maintenance of General Plant	511,542
3800-Administrative and General Expenses Total		5,726,644
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	4,395,489
	5710-Amortization of Limited Term Electric Plant	0
	5715-Amortization of Intangibles and Other Electric Plant	0
3850-Amortization Expense Total		4,395,489
3900-Interest Expense	6005-Interest on Long Term Debt	2,010,480
	6035-Other Interest Expense	142,140
	6040-Allowance for Borrowed Funds Used During Construction--Credit	(67,603)
	6042-Allowance For Other Funds Used During Construction	(70,065)
3900-Interest Expense Total		2,014,952
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	345,450
3950-Taxes Other Than Income Taxes Total		345,450
4000-Income Taxes	6110-Income Taxes	1,858,175
4000-Income Taxes Total		1,858,175
4100-Extraordinary & Other Items	6205-Donations	4,120
	6225-Other Deductions	0
	6315-Income Taxes, Extraordinary Items	0
4100-Extraordinary & Other Items Total		4,120
Grand Total		(2,979,225)

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND FINANCIAL RESULTS FILED

There are no differences between financial statements and the financial results filed.

PROPOSED ACCOUNTING TREATMENT

OPUCN's accounting methodology complies with the Board's *Accounting Procedures Handbook.*

INFORMATION ON PARENTS AND SUBSIDIARIES

Information on OPUCN's parent company is contained at Exhibit 1, Tab 1, Schedule 14 and in the Oshawa Power and Utilities Corporation Annual Report for 2006 which is at Appendix A of this filing. This report contains the Management's Discussion and Analysis. OPUCN has no subsidiary companies.

RATE BASE SUMMARY

1.0 Introduction

OPUCN's forecasted rate base for the 2008 Test Year up to and including April 30, 2009, is $64,758,238.

The rate base underlying OPUCN's revenue requirement includes a forecast of net fixed assets, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated depreciation and contributed capital. For the years in which the assets come into service, 50% of their net book value has been included in rate base.

OPUCN's regular yearly investment in enhancements and expansions is approximately $4.8 million. This investment level represents investment required to maintain safety and reliability in OPUCN's aging distribution system. The level of investment required was supported by an asset condition assessment commissioned from Kinectrics Inc which is attached as Appendix D.

The following table provides a numerical summary of OPUCN's rate base:

Rate Base Summary Table

average assets..	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved	2006-Actual	2007 Bridge	Variance form 2006 Actual	2007-Bridge	2008 Test	Variance form 2007 Bridge
Gross Assets	98,090,923	106,720,748	8,629,824	106,720,748	112,318,749	5,598,001	112,318,749	122,102,639	9,783,890
Accumulated Depreciation	(58,755,351)	(64,932,276)	(6,176,925)	(64,932,276)	(68,448,224)	(3,515,948)	(68,448,224)	(72,591,949)	(4,143,725)
Net Fixed Asset	39,335,572	41,788,471	2,452,899	41,788,471	43,870,524	2,082,053	43,870,524	49,510,690	5,640,166
Allowance for Working Capital	13,634,408	12,474,797	(1,159,611)	12,474,797	14,854,422	2,379,625	14,854,422	15,247,548	393,126
Utility Rate Base	52,969,980	54,263,268	1,293,288	54,263,268	58,724,947	4,461,678	58,724,947	64,758,238*	6,033,291

* This number includes rate base additions coming into service up to April 30, 2009 as described above.

2.0 Rate Base Variances

OPUCN's rate base materiality threshold as prescribed by the Filing Guidelines is approximately $440,000. As illustrated by the Rate Base Summary Table above, the variances in OPUCN's rate base (both actual and forecasted) exceed this materiality threshold for each year. Written explanations for these rate base variances are set out in the following sections.

2.1 2006 Approved compared to 2006 Actual

As illustrated by the Rate Base Summary Table above, OPUCN's 2006 Actual rate base was approximately $54.26 million, approximately $1.29 million more than its 2006 Board approved rate base. OPUCN's 2006 Board approved rate base was based on a historic 2004 test year. The difference between OPUCN's 2006 Board approved and Actual rate base can be primarily attributed to the use of historic 2004 data to establish the 2006 Board approved rate base. Changes in capital, and therefore rate base, are to be expected after two years (2005 & 2006) of capital expenditures.

2.2 2006 Actual compared to 2007 Bridge

OPUCN's rate base in the 2007 Bridge year is forecasted to be approximately $58.73 million, an increase of approximately $4.47 million from OPUCN's 2006 rate base (Actual). Other than regular enhancement and expansion expenditures, this increase can be attributed to two large capital projects (described at Exhibit 2, Schedule 3, Tab 3) that exceed the materiality threshold, forecasted to come into service in 2007: the overhead circuit upgrade – Durham College to

Wilson; and the 2007 portion of a pole replacement program. A definition of "regular" expansion and enhancement projects is at Exhibit 2, Tab 3, Schedule 1, page 1.

OPUCN's 2006-2007 rate base variance is primarily attributable to more capital contributions being collected in 2006 than in 2007. In 2006 there were two large construction, the 401 Interchange rebuild and the construction of the General Motors Sports Centre, built using contributed capital which had no impact on gross fixed assets.

As indicated at Exhibit 2, Tab 3, Schedule 2, OPUCN's 2007 capital budget includes 124 projects (not including the two large projects that exceed the materiality threshold) that contribute to the 2006-2007 rate base variance. These projects were rigorously scrutinized by OPUCN's capital project planning process (described at Exhibit 2, Tab 3, Schedule 1) and have been identified as high priority. Further information is at Exhibit 2, Tab 3, Schedule 2.

2.3 2007 Bridge compared to 2008 Test

OPUCN's rate base in the 2008 Test Year is forecasted to be approximately $64.76 million, an increase of approximately $6.03 million from OPUCN's forecasted 2007 rate base. Other than regular enhancement and expansion expenditures, this increase can be attributed to three large capital projects (described at Exhibit 2, Schedule 3, Tab 3) that exceed the materiality threshold.

As set out at Exhibit 2, Tab 3, Schedule 2, OPUCN's 2008 capital budget (including projects forecasted to come into service between January 1 and April 30, 2009) includes 36 projects that contribute to the 2007-2008 rate base variance. These projects were rigorously scrutinized by OPUCN's capital project planning process (described at Exhibit 2, Tab 3, Schedule 1) and have been identified as high priority. Further information on those projects is at Exhibit 2, Tab 3, Schedule 3.

3.0 Gross Assets – Property, Plant and Equipment

OPUCN applies a systematic and comprehensive planning process for all of its capital additions. This rigorous process (described at Exhibit 2, Tab 3, Schedule 1) ensures that only those capital investments required to maintain the safe and reliable operation of OPUCN's distribution system are made. In 2006, OPUCN commissioned an asset condition study from Kinetrics Inc. ("Kinetrics"). After a thorough assessment of OPUCN's distribution system, Kinetrics concluded that OPUCN's overall spending on capital replacements is in line with best practices in the industry, and that OPUCN's baseline capital replacement plan is keeping up with the ageing of equipment. A copy of the Kinetrics report is attached as Appendix G to this report.

Continuity statements for OPUCN's gross assets are at Exhibit 2, Tab 2, Schedule 1. A breakdown of OPUCN's gross assets by major plant account is at Exhibit 2, Tab 2, Schedule 2. A breakdown of OPUCN's gross assets by function is at Exhibit 2, Tab 2, Schedule 6.

4.0 Depreciation

A break-down of OPUCN's depreciation on an account basis is at Exhibit 2, Tab 2, Schedule 4. The depreciation rates used by OPUCN are consistent with those outlined in Appendix B of the 2006 Distribution Rate Handbook.

5.0 Allowance for Working Capital

The proposed working capital allowance for the 2008 Test Year is $15.23 million calculated as 15% of OM&A and cost of power. Please refer to Exhibit 2, Tab 4, Schedule 1 for the calculation of working capital allowance on an account basis from 2006-2008.

CONTINUITY STATEMENTS

	2006 Actual			2007 Bridge			2008 Test		
	Gross Asset Value	Accumulated Depreciation	Net Book Value	Gross Asset Value	Accumulated Depreciation	Net Book Value	Gross Asset Value	Accumulated Depreciation	Net Book Value
Land and Buildings									
1805-Land -Opening Balance	111,429		111,429	293,875	-	293,875	293,875	-	293,875
1805-Land -Additions	182,447		182,447	-		-	250,000		250,000
1805-Land -Depreciation			-		-	-		-	-
1805-Land -Adjustments			-	-	-	-	-	-	-
1805-Land -Closing Balance	293,875	-	293,875	293,875	-	293,875	543,875	-	543,875
Average	202,652	-	202,652	293,875	-	293,875	418,875	-	418,875
1806-Land Rights -Opening Balance			-	-	-	-	-	-	-
1806-Land Rights -Additions			-	-		-	-		-
1806-Land Rights -Depreciation			-		-	-		-	-
1806-Land Rights -Adjustments			-	-	-	-	-	-	-
1806-Land Rights -Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
1905-Land -Opening Balance			-	-	-	-	-	-	-
1905-Land -Additions			-	-		-	-		-
1905-Land -Depreciation			-		-	-		-	-
1905-Land -Adjustments			-	-	-	-	-	-	-
1905-Land -Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
1906-Land Rights-Opening Balance									

			-	-	-	-	-	-	-
1906-Land Rights-Additions			-	-		-	-		-
1906-Land Rights-Depreciation			-		-	-		-	-
1906-Land Rights -Adjustments			-	-	-	-	-	-	-
1906-Land Rights -Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
1810-Leasehold Improvements-Opening Balance			-	-	-	-	70,000	(7,000)	63,000
1810-Leasehold Improvements-Additions			-	70,000		70,000	392,220		392,220
1810-Leasehold Improvements-Depreciation			-		(7,000)	(7,000)		(53,222)	(53,222)
1810-Leasehold Improvements - Adjustments			-	-	-	-	-	-	-
1810-Leasehold Improvements - Closing Balance	-	-	-	70,000	(7,000)	63,000	462,220	(60,222)	401,998
Average	-	-	-	35,000	(3,500)	31,500	266,110	(33,611)	232,499
Total	293,875	-	293,875	363,875	(7,000)	356,875	1,006,095	(60,222)	945,873
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV-Opening Balance			-	-	-	-	-	-	-
1815-Transformer Station Equipment - Normally Primary above 50 kV-Additions			-	-		-	-		-
1815-Transformer Station Equipment - Normally Primary above 50 kV-Depreciation			-		-	-		-	-
1815-Transformer Station Equipment - Normally Primary above 50 kV-Adjustments			-	-	-	-	-	-	-
1815-Transformer Station Equipment - Normally Primary above 50 kV-Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-
DS									

1820-Distribution Station Equipment - Normally Primary below 50 kV-Opening Balance	9,944,638	(6,239,540)	3,705,097	10,178,638	(6,519,679)	3,658,959	11,223,070	(6,827,954)	4,395,116
1820-Distribution Station Equipment - Normally Primary below 50 kV-Additions	234,001		234,001	1,044,432		1,044,432	3,098,592		3,098,592
1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation		(280,139)	(280,139)		(308,275)	(308,275)		(368,480)	(368,480)
1820-Distribution Station Equipment - Normally Primary below 50 kV-Adjustments			-	-	-	-	-	-	-
1820-Distribution Station Equipment - Normally Primary below 50 kV-Closing Balance	10,178,638	(6,519,679)	3,658,959	11,223,070	(6,827,954)	4,395,116	14,321,662	(7,196,434)	7,125,228
Average	10,061,638	(6,379,610)	3,682,028	10,700,854	(6,673,817)	4,027,037	12,772,366	(7,012,194)	5,760,172
Total	10,178,638	(6,519,679)	3,658,959	11,223,070	(6,827,954)	4,395,116	14,321,662	(7,196,434)	7,125,228
Poles and Wires									
1830-Poles, Towers and Fixtures-Opening Balance			-	-	-	-	-	-	-
1830-Poles, Towers and Fixtures-Additions			-	-		-	-		-
1830-Poles, Towers and Fixtures-Depreciation			-		-	-		-	-
1830-Poles, Towers and Fixtures-Adjustments			-	-	-	-	-	-	-
1830-Poles, Towers and Fixtures-Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
1835-Overhead Conductors and Devices-Opening Balance	33,358,438	(17,964,884)	15,393,553	38,274,196	(19,176,755)	19,097,441	41,005,209	(20,427,017)	20,578,193
1835-Overhead Conductors and Devices-Additions	4,963,758		4,963,758	2,731,013		2,731,013	3,253,678		3,253,678
1835-Overhead Conductors and Devices-Depreciation		(1,246,991)	(1,246,991)		(1,250,261)	(1,250,261)		(1,345,312)	(1,345,312)
1835-Overhead Conductors and Devices-Adjustments	(48,000)	35,120	(12,880)	-	-	-	-	-	-
1835-Overhead Conductors and Devices-Closing Balance	38,274,196	(19,176,755)	19,097,441	41,005,209	(20,427,017)	20,578,193	44,258,887	(21,772,329)	22,486,558
Average	35,816,317	(18,570,820)	17,245,497	39,639,703	(19,801,886)	19,837,817	42,632,048	(21,099,673)	21,532,375
1840-Underground Conduit-Opening Balance			-	-	-	-	-	-	-
1840-Underground Conduit-									

Additions			-	-		-	-		-
1840-Underground Conduit-Depreciation			-		-	-		-	-
1840-Underground Conduit-Adjustments			-	-	-	-	-	-	-
1840-Underground Conduit-Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
1845-Underground Conductors and Devices-Opening Balance	42,745,031	(17,939,845)	24,805,186	46,305,239	(19,700,038)	26,605,201	49,229,854	(21,581,712)	27,648,142
1845-Underground Conductors and Devices-Additions	3,560,209		3,560,209	2,924,614		2,924,614	1,928,076		1,928,076
1845-Underground Conductors and Devices-Depreciation		(1,760,193)	(1,760,193)		(1,881,674)	(1,881,674)		(1,978,728)	(1,978,728)
1845-Underground Conductors and Devices-Adjustments			-	-	-	-	-	-	-
1845-Underground Conductors and Devices-Closing Balance	46,305,239	(19,700,038)	26,605,201	49,229,854	(21,581,712)	27,648,142	51,157,929	(23,560,440)	27,597,489
Average	44,525,135	(18,819,941)	25,705,194	47,767,547	(20,640,875)	27,126,672	50,193,892	(22,571,076)	27,622,815
Total	84,579,435	(38,876,793)	45,702,642	90,235,063	(42,008,729)	48,226,334	95,416,816	(45,332,769)	50,084,047
Line Transformers									
1850-Line Transformers-Opening Balance	15,494,638	(11,447,124)	4,047,513	15,483,326	(11,863,842)	3,619,483	15,806,456	(12,316,555)	3,489,901
1850-Line Transformers-Additions	(11,312)		(11,312)	323,130		323,130	33,333		33,333
1850-Line Transformers-Depreciation		(416,718)	(416,718)		(452,713)	(452,713)		(459,842)	(459,842)
1850-Line Transformers-Adjustments			-	-	-	-	-	-	-
1850-Line Transformers-Closing Balance	15,483,326	(11,863,842)	3,619,483	15,806,456	(12,316,555)	3,489,901	15,839,790	(12,776,397)	3,063,393
Average	15,488,982	(11,655,483)	3,833,498	15,644,891	(12,090,199)	3,554,692	15,823,123	(12,546,476)	3,276,647
Total	15,483,326	(11,863,842)	3,619,483	15,806,456	(12,316,555)	3,489,901	15,839,790	(12,776,397)	3,063,393
Services and Meters									
1855-Services-Opening Balance			-	-	-	-	-	-	-
1855-Services-Additions			-	-		-	33,333		33,333
1855-Services-Depreciation			-		-	-		(667)	(667)
1855-Services-Adjustments			-	-	-	-	-	-	-

1855-Services-Closing Balance	-	-	-	-	-	-	33,333	(667)	32,667
Average	-	-	-	-	-	-	16,667	(333)	16,333
1860-Meters-Opening Balance	7,855,976	(4,272,595)	3,583,380	8,130,095	(4,519,372)	3,610,722	8,528,826	(4,781,366)	3,747,460
1860-Meters-Additions	274,119		274,119	398,732	0	398,732	560,000	0	560,000
1860-Meters-Depreciation		(246,777)	(246,777)	0	-261,994	(261,994)	0	-281,169	(281,169)
1860-Meters-Adjustments			-			-			-
1860-Meters-Closing Balance	8,130,095	(4,519,372)	3,610,722	8,528,826	(4,781,366)	3,747,460	9,088,826	(5,062,535)	4,026,291
Average	7,993,035	(4,395,984)	3,597,051	8,329,461	(4,650,369)	3,679,091	8,808,826	(4,921,951)	3,886,876
2005-Smart Meters-Opening Balance	-	-	-	-	-	-	-	-	-
2005-Smart Meters-Additions			-			-	-		-
2005-Smart Meters-Depreciation			-			-		-	-
2005-Smart Meters-Adjustments			-			-	-	-	-
2005-Smart Meters-Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
Total	8,130,095	(4,519,372)	3,610,722	8,528,826	(4,781,366)	3,747,460	9,122,160	(5,063,202)	4,058,958
General Plant									
1808-Buildings and Fixtures-Opening Balance	534,820	(266,384)	268,437	534,820	(274,764)	260,057	534,820	(283,780)	251,040
1808-Buildings and Fixtures-Additions			-	-		-	-		-
1808-Buildings and Fixtures-Depreciation		(8,380)	(8,380)		(9,016)	(9,016)		(9,016)	(9,016)
1808-Buildings and Fixtures-Adjustments			-	-	-	-	-	-	-
1808-Buildings and Fixtures-Closing Balance	534,820	(274,764)	260,057	534,820	(283,780)	251,040	534,820	(292,796)	242,024
Average	534,820	(270,574)	264,247	534,820	(279,272)	255,549	534,820	(288,288)	246,532
1908-Buildings and Fixtures-Opening Balance	(6,888)	6,888	-	(6,888)	6,888	-	(6,888)	7,025	138
1908-Buildings and Fixtures-									

Additions			-	-		-	-		-
1908-Buildings and Fixtures-Depreciation			-		138	138		138	138
1908-Buildings and Fixtures-Adjustments			-	-	-	-	-	-	-
1908-Buildings and Fixtures-Closing Balance	(6,888)	6,888	-	(6,888)	7,025	138	(6,888)	7,163	276
Average	(6,888)	6,888	-	(6,888)	6,956	69	(6,888)	7,094	207
1910-Leasehold Improvements-Opening Balance	72,819	(4,084)	68,734	124,275	(22,918)	101,357	125,275	(44,642)	80,633
1910-Leasehold Improvements-Additions	51,457	-	51,457	1,000		1,000	-		-
1910-Leasehold Improvements-Depreciation		(18,834)	(18,834)		(21,724)	(21,724)		(19,121)	(19,121)
1910-Leasehold Improvements-Adjustments			-	-	-	-	-	-	-
1910-Leasehold Improvements-Closing Balance	124,275	(22,918)	101,357	125,275	(44,642)	80,633	125,275	(63,764)	61,511
Average	98,547	(13,501)	85,046	124,775	(33,780)	90,995	125,275	(54,203)	71,072
Total	652,208	(290,794)	361,414	653,208	(321,397)	331,811	653,208	(349,397)	303,811
IT Assets									
1920-Computer Equipment - Hardware-Opening Balance	1,892,858	(1,662,140)	230,718	1,926,726	(1,765,998)	160,728	1,950,966	(1,845,066)	105,900
1920-Computer Equipment - Hardware-Additions	33,867		33,867	24,240		24,240	42,000		42,000
1920-Computer Equipment - Hardware-Depreciation		(103,858)	(103,858)		(79,068)	(79,068)		(55,033)	(55,033)
1920-Computer Equipment - Hardware-Adjustments			-	-	-	-	-	-	-
1920-Computer Equipment - Hardware-Closing Balance	1,926,726	(1,765,998)	160,728	1,950,966	(1,845,066)	105,900	1,992,966	(1,900,098)	92,867
Average	1,909,792	(1,714,069)	195,723	1,938,846	(1,805,532)	133,314	1,971,966	(1,872,582)	99,384
1925-Computer Software-Opening Balance	113,689	(84,364)	29,325	136,244	(133,016)	3,228	286,244	(181,794)	104,450
1925-Computer Software-Additions	22,555		22,555	150,000		150,000	24,000		24,000
1925-Computer Software-Depreciation		(48,652)	(48,652)		(48,777)	(48,777)		(81,000)	(81,000)
1925-Computer Software-Adjustments			-	-	-	-	-	-	-
1925-Computer Software-Closing Balance	136,244	(133,016)	3,228	286,244	(181,794)	104,450	310,244	(262,794)	47,450
Average									

	124,967	(108,690)	16,276	211,244	(157,405)	53,839	298,244	(222,294)	75,950
Total	2,062,970	(1,899,014)	163,955	2,237,210	(2,026,860)	210,350	2,303,210	(2,162,892)	140,318
Equipment									
1915-Office Furniture and Equipment-Opening Balance	662,341	(559,563)	102,778	696,219	(575,947)	120,272	841,204	(603,417)	237,787
1915-Office Furniture and Equipment-Additions	33,879		33,879	144,985		144,985	212,447		212,447
1915-Office Furniture and Equipment-Depreciation		(16,384)	(16,384)		(27,470)	(27,470)		(45,342)	(45,342)
1915-Office Furniture and Equipment-Adjustments			-	-	-	-	-	-	-
1915-Office Furniture and Equipment-Closing Balance	696,219	(575,947)	120,272	841,204	(603,417)	237,787	1,053,651	(648,759)	404,892
Average	679,280	(567,755)	111,525	768,712	(589,682)	179,030	947,428	(626,088)	321,340
1930-Transportation Equipment-Opening Balance	3,623,544	(2,618,246)	1,005,298	3,229,151	(2,364,062)	865,088	3,544,261	(2,591,456)	952,804
1930-Transportation Equipment-Additions	92,905		92,905	315,110	0	315,110	350,000	0	350,000
1930-Transportation Equipment-Depreciation		(229,876)	(229,876)	0	-227,394	(227,394)	0	-300,052	(300,052)
1930-Transportation Equipment-Adjustments	(487,298)	484,060	(3,238)	0	0	-	0	0	-
1930-Transportation Equipment-Closing Balance	3,229,151	(2,364,062)	865,088	3,544,261	(2,591,456)	952,804	3,894,261	(2,891,508)	1,002,753
Average	3,426,347	(2,491,154)	935,193	3,386,706	(2,477,759)	908,946	3,719,261	(2,741,482)	977,778
1935-Stores Equipment-Opening Balance	23,366	(23,366)	-	24,516	(23,366)	1,150	24,516	(23,481)	1,035
1935-Stores Equipment-Additions	1,150		1,150	-		-	125,000		125,000
1935-Stores Equipment-Depreciation			-		(115)	(115)		(6,365)	(6,365)
1935-Stores Equipment-Adjustments			-	-	-	-	-	-	-
1935-Stores Equipment-Closing Balance	24,516	(23,366)	1,150	24,516	(23,481)	1,035	149,516	(29,846)	119,670
Average	23,941	(23,366)	575	24,516	(23,423)	1,093	87,016	(26,663)	60,353
1940-Tools, Shop and Garage Equipment-Opening Balance	693,365	(529,106)	164,258	728,260	(560,726)	167,534	800,867	(590,656)	210,211
1940-Tools, Shop and Garage Equipment-Additions	34,896		34,896	72,607		72,607	66,667		66,667
1940-Tools, Shop and Garage Equipment-Depreciation		(31,620)	(31,620)		(29,930)	(29,930)		(35,830)	(35,830)

1940-Tools, Shop and Garage Equipment-Adjustments			-	-	-	-	-	-	-
1940-Tools, Shop and Garage Equipment-Closing Balance	728,260	(560,726)	167,534	800,867	(590,656)	210,211	867,534	(626,486)	241,048
Average	710,812	(544,916)	165,896	764,564	(575,691)	188,873	834,201	(608,571)	225,629
1945-Measurement and Testing Equipment-Opening Balance	122,828	(119,882)	2,946	122,828	(121,109)	1,719	122,828	(121,723)	1,105
1945-Measurement and Testing Equipment-Additions			-	-		-	30,000		30,000
1945-Measurement and Testing Equipment-Depreciation		(1,227)	(1,227)		(614)	(614)		(1,800)	(1,800)
1945-Measurement and Testing Equipment-Adjustments			-	-	-	-	-	-	-
1945-Measurement and Testing Equipment-Closing Balance	122,828	(121,109)	1,719	122,828	(121,723)	1,105	152,828	(123,523)	29,305
Average	122,828	(120,496)	2,332	122,828	(121,416)	1,412	137,828	(122,623)	15,205
1950-Power Operated Equipment-Opening Balance			-	-	-	-	-	-	-
1950-Power Operated Equipment-Additions			-			-			-
1950-Power Operated Equipment-Depreciation			-			-			-
1950-Power Operated Equipment-Adjustments			-			-			-
1950-Power Operated Equipment-Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
1955-Communication Equipment-Opening Balance	259,585	(196,915)	62,670	259,585	(206,203)	53,382	589,585	(257,778)	331,807
1955-Communication Equipment-Additions			-	330,000		330,000	78,000		78,000
1955-Communication Equipment-Depreciation		(9,288)	(9,288)		(51,575)	(51,575)		(92,123)	(92,123)
1955-Communication Equipment-Adjustments			-	-	-	-	-	-	-
1955-Communication Equipment-Closing Balance	259,585	(206,203)	53,382	589,585	(257,778)	331,807	667,585	(349,901)	317,684
Average	259,585	(201,559)	58,026	424,585	(231,991)	192,595	628,585	(303,839)	324,746
1960-Miscellaneous Equipment-Opening Balance	1,058		1,058	14,290	-	14,290	14,290	(1,429)	12,861
1960-Miscellaneous Equipment-Additions	13,232		13,232	-		-	18,000		18,000

1960-Miscellaneous Equipment-Depreciation			-		(1,429)	(1,429)		(2,329)	(2,329)
1960-Miscellaneous Equipment-Adjustments			-	-	-	-	-	-	-
1960-Miscellaneous Equipment-Closing Balance	14,290	-	14,290	14,290	(1,429)	12,861	32,290	(3,758)	28,532
Average	7,674	-	7,674	14,290	(715)	13,576	23,290	(2,594)	20,697
Total	5,074,850	(3,851,414)	1,223,436	5,937,552	(4,189,940)	1,747,612	6,817,665	(4,673,781)	2,143,884
Other Distribution Assets									
1825-Storage Battery Equipment-Opening Balance			-	-	-	-	-	-	-
1825-Storage Battery Equipment-Additions			-			-			-
1825-Storage Battery Equipment-Depreciation			-			-			-
1825-Storage Battery Equipment-Adjustments			-			-			-
1825-Storage Battery Equipment-Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
1970-Load Management Controls - Customer Premises-Opening Balance	107,035	(107,035)	0	107,035	(107,035)	0	107,035	(107,035)	0
1970-Load Management Controls - Customer Premises-Additions			-	-		-	-		-
1970-Load Management Controls - Customer Premises-Depreciation			-		0	0		0	0
1970-Load Management Controls - Customer Premises-Adjustments			-	-	-	-	-	-	-
1970-Load Management Controls - Customer Premises-Closing Balance	107,035	(107,035)	0	107,035	(107,035)	0	107,035	(107,035)	0
Average	107,035	(107,035)	0	107,035	(107,035)	0	107,035	(107,035)	0
1975-Load Management Controls - Utility Premises-Opening Balance	600,737	(590,250)	10,487	600,737	(593,253)	7,484	645,308	(598,167)	47,142
1975-Load Management Controls - Utility Premises-Additions			-	44,571		44,571	498,000		498,000
1975-Load Management Controls - Utility Premises-Depreciation		(3,003)	(3,003)		(4,914)	(4,914)		(32,042)	(32,042)
1975-Load Management Controls - Utility Premises-Adjustments			-	-	-	-	-	-	-
1975-Load Management Controls - Utility Premises-Closing Balance	600,737	(593,253)	7,484	645,308	(598,167)	47,142	1,143,308	(630,209)	513,099

Average	600,737	(591,752)	8,986	623,023	(595,710)	27,313	894,308	(614,188)	280,120
1980-System Supervisory Equipment-Opening Balance	261,249	(245,809)	15,440	293,582	(259,993)	33,589	293,582	(265,156)	28,426
1980-System Supervisory Equipment-Additions	32,333		32,333	-		-	-		-
1980-System Supervisory Equipment-Depreciation		(14,184)	(14,184)		(5,163)	(5,163)		(5,163)	(5,163)
1980-System Supervisory Equipment-Adjustments			-	-	-	-	-	-	-
1980-System Supervisory Equipment-Closing Balance	293,582	(259,993)	33,589	293,582	(265,156)	28,426	293,582	(270,320)	23,263
Average	277,416	(252,901)	24,515	293,582	(262,575)	31,008	293,582	(267,738)	25,844
1985-Sentinel Lighting Rental Units-Opening Balance			-	-	-	-	-	-	-
1985-Sentinel Lighting Rental Units-Additions			-	-		-	-		-
1985-Sentinel Lighting Rental Units-Depreciation			-		-	-		-	-
1985-Sentinel Lighting Rental Units-Adjustments			-	-	-	-	-	-	-
1985-Sentinel Lighting Rental Units-Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
1990-Other Tangible Property-Opening Balance			-	-	-	-	-	-	-
1990-Other Tangible Property-Additions			-			-			-
1990-Other Tangible Property-Depreciation			-			-			-
1990-Other Tangible Property-Adjustments			-			-			-
1990-Other Tangible Property-Closing Balance	-	-	-	-	-	-	-	-	-
Average	-	-	-	-	-	-	-	-	-
1995-Contributions and Grants - Credit-Opening Balance	(13,062,590)	1,501,938	(11,560,652)	(19,425,220)	2,278,946	(17,146,274)	(19,425,220)	3,055,955	(16,369,265)
1995-Contributions and Grants - Credit-Additions	(6,362,630)		(6,362,630)	-		-	-		-
1995-Contributions and Grants - Credit-Depreciation		777,008	777,008		777,009	777,009		777,009	777,009
1995-Contributions and Grants - Credit-Adjustments			-	-	-	-	-	-	-

1995-Contributions and Grants - Credit-Closing Balance	(19,425,220)	2,278,946	(17,146,274)	(19,425,220)	3,055,955	(16,369,265)	(19,425,220)	3,832,964	(15,592,257)
Average	(16,243,905)	1,890,442	(14,353,463)	(19,425,220)	2,667,451	(16,757,770)	(19,425,220)	3,444,459	(15,980,761)
Total	(18,423,866)	1,318,665	(17,105,201)	(18,379,295)	2,085,597	(16,293,698)	(17,881,295)	2,825,401	(15,055,895)
Total Opening Balance	105,409,964	(63,362,308)	42,047,656	108,031,531	(66,502,244)	41,529,287	116,605,966	(70,394,204)	46,211,762
Total Additions	3,156,865	-	3,156,865	8,574,435	-	8,574,435	10,993,346	-	10,993,346
Total Depreciation	-	(3,659,116)	(3,659,116)	-	(3,891,960)	(3,891,960)	-	(4,395,490)	(4,395,490)
Total Adjustments	(535,298)	519,180	(16,118)	-	-	-	-	-	-
Total Closing Balance	108,031,531	(66,502,244)	41,529,287	116,605,966	(70,394,204)	46,211,762	127,599,312	(74,789,694)	52,809,618
Average	106,720,748	(64,932,276)	41,788,471	112,318,749	(68,448,224)	43,870,524	122,102,639	(72,591,949)	49,510,690
Total	108,031,531	(66,502,244)	41,529,287	116,605,966	(70,394,204)	46,211,762	127,599,312	(74,789,694)	52,809,618

GROSS ASSETS: BREAKDOWN BY PLANT ACCOUNT

	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved	2006 Actual	2007 Bridge	Variance form 2006 Actual	2007 Bridge	2008 Test	Variance form 2007 Bridge
	($'s)	($'s)		($'s)	($'s)		($'s)	($'s)	
Land and Buildings									
1805-Land	98,896	293,875	194,979	293,875	293,875	-	293,875	543,875	250,000
1806-Land Rights	-	-	-	-	-	-	-	-	-
1808-Buildings and Fixtures	533,720	534,820	1,100	534,820	534,820	-	534,820	534,820	-
1905-Land	-	-	-	-	-	-	-	-	-
1906-Land Rights	-	-	-	-	-	-	-	-	-
1810-Leasehold Improvements	-	-	-	-	70,000	70,000	70,000	462,220	392,220
Sub-Total-Land and Buildings	632,616	828,696	196,079	828,696	898,696	70,000	898,696	1,540,916	642,220
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV	-	-	-	-	-	-	-	-	-
Sub-Total-TS Primary Above 50	-	-	-	-	-	-	-	-	-
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV	9,177,302	10,178,638	1,001,336	10,178,638	11,223,070	1,044,432	11,223,070	14,321,662	3,098,592
Sub-Total-DS	9,177,302	10,178,638	1,001,336	10,178,638	11,223,070	1,044,432	11,223,070	14,321,662	3,098,592
Poles and Wires									
1830-Poles, Towers and Fixtures	-	-	-	-	-	-	-	-	-
1835-Overhead Conductors and Devices	32,342,983	38,274,196	5,931,213	38,274,196	41,005,209	2,731,013	41,005,209	44,258,887	3,253,678
1840-Underground Conduit	-	-	-	-	-	-	-	-	-
1845-Underground Conductors and Devices	36,313,012	46,305,239	9,992,228	46,305,239	49,229,854	2,924,614	49,229,854	51,157,929	1,928,076
Sub-Total-Poles and Wires	68,655,995	84,579,435	15,923,441	84,579,435	90,235,063	5,655,627	90,235,063	95,416,816	5,181,754

Line Transformers									
1850-Line Transformers	15,531,506	15,483,326	(48,180)	15,483,326	15,806,456	323,130	15,806,456	15,839,790	33,333
Sub-Total-Line Transformers	15,531,506	15,483,326	(48,180)	15,483,326	15,806,456	323,130	15,806,456	15,839,790	33,333
Services and Meters									
1855-Services	-	-	-	-	-	-	-	33,333	33,333
1860-Meters	7,643,931	8,130,095	486,164	8,130,095	8,528,826	398,732	8,528,826	9,088,826	560,000
1565 Conservation & Demand Management Expenditures & Recoveries	33,008	-	(33,008)	-	-		-	-	
2005-Smart Meters-Adjustments	-	-	-	-	-	-	-	-	-
Sub-Total-Services and Meters	7,676,939	8,130,095	453,156	8,130,095	8,528,826	398,732	8,528,826	9,122,160	593,333
General Plant									
1908-Buildings and Fixtures	-	(6,888)	(6,888)	(6,888)	(6,888)	-	(6,888)	(6,888)	-
1910-Leasehold Improvements	59,306	124,275	64,970	124,275	125,275	1,000	125,275	125,275	-
Sub-Total-General Plant	59,306	117,388	58,082	117,388	118,388	1,000	118,388	118,388	-
IT Assets									
1920-Computer Equipment - Hardware	1,770,083	1,926,726	156,642	1,926,726	1,950,966	24,240	1,950,966	1,992,966	42,000
1925-Computer Software	55,039	136,244	81,205	136,244	286,244	150,000	286,244	310,244	24,000
Sub-Total-IT Assets	1,825,123	2,062,970	237,847	2,062,970	2,237,210	174,240	2,237,210	2,303,210	66,000
Equipment									
1915-Office Furniture and Equipment	648,512	696,219	47,707	696,219	841,204	144,985	841,204	1,053,651	212,447
1930-Transportation Equipment	3,908,309	3,229,151	(679,159)	3,229,151	3,544,261	315,110	3,544,261	3,894,261	350,000
1935-Stores Equipment	23,366	24,516	1,150	24,516	24,516	-	24,516	149,516	125,000
1940-Tools, Shop and Garage Equipment	570,273	728,260	157,987	728,260	800,867	72,607	800,867	867,534	66,667
1945-Measurement and Testing Equipment	122,828	122,828	-	122,828	122,828	-	122,828	152,828	30,000
1950-Power Operated Equipment	-	-	-	-	-	-	-	-	-
1955-Communication Equipment									

	259,585	259,585	-	259,585	589,585	330,000	589,585	667,585	78,000
1960-Miscellaneous Equipment	1,058	14,290	13,232	14,290	14,290	-	14,290	32,290	18,000
Sub-Total-Equipment	5,533,931	5,074,850	(459,082)	5,074,850	5,937,552	862,702	5,937,552	6,817,665	880,113
Other Distribution Assets									
1825-Storage Battery Equipment	-	-	-	-	-	-	-	-	-
1970-Load Management Controls - Customer Premises	107,035	107,035	-	107,035	107,035	-	107,035	107,035	-
1975-Load Management Controls - Utility Premises	597,214	600,737	3,523	600,737	645,308	44,571	645,308	1,143,308	498,000
1980-System Supervisory Equipment	241,949	293,582	51,633	293,582	293,582	-	293,582	293,582	-
1985-Sentinel Lighting Rental Units	-	-	-	-	-	-	-	-	-
1990-Other Tangible Property	-	-	-	-	-	-	-	-	-
1995-Contributions and Grants - Credit	(7,763,546)	(19,425,220)	(11,661,675)	(19,425,220)	(19,425,220)	-	(19,425,220)	(19,425,220)	-
Sub-Total-Other Distribution Assets	(6,817,348)	(18,423,866)	(11,606,519)	(18,423,866)	(18,379,295)	44,571	(18,379,295)	(17,881,295)	498,000
GROSS ASSET TOTAL	102,275,371	108,031,531	5,756,160	108,031,531	116,605,966	8,574,435	116,605,966	127,599,312	10,993,346

VARIANCE ANALYSIS OF GROSS ASSETS

Included in this schedule are explanations of variance of gross assets on an account basis that exceed the materiality threshold of 1% of total net fixed assets. The balances in these accounts are cumulative from one year to the next and do not include depreciation. The variances reflect gross expenditures in any one year.

2006 Approved compared to 2006 Actual

Asset Account	2006 Approved	2006 Actual	Variance Amount	Variance %
1820-Distribution Station Equipment - Normally Primary below 50 kV	9,177,302	10,178,638	1,001,336	2%

Explanation:

Most of the variance in this account can be explained by the use of averaging in the calculation of the 2006 Actual amount. The only major new item was a new transformer purchase of $760,000 which is intended for the Municipal Substation referenced at Exhibit 2, Tab 3, Schedule 3. This transformer was purchased before it will be required for the MS due to the unreliability of delivery dates from Europe for this transformer type. Having it in stock early has allowed OPUCN to use it as a spare so that transformers already in service can have needed maintenance performed without affecting the reliability of the system.

Asset Account	2006 Approved	2006 Actual	Variance Amount	Variance %
1835-Overhead Conductors and Devices	32,342,983	38,274,196	5,931,213	14%

Explanation:

Many of the Overhead and Underground Conductor purchases were offset by Contributions (Contributed Capital). Including those devices would result in an additional Net Fixed Assets amount of approximately $4,261,000.

Asset Account	**2006 Approved**	**2006 Actual**	**Variance Amount**	**Variance %**
1845-Underground Conductors and Devices	36,313,012	46,305,239	9,992,228	24%

Explanation:

There were no individual projects which accounted for the variance in this asset class. Instead, the variance is a result of significant increases in Sub-division construction for 2006 and normal annual expenditures for investment to maintain system safety and reliability.

Asset Account	**2006 Approved**	**2006 Actual**	**Variance Amount**	**Variance %**
1860-Meters	7,643,931	8,130,095	486,164	1%

Explanation:

Most of the variance in this account can be explained by the use of averaging in the calculation of the 2006 Actual amount. Other expenditures causing the variance included those associated with the purchase and installation of new interval meters to update Industrial customers to interval meter systems.

Asset Account	2006 Approved	2006 Actual	Variance Amount	Variance %
1930-Transportation Equipment	3,908,309	3,229,151	(679,159)	-2%

Explanation:

The variance in this account is due largely to the disposal of ten (10) trucks which were in excess of 10 -16 years in age. The age of the vehicles was causing high repair/maintenance costs. It was deemed more economical to replace them than to continue paying these high costs.

Asset Account	2006 Approved	2006 Actual	Variance Amount	Variance %
1995-Contributions and Grants - Credit	(7,763,546)	(19,425,220)	(11,661,675)	-28%

Explanation:

This account reflects the significant increase in Contributed Capital from the General Motors Sports Center and new 401 Interchange. There was also some increase in Contributions from sub-division development.

2006 Actual compared to 2007 Bridge Year

Expenditures in the following accounts usually reflect expenditures for enhancement and expansion projects identified for 2007 in Exhibit 2, Tab 3, Schedule 3. These include the construction of a circuit to supply needed capacity to UOIT; a pole replacement program conducted in response to the need to replace aging poles; and the transformer inventory for the construction of a new municipal substation (MS9) which is being built in 2008 to accommodate residential, commercial, and industrial growth in the northern and eastern areas of the City of Oshawa. Individual accounts may have additional influences which are detailed below.

Asset Account	2006 Actual	2007 Bridge	Variance Amount	Variance %
1820-Distribution Station Equipment - Normally Primary below 50 kV	10,178,638	11,233,070	1,044,432	3%

Explanation:

OPUCN experienced a major fire in one of its Municipal Substation (MS2) in the summer of 2006. Costs in this account partially reflect a major overhaul of the MS in question. The engineering investigation performed after the fire led to the implementation of a five year program to replace specific breakers and relays for all MS stations that were found to be at risk. Costs included in this account reflect expenditures for relay replacement in 2007.

Asset Account	2006 Actual	2007 Bridge	Variance Amount	Variance %
1835-Overhead Conductors and Devices	38,274,196	41,005,209	2,731,013	7%

Explanation:

In addition to regular annual enhancements of Overhead Conductors, expenditures in this account reflect expenditures for the expansion projects identified at Exhibit 2, Tab 3, Schedule 3.

Asset Account	2006 Actual	2007 Bridge	Variance Amount	Variance %
1845-Underground Conductors and Devices	46,305,239	49,229,854	2,924,614	7%

Explanation:

Expenditures in this account largely reflect regular annual enhancements of underground devices, including the replacement of old at risk underground circuits. Identification of capacity requirements to service the new University of Ontario Institute of Technology ("UOIT") and planned developments in the northern and eastern regions of the City of Oshawa, have driven the need for additional expansion expenditures. As well, some 2006 projects, particularly the replacement of underground circuits, will go in service in 2007.

2007 Bridge Year compared to 2008 Test Year

Expenditures in the following accounts usually reflect expenditures for enhancement and expansion projects identified for 2008 in Exhibit 2, Tab 3, Schedule 3. These include a pole replacement program conducted in response to the need to replace aging poles; and the construction of a new municipal substation (MS9) which is being built in 2008 to accommodate residential, commercial, and industrial growth in the northern and eastern areas of the City of Oshawa. Individual accounts may have additional influences which are detailed below.

Asset Account	2007 Bridge	2008 Test	Variance Amount	Variance %
1820-Distribution Station Equipment - Normally Primary below 50 kV	11,233,070	14,321,662	3,098,592	7%

Explanation:

The increase in this account is driven partially by the construction of the new MS needed to service growth in the northern and eastern areas of the City of Oshawa (Exhibit 2, Tab 3, Schedule 3). The rest of the variance is largely the result of the five year program to replace specific breakers and relays for all MS stations that have been found to be at risk. This project was triggered by the major fire in MS2 in the summer of 2006.

Asset Account	**2007 Bridge**	**2008 Test**	**Variance Amount**	**Variance %**
1835-Overhead Conductors and Devices	41,005,209	44,258,887	3,253,678	7%

Explanation:

The variance in this account is largely driven by the requirements of the projects that exceeded the materiality threshold for 2008.

Asset Account	**2007 Bridge**	**2008 Test**	**Variance Amount**	**Variance %**
1845-Underground Conductors and Devices	49,229,854	51,157,929	1,928,076	4%

Explanation:

The variance in this account reflects the need for expenditures to meet capacity requirements to service new sub-divisions, the new University (UOIT), and expected developments in the northern and eastern areas of the City of Oshawa.

Asset Account	2007 Bridge	2008 Test	Variance Amount	Variance %
1860-Meters	8,528,826	9,088,820	560,000	1%

Explanation:

The variance in this account is associated with OPUCN's program to upgrade qualified customers with new interval meters. Further expenditures for single and poly phase meters were made to meet normal annual requirements for testing and replacement, and for purchases associated with sub-division growth.

Asset Account	2007 Bridge	2008 Test	Variance Amount	Variance %
1975-Load Management Controls - Utility Premises	645,308	1,143,308	498,000	1%

Explanation:

The variance in this account is associated with the project to upgrade OPUCN's SCADA system. The details of this project can be found at Exhibit 2, Tab 3, Schedule 3. Briefly, the project is driven by the need to replace an obsolete SCADA system. The upgrade is required in order to identify and safely manage events on the distribution system, including system outages.

ACCUMULATED DEPRECIATION

	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved	2006 Actual	2007 Bridge	Variance form 2006 Actual	2007 Bridge	2008 Test	Variance form 2007 Bridge
	($'s)	($'s)		($'s)	($'s)		($'s)	($'s)	
Land and Buildings									
1805-Land-Depreciation	-	-	-	-	-	-	-	-	-
1806-Land Rights-Depreciation	-	-	-	-	-	-	-	-	-
1808-Buildings and Fixtures-Depreciation	(258,004)	(274,764)	(16,760)	(274,764)	(283,780)	(9,016)	(283,780)	(292,796)	(9,016)
1905-Land-Depreciation	-	-	-	-	-	-	-	-	-
1906-Land Rights-Depreciation	-	-	-	-	-	-	-	-	-
1810-Leasehold Improvements-Depreciation	-	-	-	-	(7,000)	(7,000)	(7,000)	(60,222)	(53,222)
Sub-Total-Land and Buildings	(258,004)	(274,764)	(16,760)	(274,764)	(290,780)	(16,016)	(290,780)	(353,018)	(62,238)
TS Primary Above 50									
1815-Transformer Station Equipment - Normally Primary above 50 kV-Depreciation	-	-	-	-	-	-	-	-	-
Sub-Total-TS Primary Above 50	-	-	-	-	-	-	-	-	-
DS									
1820-Distribution Station Equipment - Normally Primary below 50 kV-Depreciation	(5,946,057)	(6,519,679)	(573,622)	(6,519,679)	(6,827,954)	(308,275)	(6,827,954)	(7,196,434)	(368,480)
Sub-Total-DS	(5,946,057)	(6,519,679)	(573,622)	(6,519,679)	(6,827,954)	(308,275)	(6,827,954)	(7,196,434)	(368,480)
Poles and Wires									
1830-Poles, Towers and Fixtures-Depreciation	-	-	-	-	-	-	-	-	-
1835-Overhead Conductors and Devices-Depreciation	(16,948,443)	(19,176,755)	(2,228,312)	(19,176,755)	(20,427,017)	(1,250,261)	(20,427,017)	(21,772,329)	(1,345,312)
1840-Underground Conduit-Depreciation	-	-	-	-	-	-	-	-	-
1845-Underground Conductors and Devices-Depreciation	(16,322,060)	(19,700,038)	(3,377,978)	(19,700,038)	(21,581,712)	(1,881,674)	(21,581,712)	(23,560,440)	(1,978,728)
Sub-Total-Poles and Wires	(33,270,503)	(38,876,793)	(5,606,290)	(38,876,793)	(42,008,729)	(3,131,936)	(42,008,729)	(45,332,769)	(3,324,040)
Line Transformers									

1850-Line Transformers-Depreciation	(11,029,954)	(11,863,842)	(833,888)	(11,863,842)	(12,316,555)	(452,713)	(12,316,555)	(12,776,397)	(459,842)
Sub-Total-Line Transformers	(11,029,954)	(11,863,842)	(833,888)	(11,863,842)	(12,316,555)	(452,713)	(12,316,555)	(12,776,397)	(459,842)
Services and Meters									
1855-Services-Depreciation	-	-	-	-	-	-	-	(667)	(667)
1860-Meters-Depreciation	(4,050,783)	(4,519,372)	(468,589)	(4,519,372)	(4,781,366)	(261,994)	(4,781,366)	(5,062,535)	(281,169)
2005-Smart Meters-Adjustments	-	-	-	-	-	-	-	-	-
Sub-Total-Services and Meters	(4,050,783)	(4,519,372)	(468,589)	(4,519,372)	(4,781,366)	(261,994)	(4,781,366)	(5,063,202)	(281,836)
General Plant									
1908-Buildings and Fixtures-Depreciation	-	6,888	6,888	6,888	7,025	138	7,025	7,163	138
1910-Leasehold Improvements-Depreciation	13,089	(22,918)	(36,007)	(22,918)	(44,642)	(21,724)	(44,642)	(63,764)	(19,121)
Sub-Total-General Plant	13,089	(16,031)	(29,119)	(16,031)	(37,617)	(21,586)	(37,617)	(56,601)	(18,984)
IT Assets									
1920-Computer Equipment - Hardware-Depreciation	(1,582,520)	(1,765,998)	(183,478)	(1,765,998)	(1,845,066)	(79,068)	(1,845,066)	(1,900,098)	(55,033)
1925-Computer Software-Depreciation	(46,990)	(133,016)	(86,026)	(133,016)	(181,794)	(48,777)	(181,794)	(262,794)	(81,000)
Sub-Total-IT Assets	(1,629,510)	(1,899,014)	(269,504)	(1,899,014)	(2,026,860)	(127,845)	(2,026,860)	(2,162,892)	(136,033)
Equipment									
1915-Office Furniture and Equipment-Depreciation	(542,624)	(575,947)	(33,323)	(575,947)	(603,417)	(27,470)	(603,417)	(648,759)	(45,342)
1930-Transportation Equipment-Depreciation	(2,980,116)	(2,364,062)	616,054	(2,364,062)	(2,591,456)	(227,394)	(2,591,456)	(2,891,508)	(300,052)
1935-Stores Equipment-Depreciation	(23,366)	(23,366)	-	(23,366)	(23,481)	(115)	(23,481)	(29,846)	(6,365)
1940-Tools, Shop and Garage Equipment-Depreciation	(501,090)	(560,726)	(59,636)	(560,726)	(590,656)	(29,930)	(590,656)	(626,486)	(35,830)
1945-Measurement and Testing Equipment-Depreciation	(118,218)	(121,109)	(2,891)	(121,109)	(121,723)	(614)	(121,723)	(123,523)	(1,800)
1950-Power Operated Equipment-Depreciation	-	-	-	-	-	-	-	-	-
1955-Communication Equipment-Depreciation	(187,627)	(206,203)	(18,576)	(206,203)	(257,778)	(51,575)	(257,778)	(349,901)	(92,123)
1960-Miscellaneous Equipment-Depreciation	-	-	-	-	(1,429)	(1,429)	(1,429)	(3,758)	(2,329)
Sub-Total-Equipment	(4,353,042)	(3,851,414)	501,628	(3,851,414)	(4,189,940)	(338,527)	(4,189,940)	(4,673,781)	(483,840)

Other Distribution Assets									
1825-Storage Battery Equipment-Depreciation	-	-	-	-	-	-	-	-	-
1970-Load Management Controls - Customer Premises-Depreciation	(102,173)	(107,035)	(4,862)	(107,035)	(107,035)	0	(107,035)	(107,035)	0
1975-Load Management Controls - Utility Premises-Depreciation	(584,611)	(593,253)	(8,642)	(593,253)	(598,167)	(4,914)	(598,167)	(630,209)	(32,042)
1980-System Supervisory Equipment-Depreciation	(238,092)	(259,993)	(21,901)	(259,993)	(265,156)	(5,163)	(265,156)	(270,320)	(5,163)
1985-Sentinel Lighting Rental Units-Depreciation	-	-	-	-	-	-	-	-	-
1990-Other Tangible Property-Depreciation	-	-	-	-	-	-	-	-	-
1995-Contributions and Grants - Credit-Depreciation	979,434	2,278,946	1,299,512	2,278,946	3,055,955	777,009	3,055,955	3,832,964	777,009
Sub-Total-Other Distribution Assets	54,559	1,318,665	1,264,107	1,318,665	2,085,597	766,932	2,085,597	2,825,401	739,803
ACCUMULATED DEPRICIATION TOTAL	(60,470,207)	(66,502,244)	(6,032,038)	(66,502,244)	(70,394,204)	(3,891,960)	(70,394,204)	(74,789,694)	(4,395,490)

VARIANCE ANALYSIS OF ACCUMULATED DEPRECIATION

OPUCN depreciates its assets in accordance with the Accounting Procedures Handbook.

Please refer to Exhibit 2, Tab 2, Schedule 4 for OPUCN's variances in accumulated depreciation.

GROSS ASSETS: BREAKDOWN BY FUNCTION

ACCOUNT: *1610:1610* *TOTAL INTANGIBLE PLANT*

	BRIDGE YEAR			TEST YEAR		
	Gross Cost	Accumulated Amortization	Net Book Value	Gross Cost	Accumulated Amortization	Net Book Value
Opening Balance	**0**	**0**	**0**	**0**	**0**	**0**
Additions	0	0	0	0	0	0
Depreciation	0	0	0	0	0	0
Retirements & Sales	0	0	0	0	0	0
Other (specify)	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
Closing Balance	**0**	**0**	**0**	**0**	**0**	**0**
Average Balance	*0*	*0*	*0*	*0*	*0*	*0*
Change in Year	*0*	*0*	*0*	*0*	*0*	*0*

ACCOUNT: **1805:1860** **TOTAL DISTRIBUTION PLANT**

	BRIDGE YEAR			TEST YEAR		
	Gross Cost	Accumulated Amortization	Net Book Value	Gross Cost	Accumulated Amortization	Net Book Value
Opening Balance	**119,200,190**	**(62,054,451)**	**57,145,739**	**93,206,341**	**(32,739,614)**	**60,466,727**
Additions	7,491,921	0	7,491,921	9,549,232	0	9,549,232

Depreciation	0	(4,170,934)	(4,170,934)	0	(4,496,436)	(4,496,436)
Retirements & Sales	(33,485,770)	33,485,770	0	31,726,502	(31,726,502)	0
Other (specify)	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
Closing Balance	**93,206,341**	**(32,739,614)**	**60,466,727**	**134,482,075**	**(68,962,552)**	**65,519,523**
Average Balance	*106,203,266*	*(47,397,033)*	*58,806,233*	*113,844,208*	*(50,851,083)*	*62,993,125*
Change in Year	*(25,993,849)*	*29,314,836*	*3,320,988*	*41,275,734*	*(36,222,938)*	*5,052,796*

ACCOUNT: 1905:1995 TOTAL GENERAL PLANT

	BRIDGE YEAR			***TEST YEAR***		
	Gross Cost	***Accumulated Amortization***	***Net Book Value***	***Gross Cost***	***Accumulated Amortization***	***Net Book Value***
Opening Balance	**(11,168,659)**	**(4,447,794)**	**(15,616,452)**	**(21,443,201)**	**7,188,236**	**(14,254,965)**
Additions	1,082,513	0	1,082,513	1,444,113	0	1,444,113
Depreciation	0	278,974	278,974	0	100,947	100,947
Retirements & Sales	(11,357,056)	11,357,056	0	10,948,270	(10,948,270)	0
Other (specify)	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
Closing Balance	**(21,443,201)**	**7,188,236**	**(14,254,965)**	**(9,050,818)**	**(3,659,087)**	**(12,709,905)**
Average Balance	*(16,305,930)*	*1,370,221*	*(14,935,709)*	*(15,247,010)*	*1,764,574*	*(13,482,435)*
Change in Year	*(10,274,543)*	*11,636,030*	*1,361,487*	*12,392,383*	*(10,847,323)*	*1,545,060*

ACCOUNT: 2005:2005 TOTAL OTHER CAPITAL ASSETS IN SERVICE

BRIDGE YEAR			***TEST YEAR***		
Gross	***Accumulated***	***Net Book***	***Gross***	***Accumulated***	***Net Book***

	Cost	Amortization	Value	Cost	Amortization	Value
Opening Balance	**0**	**0**	**0**	**0**	**0**	**0**
Additions	0	0	0	0	0	0
Depreciation	0	0	0	0	0	0
Retirements & Sales	0	0	0	0	0	0
Other (specify)	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
Closing Balance	**0**	**0**	**0**	**0**	**0**	**0**
Average Balance	*0*	*0*	*0*	*0*	*0*	*0*
Change in Year	*0*	*0*	*0*	*0*	*0*	*0*

ACCOUNT: 1805:2005 TOTAL PROPERTY, PLANT & EQUIPMENT

	BRIDGE YEAR			*TEST YEAR*		
	Gross Cost	***Accumulated Amortization***	***Net Book Value***	***Gross Cost***	***Accumulated Amortization***	***Net Book Value***
Opening Balance	**108,031,531**	**(66,502,244)**	**41,529,287**	**71,763,140**	**(25,551,378)**	**46,211,762**
Additions	8,574,435	0	8,574,435	10,993,345	0	10,993,345
Depreciation	0	(3,891,960)	(3,891,960)	0	(4,395,489)	(4,395,489)
Retirements & Sales	(44,842,826)	44,842,826	0	42,674,772	(42,674,772)	0
Other (specify)	0	0	0	0	0	0
	0	0	0	0	0	0
	0	0	0	0	0	0
Closing Balance	**71,763,140**	**(25,551,378)**	**46,211,762**	**125,431,257**	**(72,621,639)**	**52,809,618**
Average Balance	*89,897,335*	*(46,026,811)*	*43,870,524*	*98,597,198*	*(49,086,509)*	*49,510,690*
Change in Year	*(36,268,391)*	*40,950,866*	*4,682,475*	*53,668,117*	*(47,070,261)*	*6,597,856*

CAPITAL PROJECT PLANNING PROCESS

Introduction

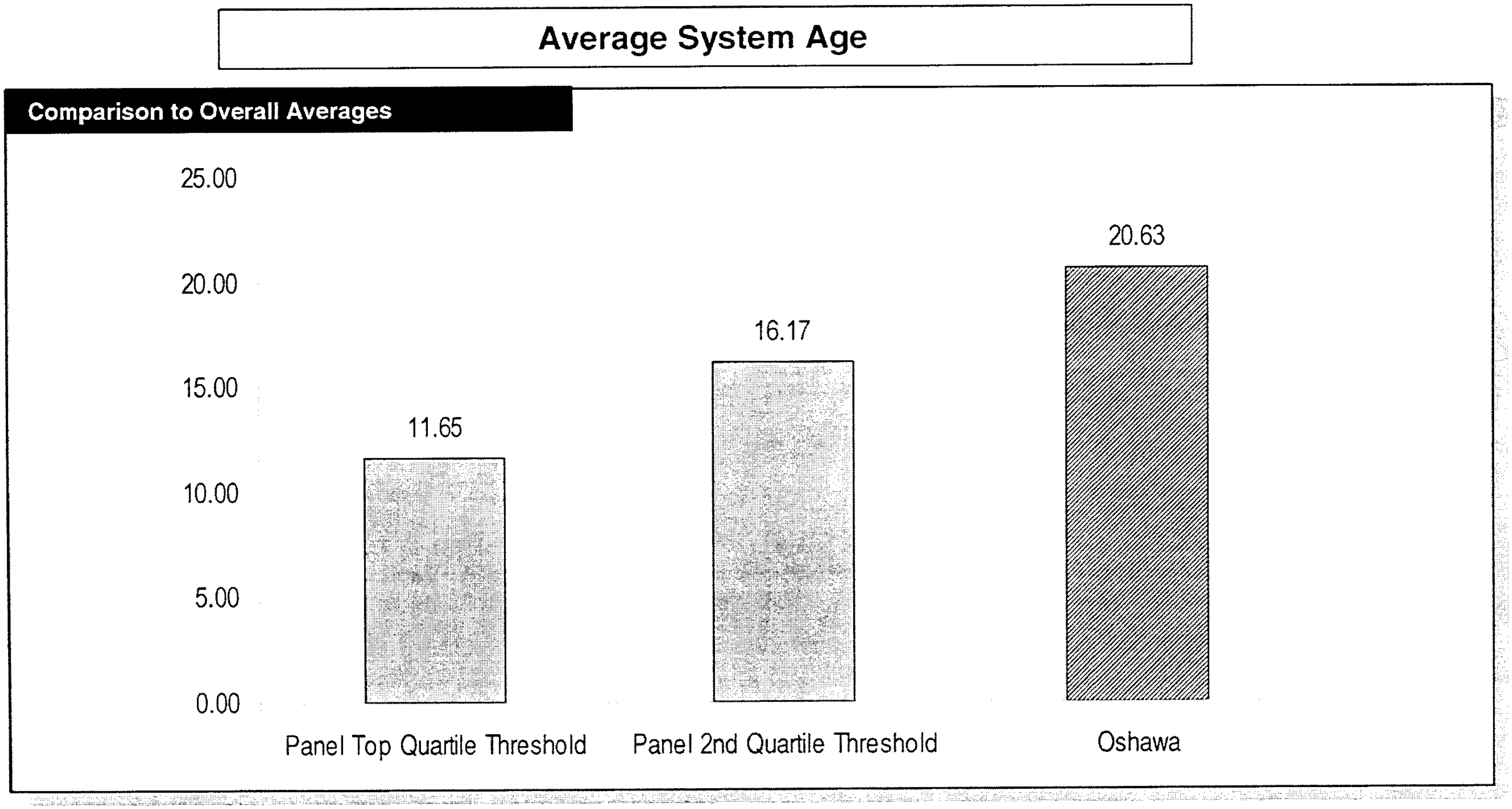
OPUCN's capital investments can generally be classified into two categories: (i) "regular" capital investment; and (ii) "non-regular" capital investment. Both of these categories are described below.

(i) "Regular" Capital Investment

Regular capital investment refers to baseline investment that is made every year to maintain OPUCN's system reliability (also referred to as regular enhancement investment), and to accommodate the typical growth of OPUCN's system (also referred to as regular expansion investment).

In regard to OPUCN's regular enhancement investment, it is important to understand the physical nature of OPUCN's system. In the early 1970's OPUCN underwent a 5 kV to 15 kV voltage conversion program. In the space of a few short years OPUCN's distribution system was almost entirely replaced. The typical engineering life of distribution system components is 40 to 50 years. Therefore, OPUCN's distribution system is nearing end of life. In a 2004 study conducted by the UMS Group it was concluded that OPUCN's distribution system is well above the average age of the systems of its peers (similarly sized distributors in North America).

The panel average system age is 15 years, Oshawa PUC Assets are Well Above the Average of The Peer Group.



Tracking average system age can help to identify potential sources of reliability issues.

The latest third-party asset condition study, undertaken in 2006, was performed by Kinetrics Inc. and included a thorough assessment of the condition of the distribution system (report is at Appendix D). Kinectrics generally concluded that the existing plant is nearing the end of its service life. For these reasons OPUCN must maintain an aggressive capital program in order to ensure its continued safe and reliable delivery of electricity to the citizens of Oshawa. OPUCN's regular enhancement investment is approximately $4 million per year.

In regard to regular expansion investment, OPUCN experiences regular baseline growth. Accordingly OPUCN invests approximately $0.8 million per year in regular expansion projects to accommodate this baseline growth. For more information on OPUCN's customer growth please refer to Exhibit 3, Tab 2, Schedule 3.

In total, OPUCN invests approximately $4.8 million per year in regular capital investments ($4 million in regular enhancement and $0.8 in regular expansions). The remainder of capital expenditures in any given year can be attributed to "non-regular" capital investments such as those discussed below.

(ii) "Non-Regular" Capital Investments

"Non-Regular" capital investments refer to investment in capital projects that are non-recurring. This type of investment fluctuates from year to year and is driven by a number of circumstances including:

- Customer demand beyond typical growth;
- Special projects; and
- Capacity growth.

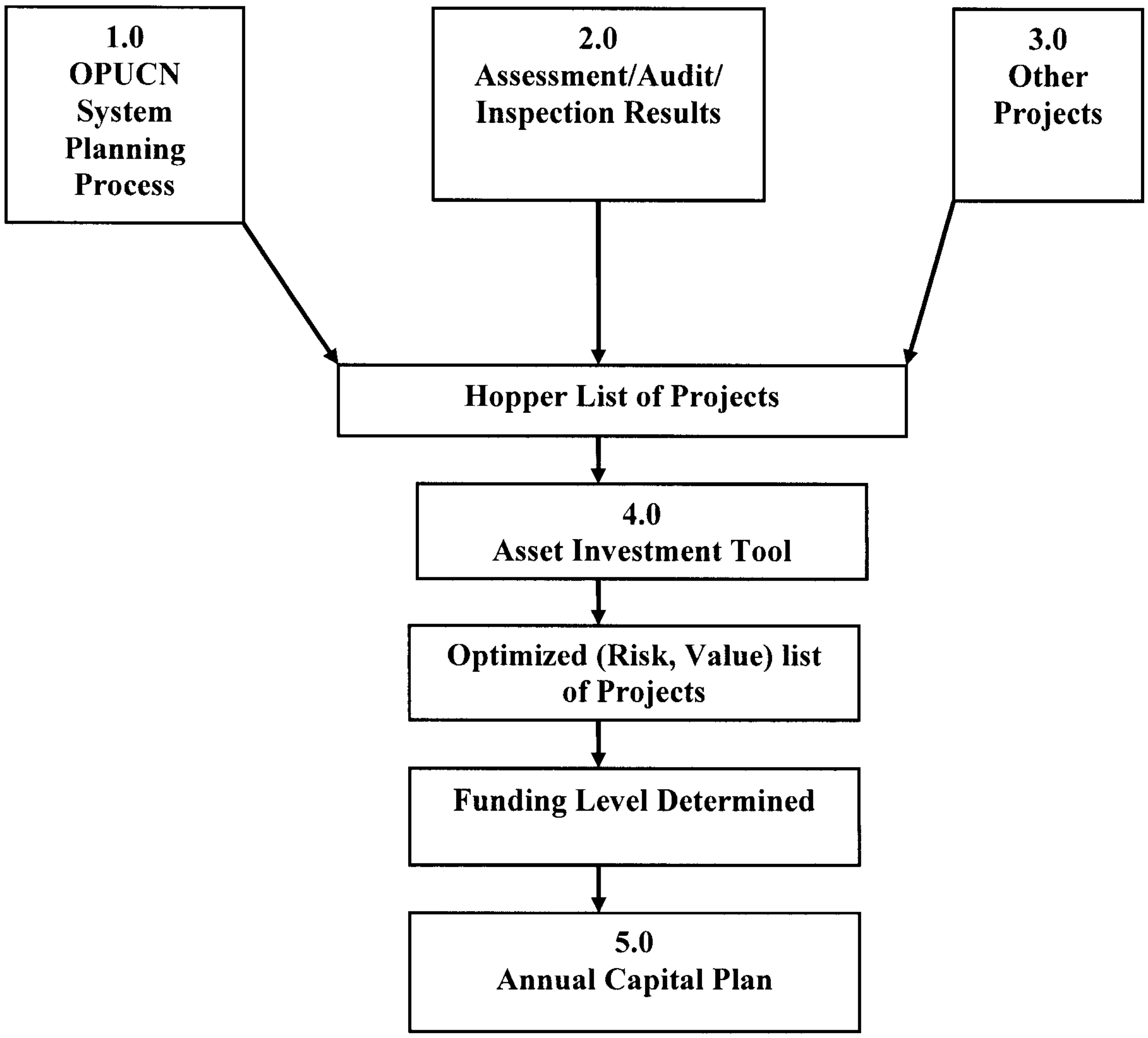
These "non-regular" capital investments primarily account for the annual variances in capital investment. The capital investments that exceed the materiality described at Exhibit 2, Tab 3, Schedule 3 are "non-regular" capital investments that contribute to OPUCN's rate base variances from 2006 to 2008.

OPUCN's Capital Project Planning Process is a formalized process that is performed annually in order to determine and create the Annual Capital Plan. This plan includes both "regular" and "non-regular" investments.

There are a number of aspects involved in determining the final Annual Capital Plan. The first aspect is to identify potential capital projects. Three systems are utilized to identify and capture the potential projects; System Planning Process, Assessment / Audit / Inspection Results and Other Projects.

The System Planning Process identifies potential projects based on traditional utility system planning inputs including but not limited to load forecasting, projected customer growth, and feeder reliability statistics. Assessment / Audit / Inspection procedures identify potential projects through periodic inspections, assessments and audits of the distribution system by qualified staff members and third parties. Potential projects that develop outside the typical utility project drivers are captured under the heading of "Other Projects".

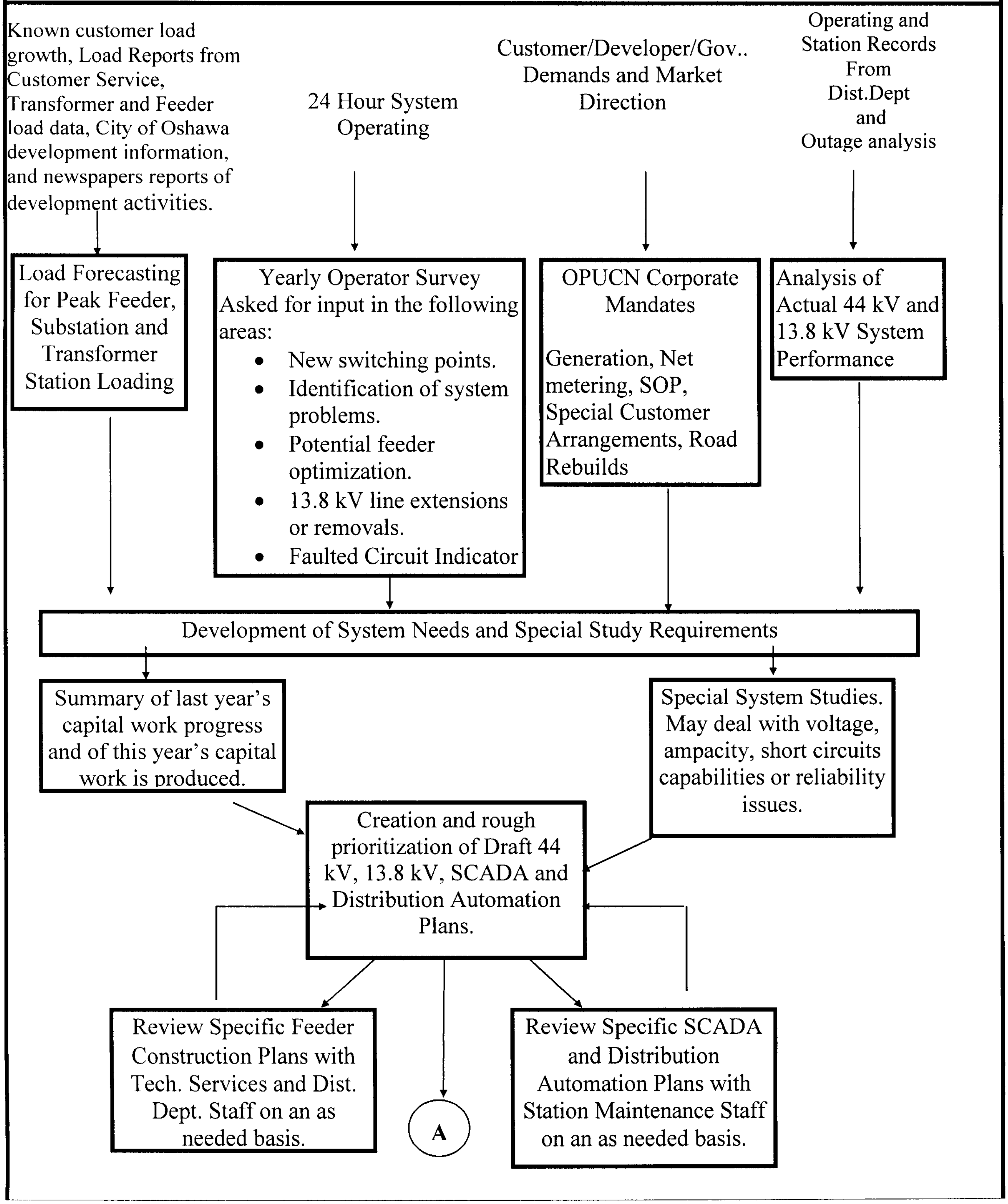
The above process results in a "hopper" list of projects which are then scored and evaluated through the Asset Investment Tool to determine the optimum priority of projects based on value, risk and probability. Once capital funding levels have been determined a prioritized, risk-assessed, cost-effective capital plan is derived for execution during the year.
The following diagram illustrates Oshawa PUC Networks Inc. (OPUCN) capital project planning process.


1.0
OPUCN
System
Planning
Process
2.0
Assessment/Audit/
Inspection Results
3.0
Other
Projects
Hopper List of Projects
4.0
Asset Investment Tool
Optimized (Risk, Value) list
of Projects
Funding Level Determined
5.0
Annual Capital Plan

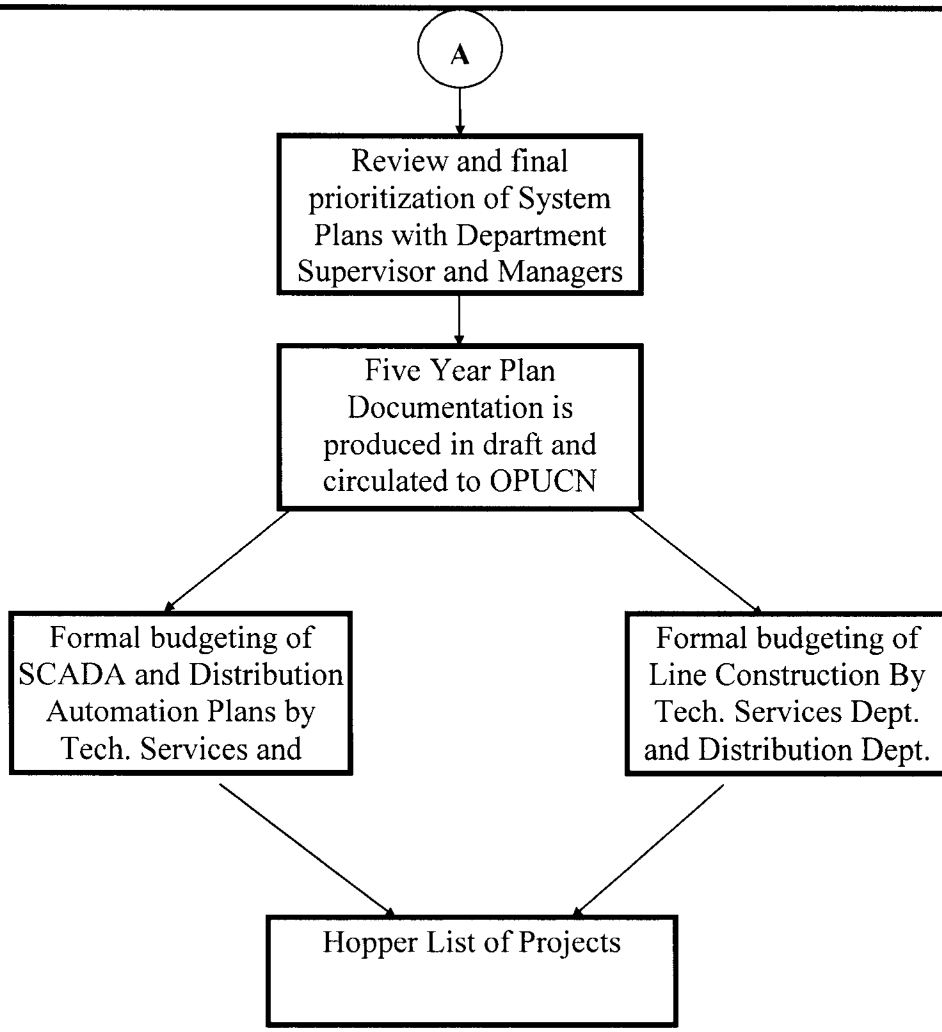
1.0 OPUCN System Planning Process

The OPUCN system planning process utilizes traditional utility distribution system planning inputs in order to determine capital projects. The following diagram provides a detailed illustration of the inputs and process:

OPUCN System Planning Process



OPUCN System Planning Process (continued)



Two key components of the planning process are: (i) the City of Oshawa development plan; and (ii) the engineering load forecast used to identify expansions and enhancements necessary to support current and expected load. These components are discussed in more detail below.

1.1 City of Oshawa Development Information

Some capital projects are driven by growth within the service area. The City of Oshawa has a five year development plan which it developed in 2005. OPUCN uses this plan to identify areas of growth within the City which will need infrastructure additions or enhancements. The areas which will be developed within the next few years are identified in the City plan as the Taunton and Windfields development areas. These areas are adjacent to each other and cover the entire north end of the City. Together they cover an area of approximately 1000 hectares bounded by Conlin road on the south, the future Highway 407 on the north, and City of Oshawa boundaries on the west and the east. Development in the area will include an extension of Durham College / UOIT; local commercial centres containing principally retail development; industrial development which will lie south of the future Highway 407; low, medium and high density residential areas; and green space and recreational areas. The area is expected to support 33,000 people in the residential areas. This number does not include student housing which will be developed on Durham College / UOIT land. This area is largely agricultural or open space at this time. There is no Municipal Substation (MS) in the area and the feeders which exist are nearing capacity and cannot be built any longer without impacting system reliability and power quality. To service the new load, OPUCN proposes to build a new MS Station in 2008 (please refer to Exhibit 2, Tab 3, Schedule 3). Initially it will be built with one transformer capable of supporting three feeders. When load increases the station can be expanded with one more transformer to serve three feeders, for a total capacity of two transformers and six feeders.

1.2 Engineering Load Forecast

The OPUCN distribution system currently consists of 46 - 13.8 kV feeders emanating from 8 - 44 to13.8 kV Municipal Substations. There are also 12 - 44 kV OPUCN owned feeders emanating from 2 - 230 to 44 kV Hydro One owned Transmission Stations. OPUCN maintains 1,250 km of overhead circuits supported by 11,907 poles, 999 km of underground circuits, 6,286 distribution transformers, and 126 underground maintenance chambers.

At least once a year the OPUCN Engineering department forecasts system load utilizing the following procedure:

1. Gather five years of historical load data. This is normalized to establish averages.
2. Use this information to calculate load growth for the system as a whole. At this point there is no indication of where load growth will appear on the system.
3. Add development information for specific areas of the City from the City of Oshawa's development plan.
4. Layer in specific project data received from customer projects. A typical example would be the construction of the regional courthouse being built in Oshawa.

5. Use station and feeder loading information from the SCADA system to identify areas where the distribution system needs enhancement or expansion to accommodate growth in specific parts of the system.
6. Enter the above data into the load forecasting tool software in order to establish the predicted, weather normalized load forecast for the distribution system and feeders.

This process identifies feeders and transformers that are at or near capacity. Load can be transferred to other feeders within a station or in a station nearby, or a new feeder or substation may be built to maintain capacity, reliability, and power quality. The preferred solution is to transfer load to feeders which are not at capacity and are not expected to be at capacity for some time. The distance of the load transfer is important because if the feeders get too long system losses increase and voltage problems develop leading to decreased reliability and degradation of power quality. If it is not possible to transfer load to a nearby feeder a new feeder and eventually a new municipal transformer station must be built to accommodate the load growth.

The current engineering load forecast at the 44 kV transformer station level is provided for reference below:

STATION	SUMMER 10-DAY LTR (MW)	2003	2004	2005	2006	2007	2008	2009	2010	2012	2014	2016	2018
Wilson T.S	160	145	139	149	152	155	160	160	160	160	160	160	160
Thornton T.S	**72**	64	66	68	71	68	72	72	72	72	72	72	72
Proposed T.S (2009)							8	13	21	28	38	48	60
Total	**232**	**209**	**205**	**217**	**223**	**223**	**240**	**245**	**253**	**260**	**270**	**280**	**292**

By taking 2% load growth in to account

Feeder Requirement:
Longer term requirements are for 5 feeders in 2022 and 6 in 2026.

Note: Hydro One TS is not available until 2009

2.0 Assessment / Audit / Inspection Results

Regular inspections of the condition of the OPUCN distribution system are conducted by qualified staff members to determine the operating condition of various components of the system. The Ontario Energy Board's Distribution System Code specifies, as a minimum, the frequency of these inspections. Information is recorded from these inspections and utilized in determining capital replacement projects.

On a periodic basis OPUCN hires an external consultant to perform an asset condition assessment to assess the condition of the distribution system in order to ensure a continued safe and reliable supply of electricity to OPUCN customers. In addition, the ESA audits OPUCN annually to ensure compliance with Ontario Regulation 22/01. The information from these audits and assessments is very useful and is utilized in the capital planning process.

The latest third party asset condition study, undertaken in 2006, was performed by Kinetrics Inc. and included a thorough assessment of the condition of the distribution system (report is at Appendix D). Kinectrics generally concluded that the OPUCN distribution system was increasing in size due to development in Oshawa and that the existing plant is nearing the end of its service life. For these reasons OPUCN must maintain an aggressive capital program in order to ensure the continued safe and reliable delivery of electricity to the citizens of Oshawa.
All capital projects identified under Assessment / Audit / Inspection Results are evaluated using the Asset Investment Tool to be described below.

3.0 Other Projects

Not all large capital projects are initiated by the need to maintain and extend physical distribution system plant. Other capital projects and needs can be identified from time to time by Customer Service, Information Technology, Fleet, and Facilities Management departments.

For 2008, one such project identified that fits in the "other projects" category is the need to replace the existing System Control and Data Acquisition (SCADA) system, as described at Exhibit 2, Tab, 3, Schedule 3.

Other Projects are evaluated using the Asset Investment Tool described next.

4.0 Asset Investment Tool

OPUCN utilizes an Asset Investment Tool developed by Metsco Inc. to create a list of optimized capital projects. The Metsco developed tool is based on an asset investment strategy whereby strategic business objectives were determined by OPUCN and a relative weighting based on importance assigned to each objective. Capital projects are then scored and evaluated through the tool to produce an optimized list of projects based on risk, value and probability of occurrence to OPUCN.

In the first step towards implementing this tool, OPUCN determined its strategic business objectives. These business objectives were accepted as the foundation to develop a project assessment framework. They were then weighted for importance. Each strategic business objective is described by specific performance attributes. The table below shows the business objectives, their weightings, and the performance standards by which OPUCN evaluates individual projects.

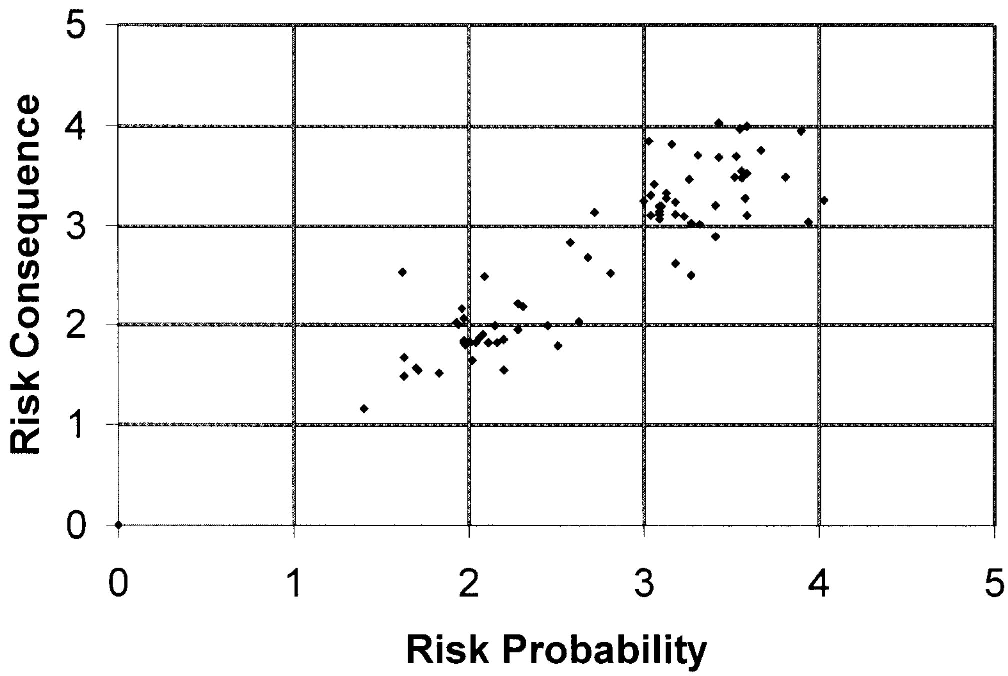
Strategic Objectives

Strategic Objective	Weighting	Performance Indicators
Investment Effectiveness	16%	Calculated modified internal rate of return
Reliability	10%	Quantitative scores for indices for reliability (System Average System Availability Index – ASAI) and Momentary Index
Brand Image	5%	Quantitative data for Customer Satisfaction Index
Safety	30%	Qualitative data for employee and public safety
Compliance	28%	Qualitative data for legal, regulatory, and environmental compliance
Operation Excellence	11%	Qualitative scores for System Operability, Process/Productivity Improvements and Asset Health Implications

The Metsco developed Asset Investment Tool utilizes the above methodology and one of the outputs from the tool is a scatter graph which relates risk probability to risk consequence for each project. Every project has a degree of risk associated with not performing the work. The project also has a degree of probability of something undesirable occurring should the work not be performed. The scatter graph provides a quick picture of where projects fall with regards to how risky they are and how probable something undesirable could occur if the work associated with the project is not performed. Projects located in the upper-right quadrant deserve the most attention because they have the highest values of risk and probability. A second output from the

Metsco Asset Investment Tool is a prioritized list of projects in ascending order based on risk and probability.

A sample scatter graph is provided for reference below.



Asset Investment Strategy Approach:

The Asset Investment Strategy (AIS) approach distinguishes between two classes of project benefits: risk mitigation and value creation.

OPUCN has performed a risk assessment and established OPUCN's risk tolerance threshold, used to identify an acceptable level of risk. The **risk mitigation** benefit ensures that the risk associated with a project is below that tolerance threshold. If the project is deferred, due consideration is given to communicating and re-evaluating the consequences associated with that deferral.

Assessing the **value creation** for a project ensures that business objectives identified above are met. This assessment also allows for tracking performance value creation against expectations.

The AIS provides an organized and coordinated approach to link strategies, actions and investment opportunities to business outcomes. This ultimately translates into a well-defined asset strategy for value-added and risk-informed selection of investment options.

Projects identified by the System Planning Process, Assessment, Inspection and Audits, and Other Projects are input into the Asset Investment Tool. Specifically excluded from individual consideration in this process are service orders, minor field maintenance (non-program work where no system reconfiguration is required), and any minor load additions. However, these items are analyzed and monitored as aggregate. All identified projects/programs are modeled and analyzed by the Asset Investment Tool. Once defined all work is integrated into an asset plan containing all work on the system: maintenance, construction, programs, equipment, vehicles, IT and office. The asset plan is a rolling plan with a horizon of one to five years for active planning, but does include known events beyond the planning horizon. The asset plan is dynamic and is continuously monitored and analyzed.

The projects included in this Application have all been evaluated using the Asset Investment Tool. All have been identified as high priority and the working capital projection was calculated partially by including the costs of these projects. More information on these projects is at Exhibit 2, Tab 3, Schedule 2.

5.0 Annual Capital Plan

The result of the application of these tools and processes is the creation of a prioritized, risk-assessed, cost-effective capital program. Exhibit 2, Tab 3, Schedule 2 identifies the components of the capital programs undertaken or proposed for 2006 Actual, 2007 Bridge, and 2008 Test year. Exhibit 2, Tab 3, Schedule 3 presents a materiality analysis of those projects whose costs are above the materiality limit of $440,000.

CAPITAL BUDGET BY PROJECT TYPE AND PROJECT

The following projects are included in the capital budgets for 2006 Actual, 2007 Bridge and 2008 Test year. Capital projects can be divided into enhancements, expansions, and connections. OPUCN uses the following definitions of these terms when classifying a capital budget item.

- **Expansion:** Expansion of distribution system on public road allowance, for example subdivisions
- **Connection:** Connection of distribution system assets on private property, for example a new business which builds its own building
- **Enhancement:** Rebuild of existing distribution system, for example pole line, underground primary cable replacement

	System Planning		Reliability/ Safety		Individual/ Special Projects		Total	
	$	Number		Number		Number		Number
2006								
Enhancement	23,724	1	3,905,888	79	25,342	2	3,955,033	82
Expansion	(95,064)	30	0	0	0	0	(95,034)	30
Connection	1,356	47	0	0	0	0	1,403	47
Meters	0	0	0	0	249,336	1	249,336	1
Vehicles	0	0	0	0	181,804	11	181,804	11
Special/ Individual Projects	0	0	0	0	119,140	14	119,140	14
Total	(69,984)	78	3,905,888	79	575,623	28	4,411,526	185
2007								
Enhancement	2,706,942	27	3,221,893	43	0	0	5,928,808	70
Expansion	1,132,357	26	0	0	0	0	1,132,383	26
Connection	0	0	0	0	0	0	0	0
Meters	0	0	0	0	360,730	1	360,730	1
Vehicles	0	0	0	0	315,110	1	315,111	1
Special/ Individual Projects	0	0	0	0	837,403	25	837,403	25
Total	3,839,298	53	3,221,893	44	1,513,243	29	8,574,435	123

2008								
Enhancement	3,484,526	8	3,253,891	24	0	0	6,738,417	32
Expansion	900,000	1	0	0	0	0	900,001	1
Connection	25,000	1	0	0	0	0	25,001	1
Meters	0	0	0	0	375,000	1	375,000	1
Vehicles	0	0	0	0	350,000	1	350,000	1
Special/ Individual Projects	0	0	0	0	1,483,425	21	1,483,425	21
Smart Meter Investment	0	0	0	0	0	0	0	0
Total	4,409,526	2	3,253,891	24	2,208,425	23	9,871,844	57
2009 (to May 1, 2009)								
Enhancement	103,333	3	575,000	14	0	0	678,350	17
Expansion	217,000	1	0	0	0	0	217,001	1
Connection	8,333	1	0	0	0	0	8,334	1
Meters	0	0	0	0	185,000	1	185,003	1
Vehicles	0	0	0	0	0	0	0	0
Special/ Individual Projects	0	0	0	0	32,808	4	32,812	4
Smart Meter Investment	0	0	0	0	0	0	0	0
Total	328,667	5	575,000	14	217,808	5	1,121,501	24

Total Expenditures	8,507,506	138	10,956,672	161	4,515,099	85	23,979,306	389

MATERIALITY ANALYSIS ON CAPITAL ADDITIONS

OPUCN used a materiality threshold of $440,000, being approximately 1% of total net fixed assets in accordance with the Filing Requirements for Transmission and Distribution Applications. Descriptions of capital additions that exceed this materiality threshold are set out below.

2006 Actual Year

There were no capital additions in 2006 that exceeded the materiality threshold.

As mentioned at Exhibit 2, Tab 1, Schedule 1, in 2006 there were two large construction projects that involved substantial construction resources of OPUCN. These were the 401 Interchange rebuild and the construction of the General Motors Sports Centre. Both of these projects were paid entirely by contributed capital and as such had no impact on net fixed assets and therefore rate base. Because staff was so heavily involved with these projects no other large capital projects were undertaken in 2006.

2007 Bridge Year

OPUCN engaged in two capital projects in 2007 that exceeded the materiality threshold. These projects are described below.

i) Overhead Circuit Upgrade: Durham College to Wilson

Start Date: September, 2007

In-Service Date: December, 2007

Project Type: Enhancement

Project Cost: $729,400

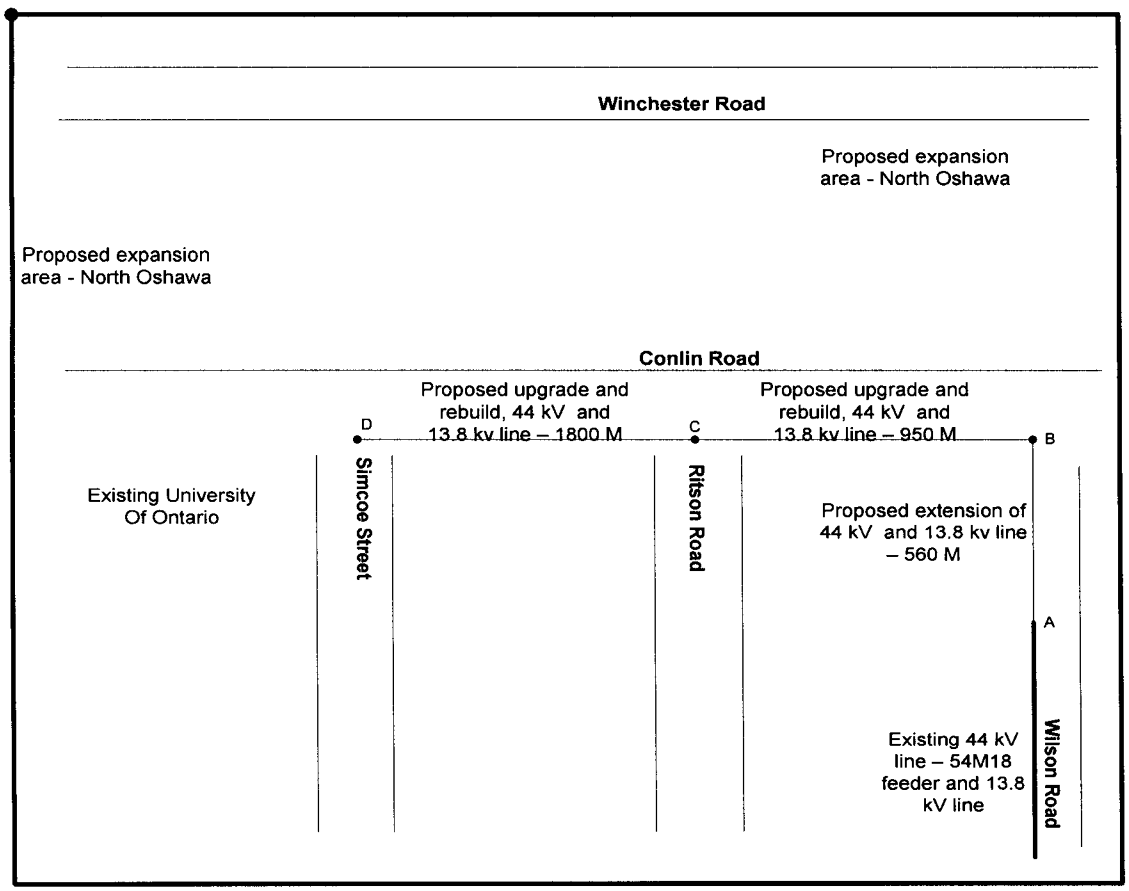
Project Description:

The University of Ontario Institute of Technology ("UOIT") and Durham College have requested an additional 8 MW of capacity to power a wind tunnel project currently under construction. This additional load is expected to be present during 2008. At present UOIT / Durham College and one half of OPUCN MS7 is supplied by the 44 kV, 54M1 feeder. The 54M1 feeder is nearing capacity and with the additional loading expected at UOIT and Durham College, along with the need for additional capacity to serve residential, commercial and industrial load growth in the Windfields planning area this overhead circuit upgrade is required.

In order to address future load growth demand and the identified supply capacity issue, OPUCN proposes reinforcing the system by rebuilding and upgrading the existing overhead line from Conlin Road / Durham College to Wilson Road to accommodate 44 kV and 13.8 kV circuits. The result will be a new 44 KV feeder and two 13.8 kV feeders in order to meet the increased loading requirement in this area of the distribution system.

The work involved is a line upgrade of approximately 3.5 km. Existing 45' poles will be replaced by 65' / 70' poles to accommodate the new 44 kV circuit and two 13.8 kV cicuits and secondary supply.

The following line diagram illustrates the proposed project.



The forecasted cost is as follows.

Mhours	Labour	Material	Vehicle	Contract	Eng.	Total Cost
3,240	$277,500	$300,000	$75,000	$22,500	$54,000	$729,000

There are a number of benefits associated with this project, including:

- The 44 kV circuit will provide the necessary capacity to UOIT and Durham College to accommodate the load growth associated with the wind tunnel project
- The 44 kV circuit will also provide connection for one half of the new OPUCN MS #9 substation
- The 13.8 kV circuit will provide the necessary infrastructure (poles) for a future 13.8 kV feeder from the new OPUCN MS #9 substation
- The 13.8 kV feeder will reduce the length of the current 7F4 and 15F2 feeders that currently serve the rural area north of Oshawa

This project is required for a number of reasons, including:

- Capacity relief to existing distribution system
- Ensure adequate capacity and reliable supply to UOIT/Durham College and northern Oshawa development
- Provide interconnection to proposed MS-9 and infrastructure development for MS-9
- Comply with regulatory requirements to connect load.

ii) 2007 Overhead Pole Replacement Program

Start Date: March, 2007

In-Service Date: December, 2007

Project Type: Enhancement

Project Cost: $545,400

Project Description:

The OPUCN distribution system includes over 12,000 poles to support approximately 1,250 kilometers of overhead circuits. The reliability of any one line segment is equal to that of the structure with the lowest reliability level (the structure that is the weakest link in the chain). Wood poles deteriorate over time and when their strength is reduced to the point that there is a risk of failure under adverse weather conditions, they are deemed to be at end of life.

In June 2004, a major power outage occurred on the OPUCN distribution system. There were about 1,000 customers affected, some for almost twenty-four (24) hours. The root cause of the failure was an internally damaged pole (due to the action of carpenter ants) that resulted in a cascade failure of several poles on a feeder. The event could have been prevented if a damaged pole had been identified and replaced at an earlier stage.

This incident triggered a comprehensive pole testing program at OPUCN carried out by PoleCare International Inc. The rational behind the pole-testing program was to plan reliability centered preventive maintenance and replacement programs. All wood poles in the system were tested under this program. A detailed finding for each pole has recorded the extent of damage and reason(s) for it. Based on the pole-testing program approximately 2.5 % of poles have been identified for replacement to maintain the safety and reliability of the distribution system. Poles identified for replacement were found to have extensive degradation at or below ground level, carpenter ant infestation, extensive mechanical damage such as cracks, decay and pole top feathering and split. PoleCare International identified 190 poles requiring replacement.

OPUCN's pole replacement program is based on the findings of the pole testing program.
By considering the physical location of the pole and work involved, these poles are separated in three categories – Easy, Medium and Hard. Poles identified as easy to replace have less than 4 hours of work required (having secondary and/or 1 phase line). Medium poles will take 4 to 12 hours to replace (Transformer and/or secondary and/or 1 phase Primary and/or dead end). Hard poles will take more than 12 hours (3 phase Secondary and/or 44kv and 13.8 kV and/or Primary, Dip or dead end etc.)

Identified Poles to be Changed	**Easy**	**Medium**	**Hard**	**Total**
Total Number of the pole to be replaced	87	29	74	190
Average Replacement Cost Per Pole	3000	5800	9000	
Expected time to change the pole in Days	43.5	29	148	220.5
Estimated cost	261,000.00	168,200.00	666,000.00	1,095,200.00
Budget 2007: for replacement of the 50% of the pole (94 poles) = $545,000				
Budget 2008: for replacement of the rest of the pole (96 poles) = $550,000				
Total Pole replacement cost for the year 2007 - 2008: $1 095 000				

OPUCN's pole-replacement program is required for a number of reasons, including:

- Failure to implement the program would result in unsafe conditions for OPUCN's employees and the public. Safety is a top priority at OPUCN.
- Failure to implement the program could seriously affect system reliability.
- The program ensures compliance with Ontario Regulation 22/04 which provides:

  > 4(2) All distribution systems and the electrical installations and electrical equipment forming part of such systems shall be designed, constructed, installed, protected, used, maintained, repaired, extended, connected and disconnected so as to reduce the probability of exposure to electrical safety hazards.

- The program is required to maintain the OEB's service quality standards.

OPUCN is implementing its pole-replacement program in a cost-effective manner by efficiently utilizing its resources wherever possible. For example, if crews are working in the vicinity of poles identified for replacement, they will replace the poles in conjunction with the other work to avoid having to return. Similarly, if OPUCN's crews identify any other hardware issues while replacing poles, they will attend to those issues at the site rather than returning at a later date.

2008 Test Year

OPUCN intends to undertake two capital projects and a special project (SCADA replacement) in 2008 that will exceed the materiality threshold of $440,000. These projects are described below.

i) Building a new Municipal Substation (MS9) (First Half)

Start Date: January, 2008

In-Service Date: July, 2008

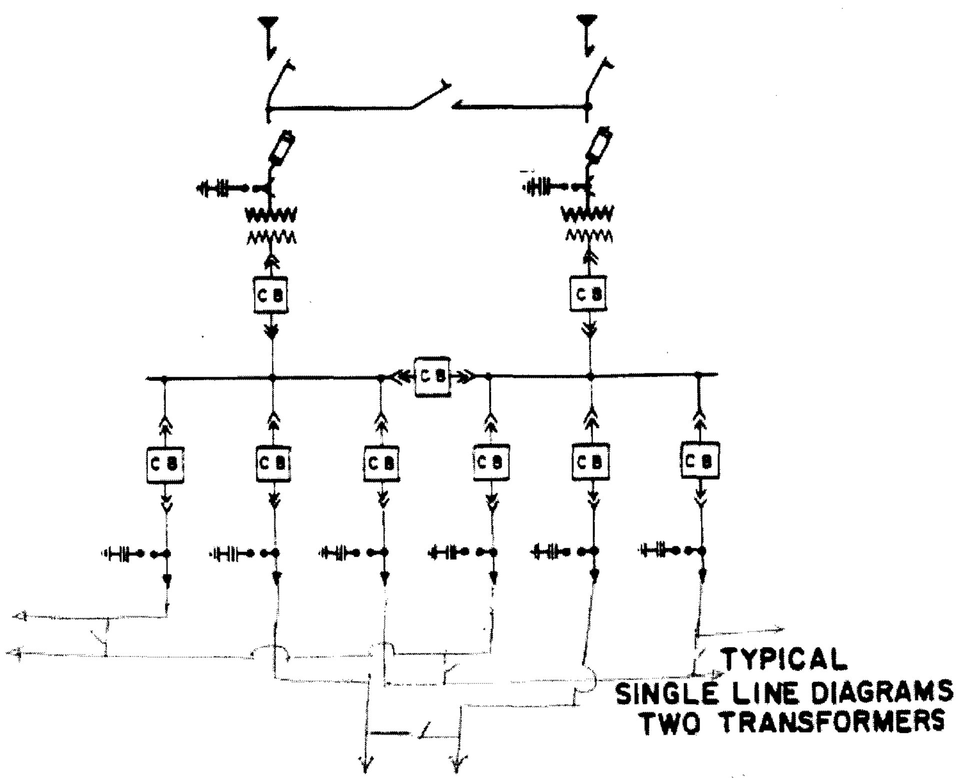
Project Type: Expansion

Project Cost: $2,000,000

Project Description:

Distribution system infrastructure development is needed in the OPUCN service territory to meet future load growth and to increase reliability. As described at Exhibit 2, Tab 3, Schedule 1, the City of Oshawa has a five year development plan which it developed in 2005. OPUCN uses this plan to identify areas of growth within the City which will need infrastructure additions or enhancements. According to the City's development plan, the area that will be developed within the next few years covers an area of approximately 1,000 hectares in Northern Oshawa. It is expected that development in this area will include the addition of approximately 33,000 new residential customers, an expansion of Durham College / UOIT, and a commercial centre. This land. This area is largely agricultural or open space at this time, and construction of residential subdivisions and the extension of Durham College / UOIT has already commenced.

Currently, this area of northern Oshawa is supplied by two longer feeders (7F4 and 15F2). Based on outage analysis data, these feeders experience a significant number of outages and have limited remaining capacity. Therefore, to service the new load, OPUCN proposes to build a new municipal substation in 2008 to meet the increased demand in a safe, reliable, and cost-effective manner.



The station arrangement of the proposed MS is shown in the above figure. The primary distribution voltage of 13.8 kV will be stepped down using two 44 /13.8 kV, 20 MVA delta/wye grounded type Power Transformers. All the substation components will be installed in Metal cubicles to enhance safety. The feeder breaker and transformer breakers which will be installed are of latest technology, Vacuum type circuit breaker. The transformer and feeder protection scheme will be secured by implementing GE Digital relays for each cell inside the substation. The additional switchgears will provide for rapid load transfers between transformer banks and incoming 44 kV feeders and outgoing 13.8 kV feeders for reliability and service security requirements. Initially one 20 MVA power transformer will be installed which will allow the egress of three 13.8 kV feeders to supply the north growth in Oshawa. When load increases in the future the station can be expanded with one more transformer to serve an additional three feeders, for a total capacity of two transformers and six feeders. Each feeder will be able to supply a maximum average peak load of 7.5 MVA.

OPUCN considered extending existing feeders to northern Oshawa as an alternative to meet the pending growth in that area, but dismissed that alternative for the following reasons. A total of 223 MW load in the Oshawa area is currently supplied by 46 distribution feeders from 8 municipal substations. The existing distribution facilities at OPUCN have already reached their capacity. Even if there were capacity on OPUCN's system, longer feeders are not a viable solution for the pending growth in northern Oshawa since they would lead to increased distribution line losses, and compromised reliability due to: increased voltage problems;

increased outages; lack of backup supply; and imbalanced loads. The proposed MS would be sited in a relatively central area of the pending load to help keep feeder lengths relatively short. Shorter feeder lengths will decrease distribution losses and improve voltage profile and reliability. The new MS will also enhance supply capacity by facilitating new feeder egress and reconfiguration of existing distribution feeders.

In order to construct the proposed MS in a cost efficient manner, OPUCN will initiate an RFP process consistent with OPUCN's purchasing policy set out at Exhibit 4, Tab 2, Schedule 5. In order to get some idea of what reasonable RFP pricing would be, OPUCN held consultations with contractors with relevant expertise and explained the scope of the work. The scope of work includes receiving approvals from all relevant authorities, construction of an indoor substation, mechanical design, electrical design, soil testing and grounding, and an oil contamination study. These consultations resulted in an initial estimate of $2,000,000 for the project.

Not proceeding with this project would result in failing to meet the demands of load growth.

ii) SCADA Upgrade

Start Date: October, 2007

In-Service Date: July, 2008

Project Cost: $498,000

Project Description:

Supervisory Control and Data Acquisition (SCADA) systems are used to monitor and control operating conditions of distribution systems. SCADA enables utility personnel to see on a PC monitor what's happening on the system in real time. OPUCN's existing SCADA system is based on technology which is more than 20 years old and has limited operational capabilities. The system is obsolete and has been progressively failing over the years and replacement parts are no longer available. In early 2006 the SCADA system failed, resulting in ten days of operations without automatic communication between the substations and the control room. OPUCN maintained communications by having linemen physically on site at each substation, each communicating with the control room using the OPUCN radio system. Real time data which is vital for the proper operation of the distribution system was lost during the period

Replacement of the existing system is necessary for the real time control of the distribution system, to promote better communication between outside staff and the control room, to minimize outage durations, and to provide enhanced control of the distribution system through the use of currently available technology. The new technology will provide improved functionality and support, and more informative and sophisticated graphics and will work with a user friendly Microsoft Windows interface, thus decreasing training times and helping to eliminate operator error. To summarize, the benefits of this capital investment include:

- A new SCADA system will allow OPUCN to access the SCADA system anywhere on the local area network, as well as remotely, providing access to many users at all times of the day or night even during those hours when the control room is not staffed. The old system restricted access to a limited number of users who had to be physically in the control room. The new system will provide access to more staff members and allow remote viewing and operation of the distribution system;
- A Windows based applications will offer superior graphics, user interface, and reporting;
- A new SCADA system with improved functionality will be used to automatically activate switches, re-closers, breakers, and relays; automate fault restoration; display alarms and system maps; obtain data for trend analysis and load forecasting;
- OPUCN can respond much faster and more effectively to emergency situations because data is captured and analyzed before, during, and after each event;
- Operators can respond quickly to alarms and perform shutdowns/re-routing without sending personnel to the scene;
- When a customer calls to report a power quality problem, the point of origin of the voltage loss is captured immediately;
- The layout of circuits via Graphical User Interface for field personnel increases response times dramatically.

- The new SCADA system will increase grid reliability and allow OPUCN to better serve business and residential customers.
- The new SCADA system is a part OPUCN's commitment to emergency preparedness to meet any power shortages due to extreme weather conditions and distribution system line or equipment failure.
- The new SCADA system will provide better management of historical data and events which can be effectively used for long term and short term planning of the distribution system and scheduling preventive maintenance.
- Provide real-time distribution system operating information, including alarms for outages and disturbances, in support of existing distribution system operating activities and initiatives.

At the time of filing, the results of the RFP process were not available. The price is an estimate and is based on discussions with qualified vendors concerning their experiences with the installation of similar systems with other utilities. The RFP will be for a turnkey system and includes the following:

- Dual stations/servers to supply backup
- Configuration of the system to reflect OPUCN's system
- Integration of the new system into all the substations to facilitate real time reporting
- Commissioning the system once installed and training OPUCN staff in the efficient operation of the system.

iii) 2008 Overhead Pole Replacement Program

Start Date: March, 2008

In-Service Date: December, 2008

Project Type: Enhancement

Project Cost: $550,000

Project Description:

This project is a continuation of the project started in 2007. As indicated in the Pole Replacement Costs table earlier in this document, the pole replacement program involves the replacement of 94 poles in 2007 and 96 poles in 2008.

The same justification for the project as outlined in the 2007 year applies.

CAPITALIZATION POLICY

The purpose of capitalizing expenditures is to provide for an equitable allocation of cost among existing and future customers. A capital expenditure is defined as any significant expenditure incurred to acquire, construct or develop land, buildings, plant, engineering structures, machinery and equipment expected to provide future economic benefits to the company and its customers. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. A"betterment" includes increasing the capacity of the asset, lowering associated operating costs, improving the quality of output or extending the asset useful life. For this industry, capital assets also include grouped assets or readily identifiable assets. Capital assets include electric plant, transmission, generation and distribution facilities, meters, vehicles, office furniture, computer equipment and other equipment.

Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

Whether capital assets are purchased or constructed by the Corporation they are stated at cost and include contracted services, material, labour, engineering costs and overheads, including associated interest costs.

1.1 Betterments Versus Repairs

As noted previously a betterment is defined as the cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced when there is an increase in physical output or service capacity, associated operating costs are lowered, the useful life is extended, or the quality of output is improved. For example a refurbished transformer in which the service potential has been enhanced should be capitalized. Further, if during an underground fault repair, the work results in a reconfiguration of the asset that will clearly benefit future periods, there may be an argument to capitalize the work.

A repair is defined as the cost incurred in the maintenance of the service potential of a capital asset.

Major Repairs / Cost Deferrals

There may be instances where the cost of a non-capital expenditure may be deferred or in effect capitalized. For example a major infrequent repair on an existing asset, a regulatory process resulting in a major cost to the operating plant without actual replacement or betterment, and repairs to property loss resulting from extraordinary events such as an ice storm are costs which may be eligible for deferment. Normally GAAP would require such repairs be expensed. However in a rate regulated environment, where such repairs would cause a significant rate impact, there is an argument to consider capitalization and subsequent amortization to operations over a reasonable number of years.

1.2 In the event of uncertainty surrounding the determination of a cost to be capital or operating or the application of materiality limits, if any exist, the Financial Analyst should be consulted.

Capital Asset Determination Procedure

In order to decide whether a transaction results in a capital expenditure or in an operating expense the following procedural test should be applied.

If the answers to either of the following questions is "Yes", then the work performed or the item purchased should be classified as a capital asset.

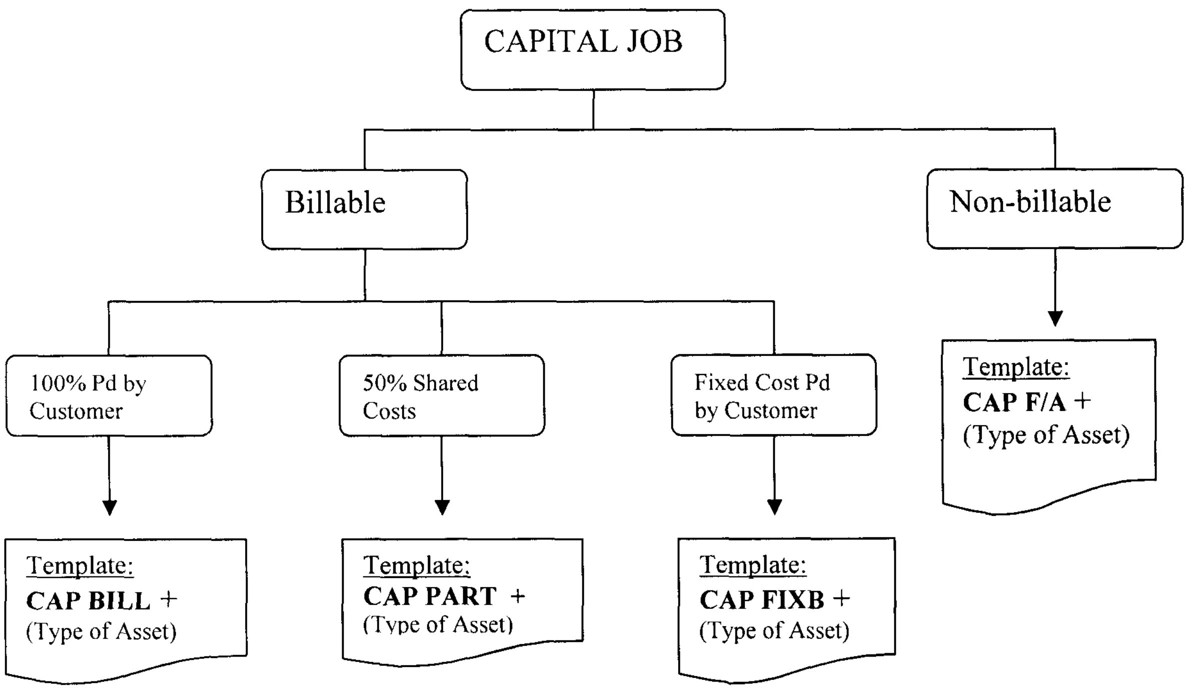
- Does the work performed or item purchased result in an asset of property, plant or equipment that will provide a benefit to the company lasting beyond one year?

- Does the work performed or item purchased improve or better an existing asset? Specifically does the work performed extend the life, enhance the reliability, increase the capacity or output or lower the associated operating costs of the existing asset?

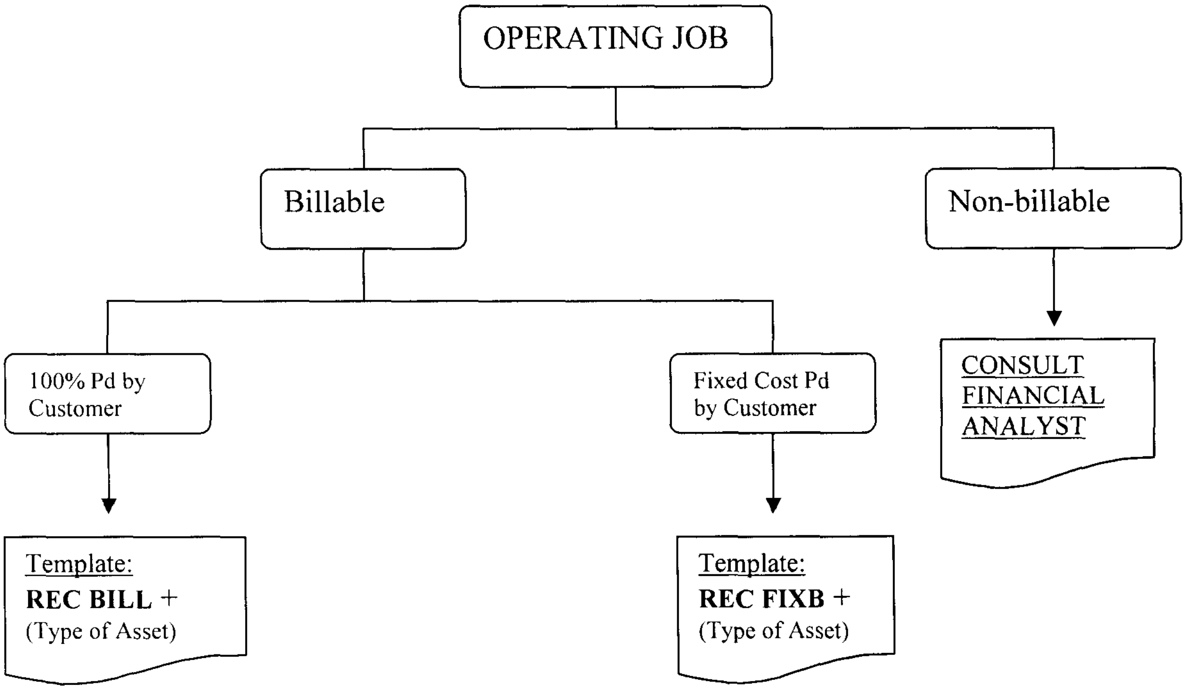
A flow chart template (Appendix A) has been developed to aid the Tech Services group to select the correct templates when setting up a capital or operating job.

In addition, the Financial Analyst position will review all green job order initiation sheets for the appropriate job template before input to the system.

Appendix A



Note: Type of Asset refers to OH (Overhead), UG (Underground), SUBSTN (Substations), MT (Meters), VEH (Vehicles)


OPERATING JOB
Billable
Non-billable
100% Pd by Customer
Fixed Cost Pd by Customer
CONSULT FINANCIAL ANALYST
Template: REC BILL + (Type of Asset)
Template: REC FIXB + (Type of Asset)

ALLOWANCE FOR WORKING CAPITAL: CALCULATION BY ACCOUNT

	2006 Actual	15%	Allowance for Working Capital	2007 Bridge	15%	Allowance for Working Capital	2008 Test	15%	Allowance for Working Capital
Operation (Working Capital)									
5005-Operation Supervision and Engineering	273,773		41,066	372,516		55,877	384,274		57,641
5010-Load Dispatching	-		-	-		-	-		-
5012-Station Buildings and Fixtures Expense	-		-	-		-	-		-
5014-Transformer Station Equipment - Operation Labour	-		-	-		-	-		-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-		-	-		-	-		-
5016-Distribution Station Equipment - Operation Labour	-		-	-		-	-		-
5017-Distribution Station Equipment - Operation Supplies and Expenses	-		-	-		-	-		-
5020-Overhead Distribution Lines and Feeders - Operation Labour	225,952		33,893	(81,483)		(12,222)	109,267		16,390
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	(210,688)		(31,603)	(182,304)		(27,346)	(165,705)		(24,856)
5030-Overhead Sub transmission Feeders - Operation	-		-	-		-	-		-
5035-Overhead Distribution Transformers- Operation	-		-	-		-	-		-
5040-Underground Distribution Lines and Feeders - Operation Labour	7,751		1,163	7,751		1,163	7,984		1,198
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	1,047		157	193		29	199		30
5050-Underground Sub transmission Feeders - Operation	-		-	-		-	-		-
5055-Underground Distribution Transformers - Operation	-		-	-		-	-		-
5060-Street Lighting and Signal System Expense	-		-	-		-	-		-
5065-Meter Expense	83,869		12,580	52,211		7,832	127,559		19,134
5070-Customer Premises - Operation Labour	-		-	-		-	-		-
5075-Customer Premises - Materials and Expenses	-		-	-		-	-		-

5085-Miscellaneous Distribution Expense	(440,282)		(66,042)		(127,912)		(19,187)		(20,840)		(3,126)
5090-Underground Distribution Lines and Feeders - Rental Paid	-		-		-		-		-		-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-		-		-		-		-		-
5096-Other Rent	-		-		-		-		-		-
Sub-Total	(58,578)		(8,787)		40,972		6,146		442,737		66,411
Maintenance (Working Capital)											
5105-Maintenance Supervision and Engineering	246,245		36,937		218,220		32,733		225,076		33,761
5110-Maintenance of Buildings and Fixtures - Distribution Stations	6,773		1,016		19,891		2,984		20,487		3,073
5112-Maintenance of Transformer Station Equipment	-		-		-		-		-		-
5114-Maintenance of Distribution Station Equipment	127,372		19,106		129,470		19,421		133,354		20,003
5120-Maintenance of Poles, Towers and Fixtures	503,320		75,498		477,847		71,677		492,183		73,827
5125-Maintenance of Overhead Conductors and Devices	-		-		-		-		-		-
5130-Maintenance of Overhead Services	-		-		-		-		-		-
5135-Overhead Distribution Lines and Feeders - Right of Way	-		-		-		-		-		-
5145-Maintenance of Underground Conduit	150,052		22,508		122,982		18,447		126,671		19,001
5150-Maintenance of Underground Conductors and Devices	-		-		-		-		-		-
5155-Maintenance of Underground Services	33,874		5,081		30,000		4,500		30,900		4,635
5160-Maintenance of Line Transformers	-		-		-		-		-		-
5165-Maintenance of Street Lighting and Signal Systems	-		-		-		-		-		-
5170-Sentinel Lights - Labour	-		-		-		-		-		-
5172-Sentinel Lights - Materials and Expenses	-		-		-		-		-		-
5175-Maintenance of Meters	-		-		-		-		-		-
5178-Customer Installations Expenses- Leased Property	-		-		-		-		-		-
5185-Water Heater Rentals - Labour	-		-		-		-		-		-
5186-Water Heater Rentals - Materials and Expenses	-		-		-		-		-		-
5190-Water Heater Controls - Labour											

	-	-	-	-	-	-
5192-Water Heater Controls - Materials and Expenses	-	-	-	-	-	-
5195-Maintenance of Other Installations on Customer Premises	-	-	-	-	-	-
Sub-Total	1,067,636	160,145	998,410	149,761	1,028,671	154,301
Billing and Collections						
5305-Supervision	222,974	33,446	212,111	31,817	218,582	32,787
5310-Meter Reading Expense	386,024	57,904	406,158	60,924	417,950	62,693
5315-Customer Billing	856,571	128,486	886,869	133,030	913,569	137,035
5320-Collecting	376,008	56,401	395,466	59,320	407,783	61,168
5325-Collecting- Cash Over and Short	-	-	-	-	-	-
5330-Collection Charges	-	-	-	-	-	-
5335-Bad Debt Expense	211,765	31,765	282,000	42,300	290,460	43,569
5340-Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-
Sub-Total	2,053,343	308,001	2,182,604	327,391	2,248,345	337,252
Community Relations						
5405-Supervision	109,253	16,388	105,594	15,839	169,589	25,438
5410-Community Relations - Sundry	14,861	2,229	23,200	3,480	23,896	3,584
5415-Energy Conservation	222,319	33,348	-	-	-	-
5420-Community Safety Program	208,165	31,225	276,902	41,535	285,376	42,806
5425-Miscellaneous Customer Service and Informational Expenses	455,509	68,326	478,470	71,771	521,354	78,203
5505-Supervision	-	-	-	-	-	-
5510-Demonstrating and Selling Expense	-	-	-	-	-	-
5515-Advertising Expense	-	-	-	-	-	-
5520-Miscellaneous Sales Expense	-	-	-	-	-	-
Sub-Total	1,010,108	151,516	884,166	132,625	1,000,216	150,032

Administrative and General Expenses						
5605-Executive Salaries and Expenses	480,000	72,000	480,000	72,000	480,000	72,000
5610-Management Salaries and Expenses	637,673	95,651	726,591	108,989	1,002,599	150,390
5615-General Administrative Salaries and Expenses	1,636,610	245,492	2,009,560	301,434	2,127,341	319,101
5620-Office Supplies and Expenses	167,356	25,103	165,149	24,772	170,103	25,516
5625-Administrative Expense Transferred Credit	(722,844)	(108,427)	(638,000)	(95,700)	(638,000)	(95,700)
5630-Outside Services Employed	412,248	61,837	373,008	55,951	530,198	79,530
5635-Property Insurance	62,251	9,338	104,669	15,700	116,766	17,515
5640-Injuries and Damages	100,859	15,129	153,531	23,030	175,190	26,279
5645-Employee Pensions and Benefits	439,811	65,972	455,253	68,288	476,312	71,447
5650-Franchise Requirements	-	-	-	-	-	-
5655-Regulatory Expenses	130,298	19,545	429,818	64,473	442,713	66,407
5660-General Advertising Expenses	1,300	195	1,579	237	1,626	244
5665-Miscellaneous General Expenses	63,026	9,454	64,325	9,649	66,255	9,938
5670-Rent	264,000	39,600	264,000	39,600	264,000	39,600
5675-Maintenance of General Plant	491,918	73,788	496,560	74,484	511,542	76,731
5680-Electrical Safety Authority Fees	-	-	-	-	-	-
5685-Independent Market Operator Fees and Penalties	-	-	-	-	-	-
6105-Taxes Other Than Income Taxes	387,704	58,156	393,000	58,950	345,450	51,818
Sub-Total	4,552,211	682,832	5,479,043	821,856	6,072,094	910,814
Cost of Power						
4705-Power Purchased	56,995,211	8,549,282	69,989,454	10,498,418	71,095,876	10,664,381
4708-Charges-WMS	5,776,516	866,477	7,230,646	1,084,597	7,344,951	1,101,743
4710-Cost of Power Adjustments	-	-	-	-	-	-
4712-Charges-One-Time	-	-	-	-	-	-
4714-Charges-NW	6,396,297	959,445	6,591,473	988,721	6,695,673	1,004,351

4716-Charges-CN	5,372,570		805,885		5,632,713		844,907		5,721,757		858,264
4730-Rural Rate Assistance Expense	-		-		-		-		-		-
5685-Independent Market Operator Fees and Penalties	-		-		-		-		-		-
Sub-Total	74,540,594		11,181,089		89,444,286		13,416,643		90,858,257		13,628,739
WORKING CAPITAL ALLOWANCE TOTAL	83,165,313	15%	12,474,797		99,029,481	15%	14,854,422		101650,320	15%	15,247,548

OVERVIEW AND VARIANCE ANALYSIS OF OPERATING REVENUE

1.0 Introduction

This exhibit provides the details on OPUCN's operating revenue for the 2006 Board Approved, 2006 Actual, 2007 Bridge and 2008 Test years. This exhibit also provides a detailed variance analysis by rate class of the operating revenue components.

For the 2007 Bridge year delivery rates are based on the EB-2007-0566 Rate Order, dated April 12, 2007. Delivery rates for the 2008 Test year are calculated using the proposed rates for the 2008 Test year (Exhibit 9, Tab 1, Schedule 6). Distribution revenues include throughput revenue and other revenue, as defined below. A summary of normalized operating revenues is presented in the table following

Summary of Operating Revenue

	* Small differences from other tables due to rates rounding								
	2006 Board Approved	2006 Actual	Variance from 2006 Board Approved	2006 Actual	2007 Bridge	Variance from 2006 Actual	2007 Bridge	2008 Test @ Proposed Rates	Variance from 2007 Actual
	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)	($'s)
Distribution Revenues									
Residential	9,296,581	9,433,029	(136,448)	9,433,029	9,418,901	(14,128)	9,418,901	10,901,500	1,482,598
GS <50	2,918,964	2,982,674	(63,710)	2,982,674	2,965,341	(17,333)	2,965,341	3,436,221	470,879
GS>50 kW < 1000 kW	3,385,442	3,480,717	(95,275)	3,480,717	3,415,321	(65,396)	3,415,321	3,899,281	483,961
GS>1000 kW < 5000 kW (Intermediate)	948,573	1,008,212	(59,639)	1,008,212	847,674	(160,538)	847,674	1,088,764	241,090
Large Use >5MW	846,488	678,258	168,230	678,258	657,448	(20,810)	657,448	750,610	93,162
Unmetered Scattered Load	70,873	51,612	19,261	51,612	57,039	5,427	57,039	65,336	8,297
Sentinel	3,226	1,515	1,711	1,515	3,060	1,545	3,060	3,493	434
Streetlight	154,841	277,361	(122,520)	277,361	253,358	(24,003)	253,358	297,162	43,804
	17,624,988	**17,913,378**	**(288,390)**	**17,913,378**	**17,618,141**	**(295,237)**	**17,618,141**	**20,442,367**	**2,824,226**
Other Distribution Revenue									
Late Payment Charges	200,532	198,733	1,799	198,733	198,733	0	198,733	198,733	0
Specific Service Charges	406,857	731,306	(324,449)	731,306	724,897	(6,409)	724,897	704,147	(20,750)
Other Distribution Revenue	667,938	1,084,854	(416,916)	1,084,854	1,084,854	0	1,084,854	698,776	(386,078)
	1,275,327	**2,014,893**	**(739,566)**	**2,014,893**	**2,008,484**	**(6,409)**	**2,008,484**	**1,601,656**	**(406,828)**
Total Revenue	**18,900,315**	**19,928,271**	**(1,027,956)**	**19,928,271**	**19,626,625**	**(301,646)**	**19,626,625**	**22,044,023**	**2,417,398**

Note: Please refer to Exhibit 9, Tab 1, Schedule 3, Page 2 of 5 for projected 2008 operating revenues at current rates.

2.0 Throughput Revenue

Information related to OPUCN's throughput revenue include details such as weather normalized forecasting methodology, normalized volume, and customer counts forecast tables. Detailed variance analysis on the forecast information is also provided at Exhibit 3, Tab 2, Schedules 4 and 7.

3.0 Other Revenue

Other revenues include revenues such as Late Payment Charges, Miscellaneous Service Revenues and Retail Services Revenues. A summary of these operating revenues is presented at Exhibit 3, Tab 3, Schedule 1. A variance analysis of these revenues is at Exhibit 3, Tab 3, Schedule 2.

4.0 Revenue Sharing

OPUCN has no Board approved revenue sharing program with its customers.

OVERVIEW OF CUSTOMER AND VOLUME FORECASTING

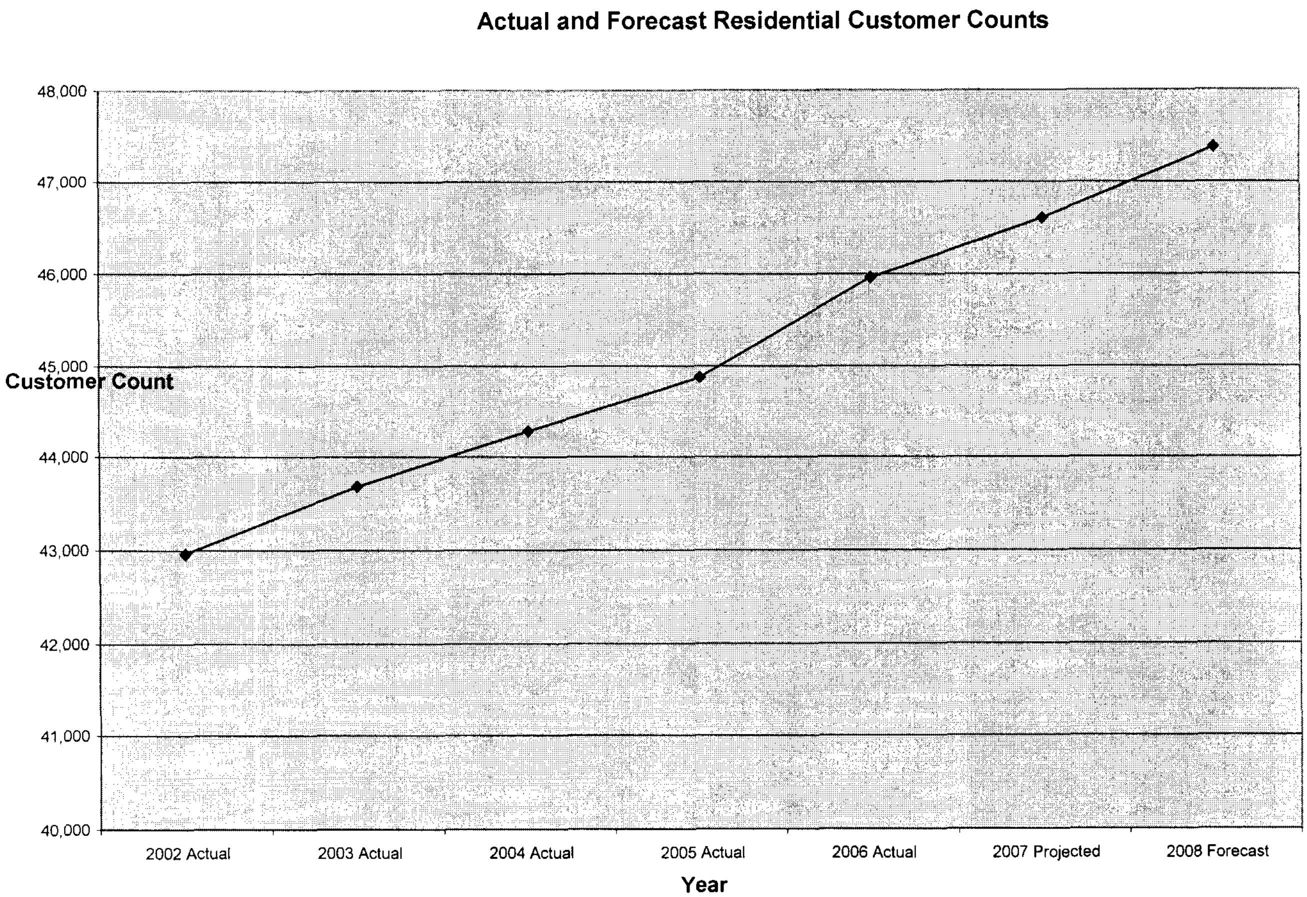
This tab discusses the methodology used to determine OPUCN's customer and load forecasts. A projection for the number of customers in each customer class is provided for both the Bridge Year (2007) and the Test Year (2008). This forecast is based on historical data for the annual number of customers in each rate class which is available for 2002 through 2006. Accurate customer data prior to 2002 is not currently available.

As required by the OEB Filing Requirements for Transmission and Distribution Applications, OPUCN is providing normalized Bridge and Test year throughput data. In order to determine a load forecast for OPUCN, it was decided to forecast volume figures by applying the HONI weatherization factor developed during the costs allocation study undertaken in 2006 to the most recent five year (2002 – 2006) average volumes for each class. These weatherized average loads for each customer class were applied to forecasted customer counts to establish loads for both the 2007 Bridge year and the 2008 Test year.

CUSTOMER COUNT FORECASTING METHODOLOGY

	2002	2003	2004	2005	2006	*2007*	*2008*
Residential	42960	43679	44280	44872	45961	*46602*	*47243*
Per cent chg		*1.7%*	*1.4%*	*1.3%*	*2.4%*	*1.4%*	*1.4%*
GS Less than 50 kW	3701	3677	3576	3641	3733	*3789*	*3845*
Per cent chg		*-0.6%*	*-2.7%*	*1.8%*	*2.5%*	*1.5%*	*1.5%*
GS > 50 kw > 1000 kw	573	545	515	524	522	*522*	*522*
Per cent chg		*-5%*	*-6%*	*2%*	*0%*	*0.0%*	*0%*
Intermediate Use (1000 - 5000 kW)	5	5	7	8	9	*8*	*9*
Per cent chg		*0%*	*40%*	*14%*	*13%*	*-11%*	*13%*
Large Use (>5000)	2	2	2	2	2	2	2
USL	291	293	295	295	301	304	305
Sentinel Lighting	38	81	77	77	77	77	77
Street Lighting Connections	9967	10072	10076	10547	10961	11340	11650
Per cent chg		*1.1%*	*0.0%*	*4.7%*	*3.9%*	*3.5%*	*2.7%*

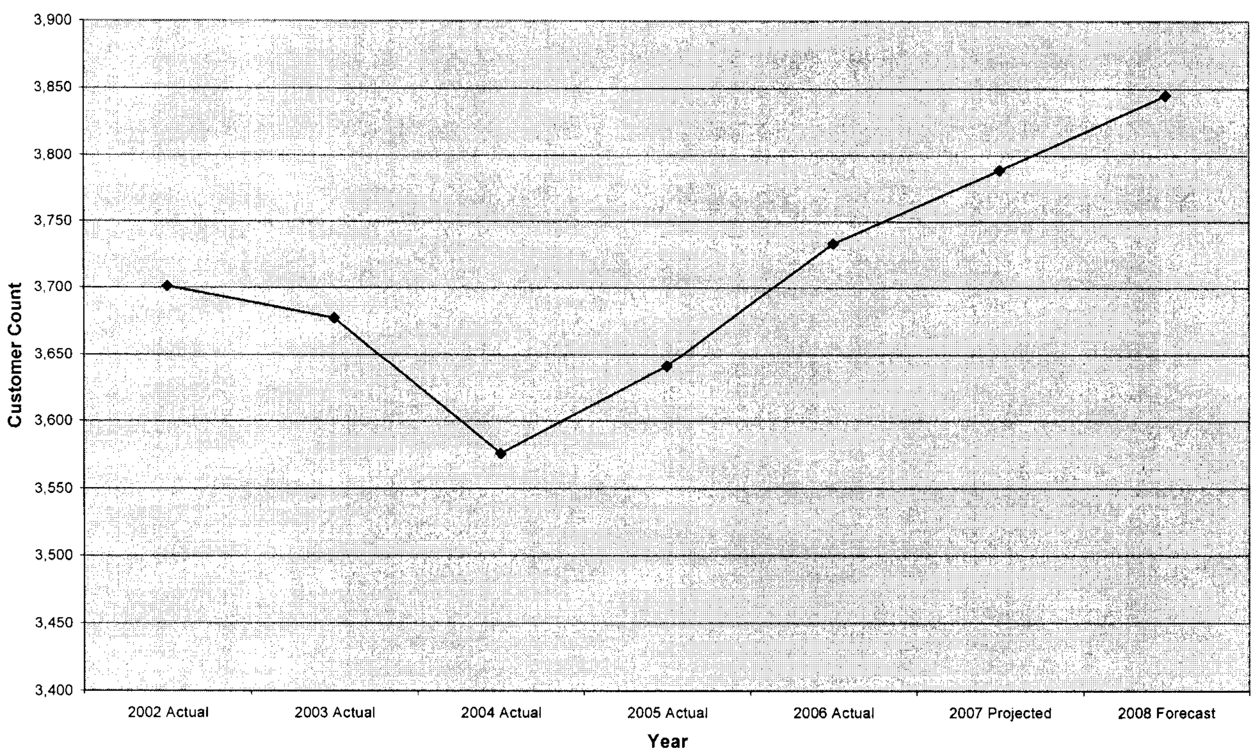
Prior to 2006, the Residential class experienced annual increases averaging 637 customers or approximately 1.5% per year. In 2006 the class experienced a growth of 1,089 units or approximately 2.4%. This growth was due to exceptional circumstances in the local economy and is not expected to be sustained in 2007 or 2008. City of Oshawa Tax projections suggest an increase of 675 new dwelling units in each of 2007 and 2008. This figure includes basement apartments which are not normally metered separately from the main dwelling unit. City of Oshawa figures suggest that 11% of all growth in residential dwelling units is an increase in the number of apartments, basement or otherwise. OPUCN is assuming that half of this apartment growth, or approximately 5% of total growth, will reflect the increase in basement apartments, which will not be metered. Applying this 5% reduction in growth estimates results in a conservative projection of (675 * 95%) or 641 new residential units in both the Bridge and Test years. OPUCN also considered other economic forecasts that show a 40 – 60% decline in residential development for year to date July 31, 2007 as compared to the same period of 2006. These forecasts are backed up by the fact that the number of new connections for 2007 shows an increase of only 1.4% to August 31, 2007. Overall, projections for customer growth have been based on conservative forecasts which suggest that customer growth rates should return to normal patterns from pre-2006 in the 2007 Bridge and 2008 Test years. The chart below shows actual and forecast growth for the residential customer class.



The GS < 50 kWclass also experienced unusually high growth in 2006. The reasons for this increase appear to have been associated with the unusually high number of residential starts in that year.

Growth for 2007 appears to be more typical. A modest amount of annualized growth has occurred during the first six months of 2007 (1.5%) which is more indicative of actual market performance during this period. OPUCN expects 2008 to be similar to 2007 and so reflects an increased annualized growth rate of 1.5%, the same as the growth rate for 2007. As with the residential class, 2006 appears to show an anomaly for customer count and growth rate for the period from 2002 to 2005 does not reflect 1.5% growth rate experienced in the first part of 2007. OPUCN is assuming a similar 1.5% growth rate for 2008, mirroring the pattern suggested for the residential class. The chart below shows growth in the GS < 50 kW customer class.

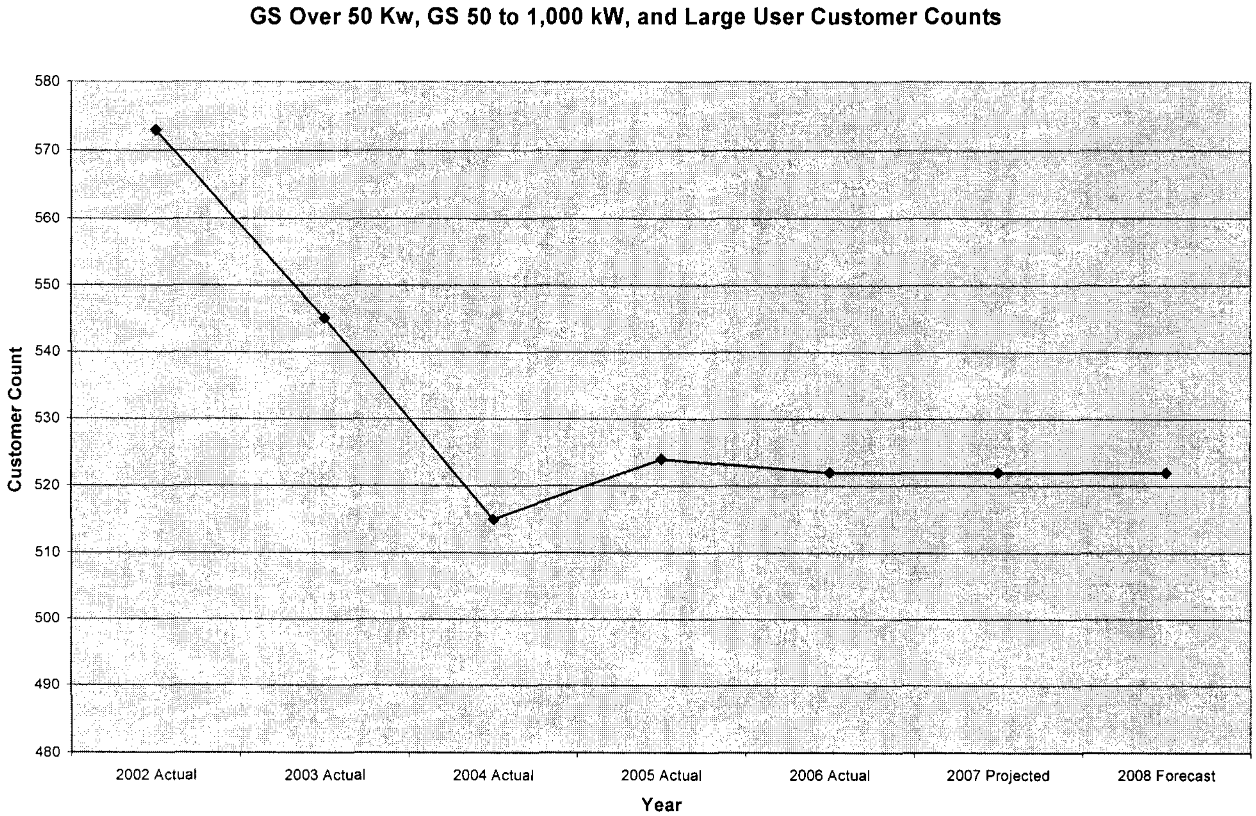
Actual and Forecast GS < 50 kW Customer Count



For the GS 50 - 100 kW and GS > 5000 kW customer classes, an annual growth rate of 0% was assumed for both 2007 and 2008. The City of Oshawa development department is aware of no new companies which would fall into this class which are considering locating in Oshawa within the next year.

For the GS 1000 – 5000 kW class, there was a reduction of one customer from 2006 to 2007 resulting in a 2007 customer count projection of eight customers. This reduction has already occurred in the customer class. Although no new customers are expected in the remainder of 2007, the new Durham Courthouse is expected to come into operation in the 2008 Test year and has been reflected in the customer count for 2008 for this class.

The following chart combines growth in the GS 50 – 1000 kW, GS 1000 – 5000 kW, and GS > 5000 kW classes. They are combined because they are all small classes and overall there is little change in customer counts for these classes over time.



Customer numbers for Sentinel Lighting and USL classes in 2007 represent the current (first half of 2007) number of connections in each of these classes. OPUCN does not expect the number of customers in the Sentinel light customer class to change within the next year and the 2007 current figures are used for 2008. Only slight growth is projected for USL in 2007 and 2008.

Growth for the Street Lighting Class is calculated based on the annual average geometric mean of growth from 2002 to the current year (2007). There is only one street lighting customer. The counts for this class refer to the number of street lights connected to the distribution system in each year.

CUSTOMER COUNT FORECAST TABLE

	2006 Board Approved	2006 Actual	Variance form 2006 Board Approved	2006 Actual	2007 Bridge	Variance form 2006 Actual	2007 Bridge	2008 Test	Variance form 2007 Actual
Customers Count									
Residential	44280	45961	1681	45961	46602	641	46602	47243	641
GS Less than 50 kW	3576	3733	157	3733	3789	56	3789	3845	56
GS > 50 kw > 1000 kw	515	522	7	522	522	0	522	522	0
Intermediate Use (1000 - 5000 kW)	7	9	2	9	8	-1	8	9	1
Large Use (>5000)	2	2	0	2	2	0	2	2	0
USL	295	301	6	301	304	3	304	305	1
Sentinel Lighting	77	77	0	77	77	0	77	77	0
Street Lighting	10076	10961	885	10961	11340	379	11340	11650	310
	58828	61566	2738	61566	62644	1078	62644	63653	1009

VARIANCE ANALYSIS ON CUSTOMER COUNT FORECAST TABLE

2006 Approved Year compared to 2006 Actual Year

Customer Class	2006 Approved	2006 Actual	Variance	% Variance
Residential	44280	45961	1681	3.8%
GS < 40 kW	3576	3733	157	4.4%
GS 50 kW – 1000 kW	515	522	7	1.4%
GS 1000 kW – 5000 kW	7	9	2	2.9%
Unmetered Scattered Load	295	301	6	2.0%
Street Lighting	10076	10961	885	8.8%

There are significant differences between the number of customers assumed in the 2006 Approved year and the number actually connected in 2006 in most of the customer classes. The only exceptions were the Large User (> 5000 kW) and Sentinel Lighting classes. The 2006 Approved figures are based on averages for 2002, 2003, and 2004. The Actual growth was driven by exceptional circumstances in the local economy in 2006 which could not be predicted from these averages and are not expected to recur. 2006 was a year of substantial economic and subdivision growth as explained earlier.

2006 Actual Year Compared to 2007 Bridge Year

Customer Class	2006 Actual	2007 Bridge Year	Variance	% Variance
Residential	45961	46602	641	1.4%
GS < 50 kW	3733	3789	56	1.5%
Street Lighting	10961	11340	379	3.5%

The only classes to show significant increases in customers from 2006 to 2007 are the Residential, GS < 50 kW, and Street Lighting classes. City of Oshawa tax role projections suggest an increase of 675 new dwelling units in 2007 over 2006. This figure includes basement apartments which are not normally metered separately from the main dwelling unit. City of Oshawa figures suggest that 11% of all growth in residential dwelling units is due to an increase in the number of apartments, basement or otherwise. OPUCN is assuming that half of this apartment growth, or approximately 5% of total residential growth, will reflect the increase in basement apartments. Applying this 5% reduction results in a conservative projection of (675 * 95%) = 641 new residential units in the 2007 Bridge Year.

The increase in the GS < 50 kW customer class reflects a similar percentage growth to that of the residential class. The growth in the number of new subdivisions appears to account for growth in both the Residential and GS < 50 kW customer classes.

The increase in the number of connections in the street lighting class from the 2006 Actual reflects the number of new street lights installed to accommodate growth in the City of Oshawa.

2007 Bridge Year compared to 2008 Test Year

Customer Class	2007 Bridge Year	2008 Test Year	Variance	% Variance
Residential	46602	47243	641	1.4%
GS < 50 kW	3789	3845	56	1.5%
Street Lighting	11340	11650	310	2.7%

The only classes expected to show significant increases in customers from 2007 to 2008 are the Residential, GS < 50 kW, and Street Lighting classes. City of Oshawa tax role projections suggest an increase of 675 new dwelling units in 2008 over 2007. This figure includes basement apartments which are not normally metered separately from the main dwelling unit. City of Oshawa figures suggest that 11% of all growth in residential dwelling units is due to an increase in the number of apartments, basement or otherwise. OPUCN is assuming that half of this apartment growth, or approximately 5% of total growth, will reflect the increase in basement apartments. Applying this 5% reduction results in a conservative projection of (675 * 95%) = 641 new residential units in the 2008 Test Year.

The increase in the GS < 50 kW customer class reflects a similar percentage growth to that of the residential class. The growth in the number of new subdivisions appears to account for growth in both the Residential and GS < 50 kW customer classes. The increases for these classes in the 2007 Bridge and 2008 Test years reflect a normalization of the rate of growth to that experienced in the period from 2003 to 2005.

There is only one street lighting customer who is billed on the number of street lights connected to the distribution system in each year. Growth in this class is calculated based on the annual average mean of growth from 2002 to the current year (2007). This average is 310 new connections.

WEATHER NORMALIZED FORECASTING METHODOLOGY

1.0 Introduction

It is necessary to forecast both normalized consumption and demand. The residential, General Service < 50 kW, and USL classes are billed for distribution services based on kWh volume consumed. The other General Service classes are billed for distribution services based on their kW demand on the system. Non-distribution charges are based on kWh volume consumed.

2.0 Methodology for forecasting normalized volume

Normalized consumption is forecast using a multi step process. The first step is to determine the number of customers for each year of the five year period from 2002 through 2006.

	Number of Customers (Connections)				
	2002	2003	2004	2005	2006
	#	#	#	#	#
RESIDENTIAL					
Regular	42,960	43,679	44,280	44,917	45,961
GENERAL SERVICE					
Less than 50 kW	3,701	3,677	3,576	3,742	3,733
Other (> 50 kW < 1000 kW)	573	545	515	528	522
Intermediate Use (1000 - 5000 kW)	5	5	7	8	9
Large Use (> 5000 kW)	2	2	2	2	2
Unmetered Scattered Load	291	293	295	301	301
Sentinel Lighting	38	81	77	77	77
Street Lighting	9,967	10,072	10,076	10,547	10,961
TOTALS	57,537	58,354	58,828	60,122	61,566

The next step is to determine load for each class for each of the five years.

	kWh per Customer Class				
	2002	**2003**	**2004**	**2005**	**2006**
RESIDENTIAL					
Regular	438,330,776	470,893,693	448,166,680	486,017,826	466,443,961
GENERAL SERVICE					
Less than 50 kW	138,084,005	145,876,487	130,771,902	136,707,568	134,155,770
Other (> 50 kW < 1000 kW)	374,217,346	373,593,458	360,631,980	362,064,784	357,086,593
Intermediate Use (1000 - 5000 kW)	41,478,177	39,872,090	65,676,068	70,098,769	80,518,764
Large Use (> 5000 kW)	72,043,337	86,022,772	80,888,648	62,906,838	59,654,446
Unmetered Scattered Load	2,106,777	2,198,851	2,166,588	2,154,487	2,205,188
Sentinel Lighting	25,600	37,376	38,906	39,118	40,719
Street Lighting	8,725,336	8,323,170	8,704,191	9,143,960	9,357,806
TOTALS	1,075,011,355	1,126,817,897	1,097,044,963	1,129,133,350	1,109,463,247

These two steps allow the calculation of an average usage per customer for each of the five years.

	kWh per Customer					Calculated kWh per Customer
	2002	**2003**	**2004**	**2005**	**2006**	**5 yr average per customer**
RESIDENTIAL						
Regular	10,203.2	10,780.8	10,121.2	10,820.4	10,148.7	10,414.9
Less than 50 kW	37,309.9	39,672.7	36,569.3	36,533.3	35,937.8	37,204.6
Other (> 50 kW < 1000 kW)	653,084.4	685,492.6	700,256.3	685,728.8	684,073.9	681,727.2
Intermediate Use (1000 - 5000 kW)	9,217,372.7	8,860,464.4	9,382,295.4	8,345,091.5	8,946,529.3	8,950,350.7
Large Use (> 5000 kW)	36,021,668.5	43,011,386.0	40,444,324.0	31,453,419.0	29,827,223.0	36,151,604.1
Unmetered Scattered Load	7,239.8	7,504.6	7,344.4	7,157.8	7,326.2	7,314.5
Sentinel Lighting	673.7	461.4	505.3	508.0	528.8	535.4
Street Lighting	875.4	826.4	863.9	867.0	853.7	857.3

Once the average load per customer has been determined, the HONI weatherization factor is applied to each customer class.

	Calculated kWh per Customer		
	5 yr average per customer	**Honi Factor for Normalization**	**Normalized kWh per Customer**
RESIDENTIAL			
Regular	10,414.9	1.012	10,536
Less than 50 kW	37,204.6	1.005	37,389
Other (> 50 kW < 1000 kW)	681,727.2	1.008	687,236
Intermediate Use (1000 - 5000 kW)	8,950,350.7	1.000	8,950,351
Large Use (> 5000 kW)	36,151,604.1	1.000	36,151,604
Unmetered Scattered Load	7,314.5	1.000	7,315
Sentinel Lighting	535.4	1.000	535
Street Lighting	857.3	1.000	857

The normalized kWh per customer can then be used, in concert with predicted number of customers in each class to calculate normalized volumes for each class of customer for each year.

3.0 Methodology for forecasting normalized demand

The calculation of normalized demand (kW) was based on an examination of demand for the same five year period. It was noted that average demand has been consistent over the period for all

The calculation of normalized demand (kW) was based on an examination of demand for the same five year period. It was noted that average demand has been consistent over the period for all customer classes and is not related to kWh usage. The only difference found was in the Large User class between 2006 and 2007. There has been a drop in demand for that class only this year. There are two large use customers in Oshawa and both are in the automobile parts manufacturing sector, which has shown a downturn this year. The large use class was adjusted to take this drop into account and the averages for the remaining customer classes were extended to 2008 for forecasting purposes.

NORMALIZED VOLUME FORECAST TABLE

Class	2006 Board Approved (kWh)	2006 Board Approved (kW)	2006 Actual (kWh)	2006 Actual (kW)	Variance from 2006 Board Approved	2006 Actual (kWh)
Rate Classes						
RESIDENTIAL	473,481,804	0	466,443,961	0	(7,037,843)	466,443,961
GENERAL SERVICE						
Less than 50 kW	135,617,463	0	134,155,770	0	(1,461,693)	134,155,770
Other > 50 kw > 1000 kw	311,047,852	895,054	357,086,593	893,941	(1,113)	357,086,593
Intermediate Use (1000 - 5000 kW)	112,199,252	182,908	80,518,764	171,299	(11,609)	80,518,764
Large Use (> 5000 kW)	96,400,490	208,230	59,654,446	141,375	(66,855)	59,654,446
Unmetered Scattered Load	2,899,511	0	2,205,188	0	(694,323)	2,205,188
Sentinel Lighting	42,103	174	43,597	139	(35)	43,597
Street Lighting	7,606,205	13,291	9,354,928	24,663	11,372	9,354,928

Class	2006 Actual (kW)	2007 Bridge (kWh)	2007 Bridge (kW)	Variance from 2006 Actual	2007 Bridge (kWh)	2007 Bridge (kW)	2008 Test (kWh)	2008 Test (kW)	Variance from 2007 Actual
Rate Classes									
RESIDENTIAL	0	491,019,690	0	24,575,729	491,019,690	0	497,773,555	0	6,753,865
GENERAL SERVICE									
Less than 50 kW	0	141,649,663	0	7,493,893	141,649,663	0	143,774,408	0	2,124,745
Other > 50 kw > 1000 kw	893,941	358,737,446	893,941	0	358,737,446	893,941	358,737,446	893,941	0

Intermediate Use (1000 - 5000 kW)	171,299	71,602,805	152,266	(19,033)	71,602,805	152,266	80,553,156	171,299	19,033
Large Use (> 5000 kW)	141,375	72,303,208	140,182	(1,193)	72,303,208	140,182	72,303,208	140,182	0
Unmetered Scattered Load	0	2,223,622	0	18,434	2,223,622	0	2,230,937	0	7,315
Sentinel Lighting	139	41,229	139	0	41,229	139	41,229	139	0
Street Lighting	24,663	9,721,448	25,516	853	9,721,448	25,516	9,987,202	26,213	697

VARIANCE ANALYISIS ON NORMALIZED VOLUME FORECAST TABLE

For the purposes of this analysis, any load increases which are greater than 1% for a class are considered significant.

2006 Approved compared to 2006 Actual

The 2006 EDR Board Approved load figures were calculated using a three year average of the loads from 2002, 2003, and 2004, as per the filing requirements for the 2006 EDR. This average somewhat distorts the loads for OPUCN as the local economy experienced substantial consumption and demand growth between 2002 and 2004. Although averaging would somewhat dampen the effects of this growth, the actual 2006 results reflected a very low year for load, with the exception of residential and street lighting loads. The combination of high average loads during the comparison period and lower than normal loads in 2006 results in significant variances between 2006 Actual and 2006 Approved loads.

2006 Actual Year compared to 2007 Bridge Year

The customer classes which show some significant variation between the 2006 Actual figures and the 2007 Bridge figures are Residential at 5.3%, GS < 50 kW at 5.6%, GS 1000 – 5000 kW at -11.1%, GS > 5000 kW at 21.2%, and the Street Lighting at 3.5 %.

The figures for the 2007 Bridge year reflect a load which has been normalized for weather effects. They are not actual figures. They were normalized using the procedure documented above. The 5.3% projected increase in consumption in the Residential class from the 2006

Actual year to the 2007 Bridge year comes as a result of a combination of the increase in customers in the class and some effect from the normalization of the 2007 Bridge year data. In particular, actual results for 2006 were abnormal since they were significantly lower, especially in relation to average load per customer, than the previous four years. The low consumption patterns in 2006 and normalized consumption predicted for 2007 result in large variances between the two years.

The 5.6% increase in consumption expected in the General Service < 50 kW class is due to an increase in customer count and some effect from the normalization of loads. As explained for the residential customer class, 2006 was a very low consumption year. As 2007 projections reflect normalization of the load, greater variances are expected.

Both of industrial classes, GS 1000-5000 kW at -11.1% and GS > 5000 kW at -21.2%, have significant variances between the 2006 Actual and 2007 Bridge years. The variance in the GS 1000 – 5000 kW class is associated with the loss of one customer in 2007. The variance in the GS > 5000 kW class reflects normalization of consumption through utilization of a five year average to project the load in 2007. There has been a decline in the automotive parts industry, and both of the large customers in this class are manufacturers in this sector. Although such a situation could lead to a decline in consumption for these customers, it is not known if the decline in the sector will be significant within the timeframe of the forecasts used for this Application. Therefore, the five year average is maintained for projection purposes.

The 3.5 % increase in load for the Street Lighting class is due to a 3.5 % increase in the number of connections from 2006 to 2007.

<u>2007 Bridge Year compared to 2008 Test Year</u>

The customer classes which show a significant variation in load from 2007 Bridge to 2008 Test are Residential at 1.5%, General Service with demand < 50 kW at 1.5%, General Service with demand of 1000 – 5000 kW at 12.5%, and Street Lighting at 2.7%.

The projected consumption for the residential class in 2008 is expected to be 1.5% higher than the residential consumption in 2007. This increase is due to the fact that the number of Residential customers is expected to increase 1.5% from 2007 to 2008.

The consumption for the General Service < 50 kW class is expected to rise by 1.5 % from 2007 to 2008. This reflects an increase of 1.5 % in the number of customers in the class.

The change in the GS 1000 – 5000 kW customer class is due to the expected new Durham Courthouse building being built in Oshawa and which is expected to be connected in late 2008. This is a small class and the addition or loss of one customer makes a significant difference in load.

The consumption for the Street Lighting class is expected to rise by 2.7 % from 2007 to 2008. This reflects a 2.7 % increase in the number of street light connections expected during that timeframe.

Although some effect can be expected from CDM activities pursued by the OPA generally and by OPUCN specifically, these effects are difficult to predict and have not been included in this forecast.

SUMMARY OF CUSTOMER AND LOAD FORECAST

OPUCN		**Historical Actual - Retail**	**Historical Board Approved**	**Historical Actual Normalized**	**Bridge Year Forecast Normalized**	**Test Year Forecast Normalized**
Year		**2006**	**2004**	**2006**	**2007**	**2008**
Customer Class						
	#	45,961	44,280	45,961	46,602	47,243
RESIDENTIAL	kWh	466,443,961	473,481,804	484,265,825	491,019,690	497,773,555
GENERAL SERVICE						
Less than 50 kW	#	3,733	3,576	3,733	3,789	3,845
	kWh	134,155,770	135,617,463	139,574,552	141,649,663	143,774,408
Other > 50 kw > 1000 kw	#	522	515	522	522	522
	kWh	357,086,593	311,047,852	358,737,446	358,737,446	358,737,446
	kW	893,941	895,054	893,941	893,941	893,941
Intermediate Use (1000 - 5000 kW)	#	9	7	9	8	9
	kWh	80,518,764	112,199,252	80,553,156	71,602,805	80,553,156
	kW	171,299	182,908	171,299	152,266	171,299
Large Use (> 5000 kW)	#	2	2	2	2	2
	kWh	59,654,446	96,400,490	72,303,208	72,303,208	72,303,208
	kW	141,375	208,230	140,182	140,182	140,182
Unmetered Scattered Load	#	301	295	301	304	305
	kWh	2,205,188	2,899,511	2,201,678	2,223,622	2,230,937
Sentinel Lighting	#	77	77	77	77	77
	kWh	43,597	42,103	41,229	41,229	41,229
	kW	139	174	139	139	139

Street Lighting	#	10,961	10,076	10,961	11,340	11,650
	kWh	9,354,928	7,606,205	9,396,542	9,721,448	9,987,202
	kW	24,663	13291	24,663	25,516	26,213
TOTALS	#	61,566	58,828	61,566	62,644	63,653
	kWh	1,109,463,247	1,139,294,680	1,147,073,638	1,147,299,112	1,165,401,141
	kW	1,231,417	1,299,657	1,230,224	1,212,044	1,231,774

HISTORICAL AVERAGE CONSUMPTION

Residential

Year	Weather Actual	Weather Normalized	Difference	Actual % Diff
2002	472,686,238	478,205,166	5,518,928	1.17%
2003	480,597,351	486,208,646	5,611,296	1.17%
2004	487,210,117	492,898,621	5,688,504	1.17%
2005	494,218,989	499,989,326	5,770,337	1.17%
2006	505,706,057	511,610,513	5,904,456	1.17%
2007	513,507,140	519,502,679	5,995,539	1.17%
2008	521,253,209	527,339,189	6,085,980	1.17%

GS Less than 50 kW

Year	Weather Actual	Weather Normalized	Difference	Actual % Diff
2002	157,178,738	157,959,366	780,628	0.50%
2003	156,159,475	156,935,042	775,566	0.50%
2004	151,870,080	152,624,343	754,263	0.50%
2005	155,819,721	156,593,600	773,879	0.50%
2006	158,537,754	159,325,132	787,378	0.50%
2007	159,217,262	160,008,015	790,753	0.50%
2008	159,939,240	160,733,578	794,338	0.50%

GS> 50 kw > 1000 kw				
Year	Weather Actual	Weather Normalized	Difference	Actual % Diff
2002	362,758,037	365,598,007	2,839,970	0.78%
2003	342,484,135	345,165,384	2,681,249	0.78%
2004	320,762,097	323,273,288	2,511,191	0.78%
2005	330,174,980	332,759,863	2,584,883	0.78%
2006	325,830,573	328,381,444	2,550,871	0.78%
2007	328,002,776	330,570,653	2,567,877	0.78%
2008	328,002,776	330,570,653	2,567,877	0.78%

GS > 200 kw > 1000 kw				
Year	Weather Actual	Weather Normalized	Difference	Actual % Diff
2002	30,394,451	30,721,093	326,642	1.07%
2003	30,394,451	30,721,093	326,642	1.07%
2004	30,394,451	30,721,093	326,642	1.07%
2005	30,394,451	30,721,093	326,642	1.07%
2006	30,394,451	30,721,093	326,642	1.07%
2007	30,394,451	30,721,093	326,642	1.07%
2008	30,394,451	30,721,093	326,642	1.07%

Intermediate Use (1000 - 5000 kW)

Year	Weather Actual	Weather Normalized	Difference	Actual % Diff
2002	52,371,520	52,862,291	490,771	0.94%
2003	52,371,520	52,862,291	490,771	0.94%
2004	73,320,128	74,007,207	687,079	0.94%
2005	83,794,432	84,579,665	785,233	0.94%
2006	94,268,736	95,152,123	883,387	0.94%
2007	94,268,736	95,152,123	883,387	0.94%
2008	94,268,736	95,152,123	883,387	0.94%

Large Use (> 5000 kW)

Year	Weather Actual	Weather Normalized	Difference	Actual % Diff
2002	85,902,259	85,902,259	-	0.00%
2003	85,902,259	85,902,259	-	0.00%
2004	85,902,259	85,902,259	-	0.00%
2005	85,902,259	85,902,259	-	0.00%
2006	85,902,259	85,902,259	-	0.00%
2007	85,902,259	85,902,259	-	0.00%
2008	85,902,259	85,902,259	-	0.00%

Unmetered Scattered Load

Year	Weather Actual	Weather Normalized	Difference	Actual % Diff
2002	2,808,146	2,808,146	-	0.00%
2003	2,827,446	2,827,446	-	0.00%
2004	2,846,746	2,846,746	-	0.00%
2005	2,866,046	2,866,046	-	0.00%
2006	2,904,646	2,904,646	-	0.00%
2007	2,933,596	2,933,596	-	0.00%
2008	2,943,246	2,943,246	-	0.00%

Sentinel Lighting

Year	Weather Actual	Weather Normalized	Difference	Actual % Diff
2002	20,095	20,095	-	0.00%
2003	42,834	42,834	-	0.00%
2004	40,719	40,719	-	0.00%
2005	40,719	40,719	-	0.00%
2006	40,719	40,719	-	0.00%
2007	40,719	40,719	-	0.00%
2008	40,719	40,719	-	0.00%

Street Lighting

Year	Weather Actual	Weather Normalized	Difference	Actual % Diff
2002	8,791,891	8,791,891	-	0.00%
2003	8,884,512	8,884,512	-	0.00%
2004	8,888,040	8,888,040	-	0.00%
2005	9,371,431	9,371,431	-	0.00%
2006	9,668,699	9,668,699	-	0.00%
2007	10,003,014	10,003,014	-	0.00%
2008	10,276,465	10,276,465	-	0.00%

OTHER DISTRIBUTION REVENUE

	2,006 Board Approved	2,006 Actual	Variance From 2006 Board Approved	2,006 Actual	2,007 Bridge	Variance From 2006 Actual	2,007 Bridge	2,008 Test	Variance From 2007 Actual
Service Transaction Requests STR Revenue	42	4,502	4,460	4,502	4,502	0	4,502	4,502	0
Rent from Electric Property	95,949	107,038	11,089	107,038	107,038	0	107,038	107,038	0
Late Payment Charges	200,531	198,734	(1,797)	198,733	198,733	0	198,733	198,733	0
Set Up Charges	51,660	188,597	136,937	202,022	202,022	0	202,022	181,272	(20,750)
Collection Charge	153,000	233,985	80,985	233,985	233,985	0	233,985	233,985	0
Reconnect Charge	44,097	77,499	33,402	77,499	77,499	0	77,499	77,499	0
NSF Charge	24,695	14,898	(9,797)	14,898	14,898	0	14,898	14,898	0
Retailer Fixed and Variable Charge	1	82,491	82,490	82,491	82,491	0	82,491	82,491	0
Misc. Service Revenues	37,456	22,294	(15,162)	2,462	2,462	0	2,462	2,462	0
	607,431	930,038	322,607	923,630	923,630	0	923,630	902,880	(20,750)

Billed Construction Jobs	51,956	56,998	5,042	56,998	56,998	0	56,998	56,998	0
Miscellenous Non-Operating Revenues	223,250	253,310	30,060	253,310	253,310	0	253,310	233,778	(19,532)
Interest Earned	392,690	774,546	381,856	774,546	774,546	0	774,546	408,000	(366,546)
	1,275,327	2,014,892	739,565	2,008,484	2,008,484	0	2,008,484	1,601,656	(406,828)

VARIANCE ANALYSIS ON OTHER DISTRIBUTION REVENUE

Other Distribution Revenues refer to revenues due to distribution activities which are not included in rates. These revenues reflect both specific service charges, as approved by the Board during the EDR 2006 generic hearing, such as new account setup charges, late penalty charges and reconnection charges; and miscellaneous revenues such as retailer STR charges, construction revenues, proceeds from the sale of used copper, and interest income. Variance analyses were performed on these figures for 2006 Approved and 2006 Actual; 2006 Actual and 2007 Bridge; and 2007 Bridge and 2008 Test. Variances for 2006 Approved and 2006 Actual were identified and are explained below. Other revenues remained constant between 2006 Actual and 2007 Bridge years. Variances for the 2007 Bridge and 2008 Test comparison occurred for set-up charges, miscellaneous non-operating income, and interest earned and are explained below.

2006 Approved Compared to 2006 Actual

Asset Account	2006 Approved	2006 Actual	Variance
4235 – Miscellaneous Service Revenues			
Set-Up Charges	51,660	188,597	136,937
Collection Charges	153,000	233,985	80,985
Reconnect Charges	44,097	77,499	33,402
Total	248,757	500,081	251,324

Explanation:

The calculations for Set-Up Charges, Collection Charges, and Reconnect Charges, all of which are components of the Miscellaneous Service Revenues, were based on EDR 2006 Rate

Application Board approved rates. These rates were established by the Board to reflect better cost recovery for Regulated Services. The 2006 Approved rates assumed that the number of service transactions would remain at the average number of transactions for 2002, 2003, and 2004. The trend over that period was to an increasing number of such transactions and the trend continued in 2005 and 2006. The effect was magnified in the Set-Up Charges component of the account due to an anomalous increase in the number of housing starts and therefore new accounts in Oshawa in 2006 as referred to in the narrative on load forecast at Exhibit 3, Tab 2, Schedule 7.

Asset Account	**2006 Approved**	**2006 Actual**	**Variance**
4235 – Miscellaneous Service Revenues			
NSF Charges	24,695	14,898	(9,797)
4225 -			
Late Payment Charges	200,531	198,734	(1,797)
Total	225,226	213,632	(11,594)

Explanation:

Most of the NSF charges and late payment charges collected are from the Residential and General Service < 50 kW classes. The cost of electricity makes up the largest portion of the bills for these customers, rendering them highly sensitive to commodity prices. The cost of electricity was lower than expected in 2006 and the burden on these ratepayers was lower. This resulted in fewer late payments and returned cheques.

Asset Account	**2006 Approved**	**2006 Actual**	**Variance**
4235 – Miscellaneous Service			

Revenues			
Service Transaction Requests	42	4,502	4,460

Explanation:

Prior to the 2005 fiscal year, Service Transaction Requests were recorded to a different account in OPUCN's general ledger. The average of this account for 2002, 2003, and 2004, which was used in the calculation of the 2006 Approved year was, therefore, inaccurate. This has since been corrected and the amounts booked from 2005 and forward are accurate.

Asset Account	2006 Approved	2006 Actual	Variance
4235 – Miscellaneous Service Revenues			
Retailer Fixed and Variable Charges	1	82,491	82,490

Explanation:

The 2006 EDR results were approved based on averages from 2002, 2003, and 2004. The variable charge for enrolled and pending customers was not charged to Retailers until 2005 and therefore not recorded prior to 2004. In fiscal 2005 OPUCN updated the charges and invoiced Retailers for service charges for 2002 through 2005. The amount recorded as 2006 Actual reflects appropriate annual retailer charges for this category.

Asset Account	2006 Approved	2006 Actual	Variance
4235 – Miscellaneous Service Revenues			
Miscellaneous Service Revenues	37,456	22,294	(15,162)

Explanation:

In 2006 OPUCN ceased doing underground dig-ins for new construction and started contracting them out to a third party. The variance in this account is due largely to this change in practice.

Asset Account	2006 Approved	2006 Actual	Variance
4405 – Investment Income			
Investment Income	392,690	774,546	381,856

Explanation:

Investment income is reflective of improvements in cash flow during 2006, as well as an increase in interest rates paid by the bank compared to rates assumed for the 2006 Approved rates. In addition, in 2006, the two large projects, the General Motors Sports Centre and the new 401 Interchange, were paid for substantially with contributed capital. This meant that OPUCN did not spend as much as budgeted on 2006 Capital expenditures and cash flow increased. Further, a T-bill was used to meet IESO prudential requirements of $6.0 million and it earned greater interest than forecast as the rate moved from 3.53% to 4.1% in 2006.

2006 Actual Year compared to 2007 Bridge Year

There were no variances between the 2006 Actual and 2007 Bridge years.

2007 Bridge Year Compared to 2008 Test Year

Asset Account	2007 Bridge	2008 Test	Variance
4325 – Miscellaneous Service Revenues			
Set Up Charges	202,022	181,272	(20,750)

Explanation:

In 2006, a record year for sub-division construction resulted in a higher than average number of housing starts. Many of those starts did not come onto the market until 2007, resulting in a higher than normal number of connections in both 2006 and 2007. Sub-division construction in Oshawa is already 45% lower in 2007 than in 2006. Therefore, set-up charges have been reduced to reflect the expected return to a normal number of starts and a return of revenues to pre-2006 levels.

Asset Account	2007 Bridge	2008 Test	Variance
4390 – Miscellaneous Non-Operating Revenue			
Miscellaneous Non-Operating Revenue	253,310	233,776	(19,534)

Explanation:

In 2006 and 2007, record metal prices, particularly copper prices, provided record earnings from scrap metal sales. Projections that prices will return to their pre-2006 normal are reflected in the estimate for Miscellaneous Non-Operating Revenue used for 2008 Test year.

Asset Account	2007 Bridge	2008 Test	Variance
4405 – Investment Income			
Investment Income	774,546	408,000	(366,546)

Explanation:

The key drivers in the reduction in Interest Income from 2007 Bridge to 2008 Test year are:

- A reduction in average cash balance due to increased capital expenditures in 2008
- A lower level of capital contribution for projects forecast for 2008
- A $1,000,000 capital contribution to Hydro One for the construction of a new Transformer Station scheduled for 2009.

While OPUCN expects a higher cash outflow for working capital on account of increased commodity prices that has not been factored into the forecast.

DISTRIBUTION REVENUE DATA

	2006 Board Approved			
	Customers	Consumption	Distribution Revenues	Unit Revenues
	(Year-End)	(kWh / KW)	($)	$ / (kWh / kW)
Residential	44,280	472,481,804	9,296,581	0.02
GS Less than 50 kW	3,576	135,617,463	2,918,964	0.02
GS > 50 kw < 1000 kw	522	895,054	3,385,442	3.78
Intermediate Use (1000 - 5000 kW)	7	182,908	948,573	5.19
Large Use (>5000)	2	208,230	846,488	4.07
USL	295	2,899,511	70,873	0.02
Sentinel Lighting	77	174	3,226	18.54
Street Lighting	10,076	13,291	154,841	11.65
TOTAL	58,835	612,298,435	17,624,988	

	2006 Actual			
	Customers	Consumption	Distribution Revenues	Unit Revenues
	(Year-End)	(kWh / KW)	($)	$ / (kWh / kW)
Residential	45,961	466,443,961	9,433,029	0.02
GS Less than 50 kW	3,733	134,155,770	2,982,674	0.02
GS > 50 kw > 1000 kw	522	893,941	3,480,717	3.89
Intermediate Use (1000 - 5000 kW)	9	171,299	1,008,212	5.89
Large Use (>5000)	2	141,375	678,258	4.80
USL	301	2,205,188	51,612	0.02
Sentinel Lighting	77	139	2,951	21.23
Street Lighting	10,961	24,663	275,925	11.19
TOTAL	61,566	604,036,336	17,913,378	

	2006 Actual - Normalized					
	Customers	Consumption	Distribution Revenues	Normalized Consumption	Normalized Distribution Revenues	Unit Revenues
	(Year-End)	(kWh / KW)	($)	(kWh / KW)	($)	$ / (kWh / kW)
Residential	45,961	466,443,961	9,433,029	470,952,246	9,059,857	0.02
GS Less than 50 kW	3,733	134,155,770	2,982,674	145,828,724	3,002,299	0.02
GS > 50 kw < 1000 kw	522	893,941	3,480,717	893,941	3,384,906	3.79
Intermediate Use (1000 - 5000 kW)	9	171,299	1,008,212	171,299	945,122	5.52
Large Use (>5000)	2	141,375	678,258	141,375	654,998	4.63
USL	301	2,205,188	51,612	2,719,994	65,324	0.03
Sentinel Lighting	77	139	2,951	139	3,034	21.83
Street Lighting	10,961	24,663	275,925	24,663	243,256	9.86
TOTAL	61,566	604,036,336	17,913,378	620,732,381	17,358,798	

	2007 Bridge - Normalized			
	Customers	Normalized Consumption	Normalized Distribution Revenues	Unit Revenues
	(Year-End)	(kWh / KW)	($)	$ / (kWh / kW)
Residential	46,602	491,019,690	9,418,901	0.02
GS Less than 50 kW	3,789	141,649,663	2,965,341	0.02
GS > 50 kw > 1000 kw	522	893,941	3,415,321	3.82
Intermediate Use (1000 - 5000 kW)	8	152,266	847,674	5.57
Large Use (>5000)	2	140,182	657,448	4.69
USL			57,039	0.03

	304	2,223,622		
Sentinel Lighting	77	139	3,060	22.01
Street Lighting	11,340	25,516	253,358	9.93
TOTAL	62,644	636,105,019	17,618,141	
	2008 Test - Normalized			
	Customers	**Normalized Consumption**	**Normalized Distribution Revenues**	**Unit Revenues**
	(Year-End)	**(kWh / KW)**	**($)**	**$ / (kWh / kW)**
Residential	47,243	497,773,555	10,894,578	0.02
GS Less than 50 kW	3,845	143,774,408	3,442,659	0.02
GS > 50 kw < 1000 kw	522	893,941	3,899,292	4.36
Intermediate Use (1000 - 5000 kW)	9	171,299	1,088,772	6.36
Large Use (>5000)	2	140,182	750,603	5.35
USL	305	2,230,937	65,333	0.03
Sentinel Lighting	77	139	3,493	25.13
Street Lighting	11,650	26,213	297,637	11.35
TOTAL	63,653	645,010,674	20,442,367	

DESCRIPTION OF REVENUE SHARING

OPUCN has no Board approved revenue sharing program for its customers.

OVERVIEW OF OPERATING COSTS

1.0 Operating Costs

OPUCN's operating costs are comprised of: Operations, Maintenance & Administration ("OM&A") expenses; Ontario Capital Taxes ("OCT") & Municipal Taxes; and Depreciation & Amortization costs. The costs represent the annual expenditures required to sustain OPUCN's distribution operations. This includes costs associated with maintaining a high level of safety for the public and OPUCN employees; complying with provisions of the Distribution System Code regarding system operation and maintenance; complying with the provisions of the Standard Supply Service Code and the Retail Settlement Code concerning the quality of customer care required; meeting environmental requirements; maintaining compliance with Board and Ministry of Energy direction; and maintaining targeted service quality and reliability performance levels.

The following table summarizes OPUCN's operating costs. The components of those costs are discussed below.

($000's)	2006 Actual	2007 Bridge	2008 Test
Operations, Maintenance & Administration	$8,237.0	$9,192.2	$10,446.6
Depreciation & Amortization	3,659.1	3,892.0	4,395.5
Capital & Property Taxes	387.7	393.0	345.5
Income Taxes	2,171.7	2,100.5	1,935.9
Total Operating Costs	**14,455.5**	**15,577.7**	**17,123.5**

2.0 OM&A Costs

OPUC compiles budget information for operating, maintenance, and administrative expenses (OM&A) by having OPUCN business units organized based on type of business function or service provided. Each unit is assigned to a manager who is responsible and held accountable for variances between actual expenditures and their original annual budget.

The Operating and Maintenance, and Administrative budgets (for example the budget for the 2007 Bridge Year), have been forecasted utilizing a bottom-up approach. These forecasts are compared to prior year experiences for reasonableness. Each business unit is reviewed by the responsible manager, finance management, and the lead executive to ensure financial projections are sufficient for known and expected activities. After every business unit has been reviewed and approved by the responsible manager, finance management, and lead executive, the budget is then consolidated. The consolidated budget is reviewed by Executive and adjusted if necessary. The consolidated budget is then presented to the OPUC Board of Directors, and if accepted it is formally approved. The principles of this process were applied to derive the OM&A costs in this Exhibit.

The OM&A costs in this Exhibit represent the costs associated with OPUCN's integrated set of asset maintenance and customer activity needs to meet public and employee safety objectives; to comply with the Distribution System Code, environmental requirements and Government direction; and to maintain distribution business service quality and reliability at targeted performance levels. These costs also include providing services to customers connected to OPUCN's distribution system, and meeting the service levels stipulated in the Distribution System Code, the Standard Supply Service Code, and the Retail Settlement Code. OPUCN's OM&A is numerically summarized by the following table.

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
OM&A expenses				
Operation (Working Capital)	1,609,132	341,422	40,972	442,737
Maintenance (Working Capital)	212,721	667,636	998,410	1,028,671
Billing and Collections	1,218,533	2,053,343	2,182,604	2,248,345
Community Relations	1,526,323	1,010,108	884,166	1,000,216
Administrative and General Expenses	4,135,697	4,164,507	5,086,043	5,726,644
Total OM&A	8,702,406	8,237,016	9,192,195	10,446,613
Variance		(465,390)	955,179	1,254,418

ESA audits OPUCN annually to check our levels of safety, maintenance, and operational excellence. To provide additional quality assurance, OPUCN hired Kinectrics Inc. in 2006 to perform an asset condition assessment to assess the reliability and safety of the distribution system and to ensure continued compliance with operational and safety standards. In regard to OM&A, Kinectrics concluded that OPUCN has a well-designed and documented maintenance plan, as illustrated by the following quote from the report:

> The overall asset condition at Oshawa PUC Networks is very good. Several examples of required maintenance were found but they had been previously identified by OPUCN staff and scheduled for maintenance. OPUCN has a well designed and documented maintenance plan for the assets that, if it continues to be followed, can be expected to maintain them in top condition and detect many incipient failures before they occur. Overall spending on maintenance and capital replacements is in line with the best practices in the industry.
>
> Generally, there was evidence that maintenance was being performed as documented. Not all identified problems had been repaired, which is one indicator that the systems are not overmaintained. The transformer stations, overhead lines, and underground systems generally appear well maintained. [Kinectrics, *Asset Condition Assessment for Oshawa PUC Networks*, Appendix "D", p.-v]

A detailed OM&A cost table is presented at Exhibit 4, Tab 2, Schedule 1. Annual variances in OM&A are discussed at Exhibit 4, Tab 2, Schedule 2.

3.0 Income Tax and Ontario Capital Taxes

This information consists of detailed calculations of income taxes, and indemnity payments to the Province. Details of the expenditures are filed at Exhibit 4, Tab 3, Schedule 1.

The Regulatory Income Taxes (PILS) totaled \$1,186,485 in 2006 Board Approved, \$1,233,639 in 2006 Actual and are forecast to be \$1,257,641 in 2007 and \$1,170,473 in 2008. Total Provision for Income Taxes projections totaled \$2,076,237 in 2006 Board Approved, \$2,171,669 in 2006 Actual and are forecast to be \$2,100,497 in 2007 and \$1,935,917 in 2008.

4.0 Depreciation and Amortization

OPUCN follows the Accounting Procedures Handbook in regards to depreciation and amortization. A detailed analysis of OPUCN's depreciation and amortization is at Exhibit 4, Tab 2, Schedule 7.

OM&A DETAILED COST TABLE

	2006 Board Approved	2006 Actual	Variance form 2006 Board Appr	2006 Actual	2007 Bridge	Variance form 2006 Actual	2007 Bridge	2008 Test	Variance form 2007 Bridge
Operation (Working Capital)									
Operation Supervision and Engineering	48,321	273,773	225,452	273,773	372,516	98,744	372,516	384,274	11,757
Load Dispatching	-	-	-	-	-	-	-	-	-
Station Buildings and Fixtures Expense	-	-	-	-	-	-	-	-	-
Transformer Station Equipment - Operation Labour	-	-	-	-	-	-	-	-	-
Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-
Distribution Station Equipment - Operation Labour	26,660	-	(26,660)	-	-	-	-	-	-
Distribution Station Equipment - Operation Supplies and Expenses	-	-	-	-	-	-	-	-	-
Overhead Distribution Lines and Feeders - Operation Labour	702,518	225,952	(476,565)	225,952	(81,483)	(307,435)	(81,483)	109,267	190,750
Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	54,478	(210,688)	(265,166)	(210,688)	(182,304)	28,384	(182,304)	(165,705)	16,599
Overhead Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-
Overhead Distribution Transformers- Operation	-	-	-	-	-	-	-	-	-
Underground Distribution Lines and Feeders - Operation Labour	175,277	7,751	(167,526)	7,751	7,751	-	7,751	7,984	233
Underground Distribution Lines & Feeders - Operation Supplies & Expenses	4,708	1,047	(3,662)	1,047	193	(854)	193	199	6
Underground Subtransmission Feeders - Operation	-	-	-	-	-	-	-	-	-
Underground Distribution Transformers - Operation	-	-	-	-	-	-	-	-	-
Street Lighting and Signal System Expense	-	-	-	-	-	-	-	-	-
Meter Expense	597,169	83,869	(513,300)	83,869	52,211	(31,658)	52,211	127,559	75,348
Customer Premises - Operation Labour	-	-	-	-	-	-	-	-	-
Customer Premises - Materials and Expenses	-	-	-	-	-	-	-	-	-
Miscellaneous Distribution Expense	-	(440,282)	(440,282)	(440,282)	(127,912)	312,370	(127,912)	(20,840)	107,072
Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-
Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	-	-	-	-	-
Other Rent	-	-	-	-	-	-	-	-	-
Sub-Total	1,609,132	(58,578)	(1,667,710)	(58,578)	40,972	99,550	40,972	442,737	401,765
Maintenance (Working Capital)									
Maintenance Supervision and Engineering	-	246,245	246,245	246,245	218,220	(28,025)	218,220	225,076	6,856
Maintenance of Buildings and Fixtures - Distribution Stations	-	6,773	6,773	6,773	19,891	13,117	19,891	20,487	597
Maintenance of Transformer Station Equipment	-	-	-	-	-	-	-	-	-
Maintenance of Distribution Station Equipment	25,761	127,372	101,611	127,372	129,470	2,098	129,470	133,354	3,884
Maintenance of Poles, Towers and Fixtures	135,136	503,320	368,184	503,320	477,847	(25,473)	477,847	492,183	14,336
Maintenance of Overhead Conductors and Devices	-	-	-	-	-	-	-	-	-
Maintenance of Overhead Services	-	-	-	-	-	-	-	-	-
Overhead Distribution Lines and Feeders - Right of Way	-	-	-	-	-	-	-	-	-

Maintenance of Underground Conduit	21,284	150,052	128,768	150,052	122,982	(27,070)	122,982	126,671	3,689
Maintenance of Underground Conductors and Devices	-	-	-	-	-	-	-	-	-
Maintenance of Underground Services	-	33,874	33,874	33,874	30,000	(3,874)	30,000	30,900	900
Maintenance of Line Transformers	-	-	-	-	-	-	-	-	-
Maintenance of Street Lighting and Signal Systems	-	-	-	-	-	-	-	-	-
Sentinel Lights - Labour	-	-	-	-	-	-	-	-	-
Sentinel Lights - Materials and Expenses	-	-	-	-	-	-	-	-	-
Maintenance of Meters	30,540	-	(30,540)	-	-	-	-	-	-
Customer Installations Expenses- Leased Property	-	-	-	-	-	-	-	-	-
Water Heater Rentals - Labour	-	-	-	-	-	-	-	-	-
Water Heater Rentals - Materials and Expenses	-	-	-	-	-	-	-	-	-
Water Heater Controls - Labour	-	-	-	-	-	-	-	-	-
Water Heater Controls - Materials and Expenses	-	-	-	-	-	-	-	-	-
Maintenance of Other Installations on Customer Premises	-	-	-	-	-	-	-	-	-
Sub-Total	212,721	1,067,636	854,915	1,067,636	998,410	(69,226)	998,410	1,028,671	30,262
Billing and Collections									
Supervision	-	222,974	222,974	222,974	212,111	(10,863)	212,111	218,582	6,471
Meter Reading Expense	160,098	386,024	225,926	386,024	406,158	20,134	406,158	417,950	11,792
Customer Billing	723,052	856,571	133,519	856,571	886,869	30,298	886,869	913,569	26,700
Collecting	-	376,008	376,008	376,008	395,466	19,458	395,466	407,783	12,318
Collecting- Cash Over and Short	-	-	-	-	-	-	-	-	-
Collection Charges	-	-	-	-	-	-	-	-	-
Bad Debt Expense	335,383	211,765	(123,617)	211,765	282,000	70,235	282,000	290,460	8,460
Miscellaneous Customer Accounts Expenses	-	-	-	-	-	-	-	-	-
Sub-Total	1,218,533	2,053,343	834,810	2,053,343	2,182,604	129,261	2,182,604	2,248,345	65,740
Community Relations									
Supervision	-	109,253	109,253	109,253	105,594	(3,659)	105,594	169,589	63,995
Community Relations - Sundry	32,634	14,861	(17,772)	14,861	23,200	8,339	23,200	23,896	696
Energy Conservation	-	222,319	222,319	222,319	-	(222,319)	-	-	-
Community Safety Program	194,587	208,165	13,578	208,165	276,902	68,737	276,902	285,376	8,474
Miscellaneous Customer Service and Informational Expenses	1,299,102	455,509	(843,593)	455,509	478,470	22,961	478,470	521,354	42,884
Supervision	-	-	-	-	-	-	-	-	-
Demonstrating and Selling Expense	-	-	-	-	-	-	-	-	-
Advertising Expense	(595)	-	595	-	-	-	-	-	-
Miscellaneous Sales Expense	-	-	-	-	-	-	-	-	-
Sub-Total	1,525,728	1,010,108	(515,620)	1,010,108	884,166	(125,942)	884,166	1,000,216	116,049
Administrative and General Expenses									
Executive Salaries and Expenses	470,000	480,000	10,000	480,000	480,000	-	480,000	480,000	-
Management Salaries and Expenses	809,979	637,673	(172,306)	637,673	726,591	88,918	726,591	1,002,599	276,008
General Administrative Salaries and Expenses	833,217	1,636,610	803,393	1,636,610	2,009,560	372,950	2,009,560	2,127,341	117,781
Office Supplies and Expenses	186,300	167,356	(18,944)	167,356	165,149	(2,207)	165,149	170,103	4,954

Administrative Expense Transferred Credit	(380,562)	(722,844)	(342,282)	(722,844)	(638,000)	84,844	(638,000)	(638,000)	-
Outside Services Employed	532,925	412,248	(120,677)	412,248	373,008	(39,240)	373,008	530,198	157,190
Property Insurance	37,680	62,251	24,571	62,251	104,669	42,418	104,669	116,766	12,097
Injuries and Damages	108,423	100,859	(7,564)	100,859	153,531	52,672	153,531	175,190	21,659
Employee Pensions and Benefits	452,328	439,811	(12,518)	439,811	455,253	15,442	455,253	476,312	21,059
Franchise Requirements	-	-	-	-	-	-	-	-	-
Regulatory Expenses	138,944	130,298	(8,646)	130,298	429,818	299,520	429,818	442,713	12,895
General Advertising Expenses	13,815	1,300	(12,514)	1,300	1,579	279	1,579	1,626	47
Miscellaneous General Expenses	53,198	63,026	9,828	63,026	64,325	1,299	64,325	66,255	1,930
Rent	264,000	264,000	-	264,000	264,000	-	264,000	264,000	-
Maintenance of General Plant	621,904	491,918	(129,985)	491,918	496,560	4,641	496,560	511,542	14,982
Electrical Safety Authority Fees	-	-	-	-	-	-	-	-	-
Independent Market Operator Fees and Penalties	-	-	-	-	-	-	-	-	-
Taxes Other Than Income Taxes	145,719	387,704	241,985	387,704	393,000	5,296	393,000	345,450	(47,550)
Sub-Total	4,287,870	4,552,211	264,341	4,552,211	5,479,043	960,476	5,479,043	6,072,094	593,052
Total OMA and Tax Other Than Income Tax	8,853,984	8,624,720	(229,265)	8,624,720	9,585,195	960,476	9,585,195	10,792,063	1,206,867

OM&A VARIANCE ANALYSIS

OPUCN has provided the following explanations for annual OM&A variances that exceed 1% of total distribution expenses before PILS.

2006 Approved compared to 2006 Actual

Account Grouping	2006 Approved	2006 Actual	Variance $	Variance %
Operations & Maintenance	1,981,951	1,618,056	(363,895)	(18.4%)

Explanation:

This is an overall variance for the operations and maintenance grouping of accounts. A substantial part of the variance was due to the fact that Approved costs were filed based on historic results of 2004, with some cost items having been averaged over three years. A further complication was that many management accounts were not matching correctly with USofA account groupings during 2004. Overall figures were correct but some account transactions did not match exactly with a single USofA account. Variances were also affected by better segmentation of costs in 2006 than was the case in 2004.

Account Grouping	2006 Approved	2006 Actual	Variance $	Variance %
Billing & Collections	1,918,935	2,198,794	279,860	14.6%

Explanation:

This is an overall variance for the billing and collection grouping of accounts. As was the case for Operations and Maintenance costs, a large part of the variance was due to the fact that

Approved costs were filed based on historic results of 2004, with some cost items having been averaged over three years. A further complication was that many management accounts were not matching correctly with USofA account groupings during 2004. Overall figures were correct but some account transactions did not match exactly with a single USofA account. Variances were also affected by better segmentation of costs in 2006 than was the case in 2004.

There were also some additional circumstances that affected the billing and collection accounts.

- Reduction in costs in many of the accounts between 2006 Approved and 2006 Actual are mainly attributable to a contract with a new ASP provider for billing and customer service software services.
- The Energy Conservation account reflects a new program that complies with the Board's CDM spending requirements which was not included in 2006 Approved amounts.
- Better collections practices were implemented in 2006 with a consequent reduction in bad debt. In addition, OPUCN applied for and received recovery of DRC from Bad Debt write offs from the Ministry of Finance. This led to a $70,000 reduction in bad debt expense over the amount approved by the Board for 2006.

Account Grouping	2006 Approved	2006 Actual	Variance $	Variance %
Administration & General Expenses	1,981,951	1,618,056	(363,895)	(18.4%)

Explanation:

This is an overall variance for the Administration & General Expenses grouping of accounts. As was the case for both the Operations and Maintenance and the Billing and Collection costs, a large part of the variance was due to the fact that Approved costs were filed based on historic results of 2004, with some cost items having been averaged over three years. A further complication was that many management accounts were not matching correctly with USofA account groupings during 2004. Overall figures were correct but some account transactions did not match exactly with a single USofA account. Variances were also affected by better segmentation of costs in 2006 than was the case in 2004. This category was also affected by the added costs of maintaining CDM programs which were not in place when the 2006 Approved amounts were calculated.

2006 Actual compared to 2007 Bridge Year

Account	2006 Actual	2007 Bridge	Variance $	Variance %
Management Salaries and Expenses	637,673	726,591	88,918	1%

Explanation:

This variance was due in part to an average compensation increase of 3% over 2006, and the hiring of new Engineer (as approved in EDR 2006). Other costs relate to a systems load study, membership in the Electrical Safety Association, and OEB related regulatory costs (reimbursements to interveners as per OEB orders). Offset to costs was the loss of one Engineer's Assistant during 2006. No replacement has been hired in 2007.

2006 Actual compared to 2007 Bridge Year

Account	2006 Actual	2007 Bridge	Variance $	Variance %
General Administrative Salaries and Expenses	1,636,610	2,009,560	372,950	4%

Explanation:

In 2007 OPUCN introduced a new management incentive program which is detailed at Exhibit 4, Tab 2, Schedule 8. The amount allotted to the program in 2007 was $65,000. This variance was also due in part to an average compensation increase of 3% over 2006, and the return of one staff member from Pregnancy Leave. Based on the results of the AON study of future benefit liabilities (available at Appendix C.1 and C.2), OPUCN increased the accrual for future benefits by approximately $173,000.

Account	2006 Actual	2007 Bridge	Variance $	Variance %
Regulatory Expenses	130,298	429,818	299,520	3%

Explanation:

The variance in this account was mainly due to the introduction of a new sub-account to comply with an OEB requirement in 2007 to record CDM operating expenditures of approximately $297,000.

2007 Bridge compared to 2008 Test Years

Account	2007 Bridge	2008 Test	Variance $	Variance %
Overhead Distribution Lines and Feeders - Operation Labour	(81,483)	109,267	190,750	2%

Explanation:

The variance in this account is due to three main reasons. OPUCN was short one linesman prior to September 2007 so that the salary for this employee was only applied for four months in 2007 as opposed to twelve in 2008. The variance also reflects an increase in average compensation of 3%, in compliance with provisions of the union contract. As detailed in Exhibit 4, Tab 2, Schedule 6, two additional linesmen will be hired in 2008 to address issues with succession planning. The salary of one linesman is projected at only half an FTE amount for 2008 to reflect expected timing that a qualified linesman can be found and that that linesman is able to commence employment. This is reasonable in that past experience in finding a qualified candidate will take time (and so reflect this savings in projected 2008 OM&A costs and pass these savings through to customer rates). For the period beyond the rate year balance of the costs will either be recovered from efficiencies or OPUCN may apply to the Board for cost recovery.

Account	2007 Bridge	2008 Test	Variance $	Variance %
Management Salaries and Expenses	726,591	1,002,599	276,008	3%

Explanation:

The variance in this account is due partially to a forecast compensation increase averaging 3% in 2008. In addition, a new Project Engineer will be required in 2008, as per Exhibit 4, Tab 2, Schedule 6. The salary of the Project Engineer is projected at only half the FTE amount for 2008 to reflect expected timing that OPUCN can find a suitable candidate and for a new candidate to be able to commence employment. This is reasonable in that past experience in finding a qualified candidate will take time (and so reflect this savings in projected 2008 OM&A costs and pass these savings through to customer rates). For the period beyond the rate year balance of the costs will either be recovered from efficiencies or OPUCN may apply to the Board for cost recovery. The remaining cost increase is the result of maintaining regulatory requirements, including costs associated with distribution rate filings with the Board.

Account	**2007 Bridge**	**2008 Test**	**Variance $**	**Variance %**
Outside Services Employed	373,008	530,198	157,190	2%

Explanation:

The variance in this account is partially due to a projected inflationary increase of 3%. In addition for 2008, OPUCN intends to address short term requirements through contracting services for filling some gaps in Finance, Human Resources / Conservation Contractor, and Information Technology. These contract positions are necessary to improve efficiencies as they result in some indirect cost savings while providing training for existing staff to eventually take over additional responsibilities. The contractor to be hired in the Finance area will, in addition to providing analysis expertise as required, train existing finance staff with a view to developing expertise in OPUCN staff who will than take over the analysis functions. The contractor serving as an interim Director has been hired to undertake special projects which will not need to be

SHARED SERVICES

Fees and charges between affiliates are reviewed annually.

Affiliates are charged monthly fee charges based on and verified by an annual internal study which determines a percentage of total costs for facilities, supplies, office equipment maintenance, IT, and corporate services (consisting of human resources, legal and finance) supplied by the distribution company. At present 3% of these costs are allocated to the affiliates. The allocation percentage was determined by a review of the amount of resources (e.g. internal staff time spent) used by affiliates. The affiliates are billed monthly for these charges. Audit and tax preparation costs are billed at cost.

Mutual agreements between affiliates have set a standard hourly rate for labour charged. The rate is established by identifying average remuneration costs (wages and benefits), of a direct staff member.

The use of vehicles, usually only pickup trucks and vans, are charged out at hourly rates as established each year in an Allocation of Costs Study, pursuant to APH Article 340 requirements.

CORPORATE COST ALLOCATION

OPUC provides corporate governance services to OPUCN, OPUC Services, and OPUC Energy Services. The cost of these services includes the cost of activities to support the board of directors, board committees as well as executive management (CEO and CFO) and legal and consulting services.

Based on the level of activities expected in 2008 at OPUCN and the other two subsidiaries of OPUC (OPUC Energy Services and OPUC Services), OPUC is proposing to allocate 80% of its costs to OPUCN in the Test years, amounting to $480,000.

PURCHASE OF SERVICES

1.0 OPUCN's Purchasing Policy

OPUCN has a Purchasing Policy that is applied to the purchase of all services and products. This policy follows.

The Materials Manager is designated as the person responsible for purchasing (please refer to corporate organizational chart at Exhibit 1, Tab, 1, Schedule 13 for the Materials Manager). Purchase requisitions are forwarded to the Materials Manager for: monitoring of authority limits; procurement; possible supply from or inclusion in inventory; and tax considerations, if applicable.

The Purchasing Policy prescribes the following rules for purchases:

i) For purchase of materials or services $200.00 or less

A small pad order, petty cash or credit/purchasing card is used for these purchases. (Small pad orders and petty cash are only available in Purchasing/Stores)

ii) For purchase of materials over $200.00 and less than $2,000.00

A purchase order is required for the acquisition of all materials and services exceeding $200.00 in value when a credit/purchasing card is not the method of procurement.

iii) For Purchases up to $500.00 by Purchasing Card

A purchasing card is used by designated employees, for purchases up to $500.00.

iv) For Purchases over $2,000.00

The Materials Manager in consultation with staff will procure all materials or services greater than $2,000.00 using the competitive procurement process as set out in "Tenders, Request for Proposals and Request for Quotations". The purchase of goods and/or services having pricing or value in excess of $2,000.00, including taxes shall not be authorized unless:

- The required goods and/or services have been requisitioned in accordance with this Policy and prescribed procedure
- A method of purchase permitted under this Policy has been used and the purchase has been approved, in writing, by the appropriate level of authority as detailed in the "Authority Limits" section following.

v) For Purchases over $10,000.00

All purchases of materials and services greater than $10,000.00 must be approved, in writing, by two Executive Officers before the requisition is forwarded to the Materials Manager, except for materials to fulfill requirements of an approved work order. Work Orders must be authorized by the VP, of Engineering and Operations.

Tenders, Request for Proposals and Request for Quotations

Tenders, RFP and RFQ approval of purchases relative to dollar value are set out in Authority Limits. Tenders require at least three (3) written sealed quotes, received on or before a specified closing date and time, to be opened by the Materials Manager and the Department Head or their designate for evaluation and formalization for the Purchase Order. All records of tenders, RFPs and RFQs including the original copies should be retained by Purchasing. Reports will be prepared by the Materials Manager, forwarded to the Department Head for approval/signature and then forwarded to the Executive for approval/signatures (minimum two (2)).

Sole source purchases

These purchases must be approved by two Executive Officers.

Confirmation of purchase orders

Confirmation of approved purchase orders will only be issued as per the approval requirements listed below.

Authority Limits

Dollar Range	Procurement Process	Authority Level
Any Dollar Value	Emergency Purchase	Department Head
0 – 200.00	Small Pad Order	Employee
0 – 500.00	Purchasing Card	Employee
0 – 2,000.00	Credit Card	Department Head
0 – 5,000.00	Credit Card	Executive Officer
2,000 – 10,000.00	Informal or Formal Quotation	Materials Manager & Department Head
10,000 + Capital Works Projects Only	Informal or Formal Quotation, Tender, Request for Proposal	Materials Manager & Executive Officer
10,000 +	Formal Quotation/Tender Direct Negotiation Contract Extension Request for Proposal	Two Executive Officers
Sole Source Purchase		Two Executive Officers

2.0 Purchasing Transactions

Following is a list of vendors from whom OPUCN purchased services related to OM&A. OPUCN applies its purchasing policy rigorously to all such purchases.

2006 Purchases

Vendor	Service
GREEN-PORT ENVIRONMENTAL LTD.	Disposal of toxic materials
KITCHEN KITCHEN SIMESON MCFARLANE	Legal services
CUNNINGHAM GREGORY & COMPANY	Conservation consultant
BELL CANADA	Telephone system
360 VISIBILITY INC.	Financial software support
GUTHRIE INSURANCE BROKERS LTD.	Property insurance
ALEX IRVINE MOTORS LTD.	Dump truck purchase
UTILITY SOLUTIONS CORPORATION	Distribution design
GE MULTILIN	Electronic equipment
POLECARE INTERNATIONAL INC.	Wood pole study
ITRON CANADA INC.	Metering services
POSI-PLUS ONTARIO INC.	Bucket truck purchase
LEA CONSULTING LTD.	Construction services
SECURITAS CANADA LIMITED	Site security
Shell Canada Products Ltd.	Fuels
KUBRA DATA TRANSFER LTD.	Bill printing & mailing
M.E.T. UTILITIES MANAGEMENT LTD.	Meter reading
HYDRO ONE	Long term load transfers
HARPER DETROIT DIESEL-ALLISON	Vehicle maintenance
ONT LINE CLEARING&TREE SRVC LT	Forestry services
LIDACO CONTRACTING LTD	Backhoe operator
MAPLE LANE NURSERIES	Lawns, gardens, etc
OPTILINX SYSTEMS INC.	Directional boring
ANGUS GEOSOLUTIONS INC.	Consultant – GIS system
Canada Power Products Corp.	Switch gear
PROMARK TELECON INC.	Cable locates
Westburne/Ruddy Electric	Electrical equipment
ERNST & YOUNG	Auditor
BLACK & MACDONALD	Contractor – substation rebuild
BADGER DAYLIGHTING INC.	Vactoring services
ENBRIDGE CONSUMERS GAS	Secondary utility hookups
ONTARIO MOTOR SALES LIMITED	Pickup trucks, vans
CPC EAST CUSTOMER COMPLIANCE	Postage
MC. G. POLELINE LTD.	Lineman services
Guelph Utility Pole Company	Wood poles
ERIE THAMES SERVICES	Billing, meter testing
RON ROBINSON	Construction contractor
Guillevin International Inc.	Maintenance hardware
ROBERT B. SOMERVILLE	Directional boring
Grafton Utility Supply	Cable, wire, transformers, line

hardware

2007 Purchases to July 31

UTILITY SOLUTIONS CORPORATION	Distribution Design
Shell Canada Products Ltd.	Fuels
SECURITAS CANADA LIMITED	Site Security
M.E.T. UTILITIES MANAGEMENT LTD.	Meter reading services
HARPER DETROIT DIESEL-ALLISON	Vehicle maintenance
MARSH CANADA LTD.	Risk management services
SkyCast	Streetlight poles
HYDRO ONE	Long term load transfers
ONTARIO ENERGY BOARD	Regulatory
LIDACO CONTRACTING LTD	Backhoe operator
ANGUS GEOSOLUTIONS INC.	Consultant
MEARIE MANAGMENT	Insurance
Westburne/Ruddy Electric	Electrical equipment
ONTARIO CENTRES OF EXCELLENCE	CDM Collaboration
ONT LINE CLEARING&TREE SRVC LT	Forestry services
ENBRIDGE CONSUMERS GAS	Secondary service hookups
ERNST & YOUNG	Auditor
Guelph Utility Pole Company	Wood poles
OPTILINX SYSTEMS INC.	Directional boring
ITRON CANADA INC.	Metering
PROMARK TELECON INC.	Cable locates
BLACK & MACDONALD	Contractor – substation rebuild
BADGER DAYLIGHTING INC.	Vactoring
SPATIALINFO INC.	Network management software
GUTHRIE INSURANCE BROKERS LTD.	Insurance services
MC. G. POLELINE LTD.	Temporary linemen
CPC EAST CUSTOMER COMPLIANCE	Postage
Guillevin International Inc.	Maintenance hardware
ERIE THAMES SERVICES	Billing, bill printing, mailing
POSI-PLUS ONTARIO INC.	Double bucket truck
RON ROBINSON	Subcontractor – construction
Grafton Utility Supply	Cable, wire, transformers, line hardware

EMPLOYEE COMPENSATION, INCENTIVE PLAN EXPENSES, PENSION EXPENSE AND POST RETIREMENT BENEFITS

1.0 Employee Compensation

Number of employees (Full-time equivalents (FTE's):

	2006 Board Approved	2006 Actual	2007 Bridge	2008 Test
Executive	0	0	0	0
Management	15	15	12	14
Non-Unionized	6	6	6	6
Unionized	63	64	64	68
	84	**85**	**82**	**88**

Executive salaries are paid by the parent company, Oshawa Power and Utilities Corporation.

Number of employees (Part-time equivalents (PTE's):

OPUCN had no part-time employees in 2006 and has no plans for any in the Bridge year or the Test year.

Proposed new full time positions for 2008 Test year

OPUCN has identified a need for six new positions in 2008 as detailed below. These positions were identified after a careful assessment of OPUCN's needs, existing resources, and retirement patterns. Past experience suggests that many of these positions, particularly the technical ones, will take some time to fill and even if all six positions are advertised as the beginning of 2008, some will not be filled until at least mid 2008 Test Year. In addition, OPUCN expects attrition due to retirements and other factors during 2008 and 2009. Practically, experience suggests that, of these six positions, the cost equivalent of only four will be filled in 2008. For that reason, OPUCN is reflecting costs for four full time employees rather than six in the 2008 OM&A forecast for 2008.

A workforce aging report entitled "The Aging Workforce And Human Resources Development Implications For Sector Councils" was prepared for The Alliance of Sector Councils by R.A. Malatest & Associates in 2003 using 2001 census figures. It found that 40% of all employees in the Utilities sector in Canada were 45 years of age or older and 6% were 55 years of age or older. The median age for retirement in the sector was 56.6 years. This means that 46%, or close to half, of all employees in the utilities sector in 2001 were within 10 years of retirement. The Canadian Electricity Association conducted a study in 2004 and issued a report entitled "Keeping The Future Bright: 2004 Canadian Electricity Human Resource Sector Study" which found similar numbers with 45.5% of employees expected to retire within 10 years. OPUCN is facing the retirement of a large part of its workforce in the next ten years. Many of the positions coming vacant are highly specialized and it is difficult to find fully qualified personnel to fill them. OPUCN will, for the most part, be hiring junior people and apprentices and training them in our operations. This succession planning takes some time and it is necessary to start the process now.

<u>Customer Service Supervisor</u>

This position was filled prior to 2007. At that time the Customer Service Manager retired and the Customer Service Supervisor has since assumed those duties in addition to her supervisory duties. This temporary arrangement cannot be sustained. Therefore, OPUCN intends to fill this vacant position in 2008.

<u>Project Engineer</u>

The increase in development in Oshawa has created a need for a new project engineer to assist with engineering design functions. OPUCN currently has one Project Engineer who is working at capacity. A second engineer is required to meet the increasing demand that OPUCN's existing Project Engineer is facing, including:

- Expansion of the distribution system to accommodate new customers
- Increased volume of enhancement projects to rebuild aging infrastructure and upgrade municipal substations
- The requirement of additional system capacity through the addition of a new municipal substation and transformer station which will be required in the near future
- Electrical Safety Authority (ESA) requirements with regards to engineering standards, distribution system material procurement and third party attachments
- Distribution system efficiency requirements to provide conservation measures such as power factor correction and distribution system optimization

Apprentice Meter Technician

OPUCN needs to hire an apprentice meter technician primarily for two reasons. The first is to fill a vacant position. Initial staffing in the OPUCN meter department had two meter technicians, three servicemen, one MDSR and one operation assistant. A supervisor position was added to cover meter and facilities and a meter technician was promoted to that position. The meter technician position was left vacant although the need for a technician has grown along with the growth in Oshawa. As equipment becomes more and more computer-controlled, OPUCN is getting more complaints of "dirty power". A technician's expertise is required to troubleshoot many of these issues. The second reason relates to two retirements that are expected in 2008 and 2009. It takes four years to train a journeyman meter technician. The shortage of meter technicians throughout the utility industry makes it very difficult to find a fully trained meter technician so OPUCN will not be hiring a junior person to fill the vacancy. An apprentice meter technician hired today will be on his or her way to becoming a journeyman technician soon after the expected retirements.

Junior Technical Services Technician

The work load for the technicians at OPUCN has recently increased due to the new third party attachment requirement. One technician has recently retired and the remaining technicians are having difficulty keeping records current for these attachments and for new jobs. A technical service technician spends over 75% of their time processing applications for attachment to OPUCN poles and making sure that joint use agreements are up-to-date and yearly billing is performed correctly. None of the current technicians are junior staff and this paperwork is not an efficient use of their expertise. A junior technician could take over this paperwork as part of his or her training and release fully trained technicians for ensuring the safety and reliability of OPUCN's system.

Apprentice Linemen (2)

OPUCN has an aging workforce, especially among its tradespeople. It is expected that four or five tradespeople will retire within the next five years. The amount of plant which has been and is being installed is very high due to the growth in Oshawa and this has led to more work for all tradespeople. It will be necessary to have more supervision within the next five years to ensure the safety of employees and the public. Supervisors with experience in the system must be drawn from the existing labour pool, resulting in a need for replacement linemen. It is very difficult to find experienced technical staff and the Ontario government, EUSA and the EDA have all called for distributors to increase their apprenticeship programs to bring more trained tradespeople into the system. OPUCN is committed to developing new staff through apprenticeship programs. It takes five years to train an Apprentice and another five years after that for most line staff to become really productive. For these reasons, OPUCN will be adding two Apprentice Lineman positions in 2008.

Compensation (Total Salary and Wages ($)):

These figures do not include compensation for the CEO, the CFO, or Board of Directors as these executives are employed by OPUCN's parent Oshawa Power and Utilities Corporation (OPUC). As described at Exhibit 1, Tab 1, Schedule 14, OPUCN pays OPUC a monthly service fee for services that include, among other things, executive management.

	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
Executive	0	0	0	0	0	0	0	0
Management	1,095,475	73,032	1,392,311	92,821	1,381,043	115,087	1,496,666	106,905
Non-Unionized	387,315	64,552	293,517	48,920	367,914	61,319	383,631	63,939
Unionized	3,889,904	61,745	3,970,306	62,036	4,255,827	66,497	4,667,667	68,642
	5,372,694	199,329	5,656,134	203,776	6,004,784	242,903	6,547,964	239,485

The difference between 2006 Approved and 2006 Actual is due to the fact that the 2006 Approved is based on salaries and wages from 2004. There were increases in both pay rates and head count between 2004 and 2006.

Compensation (Total Benefits ($)):

	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
Executive	0	0	0	0	0	0	0	0
Management	398,587	26,572	211,416	14,094	309,875	25,823	366,677	26,191
Non-Unionized	126,785	21,131	120,434	20,072	108,911	18,152	112,873	18,812
Unionized	1,385,308	21,989	1,528,891	23,889	2,028,957	31,702	2,218,508	32,625
	1,910,680	69,692	1,860,741	58,056	2,447,743	75,677	2,698,058	77,629

The average for the 2007 Bridge year includes the effect of a future benefits adjustment of $515,000 projected through 2007 and 2008. The adjustment was made based on an actuarial study performed by AON Consultants for 2007 and 2008. This study was filed as an update to the report written in 2006. the original report and the update are attached as at Appendices F.1 and F.2.

2.0 Employee Incentive Plan Expense

Compensation (Total Incentives ($)):

	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
Executive	0	0	0	0	0	0	0	0
Management	0	0	0	0	65,000	5,417	125,000	8,929
Non-Unionized	0	0	0	0	0	0	0	0
Unionized	0	0	0	0	0	0	0	0
	0	0	0	0	6,000	5,417	125,000	8,929

An incentive plan for non-executive, non-union employees will be introduced together with a performance management system during fall, 2007.

Performance Management

The system itself will help to achieve the company's current and long term goals of:

1. Achieving a safe work environment measurable in terms of "Hours worked without lost time injuries".

2. Reliability of Distribution System measurable in terms of SAIDI/SAIFI.

3. Customer Satisfaction – Measurable in terms of yearly Customer Satisfaction Index Survey results.

4. Operational Savings – Measurable in terms of OM&A (year/year) reductions.

The System will focus on progress towards goals, strengths and developmental needs for individuals as well as the organization as a whole. It has been designed to: establish clear expectations of performance; establish goals/objectives and the action plan for achieving them; monitor ongoing performance and provide coaching feedback to employees; measure and evaluate employees' contribution to corporate objectives.

The incentive program helps align performance with both corporate and individual objectives and will improve OPUCN's ability to attract and retain superior employees, thus providing a positive impact on our customers. The program is structured around corporate and individual measures of performance. Taken together, they are recognized as a successful method of enhancing the motivations of employees to undertake projects more effectively and to improve efficiencies in the workplace, thus providing increased benefit to the customer. The corporate objectives highlight a "balanced scorecard" of four measures as described above. The individual objectives are drawn from the employee's annual objective-setting process, part of the performance management system.

For participants to receive a payout from the corporate component, the company must meet or exceed each of four goals, resulting in a potential maximum of 80% of the total incentive package. The balance, 20%, is based on an evaluation of individual performance during the year. Incentive plan calculations are then based on a percentage of base salary and in each of the Bridge Year and the Test Year an amount of $125,000 has been budgeted for this program.

3.0 Pension Benefits

OPUCN and its employees contribute to the Ontario Municipal Employees Retirement Service (OMERS), a defined benefit pension plan for all OPUCN employees. OPUCN is only liable for contributions and so recognizes the expense related to this plan as contributions are due.

4.0 Post Retirement Benefits

Employee future benefits expense is recognized in the period in which the employees render services. The benefit is recorded on an accrual basis. Actuarial studies are performed on a regular basis to determine the cost of post-employment benefits offered to employees and retirees using the projected benefit method, pro-rated on years of service.

OPUCN's actuarial firm, AON Consultants, has been used to review projected benefits costs for 2005, 2006, and now 2007 and 2008. Complying with CICA 3401 Projected Benefit Costs requirements, defined benefit cost net of benefits payments for 2007 and 2008 was determined to be $597,700. The AON report for 2007 and 2008 is appended at Appendices F.1 and F.2.

Total of Costs charged to O&M ($)):

	2006 Board Approved	Average	2006 Actual	Average	2007 Bridge	Average	2008 Test	Average
TOTAL	7,283,374	269,021	7,516,875	261,832	8,577,527	328,997	9,371,022	326,042

DEPRECIATION, AMORTIZATION AND DEPLETION

As illustrated by the following table, OPUCN proposes to use the same depreciation and amortization rates in the Test Year as approved by the Board in the 2006 EDR process.

	2006 Board Approved			2006 Actual			2007 Bridge			2008 Test		
Asset Description	Gross Assets	Depr Rate	Depr Expense	Gross Assets	Depr Rate	Depr Expense	Gross Assets	Depr Rate	Depr Expense	Gross Assets	Depr Rate	Depr Expense
Conservation & Demand Mgt. Exp. & Recoveries	33,008	4%	1,320	-	4%	-	-	4%	-	-	4%	-
Land	98,896	0%	-	293,875	0%	-	293,875	0%	-	543,875	0%	-
Land Rights	-	4%	-	-	4%	-	-	4%	-	-	4%	-
Buildings and Fixtures	533,720	2%	10,674	534,820	2%	10,696	534,820	2%	10,696	534,820	2%	10,696
Leasehold Improvements	-	20%	-	-	20%	-	70,000	20%	14,000	462,220	20%	92,444
Transformer Station Equipment	-	3%	-	-	3%	-	-	3%	-	-	3%	-
Distribution Station Equipment	9,177,302	3%	305,604	10,178,638	3%	338,949	11,223,070	3%	373,728	14,321,662	3%	476,911
Storage Battery Equipment-Closing Balance	-	0%	-	-	0%	-	-	0%	-	-	0%	-
Poles, Towers and Fixtures	-	4%	-	-	4%	-	-	4%	-	-	4%	-
Overhead Conductors and Devices	32,342,983	4%	1,293,719	38,274,196	4%	1,530,968	41,005,209	4%	1,640,208	44,258,887	4%	1,770,355
Underground Conduit	-	4%	-	-	4%	-	-	4%	-	-	4%	-
Underground Conductors and Devices	36,313,012	4%	1,452,520	46,305,239	4%	1,852,210	49,229,854	4%	1,969,194	51,157,929	4%	2,046,317
Line Transformers	15,531,506	4%	621,260	15,483,326	4%	619,333	15,806,456	4%	632,258	15,839,790	4%	633,592
Services	-	4%	-	-	4%	-	-	4%	-	33,333	4%	1,333
Meters	7,643,931	4%	305,757	8,130,095	4%	325,204	8,528,826	4%	341,153	9,088,826	4%	363,553
Land	-	0%	-	-	0%	-	-	0%	-	-	0%	-
Land Rights	-	4%	-	-	4%	-	-	4%	-	-	4%	-

Buildings and Fixtures	-	2%	-	(6,888)	2%	(138)	(6,888)	2%	(138)	(6,888)	2%	(138)
Leasehold Improvements	59,306	20%	11,861	124,275	20%	24,855	125,275	20%	25,055	125,275	20%	25,055
Office Furniture and Equipment	648,512	10%	64,851	696,219	10%	69,622	841,204	10%	84,120	1,053,651	10%	105,365
Computer Equipment - Hardware	1,770,083	20%	354,017	1,926,726	20%	385,345	1,950,966	20%	390,193	1,992,966	20%	398,593
Computer Software	55,039	50%	27,520	136,244	50%	68,122	286,244	50%	143,122	310,244	50%	155,122
Transportation Equipment	3,908,309	20%	781,662	3,229,151	20%	645,830	3,544,261	20%	708,852	3,894,261	20%	778,852
Stores Equipment	23,366	10%	2,337	24,516	10%	2,452	24,516	10%	2,452	149,516	10%	14,952
Tools, Shop and Garage Equipment	570,273	10%	57,027	728,260	10%	72,826	800,867	10%	80,087	867,534	10%	86,753
Measurement and Testing Equipment	122,828	10%	12,283	122,828	10%	12,283	122,828	10%	12,283	152,828	10%	15,283
Power Operated Equipment	-	13%	-	-	13%	-	-	13%	-	-	13%	-
Communication Equipment	259,585	20%	51,917	259,585	20%	51,917	589,585	20%	117,917	667,585	20%	133,517
Miscellaneous Equipment	1,058	10%	106	14,290	10%	1,429	14,290	10%	1,429	32,290	10%	3,229
Water Heater Rental Units	-	10%	-	-	10%	-	-	10%	-	-	10%	-
Load Management Controls - Customer Premises	107,035	10%	10,703	107,035	10%	10,703	107,035	10%	10,703	107,035	10%	10,703
Load Management Controls - Utility Premises	597,214	10%	59,721	600,737	10%	60,074	645,308	10%	64,531	1,143,308	10%	114,331
System Supervisory Equipment	241,949	10%	24,195	293,582	10%	29,358	293,582	10%	29,358	293,582	10%	29,358
Sentinel Lighting Rental Units-Closing Balance	-	10%	-	-	10%	-	-	10%	-	-	10%	-
Other Tangible Property-Closing Balance	-	0%	-	-	0%	-	-	0%	-	-	0%	-
Contributions and Grants - Credit	(7,763,546)	4%	(310,542)	(19,425,220)	4%	(777,009)	(19,425,220)	4%	(777,009)	(19,425,220)	4%	(777,009)
Smart Meters	-	4%	-	-	4%	-	-	4%	-	-	4%	-
GROSS ASSET TOTAL	102,275,371	5%	5,137,194	108,031,531	5%	5,335,029	116,605,966	5%	5,874,194	127,599,312	5%	6,489,170

LOSS ADJUSTMENT FACTOR CALCULATION

		2003	2004	2005	2006
A	"Wholesale" kWh (IESO)	1,232,724,170	1,178,441,190	1174501350	1151360440
B	Wholesale kWh for Large Use customer(s) (IESO)	-	-	-	-
C	Net "Wholesale" kWh (A)-(B)	1,232,724,170	1,178,441,190	1,174,501,350	1,151,360,440
D	Retail kWh (Distributor)	1,184,173,074	1,128,300,513	1,129,123,325	1,099,278,440
E	Retail kWh for Large Use Customer(s) (1% loss)	-	-	-	-
F	Net "Retail" kWh (D)-(E)	1,184,173,074	1,128,300,513	1,129,123,325	1,099,278,440
G	Loss Factor [(C)/(F)]	1.0410%	1.0444%	1.0402%	1.0474%
H	Distribution Loss Adjustment Factor	1.0466%	1.0466%	1.0466%	1.0466%
	Loss Factor (Three Year Average)			1.0419%	1.0440%
Total Utility Loss Adjustment Factor					
	LAF				
Supply Facility Loss Factor					
Distribution Loss Factors					
Secondary Metered Customer					
Total Loss Factor - Secondary Metered Customer < 5,000kW					
Total Loss Factor - Secondary Metered Customer > 5,000kW		1.0145	1.0145	1.0145	1.0145

Primary Metered Customer				
Total Loss Factor - Primary Metered Customer < 5,000kW				
Total Loss Factor - Primary Metered Customer > 5,000kW	1.0044	1.0044	1.0044	1.0044
Total Loss Factor				
Secondary Metered Customer				
Total Loss Factor - Secondary Metered Customer < 5,000kW	1.0466	1.0466	1.0466	1.0466
Total Loss Factor - Secondary Metered Customer > 5,000kW	1.0146	1.0146	1.0146	1.0146
Primary Metered Customer				
Total Loss Factor - Primary Metered Customer < 5,000kW	1.0361	1.0361	1.0361	1.0361
Total Loss Factor - Primary Metered Customer > 5,000kW	1.0045	1.0045	1.0045	1.0045

OPUCN's distribution loss factor remains under 5%.

TAX CALCULATIONS

Summary of Income Tax Calculation

	2006 Board	2006 Actual	2007 Bridge	2008 Test
Determination of Taxable Income				
Regulatory Net Income (before tax)	**2,383,649**	**2,470,583**	**2,643,014**	**2,655,533**
Book to Tax Adjustments				
Additions to Accounting Income:				
Depreciation and amortization	3,411,711	3,659,000	3,891,960	4,395,489
Employee Benefit Plans - accrued, not paid				
Hedge loss - accrued				
Non-deductible meals and entertainment expense	4,634	5,840	6,000	6,000
Reserves from financial statements- balance at year end	8,147,142	8,608,000	8,781,800	8,954,600
Financing fees deducted in books	-	4,945	4,945	4,945
Actual Interest Expense	-	-	2,033,171	2,014,952
Research & Development ITC	1,000	-		
Total Additions	**11,564,487**	**12,277,785**	**14,717,876**	**15,375,986**
Deductions from Accounting Income:				
Capital Cost Allowance	2,843,952	2,937,236	3,214,839	3,851,485
Reserves from financial statements - balance beg. year	7,819,342	8,387,075	8,608,000	8,781,800
Interest capitalized for accounting deducted for tax				
Financing Fees for Tax Under S.20(1)(e)	-	8,667	8,667	8,667
Deemed Interest Expense	-	-	2,047,542	1,996,893
Employee Benefit Plans - amounts paid				
Hedge loss - payment				
Environmental costs (incl. in amortization)				
Capitalized pension costs				

Capitalized overhead costs				
Surplus staff payments				
Total Deductions	**10,663,294**	**11,332,978**	**13,879,048**	**14,638,845**
Regulatory Taxable Income	**3,284,842**	**3,415,390**	**3,481,842**	**3,392,674**
Corporate Income Tax Rate	36.120%	36.120%	36.120%	34.500%
Subtotal				
Less: R&D ITC (0.3)				
Regulatory Income Tax	**1,186,485**	**1,233,639**	**1,257,641**	**1,170,473**
Calculation of Utility Income Taxes				
Income Taxes (Line 23)	1,186,485	1,233,639	1,257,641	1,170,473
Large Corporation Tax (Line 14, page 2)	-	-	-	-
Total Taxes	**1,186,485**	**1,233,639**	1,257,641	1,170,473
Provision for Income Taxes (PILS)				
Income Tax Provision (Grossed up for Income Taxes)	**1,857,365**	**1,931,182**	**1,968,756**	**1,786,981**
Ontario Capital Tax (not Grossed up for Income Taxes)	**218,872**	**240,487**	**131,741**	**148,936**
Total Provision for Income Taxes (PILS)	**2,076,237**	**2,171,669**	**2,100,497**	**1,935,917**
Tax Rates				
Federal Tax	22.120%	22.120%	22.120%	20.500%
Federal Surtax	-	-	-	-
Provincial Tax	14.000%	14.000%	14.000%	14.000%
Total Tax Rate	36.120%	36.120%	36.120%	34.500%

OPUCN is not subject to Large Corporate Tax (LCT) provisions.

INTEREST EXPENSE

2006 OEB Approved

Deemed Interest Expense	1,920,162
2006 Actual Interest Expense	1,587,157
2006 Capitalized Interest (USoA 6040)	186,772
2006 Capitalized Interest (USoA 6042)	0
Interest on capitalized lease	0
2006 Actual Interest	1,773,929
Total Interest	1,773,929
Excess Interest Expense for 2006 PILs	0

2006 Actual

Deemed Interest Expense	1,968,040
2006 Actual Interest Expense	2,106,669
2006 Capitalized Interest (USoA 6040)	67,603
2006 Capitalized Interest (USoA 6042)	
Interest on capitalized lease	
2006 Actual Interest	2,174,272
Total Interest	2,174,272
Excess Interest Expense for 2006 PILs	206,232

2007

Deemed Interest Expense	2,141,463
2005 Actual Interest Expense	2,033,171
2005 Capitalized Interest (USoA 6040)	67,603
2005 Capitalized Interest (USoA 6042)	47,706
Interest on capitalized lease	0
2005 Actual Interest	2,148,480
Total Interest	2,148,480
Excess Interest Expense for 2007 PILs	7,017

2008

Deemed Interest Expense	2,141,463
2005 Actual Interest Expense	2,014,952
2005 Capitalized Interest (USoA 6040)	67,603
2005 Capitalized Interest (USoA 6042)	70,065
Interest on capitalized lease	0
2005 Actual Interest	2,152,620
Total Interest	2,152,620
Excess Interest Expense for 2008 PILs	11,157

CAPITAL COST ALLOWANCE (CCA)

2006 Board Approved (based on 2004 Tax Filing)

Class	Class Description	UCC Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule (1/2 Additions Less Disposals)	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	52,273,242	6,143,379		58,416,621	3,071,690	55,344,932	4	2,213,797	56,202,824
2	Distribution System - pre 1988				-	-	-		-	-
8	General Office/Stores Equip	529,547	120,443		649,990	60,222	589,769	20	117,954	532,036
10	Computer Hardware/ Vehicles	1,121,971	736,522		1,858,493	368,261	1,490,232	30	447,070	1,411,423
10.1	Certain Automobiles				-	-	-		-	-
12	Computer Software	19,470	16,099		35,569	8,050	27,520	100	27,520	8,050
13 1	Lease # 1	25,281			25,281	-	25,281		9,200	16,081
13 2	Lease #2	8,485			8,485	-	8,485		2,424	6,061
13 3	Lease # 3				-	-	-		-	-
13 4	Lease # 4				-	-	-		-	-
14	Franchise				-	-	-		-	-
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs				-	-	-		-	-
42	Fibre Optics	94,623			94,623	-	94,623	12	11,355	83,268
43.1	Certain Energy-Efficient Electrical Generating Equipment				-	-	-		-	-
45	Computers & Systems Software acq'd post Mar 22/04				-	-	-		-	-
46	Data Network Infrastructure Equipment (acq'd				-	-	-		-	-

	post Mar 22/04)									
47	Distribution System - post 22-Feb-2005				-	-	-		-	-
98	No CCA				-	-	-		-	-
	TOTAL	54,072,619	7,016,443	-	61,089,062	3,508,222	57,580,841		2,829,319	58,259,743

2006 Actual (based on 2006 Tax Filing)

Class	Class Description	UCC Opening Balance	Additions	Adjustments	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	56,983,957	2,376,712	(67,603)		59,360,669	1,188,356	58,104,710	4	2,324,188	56,968,878
2	Distribution System - pre 1988					-	-	-		-	-
8	General Office/Stores Equip	581,559	166,946			748,505	83,473	665,032	20	133,006	615,499
10	Computer Hardware/ Vehicles	987,996			64,000	987,996	(32,000)	923,996	30	277,199	646,797
10.1	Certain Automobiles					-	-	-		-	-
12	Computer Software	29,325	22,555			51,880	11,278	40,603	100	40,603	11,278
13 1	Lease # 1	6,881				6,881	-	6,881		6,881	-
13 2	Lease #2	3,637				3,637	-	3,637		2,424	1,213
13 3	Lease # 3					-	-	-		-	-
13 4	Lease # 4					-	-	-		-	-
14	Franchise					-	-	-		-	-
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs					-	-	-		-	-
42	Fibre Optics	73,276				73,276	-	73,276	12	8,793	64,483
43.1	Certain Energy-Efficient Electrical Generating Equipment					-	-	-		-	-
45	Computers & Systems Software acq'd post Mar 22/04	256,932	126,772			383,704	63,386	320,318	45	144,143	239,561

46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)					-	-	-		-	-
47	Distribution System - post 22-Feb-2005					-	-	-		-	-
98	No CCA	2,654,000	1,310,000			3,964,000	655,000	3,309,000		-	3,964,000
	TOTAL	61,577,563	4,002,985	(67,603)	64,000	65,580,548	1,969,493	63,447,453		2,937,237	62,511,708

2007 Bridge

Class	Class Description	UCC Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	56,968,878	-		56,968,878	-	56,968,878	4%	2,278,755	54,690,122
2	Distribution System - pre 1988	-	-		-	-	-		-	-
8	General Office/Stores Equip	615,499	593,163		1,208,662	296,582	912,080	20%	182,416	1,026,246
10	Computer Hardware/ Vehicles	646,797	315,110		961,907	157,555	804,352	30%	241,306	720,602
10.1	Certain Automobiles	-	-		-	-	-		-	-
12	Computer Software	11,278	150,000		161,278	75,000	86,278	100%	86,278	75,000
13 1	Lease # 1	1,213	-		1,213	-	1,213		1,213	-
13 2	Lease #2	-	-		-	-	-		-	-
13 3	Lease # 3	-	70,000		70,000	35,000	35,000	20%	7,000	63,000
13 4	Lease # 4	-	-		-	-	-		-	-
14	Franchise	-	-		-	-	-		-	-
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	-	-		-	-	-		-	-
43	Certain Energy-Efficient Electrical Generating Equipment	-	-		-	-	-		-	-
45	Computers & Systems Software acq'd post Mar 22/04	239,561	24,240		263,801	12,120	251,681	45%	113,256	150,544

46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	-	-		-	-	-		-	-
47	Distribution System - post 22-Feb-2005	-	7,421,921		7,421,921	3,710,961	3,710,961	8%	296,877	7,125,044
98	No CCA	3,964,000	-		3,964,000	-	3,964,000		-	3,964,000
42	Fibre Optics	64,483	-		64,483	-	64,483	12%	7,738	56,745
			-				-		-	
	TOTAL	62,511,708	8,574,434	-	71,086,142	4,287,217	66,798,925		3,214,839	67,871,303

2008 Test

Class	Class Description	UCC Opening Balance	Additions	Dispositions	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	CCA	UCC Ending Balance
1	Distribution System - 1988 to 22-Feb-2005	54,690,122	3,098,592		57,788,714	1,549,296	56,239,418	4%	2,249,577	55,539,138
2	Distribution System - pre 1988	-	-		-	-	-		-	-
8	General Office/Stores Equip	1,026,246	1,028,113		2,054,359	514,057	1,540,303	20%	308,061	1,746,299
10	Computer Hardware/ Vehicles	720,602	350,000		1,070,602	175,000	895,602	30%	268,680	801,921
10.1	Certain Automobiles	-	-		-	-	-		-	-
12	Computer Software	75,000	24,000		99,000	12,000	87,000	100%	87,000	12,000
13 1	Lease # 1	-	-		-	-	-		-	-
13 2	Lease #2	-	-		-	-	-		-	-
13 3	Lease # 3	63,000	392,220		455,220	196,110	259,110	20%	51,822	403,398
13 4	Lease # 4	-	-		-	-	-		-	-
14	Franchise	-	-		-	-	-		-	-
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	-	-		-	-	-		-	-
43	Certain Energy-Efficient Electrical Generating Equipment	-	-		-	-	-		-	-

45	Computers & Systems Software acq'd post Mar 22/04	150,544	42,000		192,544	21,000	171,544	45%	77,195	115,349
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	-	-		-	-	-		-	-
47	Distribution System - post 22-Feb-2005	7,125,044	5,808,420		12,933,464	2,904,210	10,029,254	8%	802,340	12,131,124
98	No CCA	3,964,000	-		3,964,000	-	3,964,000		-	3,964,000
42	Fiber Optics	56,745	-		56,745	-	56,745	12%	6,809	49,007
							-		-	
	TOTAL	67,871,303	10,743,345	-	78,614,649	5,371,673	73,242,976		3,851,484	74,762,236

CAPITAL TAX CALCULATIONS

	2006 Board Approved		2006 Actual		2007 Bridge		2008 Test	
	Ontario	**Federal**	**Ontario**	**Federal**	**Ontario**	**Federal**	**Ontario**	**Federal**
Total Rate Base	52,969,980	52,969,980	54,263,268	54,263,268	58,724,947	58,724,947	64,758,238	64,758,238
Exemption	(10,000,000)	(50,000,000)	(10,000,000)	(50,000,000)	(12,500,000)	(50,000,000)	(12,500,000)	(50,000,000)
Deemed Taxable Capital	42,969,980	2,969,980	44,263,268	4,263,268	46,224,947	8,724,947	52,258,238	14758,238
Rate	0.300%	0.125%	0.300%	0.125%	0.285%	0.000%	0.285%	0.000%
Gross Tax Payable	128,910	3,712	132,790	0	131,741	0	148,936	0
Surtax		0		0		0		0
Net Tax Payable	**128,910**	**3,712**	**132,790**	**0**	**131,741**	**0**	**148,936**	**0**

Note: Capital Tax has been determined by use of Rate Base as a proxy.

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

OPUCN is seeking approval to disperse its deferral and variance account balances as of December 31, 2006. The total dispersal amounts to $2.38 million as illustrated by the table at Exhibit 5, Tab 1, Schedule 2. OPUCN proposes to recover this amount using the methodology described at Exhibit 5, Tab 1, Schedule 3. Descriptions of the deferral and variance accounts used by OPUCN are set out below.

COMMODITY ACCOUNTS ARE CLASSIFIED AS FOLLOWS:

Account 1588	Retail Settlement Variance Account (RSVA) – Power
Description	This account is used to record the interest on the net difference between the energy amount billed to customers and the energy charge to a distributor using the settlement invoiced from the IESO.
Account 1588	RSVA Power – Sub-account Global Adjustments
Description	Effective January 1, 2005, this account reflects the interest on the monthly differences between IESO the amount charged to customers, which is a preliminary amount calculated by the IESO for billing purposes, and the final amount charged or credited by the IESO on the monthly Settlement Invoice for Global Adjustment.

NON-COMMODITY ACCOUNTS ARE CLASSIFIED IN TWO CATEGORIES AS FOLLOWS:

Wholesale and Retail Market Variance Accounts

Account 1580	RSVA – Wholesale Market Service Charges
Description	This account is used to record the net of the amount charged by the IESO, based on the Settlement Invoice, for the operation of the ISO administered market and operations of the IESO; and the amount billed to customers using Board approved WMS rates.
Account 1582	RSVA - One-time Wholesale Market Service
Description	This account reflects the carrying charge balance of the RSVA One-time charge. This was a non-recurring IESO charge applied through the Settlement Invoice for one time Hydro One charges recorded in IESO invoices in 2002 – 2004.

Account 1584	RSVA – Retail Transmission Network Charge
Description	This account records the net of the amount charged by the IESO, based on Settlement Invoice entries, for transmission network services; and the amount billed to customers using Board approved rates.
Account 1586	RSVA – Retail Transmission Connection Charge
Description	This account records the net of the amount charged by the IESO, based on Settlement Invoice entries, for transmission connection charges; and the amount billed to customers using Board approved rates.

Utility Deferral Accounts

Account 1508	Other Regulatory Assets
Description	This account is used to return an over collection as the result of using a Board approved rate adjustment, effective July 1, 2005, to compensate for the loss of a major customer.
Account 1555	Smart Meter Capital Variance Account
Description	This account records the collection of the generic smart meter capital rate approved by the Board in the EDR 2006 hearings. OPUCN is not proposing the recovery of this account during this rate application.
Account 1562	Deferred Payments in Lieu of Taxes (PILs)
Description	This account records the amount resulting from Board approved methodology for calculating the PILs proxy amount from 2002 onwards, and 2001 Deferred Account Allowance. As well, result from PILs Deferral Account Allowance and any entries resulting from the pass-through of variances between Deferral Account Allowance and actual results as reflected in annual tax filing to Ministry of Finance.
Account 1592, 1590	Interest Improvement Resulting from RARA Account
Description	This is the interest as a result of the establishment of the RARA account. In addition, interest has been calculated up to December 31, 2006.

The amounts recorded by OPUCN in Account 1562 (PILs) were determined from a report by RDI Consulting Inc. This report is included as Appendix B to this filing.

CALCULATION OF BALANCES BY ACCOUNT

	OEB	Opening	Carrying Charges		Net Accruals		Adjustments		Ending
	Account	Balance	Period	LTD	Period	LTD	Period	LTD	Balance
		Dec 31/ 06	Dec 31/ 06	Apr 30/08	Dec 31/ 06	Apr 30/08	Dec 31/ 06	Apr 30/08	
Commodity accounts are classified as follows:									
1588 Retail Settlement Variance Account - Power		0							
1588 RSVA Power - Sub-account Global Adjustments	1588	210,554	(94,838)	12,885	210,554	(81,953)			128,601
Non-commodity accounts are classified in two categories as follows:									
Wholesale and Retail Market Variance Accounts									
1518 Retail Cost Variance Account - Retail		0							
1548 Retail Cost Variance Account - STR		0							
1580 Retail Settlement Variance Account - Wholesale Market Service Charges	1580	(691,717)	14,147	(42,333)	(691,717)	(28,186)			(719,903)
1582 Retail Settlement Variance Account - One-time Wholesale Market Service	1582	59,408	3,997	3,636	59,408	7,633			67,041
1584 Retail Settlement Variance Account - Retail Transmission Network Charges	1584	2,891,363	106,713	176,952	2,891,363	283,665			3,175,028
	1586	(1,603,387)	(2,253)	(98,128)	(1,603,387)	(100,381)			(1,703,768)
Utility Deferral Accounts									
1508 Other Regulatory Assets	1508	(21,501)	0	0	(21,501)	0			(21,501)
1508 Other Regulatory Assets - Sub-account OEB Cost Assessments									
1508 Other Regulatory Assets - Sub-account Pension Contributions									
1525 Miscellaneous Deferred Debits									
1562 Deferred Payments in Lieu of Taxes	1562	499,155	282,952	30,548	499,155	313,500			812,655
1563 PILs contra account	1563	(499,155)			(499,155)	0	499,155		0
1565 Conservation and Demand Management Expenditures and Recoveries									
1555 Smart Meter Capital Variance Account	1555	(100,890)	0	(6,175)	(100,890)	(6,175)	100,890		

1572 Extraordinary Event Losses									
1574 Deferred Rate Impact Amounts									
2425 Other Deferred Credits									
1590 Recovery of Regulatory Asset Balances	1590	1,893,838	203,655	71,027	1,893,838	274,682		(1,523,352)	645,168
Closed Accounts not classified are as follows:									
1570 Qualifying Transition Costs (closed December 31, 2002)									
1571 Pre-Market Opening Energy Variances (closed April 30, 2002)									
Totals		2,637,668	514,373	148,412	2,637,668	662,785	600,045	(1,523,352)	2,383,321

METHOD OF RECOVERY

OPUCN has calculated the 2006 ending balance for each variance account as the actual balance at December 31, 2006. These balances agree with our Audited Financial Statements and OEB RRR filings. Disposed amounts projected to be collected through the OEB approved Regulatory Asset recovery have been applied up to May 1, 2008. Carrying costs up to April 1, 2008 have been calculated and added to determine final total for disposal in this rate application in the amount of $2,383,321. OPUCN proposes to dispose of the this balance over a two year period commencing May 1, 2008 and ending on April 30, 2010, for an annual recovery amount of $1,119,661. The model used to determine disposition and determinates for proposed rate riders follows.

Account Description	Account Number	Dec31/06 Balance	Apr 30/08 Balance	Allocation Basis	Residential	GS < 50 KW	GS > 50 to 999	Intermediate	Large Users
Unrecovered Plant and Regulatory Study Costs	1505	-	-						
Other Regulatory Assets	1508	(21,501)	(21,501)	KWh	(9,184)	(2,653)	(6,619)	(1,486)	(1,334)
Preliminary Survey and Investigation Charges	1510	-	-						
Emission Allowance Inventory	1515	-	-						
Emission Allowances Withheld	1516	-	-						
Retail Cost Variance Account - Retail	1518	-	-						
Power Purchase Variance Account	1520	-	-						
Misc. Deferred Debits - incl. Rebate Cheques	1525	-	-						
Deferred Losses from Disposition of Utility Plant	1530	-	-						
Unamortized Loss on Reacquired Debt	1540	-	-						
Development Charge Deposits/ Receivables	1545	-	-						
Retail Cost Variance Account - STR	1548	-	-						
LV Variance Account	1550	-	-						
Smart Meter Capital Variance Account	1555	-	-						
Smart Meters OM&A Variance Account	1556	-	-						
Deferred Development Costs	1560	-	-						
Deferred Payments in Lieu of Taxes	1562	782,107	812,655	Dx Revenue	433,372	136,602	155,010	43,282	29,839
PILS Contra Account	1563	-	-						

CDM Expenditures and Recoveries	1565	-	-							
CDM Contra Account	1566	-	-							
Qualifying Transition Costs	1570	-	-							
Pre-Market Opening Energy Variances Total	1571	-	-							
Extra-Ordinary Event Losses	1572	-	-							
Deferred Rate Impact Amounts	1574	-	-							
RSVA - Wholesale Market Service Charge	1580	(677,570)	(719,903)	KWh	(307,490)	(88,814)	(221,603)	(49,760)	(44,664)
RSVA - One-time Wholesale Market Service	1582	63,405	67,041	KWh	28,635	8,271	20,637	4,634	4,159
RSVA - Retail Transmission Network Charge	1584	2,998,076	3,175,027	KWh	1,356,138	391,700	977,347	219,460	196,983
RSVA - Retail Transmission Connection Charge	1586	(1,605,640)	(1,703,767)	KWh	(727,724)	(210,192)	(524,459)	(117,765)	(105,704)
RSVA - Power	1588	115,716	128,602	KWh	54,929	15,865	39,587	8,889	7,979
Deferred PILs Account	1592	144,447	144,447	KWh	61,697	17,820	44,464	9,984	8,962
Other Deferred Credits	1590	59,208	59,208	KWh	25,289	7,304	18,226	4,092	3,673
Sub-total to Dispose at May1/08 or Dec31/06?	Apr30/08	**1,858,248**	**1,941,809**		**915,664**	**275,904**	**502,590**	**121,330**	**99,894**
Clear residual 1590 balance as of April 30/08?	YES				227,878	49,304	139,777	4,829	15,505
Total to Dispose at May1/08					**1,143,542**	**325,208**	**642,367**	**126,159**	**115,399**
Disposal period?	2 YEARS				571,771	162,604	321,183	63,079	57,700

Projected 2008 Rate Riders	**0.0011**	**0.0011**	**0.3593**	**0.3682**	**0.4116**
Rate Determinant	kWh	kWh	kW	kW	kW

OVERVIEW OF COST OF CAPITAL AND RATE OF RETURN

1.0 Capital Structure

OPUCN's current Board approved deemed capital structure is 50% debt and 50% equity. In accordance with the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* dated December 20, 2006 (the "Cost of Capital Report"), OPUCN proposes to transition to a 60/40 debt/equity ratio in equal increments over three years, commencing in 2008. Accordingly, OPUCN is following Board guidelines for a capital structure for 2008 of 53.3% debt and 46.7% equity.

2.0 Cost of Capital

OPUCN proposes a weighted cost of capital of 7.60% for the 2008 Test year as set out in more detail below.

3.0 Return on Equity

OPUCN is proposing an 8.79% return on equity for the 2008 Test Year, calculated in accordance with the Cost of Capital Report. Please refer to Exhibit 6, Tab 1, Schedule 4 for this calculation.

4.0 Cost of Debt

OPUCN is proposing a 6.70% debt rate for the 2008 Test Year, calculated in accordance with the Cost of Capital Report. Please refer to Exhibit 6, Tab 1, Schedule 3 for this calculation.

CAPITAL STRUCTURE

2006 Board Approved Elements	Rate Base	Deemed Capital Component	Indicated Cost Rate	Return Component %	Deemed Return Component $
	52,969,980				
Long-term debt		50.00%	7.25%	3.63%	1,920,162
Unfunded short-term debt					0
Preference shares					0
Common equity		50.00%	9.00%	4.50%	2,383,649
Total		100.00%	16.25%	4.06%	4,303,811

2007 Bridge Elements	Rate Base	Deemed Capital Component	Indicated Cost Rate	Return Component %	Deemed Return Component $
	58,724,947				
Long-term debt		50.00%	7.25%	3.63%	2,128,779
Unfunded short-term debt					0
Preference shares					0
Common equity		50.00%	9.00%	4.50%	2,642,623
Total		100.00%	16.25%	4.06%	4,771,402

2008 Test Elements	Rate Base	Deemed Capital Component	Indicated Cost Rate	Return Component %	Deemed Return Component $
	64,758,238				
Long-term debt		49.33%	6.70%	3.31%	2,140,423
Unfunded short-term debt		4.00%	4.77%	0.19%	123,559
Preference shares					0
Common equity		46.67%	8.79%	4.10%	2,656,573
Total		100.00%	20.26%	7.60%	4,920,554

COST OF DEBT

	2006 Board Approved			2006 Actual			2007 Bridge			2008 Test		
	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate	Principle	Carrying Costs	Calculated Cost Rate
Long-Term Debt												
Original Debt – Nov. 1, 2000	23,065,665	0	7.25%	23,065,665	0	7.25%	23,065,665	0	7.25%	23,065,665	0	7.25%
TD Debt – Dec 19, 2005	0	0	0%	7,000,000	0	4.90%	7,000,000	0	4.90%	7,000,000	0	4.90%
Debt Holder 3												
Debt Holder 4												
Total	23,065,665	0	7.25%	30,065,665	0	0.00%	30,065,665	0	0.00%	30,065,665	0	6.70%
Short-Term Debt												
No Short-Term Debt	0	0	0%	0	0	0%	0	0	0%	0	0	0%
Total	0	0		0	0		0	0		0	0	

RETURN ON EQUITY

The calculations used to determine the return on equity and the debt are taken from the Cost of Capital Report. The following explanation is an excerpt from the Cost of Capital Report, Appendix A and Appendix B.

Method to Update the Deemed Long-term Debt Rate

The Board will use the Long Canada Bond Forecast plus an average spread with "A/BBB" rated corporate bond yields to determine the updated deemed debt rate.

The following approach is consistent with the ROE method. As per the approach adopted in the 2006 EDRH, the ROE and the long-term debt rates are based on the same risk-free rate forecast. Therefore, they differ only through the risk premiums that reflect their distinct natures and for which lenders/investors seek commensurate returns. This approach simplifies the calculations and aims to make it easier to understand the numbers. Specifically, the Long Canada Bond Forecast (*LCBFt*) used will be the same as that used for updating the ROE. The average spread between "A/BBB" rated corporate bond yields and 30-year (long) Government of Canada Bond yields will be calculated as the average spread over the weeks of the month corresponding to the Consensus Forecasts.

The deemed Long-Term Debt Rate (*LTDRt*) will be calculated as follows:

$$LTDR_t = LCBF_t + \frac{\sum_{w} (CorpBonds_{w,t} - {}_{30}CB_{w,t})}{n}$$

Where:

- ***CorpBonds*** $_{w,t}$ is the average long-term corporate bond yield from Scotia Capital Inc. for week w of period t [Series V121761];

- ***$_{30}CB_{w,t}$*** is the 30-year (long) Government of Canada bond yield for week *w* of period *t* [Series V121791]; and

- ***n*** is the number of weeks in the month for which data are reported.

Method to Update ROE - ROE Update for any Period

Using March 1999 as the starting calculation and substituting for the initial ROE and Long Canada Bond Forecast approved by the Board in the Decision RP-1998-0001 the following is the adjustment formula for calculating the ROE at time *t*:

$$ROE_t = 9.35\% + 0.75 \times (LCBF_t - 5.50\%)$$

The ROE must be set in advance of the approved rates. The final ROE will be factored into rates using the Long Canada Bond Forecast based on *Consensus Forecasts* (as detailed below) and Bank of Canada data three months in advance of the effective date for the rate change. Therefore, for May 1 rate changes, the ROE will be based on January data – effectively *Consensus Forecasts* published during that month and Bank of Canada data for all business days during the month of January. The necessary data is available within the first or second business days after the end of the month and thus poses no delay for determining rates.

Long Canada Bond Forecast for any Period

For any period *t* the Long Canada Bond Forecast *LCBFt* can be expressed as:

$$LCBF_t = \left[\frac{_{10}CBF_{3,t} + _{10}CBF_{12,t}}{2} \right] + \frac{\sum_i (_{30}CB_{i,t} - _{10}CB_{i,t})}{I_t}$$

Where:

$_{10}CB_{3,T}$ is the 3-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;

$_{10}CB_{12,t}$ is the 12-month forecast of the 10-year Government of Canada bond yield as published in *Consensus Forecasts* at time *t*;

$_{30}CB_{i,t}$ is the actual rate for the 30-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39056] during the month (this is the previous month data, the same as used for updating the ROE for natural gas distribution) corresponding to time *t*;

$_{10}CB_{i,t}$ is the actual rate for the 10-year Government of Canada bond yield at the close of day *i* (as published by the Bank of Canada) [Series V39055] during the month corresponding to time *t*; and

It is the number of business days for which published 10- and 30- Government of Canada bond yields are published during the month corresponding to time *t*.

The calculation of OPUCN's Return on Equity follows.

Government of Canada Bond Yields	
3-month forecast of the 10-year bond yield	4.60%
12-month forecast of the 10-year bond yield	4.80%
Average actual prior month 30-year bond yield	4.17%
Average actual prior month 10-year bond yield	4.12%
Long Canada Bond Forecast (LCBF)	4.75%
Return On Equity	**8.79%**

ROE = 9.35% + 0.75 x (4.75% - 5.50%) = 8.79%

CALCULATION OF REVENUE DEFICIENCY

Calculation of Revenue Deficiency or Surplus

This Exhibit shows the calculation of the forecasted revenue deficiency for OPUCN during the 2008 Test year. This is a multi-step process.

- Calculate service revenue using Rate Base OM&A and amortization expenses calculated in Exhibit 4 and the return on capital calculated in Exhibit 6. Rate Base OM&A includes Ontario Capital Tax and Property Taxes.
- Calculate the base revenue requirement using the PILS calculation and the revenue offsets calculated in Exhibit 3.
- Use the existing rates and the load projections determined in Exhibit 2 to calculate net utility revenue assuming no change in the distribution rate structure.
- Use these calculated revenues and the base revenue requirement to determine revenue deficiency or sufficiency.

1.1 Calculation of Service Revenue Requirement

Rate Base OM&A Expenses	$10,792,063
Amortization Expenses	4,395,489
Total Distribution Expenses	15,187,552
Regulated Return On Capital	4,920,553
PILs (with gross-up)	1,935,917
Service Revenue Requirement	**22,044,022**

1.2 Calculation of Base Revenue Requirement

Service Revenue Requirement	$22,044,022	
Less: Revenue Offsets	(1,601,831)	
Base Revenue Requirement		**20,442,367**
Allocated To:		
Low Voltage Wheeling Costs	0	
Directly Assigned CDM	0	
Other	20,442,367	
Total		**20,442,367**

1.3 Calculation of Net Utility Income and Revenue Deficiency

Revenue	
Distribution Revenue	17,905,146
Other Operating Revenue (Net)	1,601,656
Total Revenue	19,506,802
Distribution Costs	
Operation, Maintenance, and Administration	10,446,613
Depreciation & Amortization	4,395,489
Property & Capital Taxes	345,450
Payment in Lieu of Taxes (PILS)	1935,917
Total Costs and Expenses	17,123,469
Sufficiency/ Deficiency	
Revenue before Interest Expense	2,383,333
Proposed Rate Base	64,780,648
Achieve Return on Rate Base	3.68%
Required Return on Rate Base	7.60%
Sufficiency/ Deficiency Rate of Return	-3.92%
Net Deficiency	(2,539,996)
Income Tax Rate	36.12%
Gross Deficiency	(3,976,199)

The forecasted revenue deficiency is mainly attributable to (i) the fact that EDR rates do not reflect the forecasted increase in OM&A, which, as described at Exhibit 4, Tab 2, Schedule 2, was significantly caused by new hires resulting from staff attrition and succession planning; and (ii) changes in capital expenditures and the resulting return on capital as described at Exhibit 6, Tab 1, Schedule 4. EDR 2006 was based on historic net fixed asset balances, with the half-year rule in place for expenditures in 2004. OPUCN has made significant investment in fixed assets in every year since 2004. OPUCN not only continued with much needed asset enhancements, but also experienced significant expansion as a result of major growth in sub-division construction over the past four to five years. The significant capital investments will continue in 2007 and 2008. OPUCN did not receive a return on investments for part of 2004, 2005, nor 2006. The results of the revenue deficiency calculation reflect this lack of return in the period leading up to this rate application.

COST ALLOCATION OVERVIEW

1.0 Cost Allocation Overview

On September 29, 2006 the Ontario Energy Board (the "OEB" or "Board") issued the Board directions on Cost Allocation Methodology for Electricity Distributors ("the Directions"). On November 15, 2006 the OEB also issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model ("the Model") and User Instruction (the Instructions") for the Model. OPUCN prepared this information filing consistent with its understanding of the Directions, the Guidelines, the Model and the Instructions. This study is attached to this Application as Appendix E.

The main purpose of this cost allocation filing was to provide evidence to identify OPUCN rate classifications that are being subsidized by other classes and those rate classifications that are over contributing based on the assumptions of the Model.

The OPUCN filing was comprised of a first run ("Run 1") and a second run ("Run 2"). Run 1 reflected the rate classifications as they were prior to May 1, 2006. Prior to May 1, the Unmetered Scattered Load ("USL") customers were included in the General Service < 50 kW rate classification. Run 2 had the USL customers pulled out of the General Service < 50 kW class to form a class of their own which is consistent with the current rate classifications used by OPUCN.

2.0 OPUCN's Revenue to Cost Ratios

The cost allocation study carried out in 2006 resulted in the calculation of revenue to cost ratios for each customer class served by OPUCN. The ratio is the percentage of distribution revenue collected compared to the costs allocated to each class. A result of 100% for a class would indicate that revenue collected from that class would exactly equal the distribution costs attributable to that customer class. A result of less than 100% for a class would indicate that the revenue recovered form the class does not cover the costs of supplying distribution services to those customers. A result of more than 100% indicates that the revenues collected are higher than the costs associated with electricity distribution for that class.

The results of the study for Oshawa PUC Networks Inc. are summarized in the following table.

Revenue to Cost Calculations Summary

	Revenue to Cost Ratio
Rate Classification	
RESIDENTIAL	88.54
GENERAL SERVICE	
Less than 50 kW	129.77
Other > 50 kw > 1000 kw	100.72
Intermediate Use (1000 - 5000 kW)	333.66
Large Use (> 5000 kW)	257.45
Unmetered Scattered Load	131.76
Sentinel Lighting	55.33
Street Lighting	23.16

3.0 OPUCN's Proposal re Revenues to Cost Ratios

OPUCN submits that it would be premature at this time to adjust its existing Revenues to Cost Ratios, as the Board has not yet made a decision on the implementation of the cost allocation model. Although the Board has accepted a proposal by another LDC to partially implement the cost allocation model (PowerStream RP-2007-0074), the Board clearly indicated that a final decision is pending:

> "While the cost allocation model was developed collaboratively with stakeholders, the Board has not yet made a decision on the implementation of the model in rate making."

OPUCN submits that it would be prudent to maintain its existing Revenues to Cost Ratios until the Board completes its cost allocation review and provides direction to the industry, rather than speculating as to the outcome of the Board's review at this time. OPUCN will implement any cost allocation adjustment required by the Board that comes out of its review.

4.0 Changes to Monthly Fixed Charge

A second result of the cost allocation study carried out in 2006 was a calculation of customer unit costs per month for each customer class. These costs were calculated in several categories: avoided cost; directly related costs; and minimum system cost. Avoided cost for each customer class was calculated using meter related billing, and collection costs per customer. Directly related costs were calculated as avoided costs plus an allocation per customer for administrative overhead plus 20% to account for general overhead. OPUCN's current Board approved fixed rates are based on directly related costs. The following table shows the relationship between current and proposed fixed costs and the effect on customers in each class.

Summary of Monthly Service Charge

Rate Classification	Approved Fixed Charge	Minimum System Fixed Charge	Directly Related Fixed Charge	Avoided Cost Fixed Charge
Rate Classification				
RESIDENTIAL	7.29	12.23	5.98	2.62
GENERAL SERVICE				
Less than 50 kW	8.75	25.21	18.87	8.80
Other > 50 kw > 1000 kw	40.23	165.97	148.67	71.69
Intermediate Use (1000 - 5000 kW)	1,934.86	510.82	500.86	225.43
Large Use (> 5000 kW)	10,418.47	2,081.73	2,040.71	1,063.13
Unmetered Scattered Load	4.38	7.46	0.07	0.02
Sentinel Lighting	2.45	6.87	0.01	0.00
Street Lighting	0.47	6.87	0.00	0.00

OPUCN proposes to maintain the way in which its rates are split between fixed and variable charges at this time. The OEB currently has two studies underway which are intended to result in a new rate design structure for electricity utilities in Ontario. One is the Cost Allocation Review mentioned above. The other is a major Rate Redesign project which is considering, among other issues, the future calculation of fixed rates. OPUCN feels that it would be inappropriate to make any rate design methodology changes at this time. The proposed monthly service charges in the table below reflect changes which are the result of an increase in revenue requirement, not any changes in methodology. These rates were determined by examining, by class, the percentage of revenue currently recovered from fixed and variable rates. The revenue requirement was distributed among classes by using the same percentages which exist now. The fixed rate percentage for each class was applied to the new revenue requirement and then divided by the number of customers in the class to arrive at the new rate.

Proposed Monthly Service Charge

	Approved Fixed Charge	Proposed Fixed Charge
Rate Classification		
RESIDENTIAL	7.29	8.40
GENERAL SERVICE		
Less than 50 kW	8.75	10.08
Other > 50 kw > 1000 kw	40.23	46.34
Intermediate Use (1000 - 5000 kW)	1,934.86	2,228.91
Large Use (> 5000 kW)	10,418.47	12,001.85
Unmetered Scattered Load	4.38	5.05
Sentinel Lighting	2.45	2.82
Street Lighting	0.47	0.54

Transformer Ownership Allowance

Currently, OPUCN provides a transformer ownership allowance to those customers that own their transformation facilities. The present transformer ownership allowance is $0.60 per kW and this same charge is applied consistently across the province. The amount of the allowance has not been reviewed on a generic basis in recent years. This amount will be reviewed as part of the Ontario

Energy Board's Rate Redesign project. OPUCN proposes leaving the transformer allowance at its current level until that project is completed.

ALLOCATION FACTORS TO CUSTOMER CLASSIFICATIONS

OPUCN proposes to continue using its existing Board approved allocation factors until otherwise directed by the Board.

RATE DESIGN OVERVIEW

OPUCN seeks an order by the Board authorizing OPUCN to charge the rates and charges set out in Exhibit 9, Tab 1, Schedule 6. These rates will recover the OPUCN's revenue requirement of $20.44 million. OPUCN proposes:

1. Maintenance of the current rate design and current customer classes;
2. Base distribution rates set out at Exhibit 9, Tab 1, Schedule 7;
3. Recovery of deferral and variance account balances calculated at Exhibit 5, Tab 1, Schedule 2. The recovery of these variances has been included in the bill impact calculations at Exhibit 5, Tab 1, Schedule 12.
4. Maintenance of the current Specific Service Charges and Regulated Rates and Charges;
5. No changes to the Smart Meter rate adder. As approved in the Decision and Order of the Board, IRM 2007 Rate Applications, effective May 1, 2007, an amount of $0.27 per month per metered customers to be collected and the smart meter rate adder will be included in the existing variance account to help fund future smart meter activity. This rate adder has been excluded from rate impact calculations.

ALLOCATION OF REVENUE REQUIREMENT TO RATE CLASSES

1.0 Process of Allocation to Rate Classes

This Schedule presents an overview of the process to allocate OPUCN's related revenue requirement costs for the forecasted 2008 test year to the respective rate classes. This Schedule documents, by rate class, the calculation of the proposed fixed and variable distribution rates for the 2008 rate year.

The total revenue requirement of $20.44 million, for 2008 rate year, excluding miscellaneous revenues, was calculated in Exhibit 7, Tab 1, Schedule 1 and is required to be allocated to the respective customer classes for consideration in respect of rate design. The method of allocating these costs to the customer classes uses various steps to apportion the costs across all utility customer classes. This methodology is the same as the current Board-approved methodology. The following steps are followed to derive the revenues collected from fixed and variable rates under the proposed 2008 rates.

1.1 Percentage revenue generated by class

The calculation of projected customer counts by customer class for the 2008 Test year is at Exhibit 3, Tab 2, Schedule 2. The calculation of the forecast of normalized consumption by customer class is at Exhibit 3, Tab 2 Schedule 6. These forecasts were used to calculate distribution revenues by class using current distribution rates. The calculations are shown here.

Customer Class	**2008 Projected Data**			**Base Revenues (at Current Rates)**		
	Customer/ (Connections)	**kWh**	**kW**	**Fixed**	**Variable**	**Total**
RESIDENTIAL						
Regular	47,243	497,773,555	0	4,172,502	5,375,954	9,548,456
GENERAL SERVICE						
Less than 50 kW	3,845	143,774,408	0	407,416	2,602,317	3,009,733
Other > 50 kW > 1000 kw	522		893,941	254,256	3,161,065	3,415,321
Intermediate Use (1000 - 5000 kW)	9		171,299	210,845	742,787	953,632
Large Use (> 5000 kW)	2		140,182	252,294	405,154	657,448
Unmetered Scattered Load	305	2,230,937	0	16,177	41,049	57,226
Sentinel Lighting	77		139	2,282	778	3,060
Street Lighting	11,650		26,213	65,706	194,574	260,280
TOTALS	63,653	643,778,900	1,231,774	5,381,478	12,523,677	17,905,155

1.2 Percentage of revenue allocated by customer class

The totals by class and rate type, i.e. fixed and variable rates, were used along with the total revenue collected of $17,923,324 to determine the percentages of the total revenue contributed by customer class and rate type to the total collected.

Customer Class		**Percentage of Total Revenue Collected**	**Percentage Allocation**		
		Percentage	**Fixed**	**Variable**	**Total**
RESIDENTIAL					
Regular		53.3%	43.7%	56.3%	100.0%
GENERAL SERVICE					
Less than 50 kW		16.8%	13.5%	86.5%	100.0%
Other > 50 kW > 1000 kw		19.1%	7.4%	92.6%	100.0%
Intermediate Use (1000 - 5000 kW)		5.3%	22.1%	77.9%	100.0%
Large Use (> 5000 kW)		3.7%	38.4%	61.6%	100.0%
Unmetered Scattered Load		0.32%	28.3%	71.7%	100.0%
Sentinel Lighting		0.02%	74.6%	25.4%	100.0%
Street Lighting		1.5%	25.2%	74.8%	100.0%
TOTALS		100.0%	31.7%	68.3%	100.0%

1.3 Recovery of revenue requirement by customer class

The percentages by rate type for each class were applied to the distribution revenue requirement of $20,442,367 calculated at Exhibit 7, Tab 1, Schedule 1 to determine the portion of the requirement to be collected from each customer class. This total requirement is net of Other Revenues.

Customer Class	Allocation to Fixed Rate	Allocation to Variable Rate	Total	
RESIDENTIAL				
Regular	4,763,757	6,137,742	10,901,500	kWh
GENERAL SERVICE				
Less than 50 kW	465,148	2,971,072	3,436,221	kWh
Other > 50 kW > 1000 kw	290,285	3,608,997	3,899,281	kW
Intermediate Use (1000 - 5000 kW)	240,723	848,042	1,088,764	kW
Large Use (> 5000 kW)	288,045	462,565	750,610	kW
Unmetered Scattered Load	18,470	46,866	65,336	kWh
Sentinel Lighting	2,606	888	3,493	kW
Street Lighting	75,017	222,146	297,162	kW
TOTALS	6,144,049	14,298,318	20,442,367	

1.4 Proposed 2008 distribution rates

The distribution revenues to be collected from each class by rate type were used to determine the fixed and variable rates for each customer class.

Customer Class	Fixed	Variable
RESIDENTIAL		
Regular	8.40	0.0123
GENERAL SERVICE		
Less than 50 kW	10.08	0.0207
Other > 50 kW > 1000 kw	46.34	4.0372
Intermediate Use (1000 - 5000 kW)	2,228.91	4.9507
Large Use (> 5000 kW)	12,001.85	3.2997
Unmetered Scattered Load	5.05	0.0210
Sentinel Lighting	2.82	6.387
Street Lighting	0.54	8.4746

RATE MITIGATION

OPUCN submits that these impacts are reasonable and there is therefore no need to mitigate rate impacts.

TRANSFORMER OWNERSHIP ALLOWANCE

Oshawa PUC Networks Inc. currently credits customers with their own transformer the provincial standard rate of $0.60 per kW. This amount will be reviewed as part of the Ontario Energy Board's Rate Redesign project. Oshawa PUC Networks Inc. proposes to leave the transformer allowance at its current level until that project is completed.

EXISTING RATE SCHEDULES

Customer Rate Class	Metric	Rate
Residential (R1)		
Distribution	Customer	7.3600
Distribution	kWh	0.0108
Regulatory Asset Recovery	kWh	0.0012
Retail Transmission - Network	kWh	0.0059
Retail Transmission - Line and Transformation Connection	kWh	0.0045
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
GS <50 (C1)		
Distribution	Customer	8.8300
Distribution	kWh	0.0181
Regulatory Asset Recovery	kWh	0.0009
Retail Transmission - Network	kWh	0.0053
Retail Transmission - Line and Transformation Connection	kWh	0.0041
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
GS>50 kW < 1000 kW (I1) (I4)		
Distribution	Customer	40.5900
Distribution	kW	3.5361
Regulatory Asset Recovery	kW	0.4043
Retail Transmission - Network	kW	2.4441
Retail Transmission - Line and Transformation Connection	kW	1.8565
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
GS>1000 kW < 5000 kW (I2 -Intermediate)		
Distribution	Customer	1,952.2700
Distribution	kW	4.3362
Regulatory Asset Recovery	kW	0.0820
Retail Transmission - Network	kW	2.4441
Retail Transmission - Line and Transformation Connection	kW	1.8565
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500

Large Use >5MW (I3)		
Distribution	Customer	10,512.2400
Distribution	kW	2.8902
Regulatory Asset Recovery	kW	0.2860
Retail Transmission - Network	kW	2.6041
Retail Transmission - Line and Transformation Connection	kW	2.0258
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
Street Light		
Distribution	Connection	0.4700
Distribution	kW	7.4228
Regulatory Asset Recovery	kW	0.1748
Retail Transmission - Network	kW	1.2929
Retail Transmission - Line and Transformation Connection	kW	1.6867
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
Sentinel		
Distribution	Connection	2.4700
Distribution	kW	5.5941
Regulatory Asset Recovery	kW	0.1748
Retail Transmission - Network	kW	1.3152
Retail Transmission - Line and Transformation Connection	kW	1.7158
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
Unmetered Scattered Load (USL)		
Distribution	Connection	4.4200
Distribution	kWh	0.0184
Regulatory Asset Recovery	kWh	0.0022
Retail Transmission - Network	kWh	0.0053
Retail Transmission - Line and Transformation Connection	kWh	0.0041
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500

PROPOSED RATE SCHEDULE

Customer Rate Class	Metric	Rate
Residential (R1)		
Distribution	Customer	8.40
Distribution	kWh	0.0123
Regulatory Asset Recovery	kWh	0.0011
SSM and LRAM Rate Rider	kWh	0.0001
Retail Transmission - Network	kWh	0.0059
Retail Transmission - Line and Transformation Connection	kWh	0.0045
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
GS <50 (C1)		
Distribution	Customer	10.14
Distribution	kWh	0.0207
Regulatory Asset Recovery	kWh	0.0011
Retail Transmission - Network	kWh	0.0000
Retail Transmission - Line and Transformation Connection	kWh	0.0041
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
GS>50 kW < 1000 kW (I1) (I4)		
Distribution	Customer	46.34
Distribution	kW	4.0372
Regulatory Asset Recovery	kW	0.3593
Retail Transmission - Network	kW	2.4441
Retail Transmission - Line and Transformation Connection	kW	1.8565
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
GS>1000 kW < 5000 kW (I2 -Intermediate)		
Distribution	Customer	2,228.91
Distribution	kW	4.9507
Regulatory Asset Recovery	kW	0.3682
Retail Transmission - Network	kW	2.4441

Retail Transmission - Line and Transformation Connection	kW	1.8565
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
Large Use >5MW (I3)		
Distribution	Customer	12,001.85
Distribution	kW	3.2997
Regulatory Asset Recovery	kW	0.4116
Retail Transmission - Network	kW	2.6041
Retail Transmission - Line and Transformation Connection	kW	2.0258
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
Street Light		
Distribution	Connection	0.54
Distribution	kW	8.4746
Regulatory Asset Recovery	kW	0.4428
Retail Transmission - Network	kW	1.2929
Retail Transmission - Line and Transformation Connection	kW	1.6867
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
Sentinel		
Distribution	Connection	2.82
Distribution	kW	6.387
Regulatory Asset Recovery	kW	0.0023
Retail Transmission - Network	kW	1.3152
Retail Transmission - Line and Transformation Connection	kW	1.7158
Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500
Unmetered Scattered Load (USL)		
Distribution	Connection	5.05
Distribution	kWh	0.0210
Regulatory Asset Recovery	kWh	0.0000
Retail Transmission - Network	kWh	0.0053
Retail Transmission - Line and Transformation Connection	kWh	0.0041

Wholesale Market Service	kWh	0.0052
Rural Rate Protection Charge	kWh	0.0010
SSS Administrative Charge	SSS Customer	0.2500

SUMMARY OF PROPOSED RATE SCHEDULE

These changes reflect the revenue requirement increase as per rate application 2008.

Residential

	2007 IRM	2008 Proposed	% change
Service Charge	7.36	8.40	-14.2%
Distribution Volumetric Rate	0.0108	0.0123	-14.2%

GS < 50 kW

	2007 IRM	2008 Proposed	% change
Service Charge	8.83	10.08	14.2%
Distribution Volumetric Rate	0.0181	0.0207	14.2%

GS > 50 kW < 1000 kW

	2007 IRM	2008 Proposed	% change
Service Charge	40.59	46.34	14.2%
Distribution Volumetric Rate	3.5361	4.0372	14.2%

GS > 1000 kW < 5000 kW

	2007 IRM	2008 Proposed	% change
Service Charge	1952.27	2,288.91	14.2%
Distribution Volumetric Rate	4.3362	4.9507	14.2%

GS > 5000 kW

	2007 IRM	2008 Proposed	% change
Service Charge	10512.24	12,001.85	14.2%
Distribution Volumetric Rate	2.8902	3.2997	14.2%

Street Lights

	2007 IRM	2008 Proposed	% change
Service Charge	0.47	0.54	14.2%
Distribution Volumetric Rate	7.4228	8.4746	14.2%

Sentinel Lights

	2007 IRM	2008 Proposed	% change
Service Charge	2.47	2.82	14.2%
Distribution Volumetric Rate	5.5941	6.3868	14.2%

Unmetered Scattered Load

	2007 IRM	2008 Proposed	% change
Service Charge	4.42	5.05	14.2%
Distribution Volumetric Rate	0.0184	0.0210	14.2%

RECONCILIATION OF RATE CLASS REVENUE TO TOTAL REVENUE REQUIREMENTS

Rate Class	Number of Customers Or Connections	Volume (kWh or kW)	Proposed Fixed Charge	Proposed Volumetric Charge	Proposed Revenue at Proposed Rates
Residential (R1)	47,243	497,773,555	8.40	0.0123	$ 10,901,500
GS <50 (C1)	3,845	143,774,408	10.08	0.020664822	$ 3,436,221
GS>50 kW < 200 kW (I1)	522	893,941	46.34	4.037175438	$ 3,899,281
GS>1000 kW < 5000 kW (I2 -Intermediate)	9	171,299	2228.91	4.950651886	$ 1,088,764
Large Use >5MW (I3)	2	140,182	12001.85	3.299749569	$ 750,610
Street Light	11,650	26,213	0.54	8.474631895	$ 297,162
Sentinel	77	139	2.82	6.386799898	$ 3,493
Unmetered Scattered Load (USL)	305	2,230,937	5.05	0.021007332	$ 65,336
TOTAL	63,653	645,010,674			$ 20,442,367

This revenue requirement is net of Other Distribution Revenue of $1,601,656. Minor differences between this table and that presented above at Exhibit 9, Tab 1, Schedule 2 can be attributed to rounding differences.

CALCULATION OF DIFFERENCE BETWEEN REVENUE AND ALLOCATED COST UNDER CURRENT RATES AND PROPOSED RATES BY CUSTOMER CLASS

OPUCN is making no changes in allocated costs by customer class at this time.

EXPLANATION OF NON-COST FACTORS TO RATE DESIGN

OPUCN has used no non-cost factors in designing the proposed rates.

REVENUE/COST RATIOS FOR HISTORIC YEAR AND TEST YEAR

OPUCN is proposing no changes to revenue / cost ratios at this time. Please refer to Exhibit 8, Tab 1, Schedule 1 for more information.

RATE IMPACTS – RPP PRICING USED FOR COMMODITY

ɔill impact calculations use the current summer RPP pricing for calculating cost of power. All consumption up to 600 kWh per month is priced at

ion above that threshold is priced at 0.062 per kWh. Consumption has been grossed up using OPUCN's appropriate loss factor, as calculation at

				0.053	**Under**	**0.062**	**Over**	
kWh Consumption	TLF	1.04660		**600**	kWH RPP Limit			

	Metric	2007 BILL			2008 BILL			IMPACT		
		Volume	Rate $	Charge $	Volume	Rate $	Charge $	Change $	Change %	% of Total Bill
				7.36			8.40	1.04	14.2%	**1.0%**
	kWh	1,000	0.01080	10.80	1,000	0.01233	12.33	1.53	14.2%	**1.4%**
				18.16			**20.73**	**2.57**	**14.2%**	**2.4%**
	kWh	1,000	0.00120	1.20	1,000	0.00110	1.10	(0.10)	-8.3%	**-0.1%**
	kWh	1,047	0.00590	6.17	1,047	0.00590	6.17	0.00	0.0%	**0.0%**
ısformation	kWh	1,047	0.00450	4.71	1,047	0.00450	4.71	0.00	0.0%	**0.0%**
	kWh	1,047	0.00520	5.44	1,047	0.00520	5.44	0.00	0.0%	**0.0%**

	kWh	1,047	0.00100	1.05	1,047	0.00100	1.05	0.00	0.0%	**0.0%**
	kWh	1,000	0.00700	7.00	1,000	0.00700	7.00	0.00	0.0%	**0.0%**
	kWh	600	0.05300	31.80	600	0.05300	31.80	0.00	0.0%	**0.0%**
	kWh	447	0.06200	27.69	447	0.06200	27.69	0.00	0.0%	**0.0%**
				103.22			**105.70**	**2.47**	**2.4%**	**2.3%**

kWh	-	-	-
Consumption		TLF	1.04660

	Metric	**2007 BILL**			**2008 BILL**			**IMPACT**		
		Volume	**Rate $**	**Charge $**	**Volume**	**Rate $**	**Charge $**	**Change $**	**Change %**	**% of Total Bill**
				8.83			10.08	1.25	14.2%	**0.3%**
	kWh	3,400	0.01810	61.54	3,400	0.02066	70.26	8.72	14.2%	**2.3%**
				70.37			**80.34**	**9.97**	**14.2%**	**2.6%**
	kWh	3,400	0.00090	3.06	3,400	0.00110	3.74	0.68	22.2%	**0.2%**
	kWh	3,558	0.00530	18.86	3,558	0.00530	18.86	0.00	0.0%	**0.0%**
nsformation	kWh	3,558	0.00410	14.59	3,558	0.00410	14.59	0.00	0.0%	**0.0%**

kWh	3,558	0.00520	18.50	3,558	0.00520	18.50	0.00	0.0%	**0.0%**
kWh	3,558	0.00100	3.56	3,558	0.00100	3.56	0.00	0.0%	**0.0%**
kWh	3,400	0.00700	23.80	3,400	0.00700	23.80	0.00	0.0%	**0.0%**
kWh	600	0.05300	31.80	600	0.05300	31.80	0.00	0.0%	**0.0%**
kWh	2,958	0.06200	183.42	2,958	0.06200	183.42	0.00	0.0%	**0.0%**
			367.96			**378.62**	**10.65**	**2.9%**	**2.8%**

kW	-	-	-
Consumption		TLF	1.04660
kWh Consumption			

Metric	2007 BILL Volume	2007 BILL Rate $	2007 BILL Charge $	2008 BILL Volume	2008 BILL Rate $	2008 BILL Charge $	IMPACT Change $	IMPACT Change %	IMPACT % of Total Bill
			40.59			46.34	5.75	14.2%	**0.1%**
kW	135	3.53610	477.37	135	4.03718	545.02	67.65	14.2%	**1.2%**
			517.96			**591.36**	**73.40**	**14.2%**	**1.3%**
kW	135	0.40430	54.58	135	0.35930	48.51	(6.08)	-11.1%	**-0.1%**

	kW	135	2.44410	329.95	135	2.44410	329.95	0.00	0.0%	**0.0%**
sformation Connection	kW	135	1.85650	250.63	135	1.85650	250.63	0.00	0.0%	**0.0%**
	kWh	57,563	0.00520	299.33	57,563	0.00520	299.33	0.00	0.0%	**0.0%**
	kWh	57,563	0.00100	57.56	57,563	0.00100	57.56	0.00	0.0%	**0.0%**
	kWh	55,000	0.00700	385.00	55,000	0.00700	385.00	0.00	0.0%	**0.0%**
	kWh	0	0.05300	0.00	0	0.05300	0.00	0.00	0.0%	**0.0%**
	kWh	57,563	0.06200	3,568.91	57,563	0.06200	3,568.91	0.00	0.0%	**0.0%**
				5,463.92			**5,531.24**	**67.32**	**1.2%**	**1.2%**

kW Consumption	-	-	-
kWh Consumption		TLF	1.04660

		2007 BILL			2008 BILL			IMPACT		
	Metric	**Volume**	**Rate $**	**Charge $**	**Volume**	**Rate $**	**Charge $**	**Change $**	**Change %**	**% of Total Bill**
				1,952.27			2,228.91	276.64	14.2%	**0.3%**
	kW	1,625	4.33620	7,046.33	1,625	4.95065	8,044.81	998.48	14.2%	**1.2%**
				8,998.60			**10,273.72**	**1,275.13**	**14.2%**	**1.5%**

	kW	1,625	0.08200	133.25	1,625	0.36820	598.33	465.08	349.0%	**0.6%**
	kW	1,625	2.44410	3,971.66	1,625	2.44410	3,971.66	0.00	0.0%	**0.0%**
ısformation Connection	kW	1,625	1.85650	3,016.81	1,625	1.85650	3,016.81	0.00	0.0%	**0.0%**
	kWh	881,237	0.00520	4,582.43	881,237	0.00520	4,582.43	0.00	0.0%	**0.0%**
	kWh	881,237	0.00100	881.24	881,237	0.00100	881.24	0.00	0.0%	**0.0%**
	kWh	842,000	0.00700	5,894.00	842,000	0.00700	5,894.00	0.00	0.0%	**0.0%**
	kWh	0	0.05300	0.00	0	0.05300	0.00	0.00	0.0%	**0.0%**
	kWh	881,237	0.06200	54,636.71	881,237	0.06200	54,636.71	0.00	0.0%	**0.0%**
				82,114.70			**83,854.90**	**1,740.20**	**2.1%**	**2.1%**

	-	-	-
kW Consumption		TLF	1.01460
kWh Consumption			

		2007 BILL			2008 BILL			IMPACT		
	Metric	**Volume**	**Rate $**	**Charge $**	**Volume**	**Rate $**	**Charge $**	**Change $**	**Change %**	**% of Total Bill**
				10,512.24			12,001.85	1,489.61	14.2%	**0.5%**
	kW	7,900	2.89020	22,832.58	7,900	3.29975	26,068.02	3,235.44	14.2%	**1.0%**
				33,344.82			**38,069.88**	**4,725.06**	**14.2%**	**1.5%**
	kW	135	0.28600	38.61	135	0.41160	55.57	16.96	43.9%	**0.0%**

	kW	135	2.60410	351.55	135	2.60410	351.55	0.00	0.0%	**0.0%**
ısformation Connection	kW	135	2.02580	273.48	135	2.02580	273.48	0.00	0.0%	**0.0%**
	kWh	3,652,560	0.00520	18,993.31	3,652,560	0.00520	18,993.31	0.00	0.0%	**0.0%**
	kWh	3,652,560	0.00100	3,652.56	3,652,560	0.00100	3,652.56	0.00	0.0%	**0.0%**
	kWh	3,600,000	0.00700	25,200.00	3,600,000	0.00700	25,200.00	0.00	0.0%	**0.0%**
	kWh	0	0.05300	0.00	0	0.05300	0.00	0.00	0.0%	**0.0%**
	kWh	3,652,560	0.06200	226,458.72	3,652,560	0.06200	226,458.72	0.00	0.0%	**0.0%**
				308,313.06			**313,055.07**	**4,742.01**	**1.5%**	**1.5%**

)

kWh Consumption - TLF 1.04660

		2007 BILL			2008 BILL			IMPACT		
	Metric	**Volume**	**Rate $**	**Charge $**	**Volume**	**Rate $**	**Charge $**	**Change $**	**Change %**	**% of Total Bill**
				4.42			5.05	0.63	14.2%	**0.7%**
	kWh	770	0.01840	14.17	770	0.02101	16.18	2.01	14.2%	**2.4%**
				18.59			**21.22**	**2.63**	**14.2%**	**3.1%**
	kWh	770	0.00220	1.69	770	0.00000	0.00	(1.69)	-100.0%	**-2.0%**

	kWh	806	0.00530	4.27	806	0.00530	4.27	0.00	0.0%	**0.0%**
sformation Connection	kWh	806	0.00410	3.30	806	0.00410	3.30	0.00	0.0%	**0.0%**
	kWh	806	0.00520	4.19	806	0.00520	4.19	0.00	0.0%	**0.0%**
	kWh	806	0.00100	0.81	806	0.00100	0.81	0.00	0.0%	**0.0%**
	kWh	770	0.00700	5.39	806	0.00700	5.64	0.25	4.7%	**0.3%**
	kWh	600	0.05300	31.80	600	0.05300	31.80	0.00	0.0%	**0.0%**
	kWh	206	0.06200	12.76	206	0.06200	12.76	0.00	0.0%	**0.0%**
				82.81			**84.00**	**1.19**	**1.4%**	**1.4%**

kW Consumption	-	TLF	1.04660
kWh Consumption			

		2007 BILL			**2008 BILL**			**IMPACT**		
	Metric	**Volume**	**Rate $**	**Charge $**	**Volume**	**Rate $**	**Charge $**	**Change $**	**Change %**	**% of Total Bill**
				2.47			2.82	0.35	14.2%	**4.7%**
	kW	0.14	5.59410	0.78	0.14	6.38680	0.89	0.11	14.2%	**1.5%**
				3.25			**3.71**	**0.46**	**14.2%**	**6.2%**
	kW	0.14	0.17480	0.02	0.14	0.00230	0.00	(0.02)	-98.7%	**-0.3%**

	kW	0.14	1.31520	0.18	0.14	1.31520	0.18	0.00	0.0%	**0.0%**
sformation Connection	kW	0.14	1.71580	0.24	0.14	1.71580	0.24	0.00	0.0%	**0.0%**
	kWh	44	0.00520	0.23	44	0.00520	0.23	0.00	0.0%	**0.0%**
	kWh	44	0.00100	0.04	44	0.00100	0.04	0.00	0.0%	**0.0%**
	kWh	42	0.00700	0.29	42	0.00700	0.29	0.00	0.0%	**0.0%**
	kWh	0	0.05300	0.00	0	0.05300	0.00	0.00	0.0%	**0.0%**
	kWh	44	0.06200	2.73	44	0.06200	2.73	0.00	0.0%	**0.0%**
				6.99			**7.43**	**0.44**	**6.2%**	**5.9%**

kW Consumption	-	-	-
		TLF	1.04660
kWh Consumption			

	Metric	2007 BILL			2008 BILL			IMPACT		
		Volume	**Rate $**	**Charge $**	**Volume**	**Rate $**	**Charge $**	**Change $**	**Change %**	**% of Total Bill**
				0.47			0.54	0.07	14.2%	**0.6%**
	kW	0.45	7.42280	3.37	0.45	8.47463	3.85	0.48	14.2%	**4.2%**
				3.84			**4.38**	**0.54**	**14.2%**	**4.8%**

	kW	0.45	0.17480	0.08	0.45	0.44280	0.20	0.12	153.3%	**1.1%**
	kW	0.45	1.29290	0.59	0.45	1.29290	0.59	0.00	0.0%	**0.0%**
sformation Connection	kW	0.45	1.68670	0.77	0.45	1.68670	0.77	0.00	0.0%	**0.0%**
	kWh	74	0.00520	0.38	74	0.00520	0.38	0.00	0.0%	**0.0%**
	kWh	74	0.00100	0.07	74	0.00100	0.07	0.00	0.0%	**0.0%**
	kWh	70	0.00700	0.49	70	0.00700	0.49	0.00	0.0%	**0.0%**
	kWh	0	0.05300	0.00	0	0.05300	0.00	0.00	0.0%	**0.0%**
	kWh	74	0.06200	4.56	74	0.06200	4.56	0.00	0.0%	**0.0%**
				10.78			**11.44**	**0.67**	**6.2%**	**5.8%**

PROPOSED CHANGES TO TERMS AND CONDITIONS OF SERVICE

OPUCN is not proposing any changes to its existing Conditions of Service as filed with the Board in June 2007.

CUSTOMER ELIGIBILITY CRITERIA

OPUCN uses the customer eligibility criteria approved by the Board in 2006 EDR.

Residential

This classification refers to the supply of electrical energy to residential customers residing in detached, semi-detached, or townhouse (freehold or condominium) dwelling units, duplexes and triplexes. Basic connection is defined as 100 amp 12/240 volt overhead services. Further servicing details are available in OPUCN's Conditions of Service.

General Service < 50 kW

This classification refers to a non-residential account taking electricity at 750 volts or less, with a monthly peak demand that is less than or expected to be less than 50 kW. Further servicing details are available in OPUCN's Conditions of Service.

General Service 50 to 1000 kW

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 1,000 kW. Further servicing details are available in OPUCN's Conditions of Service.

General Service 1,000 to 5,000 kW

This classification applies to a non-residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecasted to be equal to or greater than, 1,000 kW but less than 5,000 kW. Note that for the application of the Retail Transmission Rate – Network Service Rate and the Retail Transmission Rate – Line and Transformation Connection Service Rate the following sub-classifications apply: General Service 1,000 to 5,000 kW non-interval metered, and General Service 1,000 to 5,000 kW interval metered. Further servicing details are available in OPUCN's Conditions of Service.

Large Use

This classification applies to an account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater then, 5,000 kW. Further servicing details are available in OPUCN's Conditions of Service.

Unmetered Scattered Load

This classification applies to an account whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and whose consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The level of consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information / documentation with regards to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Further servicing details are available in OPUCN's Conditions of Service.

Sentinel Lighting

This classification applies to accounts that are an unmetered lighting load supplied to a sentinel light. Further servicing details are available in OPUCN's Conditions of Service.

Street Lighting

This classification applies to accounts concerning roadway lighting for a Municipality, Regional Municipality, and / or Ministry of Transportation. This lighting will be controlled by photo cells. The consumption for these customers will be based on the calculated connected load times as established in the approved OEB Street Lighting Load Shape Template. Further servicing details are available in OPUCN's Conditions of Service.

DESCRIPTION OF LRAM AND SSM

OPUCN is seeking to recover $49,788.00 in relation to LRAM, and $97,237.01 in relation to Shared Savings Mechanism (SSM), for a total of $147,025.01. Both the LRAM and SSM relate to fiscal year 2006.

Please refer to the report attached as Appendix F to this Application that supports this request.

OPUCN's proposed method of recovery is by way of a rate adder. OPUCN proposes the recovery be over a six month period, commencing May 1 2008 and ending on June 30, 2008, as set out at Exhibit 10, Tab 1, Schedule 2.

CALCULATION OF LRAM AND SSM

Customer Class	Allocation to Customer Classes %	Allocation to Customer Classes % for LRAM	Allocation to Customer Classes % for SSM	LRAM to Dec 31 06	SMM to Dec 31 06	Total to Be Recovered over 1 Year	kWh Forecast Test Year 2008	kW Forecast Test Year 2008	Proposed Rate Rider
	Total for Customer class as % of Total for all Classes	Total kWh savings per class/ Total kWh savings	Total kWh savings per class/ Total kWh savings	Total kWh savings per class/ Total kWh savings	Total kWh savings per class/ Total kWh savings	Total kWh savings per class/ Total kWh savings			
RESIDENTIAL									
Regular	53.3%		95.80%	49,788.00	97,237.01	147,025.01	497,773,555		0.0001
GENERAL SERVICE									
Less than 50 kW	16.8%		0.07%		-	-	143,774,408		-
Other > 50 kW > 1000 kw	19.2%		4.08%		-	-	5,600	899,079	-
Intermediate Use (1000 - 5000 kW)	5.3%		0.00%		-	-	-	171,299	-
Large Use (> 5000 kW)	3.7%		0.00%		-	-	-	140,182	-
Unmetered Scattered Load	0.3%		0.00%		-	-	2,230,937		-
Sentinel Lighting	0.0%		0.00%		-	-	-	139	-
Street Lighting	1.5%		0.00%		-	-	-	26,213	-
TOTALS	100.0%	0.0%	100.0%	47,788.00	97,237.01	147,025.01	643,784,500	1,236,912	

BILL IMPACTS

As the proposed rate rider for LRAM and SSM is .0001 per kWh, only to be charged to Residential Class customers, the rate impact is minimal.

APPENDIX A

OSHAWA POWER AND UTILITIES CORPORATION ANNUAL REPORT 2006

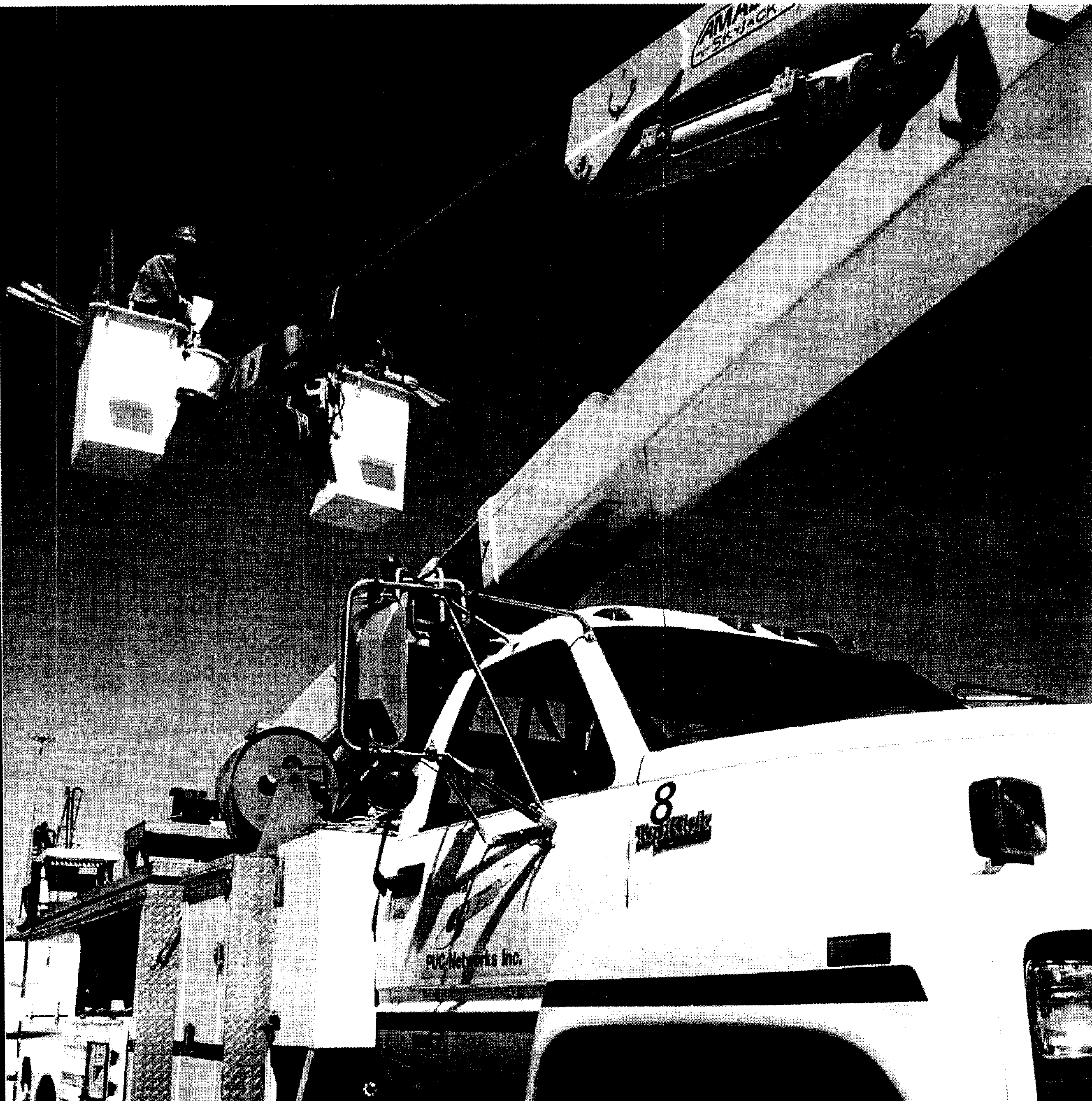
Oshawa Power and Utilities Corporation

2006 Annual Report

leadership

diversification

performance



Oshawa Power & Utilities Corporation

Welcome to the Oshawa Power and Utilities 2006 Annual Report. The performance reflected in this publication is a result of the dedication and hard work of our entire team. We are proud of our role in the Utility industry in Ontario and look forward to the many opportunities that lay ahead for us.

Irv Harrell,
Chairman of the Board
Oshawa Power and Utilities Corporation

Message from the Chair

I am delighted to announce the accomplishments of the *Oshawa Power and Utilities Corporation* for 2006. Our core Local Distribution Company (LDC) continued to perform at a very high level in both the financial and operational arenas.

We achieved a range of successes in the areas of earnings, our diversified energy portfolio, combined heat and power, safety, and conservation, to name a few.

Our 2006 earnings were strong. We are very pleased to declare a dividend of $1 million. Since 2002, we have transferred approximately $38 million to the City of Oshawa in the form of dividends and interest. In addition, we continue to make progress in creating a capital structure for the utility that is robust enough to withstand sudden and unexpected shocks, meet regulatory requirements, satisfy outside lenders, and meet future financial demands.

> "In 2006, Oshawa Power and Utilities took a major step forward in creating a diversified energy portfolio."

In 2006, Oshawa Power and Utilities took a major step forward in creating a diversified energy portfolio. Through a combination of solid performance by the LDC, new revenues from our business ventures, including fibre optic cable leasing, and a successful negotiation with the Ministry of Finance that saved a million dollars on tax claims, we are very pleased to inform you that our net income for 2006 surpassed $4 million.

In addition, with the growth of the City, our capital expenditure program on both new plant and required upgrades continues at an unprecedented rate. We anticipate this will continue for at least the next five years as our plant expansion requirement will include the construction of a new Municipal Substation in the City.

We made great strides in the area of combined heat and power in 2006. We are very proud that we were successful in our bid to the Ontario Power Authority for construction of a

Combined Heat and Power Plant at Durham College. The plant is currently under construction and will be on line in the Spring of 2008. This is a significant step for our organization.

Our company continues to focus on safety as a key pillar of our success and we have worked very hard to engrain safe work practices and attitude into our corporate culture. In 2006, we achieved our fourth straight year without a lost time accident.

Conservation was another area in which we made important accomplishments. Through our conservation and demand initiatives, we have worked with low income housing, the Durham school boards, and the University of Ontario Institute of Technology to assist the province in attaining its ambitious conservation targets. We will continue to work with the province, our partners and our customers to enable conservation programs in Oshawa.

In closing, our evolution as a business mirrors the changes that are occurring in Oshawa, as the City transforms into a more diverse community. It is our intention to evolve to meet the needs of a new and growing city. We are proud to continue to play an important role in that transformation.

Irv Harrell

Irv Harrell,
Chairman of the Board

Board of Directors

Back row, Left to right

Bruce Fenton
Maracle Press Ltd.

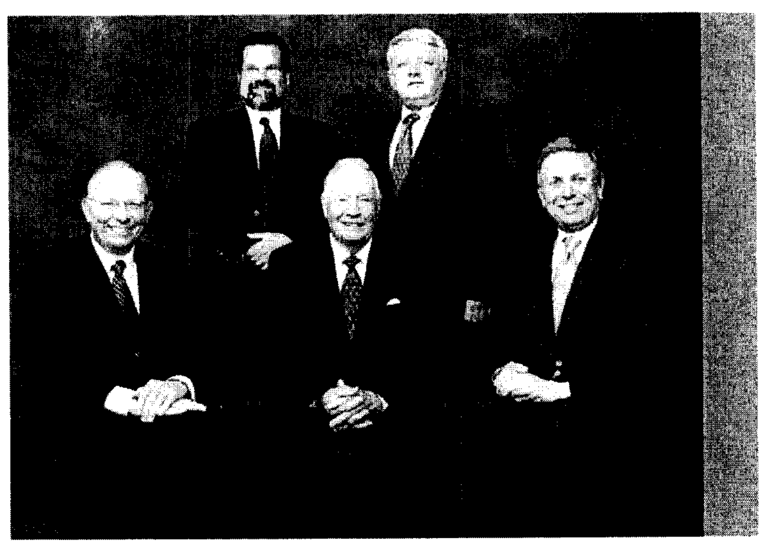
Louis Meehan, CA
Sunnyside Capital Corporation

Front row, Left to right

Bernie Schroder,
Vice Chairperson
B. Schroder and Associates

Irv Harrell
Chair

Jay Swartz, LL.B.
Davies Ward Phillips & Vineberg LLP



About Us

Oshawa PUC Networks Inc. completed its largest capital expenditure program in history in 2006. A part of that work included the reconfiguration of the distribution system at Highway 401 and Stevenson Road.

2006 Facts and Figures

Service Territory Size: 143 square kilometers

Number of Employees: 87

Total Revenue: 93.9 million

Energy Sales: 1,159,252,261 kWh

Peak Load (2006): 223 megawatts

Total Number of Hydro Poles: 11,907

Total Number of Distribution Transformers: 6,286

Total Length of Overhead Circuits: 1,250 km

Total Length of Underground Circuits: 999 km

Total length of Fibre Optic Cable Installed: 50 km

Total Number of Underground Maintenance Chambers: 126

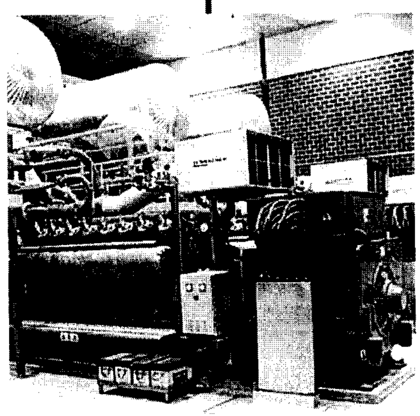
SAIDI: 136.1 minutes (The number of minutes that the average customer's power is off yearly)

SAIFI: 1.289 interruptions (The number of power interruptions that the average customer experiences yearly)

Corporate Structure

Oshawa Power and Utilities Corporation

Oshawa PUC Networks Inc.



Oshawa PUC Energy Services Inc.

Oshawa PUC Services Inc.

Corporate Officers

Jeff Rosenthal,
P.Eng, MBA
President and CEO

Atul Mahajan, *CMA, CA*
Chief Financial Officer

Mark Turney, *CET*
VP Engineering and Operations

Executive Office

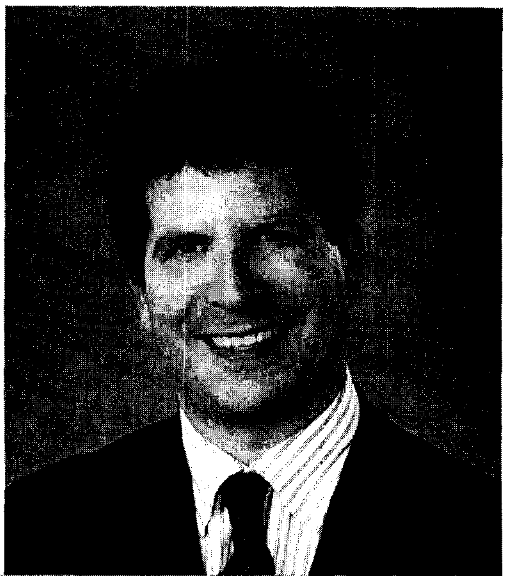
100 Simcoe St. S.
Oshawa, ON
L1H 7M7
Tel: 905.723.4623
www.opuc.on.ca

Legal Advisors

Ogilvy Renault LLP
TD Centre
Toronto, ON

Auditors

Ernst & Young LLP
TD Centre
Toronto, ON



Jeff Rosenthal, P.Eng, MBA
President and CEO

> "As always, our primary focus remains on ensuring that Oshawa PUC Networks Inc. provides service in a safe, efficient, and reliable manner."

Message from the CEO

2006 was another successful year for Oshawa Power and Utilities Corporation in which we continued to build on the foundation of our achievements from previous years. We have structured our Local Distribution Company around five key areas in which we strive for excellence: Health, Safety and Wellness; Financial; Operational; Corporate Social Responsibility, and Innovation.

Our performance on the targets we set for these areas was excellent, and we have created a program to maintain this level of performance. Here are some of the highlights of our 2006 achievements in safety, earnings, our diversified energy portfolio, human resources, combined heat and power, and conservation.

Our Health and Safety Program continues to be the cornerstone of our organization. In 2006, our organization surpassed 900,000 hours without a loss-time accident, which represents four years as an accident-free workplace. Furthermore, we introduced a comprehensive training program in Health and Safety Leadership for all management and senior union personnel that will continue through 2007.

Our 2006 earnings were significant. Our Earnings Before Interest Taxes Depreciation and Amortization (EBITDA) surpassed $10.5 million and our net income was $4.2 million. These figures were due, in part, to rebates from Greenshield for lower benefits costs, a more aggressive tax planning effort, increased revenue from new business ventures, and overall cost controls through the continued implementation of new technologies and equipment. In addition, we were successful in our negotiation with the Ministry of Finance regarding the transition tax issues that arose when the corporation was formed in 2000. The outcome of these negotiations was in our favor: the corporation did not have to pay approximately $1 million in tax claims for previous years.

We instituted an aggressive pre-payment plan to reduce our exposure to bad debts, especially those from our larger customers.

We took this action to address our past exposure to bad debts and the loss of major customers, where the company still had to pay for energy usage. In addition we have worked with all of our customers to provide a variety of payments such as budget billing, internet payment and, most recently, credit card payments. Finally, we have been fortunate to have a very successful collections program.

Our operational performance is the result of the exceptional effort on the part of all of our staff. In 2006, we surpassed 50,000 customers served by the Local Distribution Company. In addition, we completed the largest capital program of work ever faced by OPUC, including meeting the deadlines for the new downtown arena and the Stevenson Road – 401 interchange. We continue to make investments in our infrastructure to support an ongoing refurbishment program and to meet Oshawa's rapid growth. To this end, we are currently in the planning phase of building the first new Municipal Substation in Oshawa in several decades. In addition, we are working with Hydro One to bring a new supply to our City to meet the growing demand.

We are extremely proud of the successes that we have had in our new business ventures. Our co-generation and fibre optic cable businesses will strengthen our corporate performance now and into the future. *Furthermore, our Smart Meter pilot projects are allowing* us to identify the best technology that will meet both our customer and utility's requirements. We are preparing for the full conversion of utility meters to Smart Meters by December 2010 and will begin the full scale replacement program in Oshawa in 2008.

Our employees are the foundation of our business success. We are fortunate to have an exceptional customer service staff, who act as our front line representatives to resolve issues and clarify an increasingly complex industry on a daily basis. Indeed, we value and support our staff in all areas of the company. For that reason, we are pleased with our successful negotiation of a four year collective agreement *with IBEW 636. Throughout the year, we have* worked with the Union executive to resolve issues and maintain high levels of mutual respect.

In 2006, we worked on the development and delivery of several conservation and demand management programs in order to support the Province's overall targets. This was a response to the Ontario Energy Board approval of a distribution rate increase for *the utility in April 2005. At that time, the increase was conditional* upon the utility investing the equivalent of one year's increase in conservation and demand management (CDM) initiatives over the next three years ($1.4 million). Our efforts focused on supporting research at UOIT, development of a Grade 5 curriculum program in the Durham School Board, and contributing to low cost housing energy retrofits.

OPUC excelled in the area of combined heat and power over the past year. The Ontario Power Authority accepted a submission from Oshawa PUC Energy Services Inc. (OPUCES), a wholly owned subsidiary of Oshawa Power and Utilities Corporation, to build a 2.4 megawatt Combined Heat and Power (CHP) plant on the campus of the University of Ontario Institute of Technology/Durham College in Oshawa. This project was one of only seven successful CHP projects in the Province. This 2.4 megawatt natural gas fired (CHP) generating plant will provide a clean and efficient supply of electricity and thermal energy to Durham College and the University Of Ontario Institute Of Technology. The thermal energy, in the form of hot water, will heat existing and new buildings located on the campus of both educational institutions. We will use the electricity produced by the plant to displace the existing electrical load from the provincial supply grid.

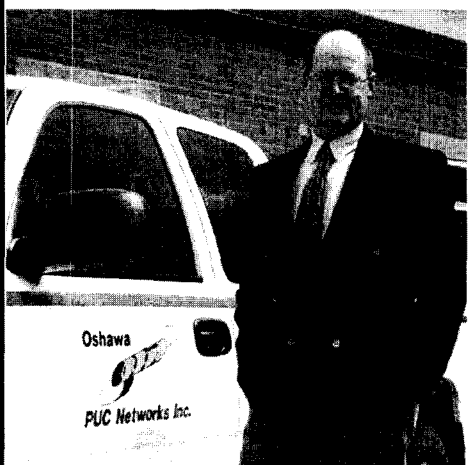
As I look forward to the upcoming years, I envision a clear plan for achieving the high goals that we have set for OPUC, in order to continuously increase the value of the enterprise in the long term and ensure a secure income stream for our Shareholders. We intend to create the standard for electrical utilities and to continue to diversify and strengthen our organization through fundamentally sound business ventures and opportunities.

As always, our primary focus remains on ensuring that Oshawa PUC Networks Inc. provides service in a safe, efficient, and reliable manner. We are very proud of our team at OPUC and recognize that one of the keys to our success is that we maintain a deep respect for the essential service that we currently provide, and will continue to provide in the future.

Jeff Rosenthal

Jeff Rosenthal, P.Eng, MBA
President and CEO

Distribution Update



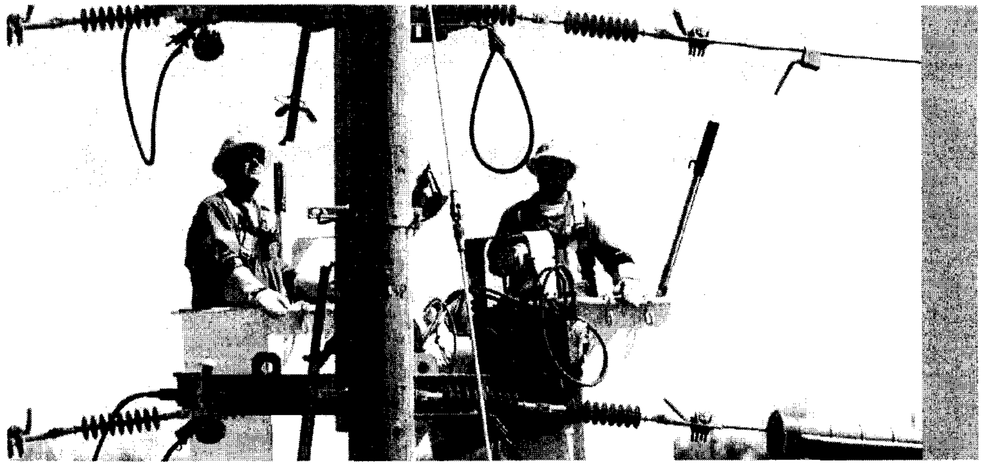
Mark Turney, CET
Vice President Engineering and Operations

Workplace health and safety continues as a top priority in the management of our business. Our record of nearly one million hours worked without a lost time injury is commendable, but we will never rest on the laurels of our past success. We continue to improve our health and safety system and in 2006 made the decision to implement the CSA Z1000 standard for managed occupational health and safety systems. This new Canadian standard will allow us to consolidate our many health and safety programs under one managed system, ensuring the continued success of our health and safety program and allowing for continual improvement.

In looking ahead, we are setting ourselves the goal of achieving the Electrical and Utilities Safety Association (E&USA) Gold award which recognizes results in health and safety for our industry. We recognize that the health and safety of our employees and the public is of paramount importance to the continued success of our organization.

During 2006, we once again experienced tremendous growth within our service territory. Careful attention must be paid during periods of rapid growth by engineering and planning staff to ensure the continued availability and quality of electric supply. A new municipal substation is being planned for the north east area of Oshawa and a Hydro One owned transformer station is in the planning stages for future supply to Oshawa and Clarington. Both of these electric power stations are required to meet the electricity demands of an ever expanding Oshawa and Durham Region.

We continue to utilize a process whereby all capital and maintenance projects are put through a rigorous scoring system in order to determine the optimum list of capital and



maintenance projects to complete, based on factors such as safety, reliability, and operability. In 2006, we added fleet vehicle purchase decisions to this process in order to expand the scope of the program. Our goal is to develop an optimum spending plan with respect to all capital and maintenance decisions, ensuring that each dollar spent yields the most beneficial results for the customers of our utility.

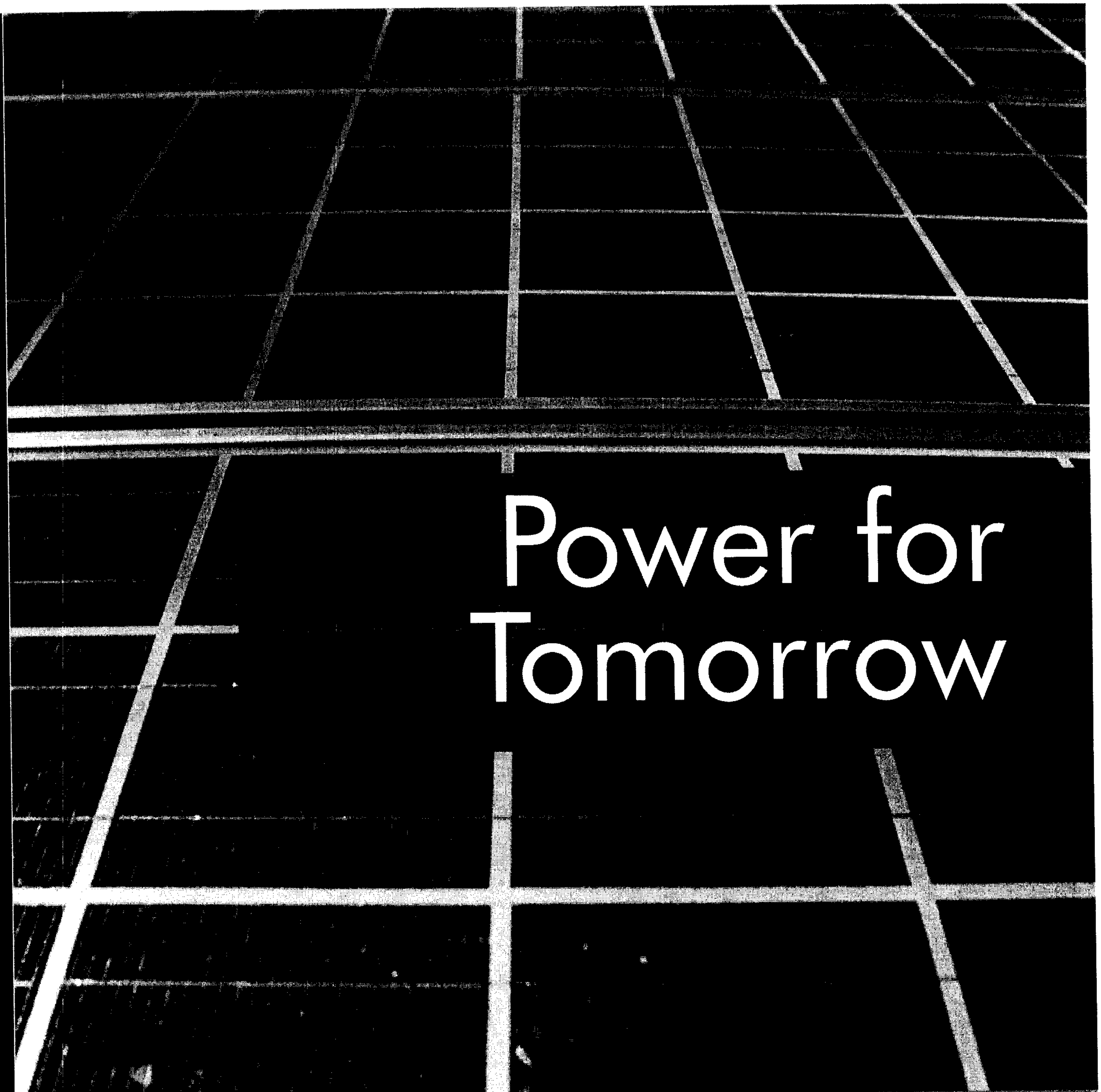
In 2006, OPUC spent approximately $10.6 million in capital work on the electric distribution system. This work included the replacement of 8.7 km of overhead distribution and the replacement of 4.0 km of underground primary cable distribution, due to reaching the end of its service life. We performed tree trimming on 1/3 of our overhead distribution system plant and tested approximately 4,000 wood poles to ensure their continued integrity. Electrical servicing was completed to provide power to the new General Motors Centre, our work continued to rebuild and enhance electrical distribution in the area of the new Stevenson Road – 401 interchange and property was purchased in the area of Wilson Road North and Conlin Road for the ninth electrical distribution station on our system. We continued our program of upgrading to electronic relays at each of our existing eight electric distribution stations and expanded our electric distribution system to accommodate the tremendous growth in the north east area of Oshawa.

In addition, this past year, we connected and installed meters for 1,027 new residential services and 58 new commercial services on our distribution system. We provided underground electrical servicing for an additional 1,079 new subdivision residential lots.

We continued the pilot testing of two "smart metering" systems and developed a smart meter implementation plan to ensure our preparedness for the province's smart metering program.

Although we had a set back in year after year improvements to system reliability in 2006, we continued our trend of improving the overall reliability of electricity supply since 2000. Two severe wind storms and an electric distribution station fire due to component failure impacted our overall quality statistics for 2006. We are proud of the progress that we have made in improving electric distribution system quality since 2000 and will continue to work hard to make the improvements to the electric distribution system that translate into more "on-time" for our customers.

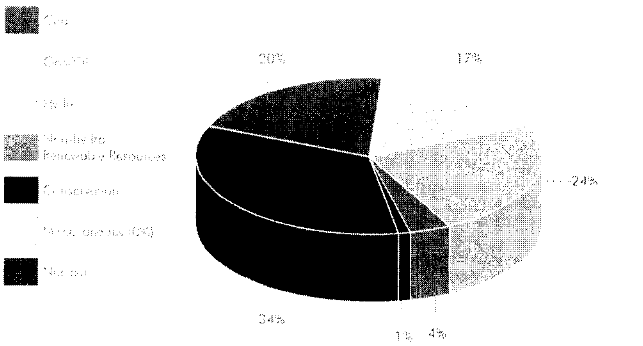
In 2006, the City of Oshawa continued to grow at a rate never experienced in its history. This substantive growth provided a challenge for our team members that design, construct, maintain and operate the electric distribution system in Oshawa. I am very proud to say that our team has performed tremendously in meeting the challenge. I consider myself fortunate to have such a high caliber staff and the customers of our utility benefit every day by having them available to sustain the electric distribution system in Oshawa.



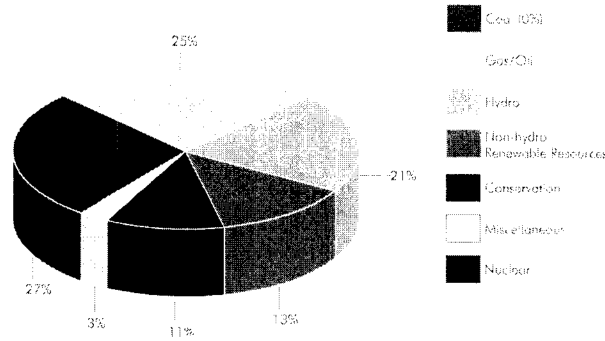
Power for Tomorrow

A compact fluorescent bulb is a simple but effective tool to reduce our electrical usage. Based on average consumption the energy saved by 125 CFL bulbs used will power an average home for a year.

Installed Generation and Conservation 2007



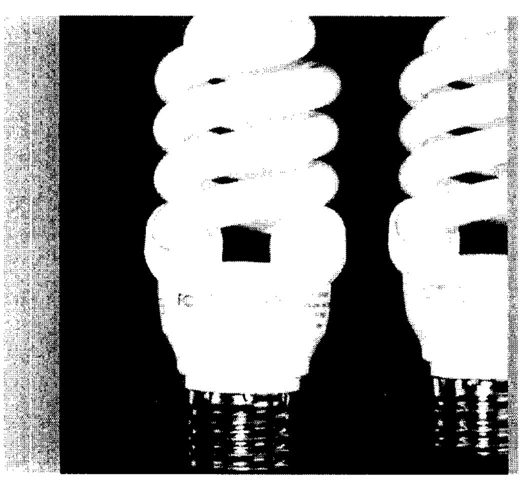
Planned Generation and Conservation 2027



The Role of The Ontario Power Authority

In 2006, the Ontario Power Authority (OPA) continued with its task of leading electricity conservation programming and facilitating the adoption of a culture of conservation in Ontario. In addition, the OPA continued to develop integrated plans for both the generation and transmission infrastructures, and encouraged investments in new electricity supply.

This plan, called the Integrated Power System Plan (IPSP), will chart the course of the evolution of the electricity supply systems over the next twenty years. OPA sees the plan as a living document that can adjust to changes in the electricity markets or technological change. When developing the plan the OPA will be considering the role of energy conservation measures, increasing the use of renewable energy sources such as solar and wind power, continuing to use natural gas (clean energy) for generation in high demand periods and strengthening the transmission system. The first detailed draft of this plan is due out in early 2007.



The Role of Conservation

Conservation and demand management have an important role to play in meeting our power needs. By reducing electricity use, customers can contribute to improving the environment by reducing the size of the supply system needed. Conservation is cost-effective and has many environmental advantages. In fact, in developing the plan, this is the first resource considered. Conservation is, therefore, an important part of the plan.

Oshawa has already taken a lead in conservation and demand measures locally and will be investigating new programs for implementation in 2007. A review of some of our current initiatives are detailed in this publication

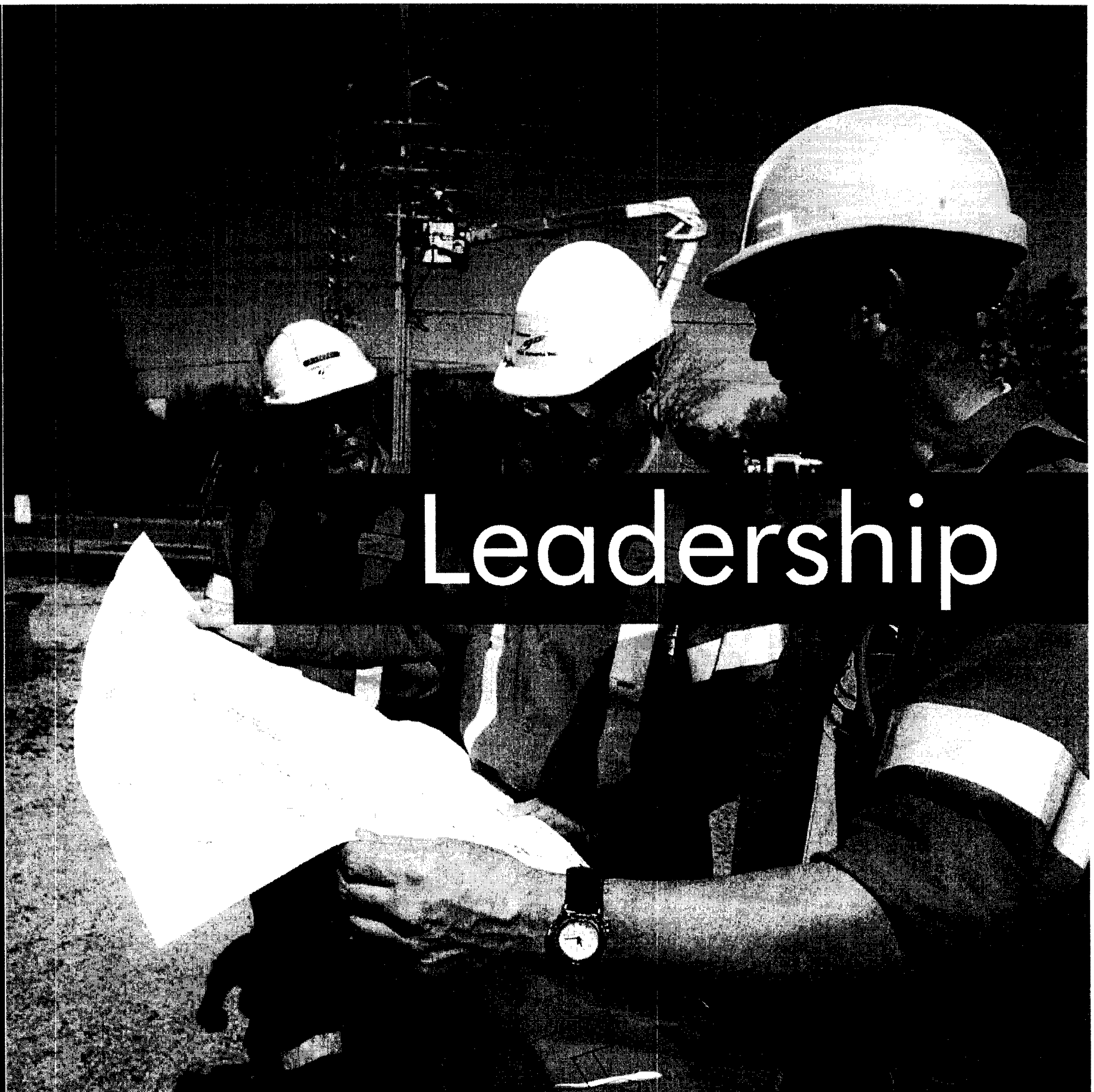
The Role of Distributed Generation

One of the challenges the OPA faces is how to deal with the replacement of the coal-fired generators in the Province of Ontario and transmission systems nearing their maximum loading.

One answer to this dilemma is distributed generation. This places generation close to the end user eliminating the need to transmit the energy across transmission and distribution systems. When coupled with energy recovery systems in the form of a combined heat and power generators, energy usage efficiencies can be as high as 80%.

A subsidiary of Oshawa Power and Utilities Corporation, Oshawa PUC Energy Services Inc. has looked closely at the opportunity of combined heat and power and has invested in its first project at Durham College. We hope this will be a model for other CHP projects to be built upon.

Leadership



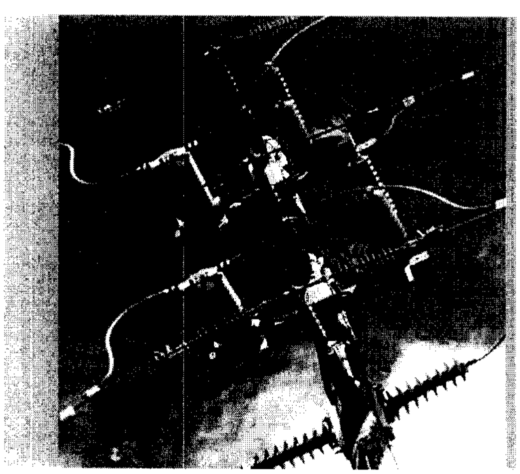
L-R: Bruce Skelton *Power Maintenance Electrician*, Steve Treen *Distribution Supervisor*, Ted Allen *Professional Lineperson*.

One of our subsidiaries designed a metering unit that contains both current and potential transformers on a single vertical mount that can be attached to either a wood, concrete or composite pole.

Metering Design

After the opening of the electricity markets in 2002, the need to accurately meter electricity loads on circuits feeding utilities became the responsibility of each utility. Until that time, electricity metering had been done by Ontario Hydro within their transformer stations on horizontal steel girders. There was a need to find a way to meter loads on single and dual vertical high voltage circuits mounted on hydro poles.

Oshawa PUC Meter Services Inc. designed a metering unit that contains both current and potential transformers on a single vertical mount that can be attached to either a wood, concrete or composite pole. This design not only allows for a single lift of the equipment in the field for easier installation but accommodates individual component replacements if required.



Oshawa PUC Networks Inc., Oshawa's Electricity Distributor, has installed twelve of these metering units for its wholesale metering points. These meters are read automatically and daily by our Meter Data Management System. This unit design has saved several thousands of dollars in acquisition and installation costs compared to the old standard horizontal design of metering. The design has been so successful that other Utilities have requested our assistance with metering through our Meter Service Provider (MSP) business.

School Fundraiser

Oshawa PUC Networks Inc. is planning to introduce a "green" fundraising option for Oshawa schools. This project includes an educational component which will focus on the importance of energy conservation and the benefits of Compact Fluorescent Light (CFL) technology. The students would then share this information with others in their communities through the sales of CFL bulbs. This pilot project is designed to give the students the opportunity to take an active role in energy conservation in their communities.

Safety

Safety continues to be the top priority in the operations of Oshawa Power and Utilities Corporation (OPUC) and its affiliates. The staff of our combined companies surpassed 850,000 work hours without a lost time incident this year.

OPUC continues to implement its Managed Health and Safety System which is at the hub of leading indicators that create and improve on safe work practices.

Safety, Health, Environment and Quality Management are all inter-related areas that need to be considered when operating any business. The Corporation recognized the importance of this training and made it a priority for its leadership staff this year. In addition, plans are being made to deliver the course to all front line staff in 2007.

Regular communication on safety is also key and management and staff attend ten safety meetings annually to discuss new safety procedures and to follow up on any safety issues identified. Monthly Cardio Pulmonary Resuscitation (CPR) practices are held for each staff member trained in the procedure. This year the decision was made to purchase Automated External Defibrillators (AED)s for installation in our office and on six of our vehicles. Staff have been trained in the use of these units which can increase the survival rate of a heart attack victim to 80% if used within the first three minutes of an attack. There are plans to expand the number of units further in 2007.

Safety is the Corporation's highest priority and we will continue to work diligently in all areas to ensure the safety of both our staff and customers.

Diversification

Jenbacher 6 Series Combined Heat and Power Unit.

Over the past five years Oshawa PUC Services Inc. has built more than 50 kilometers of dark fibre optic cable across Oshawa's 143 square miles of service area. Our clients include a University, College, and Health Care Facilities.

Combined Heat and Power (CHP)

In September 2006, Oshawa PUC Energy Services Inc. (OPUCES) was awarded an Ontario Power Authority (OPA) contract for a combined heat and power project at Durham College in Oshawa. The contract award was in response to a submission made by OPUCES in August to a request for proposals by the OPA for up to 1,000 megawatts of combined heat and power generation in the Province of Ontario. Our project was one of only seven projects selected in the province as a result of the request for proposals.

Combined heat and power is a process by which one fuel, natural gas in our particular project, is utilized to produce two forms of energy; electricity and heat. During the production of electricity the waste heat is captured from the electricity generating equipment and used for the purpose of space and hot water heating. By capturing and using the waste heat the entire process becomes nearly 80% efficient.

The Durham College CHP project will produce 2.4 megawatts of electrical and thermal energy for use at Durham College and UOIT. The electricity will be used to displace electrical load from the provincial grid and the thermal energy will be used to heat buildings and hot water on campus. The project will be constructed during 2007 and be ready for operation at the beginning of 2008.

We are very proud to have been awarded a CHP contract by the OPA and are looking forward to supplying Durham College and UOIT with a clean and efficient source of electrical and thermal energy now and in the future.

Fibre Optic

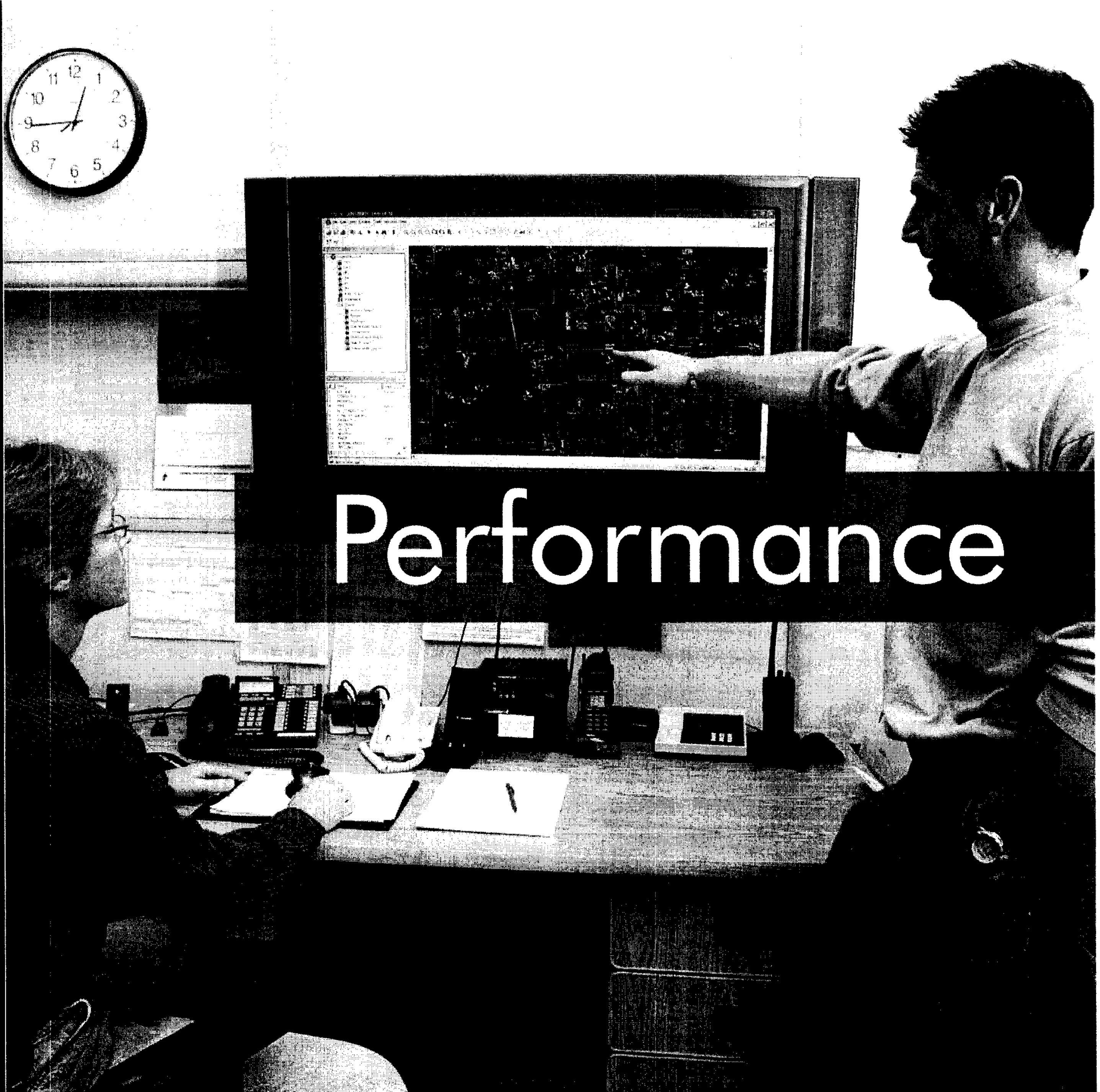
Oshawa Power and Utilities Corporation created Oshawa PUC Services Inc. (OPUCS) in 2001, to develop a fibre optic cable network across Oshawa's 143 square kilometer service area. In 2006, OPUCS has more than 50 km of fibre optic cable integrated into its distribution system.

The fibre network serves two purposes, one to provide high speed data transmission network to companies and institutions within the Region. The second is to provide a high speed data transmission line to and from our own municipal substations.

Because OPUCS provides "dark fibre" cable, customers can use whatever type of transmission technology they wish. This provides a wider variety of transmission speeds for each client and eliminates any restrictions due to pre installed technology.

OPUCS has strategic alliances with other supplies of fibre optic cabling across the Region of Durham and can provide data transport across a wide area of the Region if required.

OPUCS clients currently include national carriers, media companies, hospitals, colleges and a university.

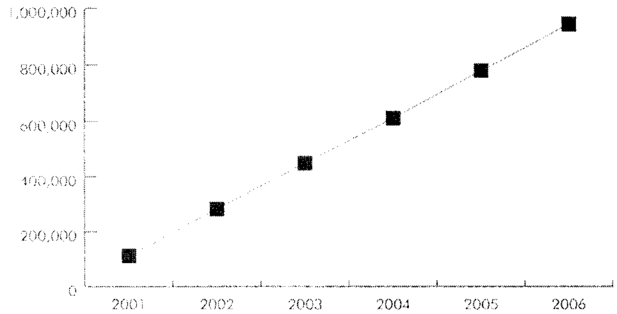


Performance

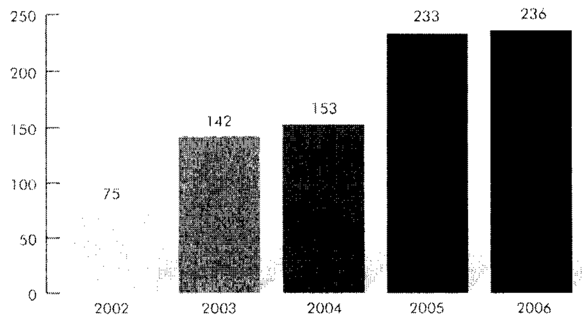
L-R: Ken Benson Operations Technician; Rod Plain Technical Services Technician.

Oshawa PUC Networks Inc. capital construction program totaled more than $10 million dollars in 2006. This is the largest capital building program in our history. Two major projects included the reconfiguration of our distribution system to accommodate the new interchange at Stevenson Road and the 401 and the completion of the underground plant, shown at the right, to service the new General Motors Centre.

Hours Worked Without a Lost Time Incident



Capital Expenditures per Customer (in $)

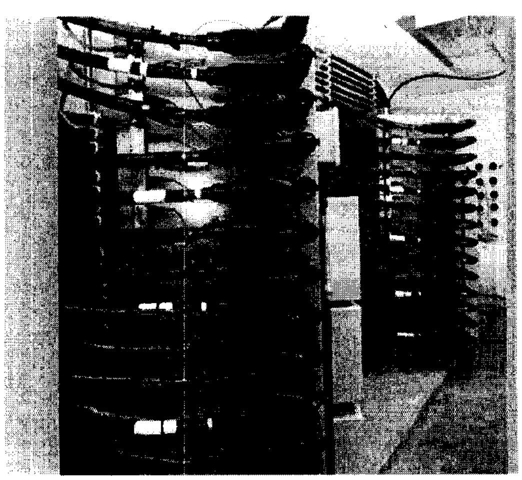


Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA)
($ in thousands)

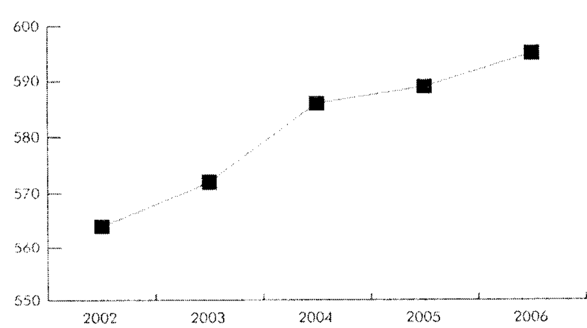
2006 was a stellar year for OPUC in terms of performance. In particular, we excelled in the areas of: customers served per employee, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) and hours worked without a lost time incident.

Our employees and the systems they use are streamlining processes: the number of customers served per employee reached a high of over 590 in 2006. In addition, our earnings climbed from $9.5 to $10.5 million dollars in 2006. At the same time, our capital expenditures per customer continued to increase steadily indicating our continued commitment to invest in and strengthen our electrical distribution system.

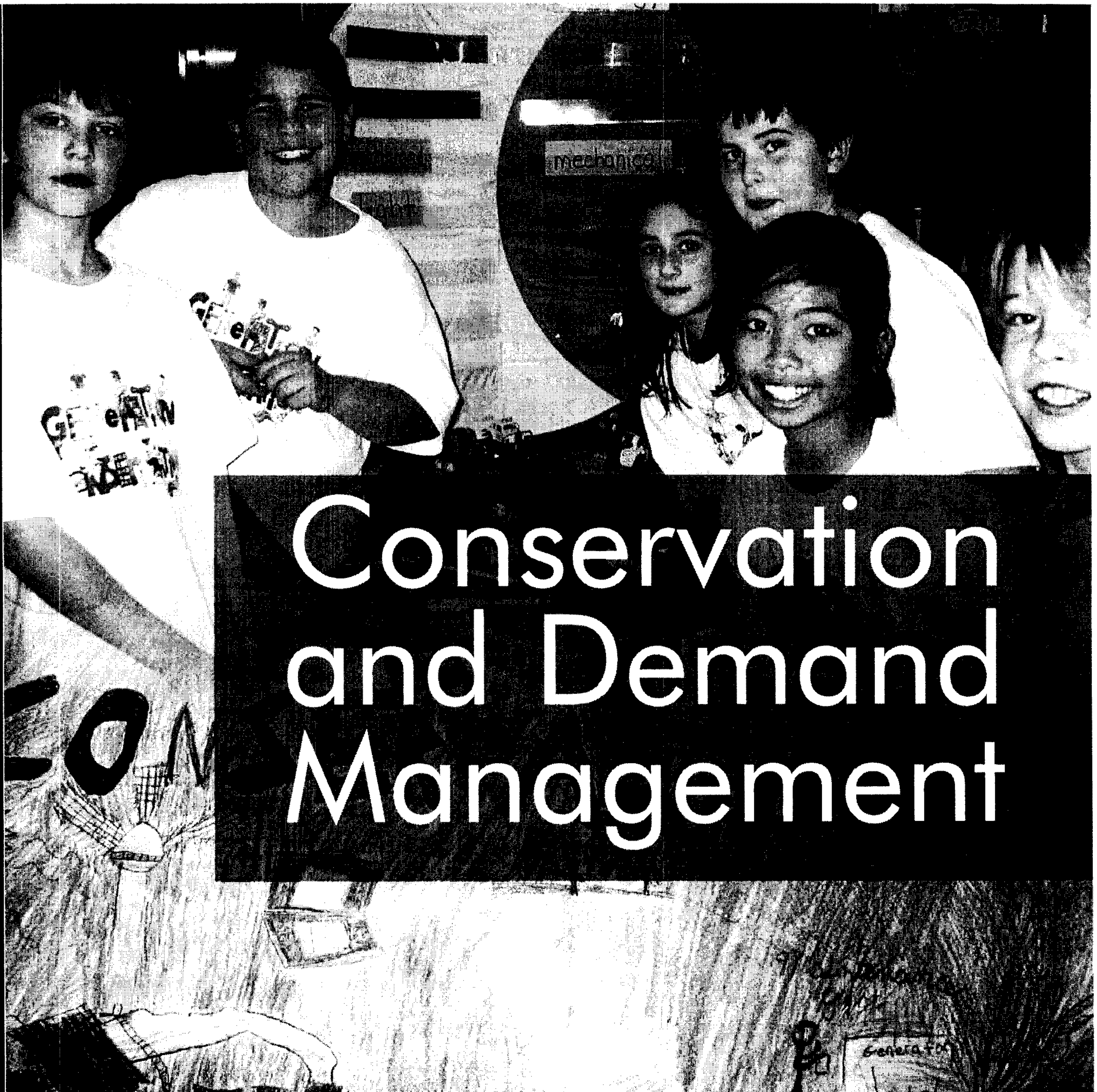
We challenge ourselves each year to improve on our past performance.



Customers Served per Employee

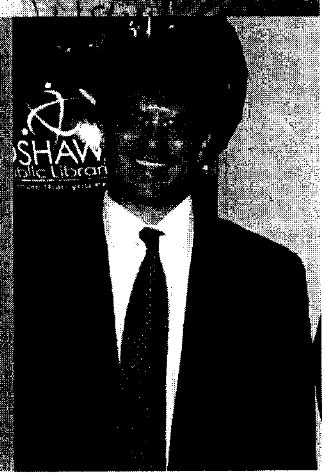


Conservation and Demand Management



Grade five students attend the "Generation Conservation" launch.

"Oshawa PUC Networks Inc." joined forces with the Oshawa Public Libraries to make available on loan "Watt Readers". These units help customers discover how many kilo-watt hours individual appliances use. Upon the return of the unit each customer was provided a free Compact Fluorescent Bulb.



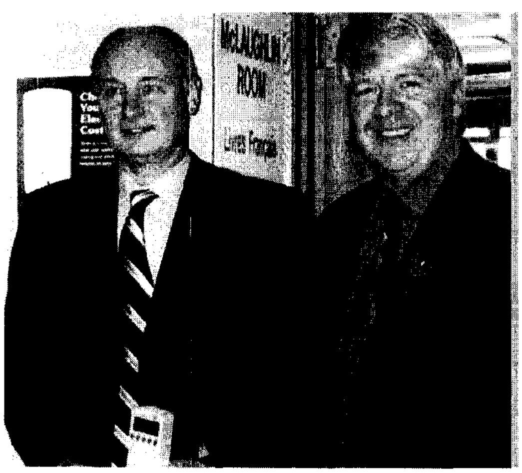
L-R: Jeff Rosenthal President and C.E.O. of Oshawa PUC Networks Inc., Ian Heckford C.E.O. of Oshawa Public Libraries and His Worship Mayor John Gray of Oshawa at the launch of the program.

In 2006, Oshawa PUC Networks Inc. (OPUCN) continued to deliver energy conservation programs to all sectors in our customer base. We also introduced the following new projects in our community that focus on increasing customer awareness and reducing energy consumption:

Generation Conservation:

In December, Oshawa PUC Networks Inc., launched Generation Conservation, an exciting grade five science curriculum-based pilot program. The pilot program was delivered in 16 Durham Public and Durham Catholic District schools involving more than 400 students, with the objective of giving youth knowledge and the tools to become "Generation C", a generation of dedicated energy conservers.

A unique partnership with the three utility companies, CGC Educational Communications, the Durham District School Board, the Durham Catholic District School Board and 17 teacher volunteers, resulted in the development of comprehensive teacher resource material to support the program.



The Generation Conservation partners envision the program as a full support to the new Ontario science curriculum which is due to be implemented in the fall 2007.

UOIT Study

OPUCN has continued to work in conjunction with UOIT to study individual electricity usage habits of customers in Oshawa. After extensive research, a customer survey was developed to collect data regarding individual energy usage patterns. The categories for the study were also established related to the age, style, and heating of the home. There are 300 meters scheduled to go into service in 2007. The data, when compiled, will be used to design best fit conservation programs for our customers.

Watt Reader Program

The Watt Reader lending program offers a simple and cost-free way for residents to determine how much energy their appliances are consuming. The Watt Reader then keeps track of the usage of your appliance and allows you to calculate its cost of operation. By empowering the customer with better information, it gives them the ability to make cost-saving choices.

The Watt Readers can be signed out with a library card at any Oshawa Public Library branch. Upon return of the Watt Reader, a complementary compact fluorescent light bulb will be received, courtesy of OPUCN.

Rogers Watt-Wise Energy Tips

In order to increase customer awareness about electricity conservation at home, OPUCN developed a series of 12 energy tips that aired on Rogers Television. These tips demonstrated to viewers some practical and simple changes that they can make around their homes to use electricity more efficiently.

Non-Profit Housing

OPUCN provided funding for energy retrofits at four non-profit housing locations in Oshawa in 2006.

The Cornerstone Community Association, with buildings in downtown and south Oshawa, completed an energy retrofit that included upgrades to energy efficient T-8 bulbs with reflectors, all exit signs retrofitted to LED technology and all room lighting changed to compact fluorescent bulbs. The New Hope Non Profit Housing Corporation has two locations in Oshawa and underwent a similar retrofit. Annual energy savings for all locations totaled more than 250,000 kWh annually.

Management's Discussion and Analysis

Atul Mahajan, CA, CMA
Chief Financial Officer

This Management's Discussion and Analysis section should be read in conjunction with the audited consolidated financial statements and related notes for the year ended December 31, 2006. The consolidated financial statements of Oshawa Power and Utilities Corporation (OPUC) are prepared in accordance with Generally Accepted Accounting Principles (GAAP) in Canada and the accounting principles prescribed by its regulator, the Ontario Energy Board (OEB). Included in this discussion are certain non-GAAP measures that may be appropriate to enhance an overall understanding of our historical performance and future projects. Accordingly, these non-GAAP measures are intended to provide additional information and should not be considered in isolation or as a substitute for measures of performance in accordance with GAAP.

Overview

OPUC, incorporated under the Ontario Business Corporation Act, was formed to conduct electricity distribution and non-regulated service ventures. OPUC is wholly owned by the Corporation of the City of Oshawa.

OPUC has three wholly owned subsidiaries, Oshawa PUC Networks Inc., Oshawa PUC Services Inc. and Oshawa PUC Energy Services Inc.

Through its principal subsidiary, Oshawa PUC Networks Inc. (OPUCN), OPUC provides electricity distribution services to businesses and residences in the service area of Oshawa, Ontario. OPUCN distributes electricity to over 50,000 customers in the City of Oshawa.

Oshawa PUC Services Inc. (OPUCS) provides dark fibre-optic network connections to various MUSH (Municipalities, Universities, Schools and Hospitals), enterprise and carrier customers. OPUCS also provides electric meter installation, verification and maintenance services within Ontario. Oshawa PUC Energy Services Inc. is currently in the process of constructing a combined heat and power generating unit to be located at Durham College, Oshawa and is expected to commence operations in 2008.

Revenue

In 2006, OPUC earned revenues primarily from OPUCN, a rate regulated entity and from non-regulated ventures operated through OPUCS.

OPUCN earns distribution revenue based on a fixed monthly service charge combined with a variable charge that reflects the consumption of electricity by our customers. The Ontario Energy Board regulates these revenue charges. In addition to distribution revenue charges, OPUCN is required to charge its customers for amounts that are payable to third parties, which include the cost of electricity, line and connection rates, retail transmission rates, and wholesale market charges.

OPUCN also derives other revenue from the completion of service work such as cable installations, pole rentals for third party communication lines and other miscellaneous operational services.

OPUCS generates revenues from two segments.

1. Providing accredited wholesale and retail metering services to other *Local Distribution Companies* (LDC) in the Province of Ontario.

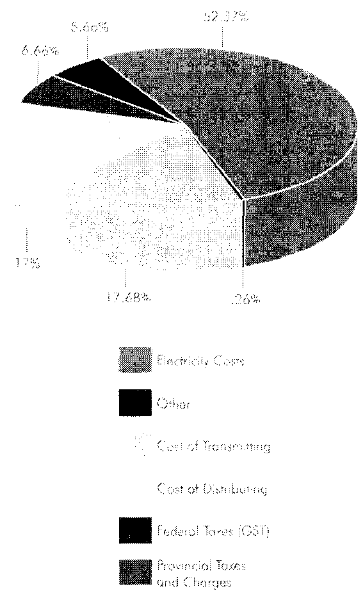
2. "Dark" Fibre optic capacity to *enterprise customers and* telecommunication carriers.

Rate Setting and Regulation

The *Energy Competition Act, 1998* (the "Act") which was given Royal Assent on October 30, 1998, provides for a competitive market in the sale of electricity and the regulation of the monopoly electricity delivery system in the Province of Ontario (the "Province") by the OEB.

The OEB has regulatory oversight of electricity matters in the Province. The *Ontario Energy Board Act, 1998* sets out the OEB's powers to issue a distribution licence which must be obtained for owning or operating a distribution system under the *Ontario Energy Board Act, 1998*. The OEB is charged with the responsibility of approving or setting rates for the

Electricity Cost Breakdown
(for OPUCN residential customers)



transmission and distribution of electricity and the responsibility for ensuring that distribution companies such as OPUCN fulfill obligations to connect and service customers.

Regulatory Assets/Liabilities

Due to the rate regulated operations of OPUCN, OPUC is obliged to record certain amounts in its financial statements as regulatory assets and liabilities. These amounts are deferred for disposition in accordance with the decisions to be issued by the regulator, OEB.

Results of Operations

OPUC's operating earning (EBITDA – Earnings Before Income Taxes, Depreciation and Amortization) increased from $9.55 million in 2005 to $10.51 million in 2006, through a combination of increased regulated distribution income and increased non-regulated revenues from leasing of "dark" fibre optic capacity.

After adjustments for depreciation, interest income, interest expense net of capitalized interest and taxes, OPUC earned a net income of $4.21 million in 2006 as compared to $3.02 million in 2005.

Included in the increased net income were one time impacts of savings due to tax deferral strategies and refunds from the group employee benefits plan.

Revenue

From the distribution of electricity to customers located within the City of Oshawa.

The total revenue includes regulated distribution income for OPUC and the flow through revenue that is collected on behalf of others. The flow through revenue includes cost of electricity, transmission and wholesale charges. Due to a decline in the wholesale cost of electricity in 2006, the total revenue including flow through revenue decreased by $30.27 million. However, the overall net distribution revenue received by OPUC increased from $17.41 million to $17.91 million.

Other Revenues

i) OPUCN - includes revenues derived from the completion of service work and other miscellaneous operational services.

ii) OPUCS - includes revenues from metering services and from lease of fibre optic capacity.

The increase in other revenue in 2006 is primarily on account of increased regulated miscellaneous charges (account set up and collection etc.) and the increase in the leasing capacity of the fibre optic network.

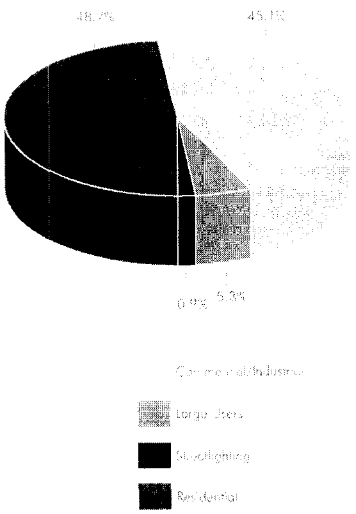
Expenses

Operating expenses prior to costs allocated to Capital projects, increased

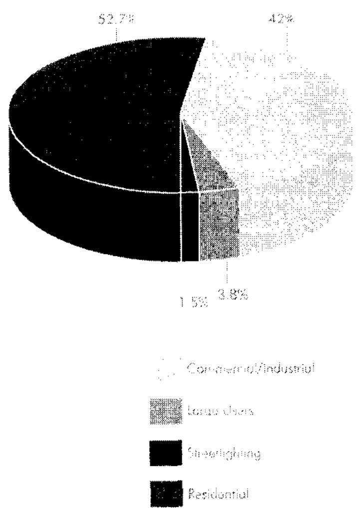
Revenue *(in thousands of $)*	2006	%	2005	%
RESIDENTIAL CUSTOMERS	$45,022	48.7	$65,148	53.1
LARGE SERVICE CUSTOMERS	41,686	45.1	50,487	41.1
LARGE USERS	4,903	5.3	6,189	5.0
STREET LIGHTING	843	0.9	905	0.8
TOTAL REVENUE FROM DISTRIBUTION	$92,454	100%	$122,729	100%

Other Revenue *(in thousands of $)*	2006	%	2005	%
OTHER REVENUE – OPUC NETWORKS	$1,256	88.9	$713	89.8
OTHER REVENUE – OPUC SERVICES	156	11.1	81	10.2
TOTAL OTHER REVENUE	$1,412	100%	$794	100%

% of Total Revenue by Customer Class 2006



% of Distribution Revenue by Customer Class 2006



by \$0.39 million from \$12.84 million in 2005 to \$13.23 million in 2006. Year over year increases were mainly attributable to increases in labour and benefits, repairs and maintenance, and interest on customer deposits.

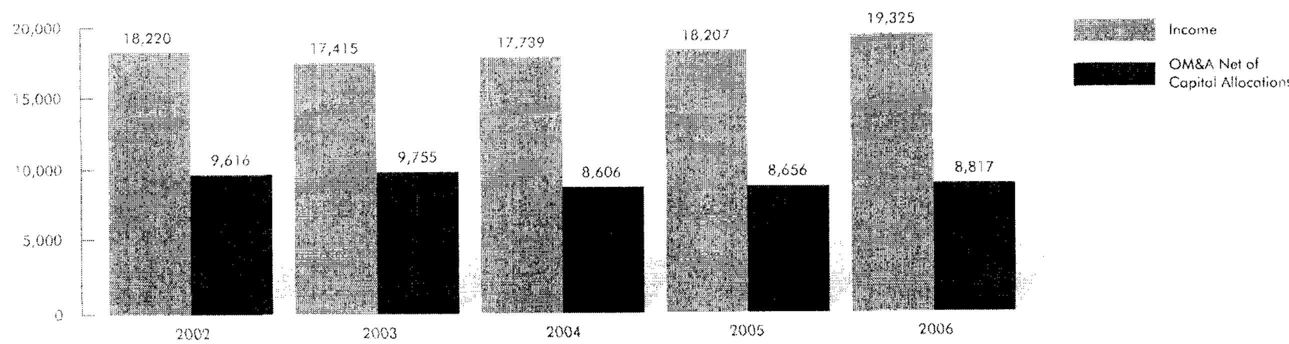
Shareholder Related Operating Costs

OPUC pays an annual rent of \$0.26 million for its office, warehouse and distribution premises located at 100 Simcoe Street South. This property is owned by the City of Oshawa. In addition, OPUC also pays property taxes of \$0.15 million on the Municipal sub-stations owned by OPUC.

Employee Future Benefits

As part of negotiated settlements reached over the years, the Corporation provides its employees and retirees with

Income vs Expenses
(\$ in thousands)



a comprehensive health benefit package. The coverage extended by this benefit covers retirees for life with a joint survivor clause. The liability recognized for the employee future benefits is based on an actuarial valuation of the estimated cost of providing employees and retirees with the health and dental benefits post retirement. As of December 31, 2006, the Post Employment Benefit liability for OPUC was $8.18 million.

Investing and Financing Activities

Property Plant and Equipment

In 2006, OPUC carried out planned additions to its property, plant and equipment. Year over year capital expenditure activity increased slightly from $11.55 million in 2005 to $11.94 million in 2006.

Primarily the construction activity included **Connecting** new customers ($0.9M), **Expanding** the Distribution and Fibre System ($2.0M) and **Enhancing** the distribution plant ($8.0M) to ensure safety and reliability of its distribution plant.

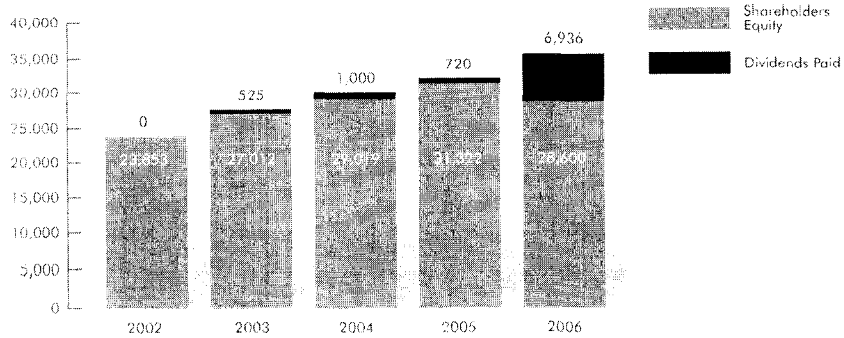
Dividends

A total Shareholder Dividend of $6.94 million was paid in 2006.

Risk and Uncertainties

The financial performance of OPUC is subject to risks and uncertainty as described below.

Shareholder Equity & Dividends Paid



Credit Risk

OPUC is subject to credit risk with respect to customer and energy retailers (under billing and settlement services it is required to provide to such retailers). LDCs in Ontario are permitted to mitigate the risk of customer non-payment using various means as permitted by law, including deposits, late payment interest penalties, prepayment, preauthorized payments or load limiters.

In 2004, the Distribution System Code (DSC) was changed to outline the maximum amounts of security deposits and the length of time that electricity distributors can hold them. The Corporation has changed its deposit policies and have adjusted its customer accounts as prescribed by the OEB. The overall effect for 2005 had been a reduction in customer's advance deposits held from $4.54 million in 2004 to $3.79 million in 2005. This trend continued for 2006 when customer advance deposits decreased to $3.46 million.

Such regulatory changes increase the credit exposure, in spite of active credit management programs in place at OPUC.

Regulatory Risks

Changes to any of the laws, rules, regulations or policies applicable to the businesses carried on by OPUC could have a significant impact on its operations and cash flows. There can be no assurance that OPUC will be able to comply with applicable future laws, rules, regulations and policies. Failure by OPUC to comply with applicable laws, rules, regulations and policies may subject OPUC to civil or regulatory proceedings, which may have a material adverse effect.

Environmental Risk

OPUC has conducted environmental assessments on its properties. No significant remediation liability has been identified as at the date of reporting.

Natural and Other Unexpected Occurrences

The facilities of OPUC are exposed to the effects of natural and other unexpected occurrences. Although OPUC's facilities are constructed, operated and maintained to withstand severe weather conditions, there can be no assurance they will successfully do so in all circumstances. For example, an ice storm in January 1998 caused significant damage to transmission and distribution facilities in Ontario, Quebec and northeastern United States. Any major damage to OPUC's facilities could result in lost revenues and repair costs that are substantial. If it sustained a large uninsured loss caused by natural or other unexpected occurrences, OPUC would apply to the OEB for the recovery of the loss. There can be no assurance that the OEB would approve any such application, in whole or in part.

Risk Management

Various internal and external factors have an impact on OPUC's results. OPUC's risk management practices currently in place are designed with the objective of providing reasonable assurance its business objectives will be met.

In order to minimize the impact of some of the risks including physical risks to OPUC's distribution and other assets, OPUC has put in place an insurance program.

In addition, OPUC is implementing a comprehensive Risk Management program, *Risk Focus*. The core purposes of *Risk Focus* are:

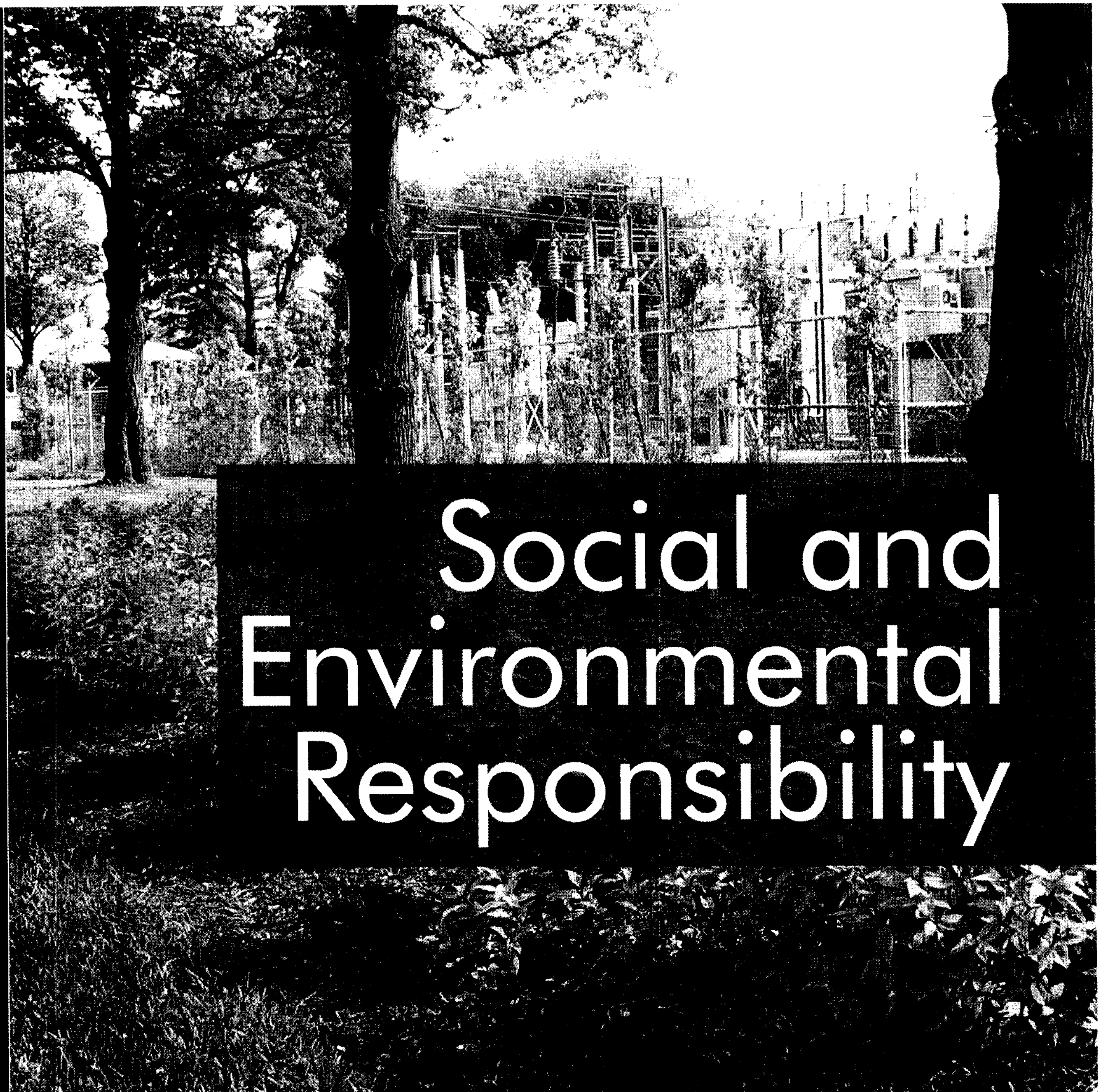
- To evaluate OPUC's risk management practices, identifying opportunities for improvement.
- To review and prioritize strategic, operational, financial and physical hazard risks and evaluate the general effectiveness of present controls.
- To apply these outcomes to check the efficiency of OPUC's insurance practices and to identify opportunities for improvement or risk retention and transfer strategies.

Collective Labour Agreement

The International Brotherhood of Electrical Workers Local 636 represents our employees. A new collective agreement was signed in July of 2006 and covers a four year period from March 1, 2006 to February 28, 2010.

Employees

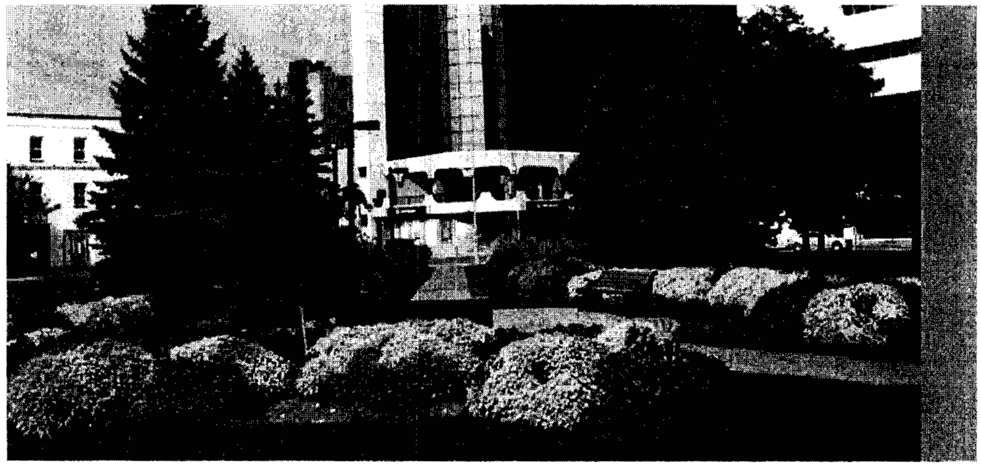
As at December 31, 2006, the Corporation had 23 active non-union employees, 61 union employees and 89 retirees.



Social and Environmental Responsibility

Municipal substation number 5 after the completion of landscaping.

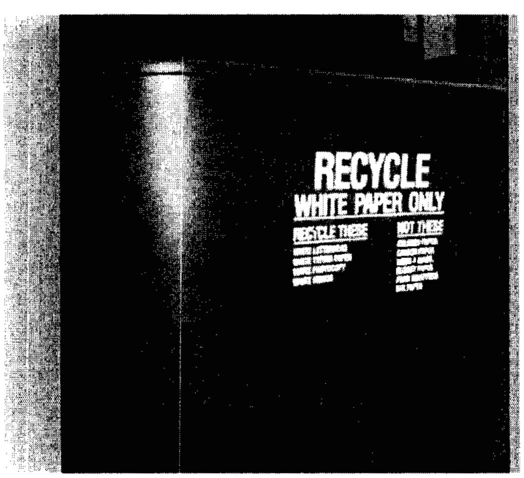
As good neighbours we embarked on a substation beautification program that helps our substations compliment the neighbourhoods they are located in. In addition we are always conscious of the impact of our operations on the environment and take care in everything we do. We explore new opportunities to recycle and purchase products that contain recycled materials.



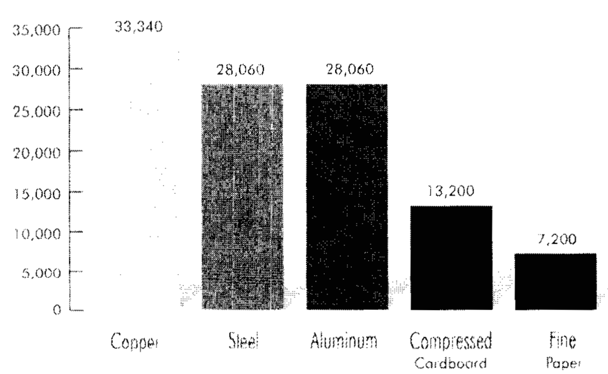
Oshawa Power and Utilities Corporation integrates social and environmental considerations into its corporate activities. We support several events and associations in our community. Some of these organizations are:

- The Greater Oshawa Chamber of Commerce
- Friends of the Second Marsh
- Wetland Stomp Committee
- Central Lake Ontario Conservation Authority
- Oshawa Community Health Center
- City of Oshawa
- Region of Durham
- United Way
- Durham District School Board

At Oshawa Power and Utilities Corporation, we encourage sound environmental practices and promote product recycling. We are proud to report that our PCB transformer removal program will be completed by May 31, 2007.



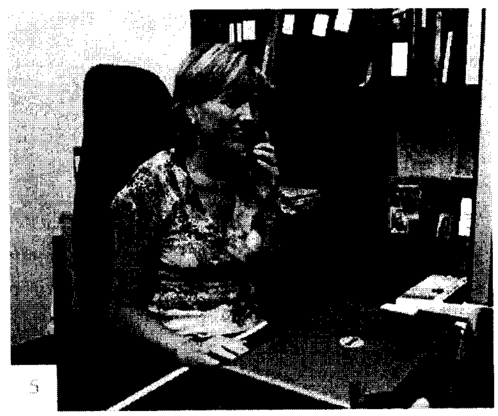
Environmental Recycling (in lbs)



1. Left to right:
   Tara Storey, *Conservation Projects Coordinator*
   Nadeige Carter, *Executive Assistant*
2. Vivian Leppard, *Regulatory Analyst*
3. Mike Chase, *Corporate Controller*
4. Dave Osborne, *Distribution Manager*
5. Tracey Strong, *Acting Manager of Accounting*

2

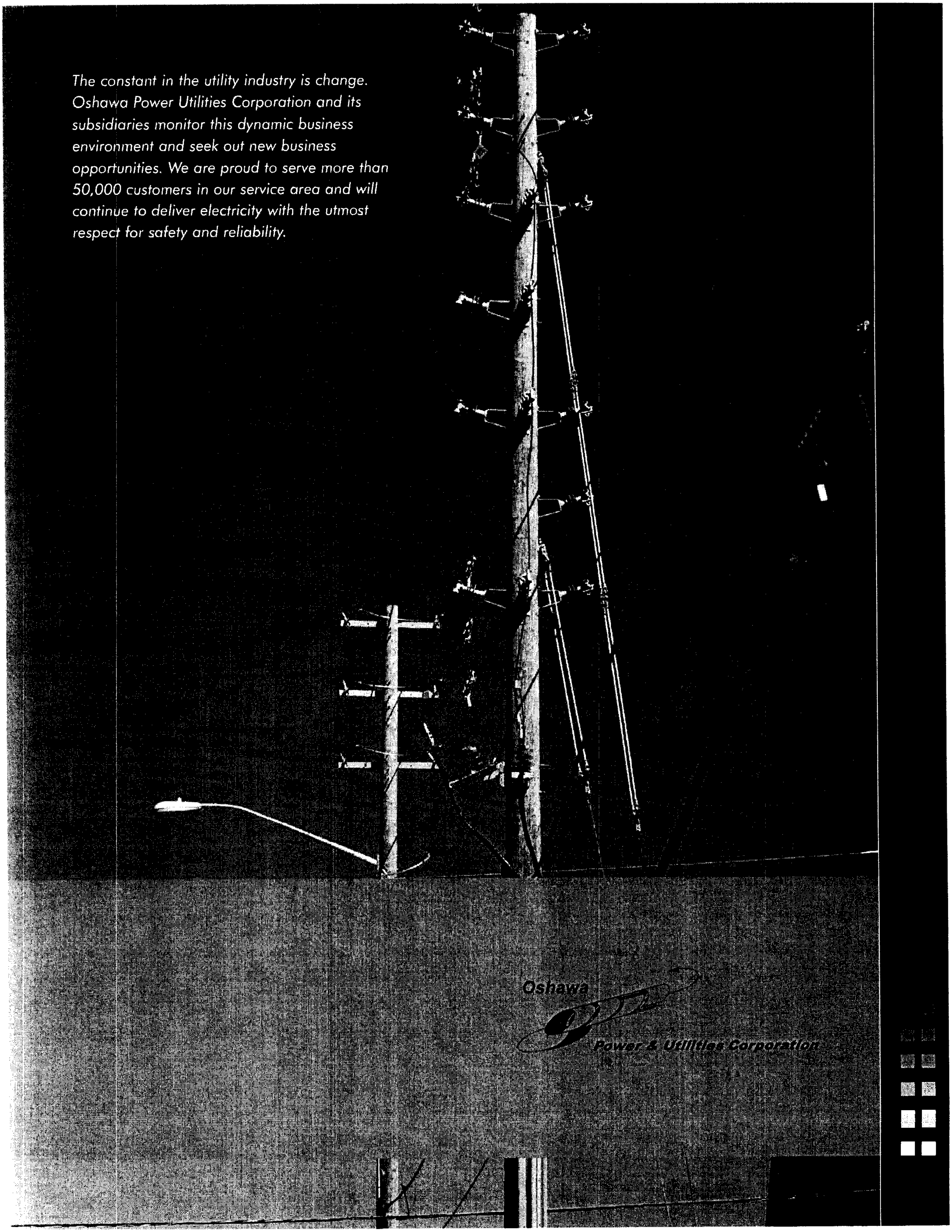
4



5

Our success is the result of the hard work and dedication of the more than 80 men and women who work for the affiliates of Oshawa Power and Utilities Corporation. From office management, to finance to electrical distribution each person plays a key role in ensuring the corporation's services are delivered in a safe and professional manner.

The constant in the utility industry is change. Oshawa Power Utilities Corporation and its subsidiaries monitor this dynamic business environment and seek out new business opportunities. We are proud to serve more than 50,000 customers in our service area and will continue to deliver electricity with the utmost respect for safety and reliability.



Oshawa

Power & Utilities Corporation

Oshawa Power and Utilities Corporation
100 Simcoe Street South
Oshawa, Ontario L1H 7M7
Tel: 905-723-4623
Toll Free: 1-877-997-2899
Fax: 905-723-7947
www.opuc.on.ca

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APPENDIX B

DEFERRED PILS ACCOUNT REVIEW REPORT (RDI CONSULTING)

Oshawa PUC Networks Inc.

Deferred PILs Accounting Review Report

Prepared By:

Jim Hopeson
Ian McKenzie

RDI Consulting Inc.
London, Ontario

August 2007

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Introduction

RDI Consulting Inc. (RDI) was retained by Oshawa PUC Networks (Oshawa) to independently review the determination of the Deferred PILs account 1562 balance as of December 31, 2006.

Oshawa is preparing a 2008 rate rebasing application to the Ontario Energy Board (OEB) and wishes to include the accumulated amount in the 1562 account as part of the Deferral and Variance Account Disposition component of the application.

The deferred PILs account has not yet been addressed as part of a rate setting process.

Oshawa has selected accounting option 3 which results in the use of an equal and offsetting contra account 1563 on the balance sheet.

Review Methodology

Basic Approach

Due to the complexity of the PILs accounting process RDI chose to adopt a zero based approach.

RDI independently recreated the Deferred PILs accounting process from its start on October 1, 2001 when Oshawa first became taxable through to the end of fiscal year 2006 (December 31, 2006). An accounting model was used and the results are set out in Appendix A.

The key components of the Deferred PILs accounting process are described below.

PILs Entitlement

The monthly entitlement to recover PILs revenue from customers is determined by the amount of PILs included in final rates approved by the OEB.

RDI validated the monthly entitlement used in the accounting model against all approved rate orders from March 2002 to May 2006.

RDI followed Board direction to stop tracking the difference between monthly PILS entitlement and monthly PILS revenue recoveries effective May 1, 2006.

Revenue Recovery

PILs revenues are embedded in distribution rates over the period. Also, different rate designs were utilized over the period. As a result RDI has developed rate year specific PILs revenue recovery models that extract PILs revenues based on the rate design for each specific year.

These extraction models utilize details from the prescribed OEB rate models that were used to develop distribution rates. The rate models were tied in to the final approved rate orders to insure proper PILs revenue determination.

Essentially the extraction models develop on a customer class basis the percentage of both fixed and variable distribution revenue that relates to PILs. The percentages are applied on a monthly basis against the monthly billed customer class fixed/variable revenues provided by Oshawa.

The monthly recoveries are applied against the monthly entitlements up to April 30, 2006.

PILs Reconciliations

Up to July 2006 LDCs were required to file a PILs reconciliation for the previous taxation year that compared PILs in rates to taxes actually paid. In some instances these reconciliations generated a true-up adjustment that must be recorded as part of the Deferred PILs accounting process.

RDI reviewed the PILs reconciliations filed with the Board and validated that these were correctly filed.

The accounting spreadsheets include all of the filed true-up amounts in the month of July for the previous fiscal year. (ie. true-up for 2004 recorded in July 2005)

LCT Implications

Oshawa did not have an LCT tax provision included in either 2005 or 2006 rates therefore no 1592 account entry is required as per direction included in the Accounting Procedures Handbook (APH) frequently asked questions in December 2005 and July 2007.

Interest Improvement

RDI has calculated monthly interest improvement on the starting monthly principal balance (Entitlement – Recoveries +/- PILs Reconciliation true-up) using the Board prescribed interest rates. The simple interest method was used with no interest compounding.

Results

Appendix A sets out the balance as at December 31, 2006

- Principal balance of $499,155.08
- Interest improvement of $282,951.57

Recommendations

Rate Disposition Methodology

The Filing Guidelines for Transmission and Distribution Rate Applications does not provide specific direction regarding an approach to deal with variance and deferral account recovery rate setting.

The general principle is that an application should be based on a forward test year which requires forecasting future expected results. This is very difficult for variance and deferral accounts given the actual nature of these accounts.

In our view the approach taken by the OEB to establish regulatory asset recovery rate riders as part of the May 2006 rate setting process is a reasonable one.

RDI recommends paralleling this approach:

- Disposition the December 31, 2006 variance and deferral account balances (essentially 2005 and 2006 cumulative values as December 31, 2004 balances approved by the Board in the May 2006 rate application have been eliminated in the accounts as per Board APH direction).
- Include additional interest improvement on the December 31, 2006 principal balance for the 16 month period from January 1, 2007 to April 30, 2008
- Allocate to customer classes
- Recover over a 2 year period

Principal and Interest Amounts To Be Recovered

The total amount to be recovered would be ***$812,654.94*** comprised of the following:

- $499,155.08 - Principal at December 31, 2006
- $282,951.57- Interest improvement at December 31, 2006
- $30,548.29 - Additional interest improvement (January 2007 to April 2008) - ($499,155.08 X 4.59% X 16/12)

Allocation to Customer Classes

As per the May 2006 regulatory assets rate setting process each USoA account is allocated to customer classes on the most reasonable basis. The Deferred PILs account has not been dealt with so what would be a reasonable allocation basis.

In our view the PILs balance should be allocated to customer classes based on relative distribution revenue. Taxation is driven by revenue determination.

The use of customer numbers or energy would not be appropriate allocators.

Appendix A
Oshawa PILS Interest Improvement Schedule - RDI Version July 18, 2007

Includes reconciled:

2001 - 2006 PILS Entitlements
2002-2003, 2004, 2005, 2006 Revenue Splits
2002 - 2006 Distribution Revenue
OEB Approved Interest Rates and Methodology
PILS Reconciliation Amounts

2001	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Starting Balance	-	-	-	-	-	-	-	-	-	-	197,479.67	394,959.33
Allowed Entitlement (expense)	-	-	-	-	-	-	-	-	-	197,479.67	197,479.67	197,479.67
Actual Recoveries (revenue)	-	-	-	-	-	-	-	-	-	-	-	-
PILS Reconciliation Amount												
Ending Balance	-	-	-	-	-	-	-	-	-	197,479.67	394,959.33	592,439.00
Annual Interest Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%
Days in Month	31	28	31	30	31	30	31	31	30	31	30	31
Days in Year	365	365	365	365	365	365	365	365	365	365	365	365
Monthly Interest Rate	0.616%	0.556%	0.616%	0.596%	0.616%	0.596%	0.616%	0.616%	0.596%	0.616%	0.596%	0.616%
Interest Improvement	-	-	-	-	-	-	-	-	-	-	1,176.76	2,431.98
Cumulative Interest	-	-	-	-	-	-	-	-	-	-	1,176.76	3,608.74

2002	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Starting Balance	592,439.00	769,418.42	946,397.83	1,047,924.95	1,128,795.19	1,156,422.38	1,010,645.90	1,022,028.10	1,096,580.57	1,043,935.45	1,002,486.73	951,584.45
Allowed Entitlement (expense)	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42
Actual Recoveries (revenue)	-	-	75,452.30	96,109.17	149,352.23	322,755.90	165,597.21	102,426.95	229,624.54	218,428.14	227,881.69	265,541.42
PILS Reconciliation Amount												
Ending Balance	769,418.42	946,397.83	1,047,924.95	1,128,795.19	1,156,422.38	1,010,645.90	1,022,028.10	1,096,580.57	1,043,935.45	1,002,486.73	951,584.45	863,022.45
Annual Interest Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%
Days in Month	31	28	31	30	31	30	31	31	30	31	30	31
Days in Year	365	365	365	365	365	365	365	365	365	365	365	365
Monthly Interest Rate	0.616%	0.556%	0.616%	0.596%	0.616%	0.596%	0.616%	0.616%	0.596%	0.616%	0.596%	0.616%
Interest Improvement	3,647.96	4,279.23	5,827.48	6,244.48	6,950.60	6,891.01	6,223.09	6,293.17	6,534.42	6,428.07	5,973.72	5,859.41
Cumulative Interest	7,256.70	11,535.93	17,363.41	23,607.89	30,558.49	37,449.50	43,672.59	49,965.76	56,500.18	62,928.25	68,901.97	74,761.38

2003	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Starting Balance	863,022.45	910,250.58	826,899.50	746,964.59	794,939.16	708,804.67	709,050.79	860,643.60	863,082.75	843,117.18	811,791.34	820,599.26
Allowed Entitlement (expense)	226,349.33	226,349.33	226,349.33	226,349.33	226,349.33	226,349.33	226,349.33	226,349.33	226,349.33	226,349.33	226,349.33	226,349.33
Actual Recoveries (revenue)	179,121.20	309,700.41	306,284.24	178,374.77	312,483.82	226,103.21	254,747.53	223,910.18	246,314.90	257,675.18	217,541.41	240,697.01
PILS Reconciliation Amount							179,991.00					
Ending Balance	910,250.58	826,899.50	746,964.59	794,939.16	708,804.67	709,050.79	860,643.60	863,082.75	843,117.18	811,791.34	820,599.26	806,251.59
Annual Interest Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%
Days in Month	31	28	31	30	31	30	31	31	30	31	30	31
Days in Year	365	365	365	365	365	365	365	365	365	365	365	365
Monthly Interest Rate	0.616%	0.556%	0.616%	0.596%	0.616%	0.596%	0.616%	0.616%	0.596%	0.616%	0.596%	0.616%
Interest Improvement	5,314.09	5,062.49	5,091.66	4,451.09	4,894.87	4,223.70	4,366.00	5,299.44	5,143.03	5,191.52	4,837.39	5,052.87
Cumulative Interest	80,075.47	85,137.96	90,229.62	94,680.71	99,575.58	103,799.28	108,165.28	113,464.73	118,607.75	123,799.28	128,636.66	133,689.53

Oshawa PUC Network Inc.

EB-2007-0710

2004

	January	February	March	April	May	June	July	August	September	October	November	December
Starting Balance	806,251.59	788,552.59	768,989.03	700,900.84	673,268.84	712,940.53	701,920.49	791,681.55	783,890.24	758,072.04	771,935.05	765,703.84
Allowed Entitlement (expense)	226,349.33	226,349.33	226,349.33	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42	176,979.42
Actual Recoveries (revenue)	244,048.33	245,912.90	294,437.52	204,611.42	137,307.73	187,999.46	180,011.35	184,770.73	202,797.62	163,116.41	183,210.63	170,153.82
PILS Reconciliation Amount							92,793.00					
Ending Balance	788,552.59	768,989.03	700,900.84	673,268.84	712,940.53	701,920.49	791,681.55	783,890.24	758,072.04	771,935.05	765,703.84	772,529.44
Annual Interest Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%
Days in Month	31	29	31	30	31	30	31	31	30	31	30	31
Days in Year	366	366	366	366	366	366	366	366	366	366	366	366
Monthly Interest Rate	0.614%	0.574%	0.614%	0.594%	0.614%	0.594%	0.614%	0.614%	0.594%	0.614%	0.594%	0.614%
Interest Improvement	4,950.96	4,529.87	4,722.14	4,165.19	4,134.35	4,236.74	4,310.29	4,861.49	4,658.36	4,655.10	4,587.32	4,701.97
Cumulative Interest	138,640.49	143,170.36	147,892.49	152,057.68	156,192.03	160,428.77	164,739.06	169,600.55	174,258.91	178,914.01	183,501.33	188,203.30

2005

	January	February	March	April	May	June	July	August	September	October	November	December
Starting Balance	772,529.44	752,802.52	739,142.46	727,091.66	747,708.83	768,851.84	801,991.35	691,356.44	672,901.07	709,131.05	737,444.75	763,146.58
Allowed Entitlement (expense)	176,979.42	176,979.42	176,979.42	193,927.58	193,927.58	193,927.58	193,927.58	193,927.58	193,927.58	193,927.58	193,927.58	193,927.58
Actual Recoveries (revenue)	196,706.34	190,639.48	189,030.22	173,310.41	172,784.57	160,788.08	166,321.49	212,382.95	157,697.60	165,613.89	168,225.76	176,917.56
PILS Reconciliation Amount							(138,241.00)					
Ending Balance	752,802.52	739,142.46	727,091.66	747,708.83	768,851.84	801,991.35	691,356.44	672,901.07	709,131.05	737,444.75	763,146.58	780,156.60
Annual Interest Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%
Days in Month	31	28	31	30	31	30	31	31	30	31	30	31
Days in Year	365	365	365	365	365	365	365	365	365	365	365	365
Monthly Interest Rate	0.616%	0.556%	0.616%	0.596%	0.616%	0.596%	0.616%	0.616%	0.596%	0.616%	0.596%	0.616%
Interest Improvement	4,756.88	4,186.82	4,551.30	4,332.67	4,604.04	4,581.51	4,938.29	4,257.05	4,009.75	4,366.50	4,394.36	4,699.10
Cumulative Interest	192,960.17	197,146.99	201,698.29	206,030.96	210,635.00	215,216.51	220,154.80	224,411.85	228,421.61	232,788.11	237,182.47	241,881.57

2006

	January	February	March	April	May	June	July	August	September	October	November	December
Starting Balance	780,156.60	773,487.64	782,446.59	785,795.54	803,007.08	803,007.08	803,007.08	499,155.08	499,155.08	499,155.08	499,155.08	499,155.08
Allowed Entitlement (expense)	193,927.58	193,927.58	193,927.58	193,927.58								
Actual Recoveries (revenue)	200,596.54	184,968.63	190,578.63	176,716.05								
PILS Reconciliation / LCT Adjustment				-			(303,852.00)					-
Ending Balance	773,487.64	782,446.59	785,795.54	803,007.08	803,007.08	803,007.08	499,155.08	499,155.08	499,155.08	499,155.08	499,155.08	499,155.08
Annual Interest Rate	7.25%	7.25%	7.25%	7.25%	7.25%	7.25%	4.59%	4.59%	4.59%	4.59%	4.59%	4.59%
Days in Month	31	28	31	30	31	30	31	31	30	31	30	31
Days in Year	365	365	365	365	365	365	365	365	365	365	365	365
Monthly Interest Rate	0.616%	0.556%	0.616%	0.596%	0.616%	0.596%	0.390%	0.390%	0.377%	0.390%	0.377%	0.390%
Interest Improvement	4,803.84	4,301.86	4,817.94	4,682.48	4,944.54	4,785.04	3,130.41	1,945.88	1,883.11	1,945.88	1,883.11	1,945.88
Cumulative Interest	246,685.41	250,987.27	255,805.22	260,487.70	265,432.24	270,217.28	273,347.69	275,293.57	277,176.69	279,122.57	281,005.69	282,951.57

APPENDIX C.1

AON CONSULTANTS ACTUARIAL STUDY 2006

January 26, 2007

PRIVATE & CONFIDENTIAL

BY E-MAIL

Mr. Michael Chase, C.M.A., M.B.A.
Corporate Controller
Oshawa PUC Networks Inc.
100 Simcoe Street South
Oshawa, Ontario
L1H 7M7

RE: CICA3461 – RETIREE NON-PENSION BENEFITS OF OSHAWA PUBLIC UTILITIES CORPORATION NETWORKS INC.

Dear Michael:

As requested, we are pleased to provide information concerning the 2006 annual benefit cost and year-end disclosure for the Oshawa Public Utilities Corporation Networks Inc. (the "Corporation") in accordance with the Canadian Institute of Chartered Accountants Handbook Section 3461 ("CICA 3461"). The Corporation sponsors post-retirement medical and dental benefits and provides life insurance to retirees. The results summarized below pertain to the post-retirement medical, dental and life insurance benefits.

Summary of Results	
Expected Average Remaining Service Life	9.89 years
2006 Annual Benefit Cost (Income)	$877,800
Estimated Liabilities—Accrued Benefit Obligation at December 31, 2006	$10,209,000
Experience Gain or (Loss) arising during 2006	$0
Asset Value at December 31, 2006	$0
Accrued Benefit Liability at January 1, 2006	$7,796,869
2006 Annual Benefit Cost (Income)	$877,800
Company Contributions	$(409,600)
Accrued Benefit Liability at December 31, 2006	$8,265,069

Aon Consulting Inc.
145 Wellington Street West • Suite 500 • Toronto, Ontario M5J 1H8
Telephone: 416-542-5500 • Fax: 416-542-5504 • www.aon.com

We have relied on information provided by your office to establish the accrued benefit liability as at January 1, 2006.

Please note that the estimated annual benefit cost for 2007 is $895,200 and the estimated benefit payments (or employer contributions) are $433,200. Thus, the difference between the estimated annual benefit cost and estimated benefit payments for fiscal year 2007 is $462,000. For budgeting purposes, the Corporation may wish to recognize $38,500 per month, if the Corporation wishes to continue the practice established in 2004 of recognizing the difference between the estimated annual benefit cost and estimated benefit payments on a monthly basis.

Exhibit A summarizes the important elements of the valuations assumptions employed in developing the disclosures and includes a summary of plan provisions. Detailed results are enclosed in Exhibits B and C, which set out the required disclosures for 2006 (Exhibit B) and certain estimated elements of the 2007 accounting (Exhibit C), assuming no change to the valuation assumptions.

Assumptions

The 2006 annual benefit cost and December 31, 2006 accrued benefit obligation are calculated based on the actuarial assumptions used to determine the liabilities at January 1, 2005 for purposes of the Actuarial Report on the Postretirement Benefits of Oshawa Public Utilities Corporation Networks Inc. as at January 1, 2005, as previously prepared by Aon Consulting Inc., with the exception of the discount rate. A discount rate of 5.25% per annum was used to determine the 2006 annual benefit cost and accrued benefit obligation as at December 31, 2006. A summary of the assumptions is provided in Exhibit A.

Emerging experience differing from the assumptions will result in gains or losses that will be revealed in future valuations.

Recognition of Actuarial Gains and Losses

CICA3461 prescribes a minimum amortization schedule to be used for unrecognized actuarial gains and losses. The methodology applies to actuarial gains or losses arising from changes in actuarial assumptions, or experience different from expected. Such gains or losses in excess of 10% of the accrued benefit obligation are to be amortized over the expected average remaining service lifetime of the active employees, or the average life expectancy of the retired employees if the majority of the plan participants are retirees.

An employer may choose to adopt a practice to amortize more rapidly than the minimum. It is our understanding that the Corporation wishes to follow the minimum required amortization.

Membership Data

In estimating the actuarial liabilities as at December 31, 2006, we first determined the liabilities at January 1, 2005 based on a 5.25% per annum discount rate. The results of this valuation were rolled forward to January 1, 2006 to determine the annual benefit cost for 2006. The Corporation provided the data used to determine the liabilities at January 1, 2005 for purposes of the actuarial valuation. A summary of the membership data is provided in the actuarial report as at January 1, 2005.

Assets

There are no assets to support the postretirement benefits provided by the Corporation.

Actuarial Cost Method

The actuarial cost method used is the projected accrued benefit cost method. The method is unchanged from the previous valuation.

Actuarial Opinion

Regarding this report we confirm the following:

1) I am familiar with the recommendations in Section 3461 of the Handbook of the Canadian Institute of Chartered Accountants, and the differences between actuarial valuations for funding purposes and those for determining benefit costs, assets, and obligations for accounting purposes. The actuarial methods used in the funding valuations and the extrapolations are consistent with those recommendations.

2) The postretirement benefits are defined benefit plans as defined by Section 3461 of the CICA Handbook.

3) This valuation had been prepared, and my opinions given, in accordance with accepted actuarial practice and the standards of the Canadian Institute of Actuaries.

4) The benefit costs and obligations are determined using the projected accrued benefit cost method.

5) The Corporation has adopted the actuarial assumptions used for the funding valuations as management's best estimates for the purpose of reporting in the Corporation's financial statements.

6) These results are based upon the provisions of the Plan described in the valuation report. A summary of the Plan provisions is provided in the actuarial report as at January 1, 2005 and attached to this letter as an Exhibit. I am not aware of any other events subsequent to January 1, 2007, which would have a material effect on the valuations of the plans. The effective date of the next required actuarial valuation is January 1, 2008.

Please do not hesitate to call me or in my absence, Yun-Suk Kang at (416) 542-5532, if you have any questions.

Yours truly,

Donald Blue, FSA, FCIA
Senior Consultant
(416) 542-5997

cc: Atul Mahajan, Oshawa Power & Utilities Corporation
Christine Dade, Oshawa Power & Utilities Corporation
Yun-Suk Kang, Aon Consulting Inc.

Enclosures

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Exhibit A
Actuarial Methods and Assumptions

The following method and assumptions were used in performing this accounting valuation.

VALUATION METHOD

The method prescribed by CICA is the projected accrued benefit cost method pro-rata on service. The actuarial present value of postretirement life, medical and dental insurance benefits, called the obligation for employee future benefits (OEFB) is allocated or attributed to each employee's years of service from the date at which eligible service begins to accrue to the first date that the employee is fully eligible for benefits under the **Plan** on retirement (i.e. "the full eligibility date"). The full eligibility date is assumed to be the attainment of age 55 with10 or more years of service.

The accrual for service or "service cost" is the OEFB divided by this attribution period and multiplied by one year (or less if the attribution period ends before or during the valuation year). The accrued liability, called the accrued benefit obligation (ABO), is the OEFB divided by the attribution period and multiplied by the years of service rendered up to the valuation date (that are included in the attribution period).

The "unamortized transitional obligation" represents the portion of the initial obligation existing at the adoption of the Canadian Standards that is yet to be recognized. It is our understanding that the **Company** had chosen to recognize this initial obligation on a retroactive basis whereby the initial obligation existing at the adoption of the Canadian Standards was recognized immediately.

The accumulated unamortized gains or losses as at January 1, 2006 to the extent that they exceed 10% of liabilities are amortized on a straight-line basis over the expected average remaining service period of active members or the average life expectancy of the retirees if the majority of the participants have already retired, as calculated at January 1, 2005. The EARSL as at January 1, 2005 is equal to 9.89 years.

Exhibit A
Actuarial Methods and Assumptions

For the purposes of the **Company**'s income statement, the 2006 annual benefit cost is equal to:

- The 2006 service cost at the end of the year, plus
- The interest cost on the ABO less interest on expected benefit payments, plus
- The amortization of the transitional obligation, plus
- The amortization of the accumulated unamortized actuarial gains of losses that exceed 10% of liabilities.

The post retirement annual benefit cost in later years may be affected by other components such as:

- The amortization of future actuarial gains and losses;
- The amortization of prior service costs due to plan amendments; or
- The impact of any settlements or curtailments.

Exhibit A
Actuarial Methods and Assumptions

GENERAL ASSUMPTIONS

The following assumptions were established for the purposes of performing the roll-forward as at December 31, 2006.

1. Valuation Date

The valuation date is January 1, 2005. The results as at December 31, 2006 are rolled forward from this date.

2. Discount Rate

We have assumed a discount rate of 5.25% per annum as at December 31, 2005 to determine the 2006 service cost and interest cost. We assumed a discount rate of 5.25% per annum as at December 31, 2006 to determine the accrued benefit obligation and to estimate the 2007 service cost and interest cost.

3. Inflation Rate

This assumption has no effect on the liabilities.

4. Mortality

Mortality was assumed to be in accordance with the "1994 Uninsured Pensioner Mortality Table projected to 2005".

5. Termination Rates

The Ontario Light Termination scale was used for terminations prior to early retirement age.

6. Disability Rates

The incidence of disability was ignored.

7. Salary Increases

We assumed a 3% annual increase for future salaries. This rate reflects the expected Consumer Price Index adjusted for productivity, merit and promotion, as at January 1, 2006.

8. Retirement Rates

We have assumed that all employees retire at age 60.

9. Marital and Family Status

We assumed that 85% of active employees retiring are married and that the husband is three years older than the wife. Actual family status was used for retirees where the information was available.

10. Plan Amendments

We have prepared our accounting figures based on current plan provisions. We are not aware of any future plan amendments and have therefore ignored the impact of any such amendments.

11. Medical Plan Assumptions

We have used the premium rates charged to retirees as an estimate of the claims to be incurred. We have made assumptions for health care cost trend rates.

A. Premium Rates

The monthly premium rates at January 1, 2005 as provided by GreenShield Canada are as follows:

Retirees Under Age 65	Single Coverage	Family Coverage
Health Care	$187.14	$369.31
Dental	$26.21	$59.49

Exhibit A
Actuarial Methods and Assumptions

Retirees Aged 65 and Older	Single Coverage	Family Coverage
Health Care	$95.63	$177.19
Dental	$24.05	$54.52

B. Health Care Cost Trend Rates

The health care cost trend rates reflect expectations with regard to health care inflation, changes in health care utilization or delivery patterns, technological advances and changes in the health status of the plan participants. We have used the following trend rates:

Benefit	Trend Rate
Health Care	10% per annum graded down to 4.5% per annum over 5 years.
Dental	Flat 4.0%

In the prior valuation, health care trend rates began at 6.5% per annum and decreased annual by 1% per annum until an ultimate rate of 4.5% per annum was reached. The dental care cost trend rates were 4.5% per annum.

C. Health Care Cost Aging Factor

Health Care costs were inflated by 2.0% per annum by year of age. Dental Care costs were not inflated for aging.

Summary of Plan Provisions

The following is a brief description of the post-retirement non-pension benefits provided to retirees:

Eligibility The first full eligibility date is attainment of age 55.

Medical and Dental Expenses Dental coverage includes an annual limit of $1,000; insured percentage of 100% and 50% for basic and major procedures respectively.

Medical expenses are covered at 100% with a deductible of $10 for single coverage and $20 for family coverage. Medical coverage includes drug benefits, semi-private hospital, vision, professional therapists, etc.

Life Insurance Employees can fall into one of the following five plan options:

Plan Option	Amount of Coverage	Eligibility
1	Flat $2,000.	If employee retires with less than 10 years of service in the plan.
2,3,4	50% of final annual earnings reducing by 2.5% each year thereafter for 10 years, to a final benefit equal to 25% of final annual earnings.	If employee was ever insured under Employee Plan options 2, 3, or 4, or if employee retires with 10 or more years of service in Plan but was never in superseded plan.
5	50% of final annual earnings.	If employee was insured under superseded plan and was hired on or after May 1, 1967 and elected coverage under Option 1 only.

Exhibit B

OPUC
CICA 3461 Disclosure
For the Period Ending December 31, 2006

		January 1, 2005 - December 31, 2005		*January 1, 2006 - December 31, 2006*
Defined benefit plan obligations				
Accrued benefit obligation -				
Liabilities at beginning of period	$	8,517,100	$	9,848,700
Current service cost		199,800		250,400
Interest cost		511,600		519,500
Transfers in		-		-
Benefits paid		(381,200)		(409,600)
Actuarial (gains) losses		1,001,400		-
Balance at end of period	$	9,848,700	$	10,209,000
Defined benefit plan assets				
Fair value of plan assets -				
Balance at beginning of period	$	-	$	-
Actual return on assets		-		-
Employer contributions		381,200		409,600
Employee contributions		-		-
Transfers in		-		-
Benefits paid		(381,200)		(409,600)
Balance at end of period	$	-	$	-
Asset Category				
Equity securities		0.0%		0.0%
Debt securities		0.0%		0.0%
Real estate		0.0%		0.0%
Other		0.0%		0.0%
Total		0.0%		0.0%

Exhibit B

OPUC
CICA 3461 Disclosure
For the Period Ending December 31, 2006

		January 1, 2005 - December 31, 2005		*January 1, 2006 - December 31, 2006*
Reconciliation of the funded status of the benefit plans to the amounts recorded in the financial statements				
Fair value of plan assets	$	-	$	-
Accrued benefit obligation		9,848,700		10,209,000
Funded status of plans - surplus (deficit)		(9,848,700)		(10,209,000)
Unamortized net actuarial loss		2,051,831		1,943,931
Unamortized past service costs		-		-
Unamortized transition obligation		-		-
Accrued benefit asset (liability)		(7,796,869)		(8,265,069)
Valuation allowance		-		-
Accrued benefit asset (liability), net of valuation allowance	$	(7,796,869)	$	(8,265,069)
Reconciliation of accrued benefit asset (liability)				
Accrued benefit asset (liability) at beginning of period		(7,444,369)		(7,796,869)
Contributions during period		381,200		409,600
Pension income / (cost) during period		(733,700)		(877,800)
Accrued benefit asset / (liability) at end of period	$	(7,796,869)	$	(8,265,069)
Elements of defined benefit costs recognized in the period				
Current service cost, net of employee contributions	$	199,800	$	250,400
Interest cost		511,600		519,500
Actual return on plan assets		-		-
Actuarial (gains) losses		1,001,400		-
Plan amendments		-		-
Elements of employee future benefits costs before adjustments to recognize the long-term nature of employee future benefit costs		1,712,800		769,900
Adjustments to recognize the long-term nature of employee future benefit costs:				
- Difference between expected return and actual return on plan assets for period		-		-
- Difference between actuarial (gain)/loss recognized for period and actual actuarial (gain)/loss on accrued benefit obligation for period		(979,100)		107,900
- Difference between amortization of past service costs for period and actual plan amendments for period		-		-
- Amortization of the transitional obligation		-		-
		(979,100)		107,900
Valuation allowance provided against the accrued benefit asset		-		-
Defined benefit costs recognized	$	733,700	$	877,800

For your convenience, we are also providing the defined benefit cost for the period in a form with which you may be more familiar.

Current service cost, net of employee contributions	$	199,800	$	250,400
Interest cost		511,600		519,500
Amortization of actuarial (gains) losses		22,300		107,900
Defined benefit costs recognized	$	733,700	$	877,800

Exhibit C

OPUC
CICA 3461 Projected Benefit Cost
For the Period Ending December 31, 2007

		January 1, 2006 - December 31, 2006		*January 1, 2007 - December 31, 2007*
Elements of defined benefit costs recognized in the period				
Current service cost, net of employee contributions	$	250,400	$	263,500
Interest cost		519,500		538,400
Actual return on plan assets		0		-
Actuarial (gains) losses		0		-
Plan amendments		-		-
Elements of employee future benefits costs before adjustments to recognize the long-term nature of employee future benefit costs		769,900		801,900
Adjustments to recognize the long-term nature of employee future benefit costs:				
- Difference between expected return and actual return on plan assets for period		-		-
- Difference between actuarial (gain)/loss recognized for period and actual actuarial (gain)/loss on accrued benefit obligation for period		107,900		93,300
- Difference between amortization of past service costs for period and actual plan amendments for period		-		-
- Amortization of the transitional obligation		-		-
		107,900		93,300
Valuation allowance provided against the accrued benefit asset		-		-
Defined benefit costs recognized	$	877,800	$	895,200

		+1% Trend		-1% Trend
Sensitivity analysis for post-retirement non-pension benefits				
Change to service cost and interest cost	$	135,000	$	(113,100)
Change to accrued benefit obligation	$	1,356,700	$	(1,096,600)

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APPENDIX C.2

AON CONSULTANTS ACTUARIAL UPDATE 2007

OPUC
CICA 3461 Projected Benefit Cost
For the Years Ending December 31, 2007 and December 31, 2008

	January 1, 2007 - December 31, 2007	*January 1, 2008 - December 31, 2008*	*January 1, 2008 - December 31, 2008*
Elements of defined benefit costs recognized in the period			
Current service cost, net of employee contributions	$ 263,500	$ 262,000	$ 298,700
Interest cost	538,400	563,000	641,800
Actual return on plan assets	-	-	-
Actuarial (gains) losses	(375,700)	-	-
Plan amendments	-	-	-
Elements of employee future benefits costs before adjustments to recognize the long-term nature of employee future benefit costs	426,200	825,000	940,500
Adjustments to recognize the long-term nature of employee future benefit costs:			
- Difference between expected return and actual return on plan assets for period	-	-	-
- Difference between actuarial (gain)/loss recognized for period and actual actuarial (gain)/loss on accrued benefit obligation for period	558,100 [1]	46,000	176,000
- Difference between amortization of past service costs for period and actual plan amendments for period	-	-	-
- Amortization of the transitional obligation	-	-	-
	558,100	46,000	176,000
Valuation allowance provided against the accrued benefit asset	-	-	-
Defined benefit costs recognized	$ 984,300	$ 871,000	$ 1,116,500
Estimated benefit payments	$ 433,200	$ 455,100	$ 518,800
Defined benefit cost net of benefit payments	$ 551,100	$ 415,900	$ 597,700

Note

1 Amortization of actuarial gains and losses in 2007 includes an additional $89,100 in respect of amounts not recognized in 2006 in respect of the amortization of actuarial gains and losses.

C:\Clients\OPUC\G0\GP\64\2007\Roll Forward\[OPUC_CICA3461-without adjustment to amortization in 2006.xls]Exhibit B - Disclosures

APPENDIX D

ASSET CONDITION ASSESSMENT FOR OSHAWA PUC NETWORKS ("THE KINETICS REPORT")

ASSET CONDITION ASSESSMENT FOR OSHAWA PUC NETWORKS

Kinectrics Inc. Report No.: K-012228-010-RA-0001-R00

March 16, 2006

Stephen L. Cress
Manager
Distribution Department
Transmission and Distribution Technologies Business

Ray Piercy
Senior Engineer
Distribution Department
Transmission and Distribution Technologies Business

Kinectrics Inc., 800 Kipling Avenue
Toronto, Ontario, Canada M8Z 6C4

ASSET CONDITION ASSESSMENT FOR OSHAWA PUC NETWORKS

Kinectrics Inc. Report No.: K-012228-010-RA-0001-R00

March 16, 2006

Ray Piercy

Prepared by:

Ray Piercy
Senior Engineer
Distribution Department
Transmission and Distribution Technologies Business

Peer Review by:

Stephen L, Cress
Manager
Distribution Department
Transmission and Distribution Technologies Business

Approved by:

Dr. John Kuffel
General Manager
Transmission and Distribution Technologies Business

Dated: March 16, 2006

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the contract between Kinectrics Inc. and Oshawa PUC Networks Inc.

REVISIONS

Revision Number	Date	Comments	Approved
Draft 0	November 15, 2005		
Draft 1	February 6, 2006		
Final	March 15, 2006		

ASSET CONDITION ASSESSMENT FOR OSHAWA PUC NETWORKS

Kinectrics Inc. Report No.: K-012228-010-RA-0001-R00

Stephen L. Cress
Manager - Distribution Department

Ray Piercy
Senior Engineer - Distribution Department

SUMMARY

This report contains the results of an asset condition assessment and valuation of the electrical plant assets of Oshawa PUC Networks. It is based upon information provided by Oshawa PUC Networks and upon visual inspections and analysis conducted by Kinectrics.

The overall asset condition at Oshawa PUC Networks is very good. Several examples of required maintenance were found but they had been previously identified by OPUCN staff and scheduled for maintenance. OPUCN has a well designed and documented maintenance plan for the assets that, if it continues to be followed, can be expected to maintain them in top condition and detect many incipient failures before they occur. Overall spending on maintenance and capital replacements is in line with the best practices in the industry.

Generally, there was evidence that maintenance was being performed as documented. Not all identified problems had been repaired, which is one indicator that the systems are not over-maintained. The transformer stations, overhead lines, and underground systems generally appear well maintained.

The average age of equipment in the OPUCN system is 20 years. This is the expected average age given the patterns of past growth. The capital replacement plan is keeping up with the ageing of equipment. It is anticipated that in the future the capital replacement budget will need to be increased as more equipment reaches the end of its life. The increase in replacement is created by the increase in system size in past years. Over the next twenty years the budget is predicted to increase by three million dollars.

Replacement rate of underground cable was identified as a specific concern at the start of the project. Underground cable end of life cannot be determined based only on age as environmental and loading conditions play an essential role. OPUCN presently uses the industry best practice of monitoring failure rates and other factors, including age, to determine which cables need to be replaced. This condition based monitoring is recommended because it uses capital efficiently, but it makes the prediction of future capital needs less certain than a more costly system based on age alone. Over the next 10 years replacement of underground cable can be expected to stay close to the present rate of 3 km per year.

The book value of the power system assets only is $100,000,000 with a depreciated value of $51,000,000 based on straight line depreciation over 25 or 30 years depending on the asset. Although this is the recommended accounting procedure for rate setting, the actual condition of the assets indicates that the expected life will average at least 40 years and for many components could easily stretch to 60 or 80 years. This means that the actual worth of the assets is larger than their depreciated book value. Based on the present condition and age, the power system assets are valued at $74,000,000 at the present time.

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KINECTRICS

To:

Mark Turney
Vice President
Oshawa PUC Networks
100 Simcoe Street South
Oshawa, ON
L1H 7M7

ASSET CONDITION ASSESSMENT FOR OSHAWA PUC NETWORKS

CONCLUSIONS AND RECOMMENDATIONS

1. The overall asset condition at Oshawa PUC Networks (OPUCN) is very good. A health index of 0.62 has been calculated for the system. A brand new system would have a health index of 1 and an old, well maintained and designed system with no growth would have a health index of 0.5.

2. OPUCN has a well designed and documented maintenance plan for the assets that, if it continues to be followed, can be expected to maintain them in top condition and detect many incipient failures before they occur.

3. Overall spending on maintenance and capital replacements is in line with the best practices in the industry.

4. The capital replacement plan is keeping up with the ageing of equipment. It is anticipated that in the future the capital replacement budget will need to be increased as more equipment reaches the end of its life. The increase in replacement is created by the increase in system size in past years. Over the next twenty years the budget is predicted to increase by three million dollars.

5. Over the next 10 years replacement of underground cable can be expected to stay close to the present rate of 3 km per year.

6. Based on the present condition and age, the power system assets are valued at $74,000,000 at the present time. The book value is $100,000,000 with a depreciated value of $51,000,000 based on straight line depreciation over 25 or 30 years depending on the asset. Although this is the recommended accounting procedure for rate setting, the actual condition of the assets indicates that the expected life will average at least 40 years and for many components could easily stretch to 60 or 80 years. This means that the actual worth of the assets is larger than their depreciated book value.

7. Inspection and testing of station grounding grids is recommended.

8. Secondary oil containment systems are recommended for all substations. A "sorbweb" system is highly recommended for the storm sewer grating in MS 2.

1. INTRODUCTION

As part of their asset management program Oshawa PUC Networks has requested a review of their asset condition, maintenance program, and a valuation of their assets. The review of the asset condition has been conducted to ensure that the maintenance is adequate to ensure that equipment reaches the expected age at the end of its life and that the capital equipment replacement rate is adequate to ensure that there are no large unexpected increased capital requirements in future years.

This report deals with the findings of the asset condition and valuation process and contains a review of the asset condition and maintenance issues at Oshawa PUC Networks. The report provides an assessment of the asset value of the utility based on an examination of the assets themselves, the maintenance programs, the capital planning, and operation and maintenance budgets.

The review has been restricted to power system equipment, excluding the land, buildings, office equipment, tools and maintenance vehicles.

2. DOCUMENTATION AND INFORMATION

2.1 Requested Information

Requests were made for the detailed information listed in Appendix A of this report. The following summarizes key documentation that was made available by Oshawa PUC Networks:

- number of stations and feeder circuits
- present loading of stations and feeder circuits
- age and ratings of transformer stations
- number of wood poles, switches, automated switches, breaker/reclosers, distribution transformers, km of overhead line and underground cable
- age distribution of most assets
- reliability indices
- capital expenditure budget
- book value of capital costs

2.2 Field Visits

Field visits to Oshawa PUC Networks were conducted in October and November 2005. All of the distribution stations were visited and assessed. Example sites of overhead distribution lines were evaluated. The information obtained in the field visits has been incorporated into the asset condition assessment in report section 3.2.

2.3 Interviews

Additional information utilized in this review was received verbally from interviews with Oshawa PUC Networks staff. Interviews were conducted with the following staff: Mark Richards, Ron Little, Dave Osborne, Falguni Shah, Brian Watts, Mark Turney, Dave Skirrow, Dave McCaully and Jeff Rosenthal.

Information was solicited in each of the interviews on the historical condition, present condition, maintenance activity, and future issues for Oshawa PUC assets on both Overhead and Underground systems. The notable issues related to asset condition and management are detailed in Appendix E. The information has provided the contractor with insight into a number of asset issues that were not readily apparent from site inspection and documentation. Topics were discussed in the general categories of Stations, Overhead and Underground distribution plant.

In general, it was noted that OPUC is aware of the impact of most asset issues and is taking systematic steps to solve problems as they arise.

In summary, the interviews indicated that Station assets were considered to be in good condition after recent refurbishment activity which upgraded transformer gasket and tap changer condition. A program to replace older electro-mechanical feeder relays with electronic GE Multilin relays will upgrade this asset. Problems with porcelain potheads are being mitigated by replacement with polymer terminations. Station grounding grids were reported as one asset that could be given further attention by OPUC.

OPUC has experienced ongoing breakages of porcelain distribution cutouts which have been addressed by replacing porcelain cutouts with polymer cutouts. OPUC had experienced a significant number of failures of EPAC insulators and these have been changed in stations. 44kV porcelain insulator failures on cross arms have also led to ongoing replacement with polymer insulators until complete change-out has been accomplished. Some reports of ground operated air break switches that are closed-in and locked but inoperable would be worth addressing.

Pole asset condition is being evaluated by an ongoing pole testing program. Approximately 4000 poles are being tested per year over a 3 year period to be completed in 2007.

Past cable failure issues have been addressed by a program to utilized #2 XLPE jacketed tree-retardant cable-in-duct and a cable replacement program. A secondary cable replacement program was suggested as being necessary during the interviews. It was also acknowledged that there is additional structural refurbishment to be done on vaults and manholes including improved sealing and repair of crumbling around collars and lids.

Opportunities to improve asset condition or management discussed in the interviews included: improvements to monitoring systems, addition of automated switches in rural areas, moving back-lot construction to front-lot for better access and maintenance, the need to continue fleet replacement and inclusion of computers in vehicles. Also the security of OPUCs assets from vandals was also raised as an asset management concern.

Through the interview process Kinectrics was satisfied that OPUC staff are knowledgeable, vigilant and in a continuous improvement mode regarding distribution assets.

3. REVIEW OF ASSET POPULATIONS, CONDITION AND VALUE

3.1 Asset Populations and Age

A review of the assets held by Oshawa PUC Networks was conducted based on the information provided by the utility in response to Kinectrics requests and on the site visits conducted by Kinectrics.

An objective of this review was to validate that assets reported as owned by the utility were currently in place and in use. In addition, the review provided a validation of the associated age of the assets.

Table 1 provides a summary of the assets of Oshawa PUC Networks as well as the populations and relative ages of these populations. Oshawa PUC Networks has power system assets with a cumulative actuarial net book value of approximately 58 million dollars.

The major asset values are in transformer stations, overhead and underground conductor, distribution transformers, vaults/ manhole/ conduit, and meters. The following graph shows the relative contributions to the asset original cost. It is within the typical range for a utility with a mixed urban and rural service area.

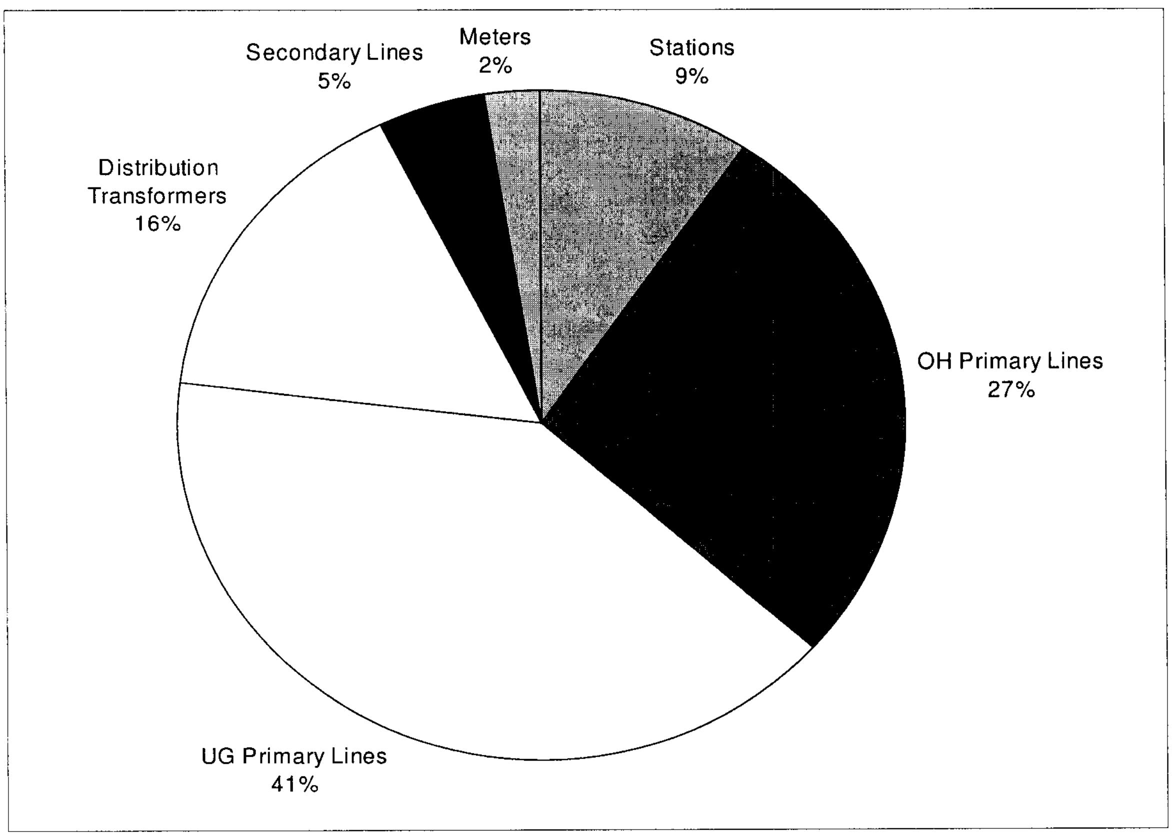


Figure 1 Contributions to Asset Value

Table 1 Asset Populations and Age Distribution

Asset Type	Net Value (k$)	Quantity	Average Age[*2]	Age Range
Transformer Stations	2,527	8	28	1 to 38
Breakers	220	86	26	14 to 38
OH 3phase switches	19	19		
UG 3 phase Switches	191	94		
OH In-line switch	148	438		
OH fused cutout	408	5177		
OH conductor	1,373	501 km	12[*1]	1 to 50
UG conductor	7,892	92 km	15	1 to 40
Line Transformers UG	6,395	3385	17	1 to 40
Line Transformers OH	1,872	2629	19	1 to 50
Arresters	1,729	4825	10	1 to 40
Secondary	1,467	868 km	21	1 to 50
All poles	12,939	11824	19	1 to 70
Conduit and trench	11,139	225 km	21	1 to 70
Padmounts	1,709	2802		
Meters	1,122	55400	20	1 to 40

[*1] This is the average age of the conductor for which the age is known, but 72% of the conductor is of unknown age.
[*2] Blank cells indicate no age data was available

3.2 Asset Condition Assessment

As part of the condition assessment, a visual inspection of the power system physical assets was conducted at Oshawa PUC Networks.

The objectives of the inspections were to confirm the accuracy of the asset lists provided by the company, to assess the general condition of the equipment in order to ensure an accurate valuation, and to identify any significant engineering or liability risks.

Visual inspection was conducted for all substations and for a selected sample of the distribution lines. The overhead lines were inspected directly by staff traveling to the sites. The overhead system was spot sampled at 10 locations covering every age of line. Some photographs illustrating the visual observations are included in Appendix D.

For downtown underground duct and access chamber facilities, it was agreed that inspection via photographs of a sampling of sites would be adequate. Direct inspection of the underground system was not feasible due to the difficulty of accessing the equipment (need for traffic control, pumping of water, gas sampling etc.) and the safety requirement for training in confined space entry and rescue. The underground system was spot sampled using photographs taken by line maintainers.

Appendix C contains copies of the blank inspection forms that were used for the inspections.

In general, the documentation available provided a reasonable description of the facilities observed in the field visits. The number of transformer stations, size and rating of equipment, approximate age of equipment, and approximate loading of equipment was as documented.

Generally, there was evidence that maintenance was being performed as documented. Not all identified problems had been repaired, which is one indicator that the systems are not over-maintained. The transformer stations, overhead lines, and underground systems generally appear well maintained.

The notable observations from the field visits are provided below.

3.2.1 Substations

It was noted that Oshawa PUC Networks is experiencing a significant number of station transformer leaks. This is to be expected for the age of the transformers and a program of refurbishment is well under way to rectify the problems. The observed leaks were all apparently of a minor volume and are not likely to have contaminated soil beyond the station boundary.

Several equipment replacement programs are underway to maintain high reliability and increase safety. They include replacement of porcelain bus insulators, potheads, cable terminations, and arresters with polymer units. New boots are being installed on secondary bushings at the entrance to the metal clad switchgear that do not trap water next to the bushing. Bare spots on the secondary bus are being covered with sliding covers to reduce animal outages. Old isolation switches have been replaced with in-line switches and the 44 kV bus on the lattice structure has been simplified to improve appearance.

When transformers are replaced, up to date equipment such as improved explosion vents, continuous oil filtering and new design cartridge type water filters are retrofitted as appropriate.

Table 2 Station Visual Inspections Results

Stations	MVA	Age	End of Life	Significant Results
MS #2	40	30	2035	T1 has a small oil leak. Refurbishing is already planned.
MS #5	66	21	2044	
MS #7	66	25	2040	
MS #10	66	25	2040	One brand new transformer
MS #11	60	30	2035	
MS #13	82	37	2028	
MS#14	66	27	2038	Chipped bushing on 44 kV breakers from vandals throwing stones, significant theft of copper ground leads from fences
MS#15	40	38	2027	

Although a full environmental risk assessment was not requested as part of this project, it was noted that none of the stations have secondary oil containment systems in case of a major transformer tank rupture. Station MS#2 has a direct connection to a storm sewer within the station fence. There are oil containment systems available that could be retrofit to reduce the risk of environmental damage such as the "SorbWeb" system. This is highly recommended for the storm sewer connection and generally recommended for all stations.

3.2.2 Overhead Lines

Sites for overhead line inspection were selected from the utility operating maps in order to choose sites from a random sample of line ages and types. The following paragraphs provide some highlights of the observations and Table 3 further summarizes the results of the overhead line inspections.

Table 3 Summary of Overhead Line Inspections

Condition	% of locations
tree touching phase wire	0
low clearance to trees	10
damaged ground wires	6
exposed ground wires or rod	26
slack or over-tightened guy wire	14
guy guard missing/damaged	7
guy close to conductor	0
pole rotted at top	13
pole rotted at ground	3
pole leaning	20
Surface damage on pole	17
conductor sagging	0
arrester disconnected on ground side	0
Frayed conductor cover	3
No stirrup	7
Fuse tube surface loose	7

In general the visual inspection found that the overhead system assets at Oshawa PUC Networks are in above average condition. Tree trimming particularly was noticed as being very thorough compared to other utilities. This is likely a major contributor to the lower than average failure rates at Oshawa PUC Networks.

No major deficiencies or safety concerns were observed. Of the minor deficiencies the most common were, exposed ground leads (26%), leaning pole (20%) and surface damage to the pole (17%).

These results provided Kinectrics staff with a general overview of the condition of the overhead system and the state of maintenance practices. (A further indicator of the adequacy of maintenance is the actual experienced failure rates.) It is also worth noting that if no line problems had been observed, this would be an indicator that too much maintenance was being performed.

From these line inspections, the most significant issue that was evident concerned the need for a pole inspection program to target minor repairs or replacement. A suitable program was begun earlier this year.

During the inspection there were two design issues noted that are not related to asset condition, but should be given consideration. One is the connection of transformers to the phase conductor using a live line clamp directly onto the conductor rather than through a stirrup. This was notices in two locations, Farewell and Raleigh and at Fisher and Albert. In both cases the conductor is 4/0 copper so the risk of a poor connection is low and the use of live line clamps directly onto the conductor may be an acceptable risk. However this practice is not consistent with the system design elsewhere in Oshawa PUC Networks where stirrups are always used.

The other design issue noted during the visual inspections concerned the arrester ground leads at transitions from overhead to underground. The arrester lead is carried all the way down the pole to the pole ground without being connected to the neutral of the cable or of the overhead line. The last photograph in appendix illustrates the situation. This practice increases the voltage stress on the cable during a lightning stroke, because of the long ground lead all the way down the pole. Most utilities connect the arrester ground lead to the cable neutral as high up the pole as possible and then run it down to the neutral of the overhead system. This provides the shortest possible lead lengths for the arrester and also the best ground, since the overhead system ground is always of lower impedance than a single ground rod at the base of the pole.

3.2.3 Downtown Underground Duct and Access Chambers

Visual inspection of the underground plant was conducted by reviewing photographs of selected sites provided by Oshawa PUC Networks. While this process was convenient and significantly safer for the contractor and the utility, it had the trade-off of being less than ideal, since the photographs in some instances did not show all the equipment of interest in the vault.

The following paragraphs provide the significant results from the review of the photographic evidence.

Reviewers were looking for signs of excessive corrosion, oil leaks, missing grounds, crumbling concrete, poorly supported cables etc.

Thirty seven pictures were available from five underground vaults in the downtown area, vaults numbered 1 through 6. In general the condition appeared to be poor, although no immediate hazards were observed. There was no evidence of serious structural cracks in the concrete and the rust on the surface beams was not enough to seriously reduce the strength of the beams. Two of the six vaults showed indications of recent maintenance in painted beams and apparently repaired concrete on the ceilings. Two other vaults showed signs of needing those repairs, spalled concrete, significant rust on the ceiling beams, and joint caulking falling out.

Subsequent conversations with Oshawa PUC staff indicated that some of those repairs had been performed since the pictures were taken on January 6, 2006.

The equipment in the vaults was generally in good condition. There were no visible oil leaks. Cable supports were adequate and ground connections intact. The fuse cabinet in vault 3 had significant rust and cabinet integrity could be questionable within ten years.

3.3 Asset Value

A further objective of the asset review was to determine if the asset condition was commensurate with the asset age and hence if the net book values were accurate reflections of the actual remaining value of the assets observed in the field. Actual values could be higher than the net book values if equipment lifetimes are longer than the actuarial depreciation period or original purchase prices were lower than purchased value. The actual values could be lower than the net book value if poor maintenance, overloading, or severe service environments had reduced the expected lifetime below the actuarial depreciation period.

The condition and assessment of the remaining life of the assets was based on the visual inspections, review of maintenance programs, review of asset utilization and planning, and Kinectrics knowledge of the replacement costs and normal lifetimes for equipment.

Table 4 provides a list of the major asset categories, the reported original cost, the depreciated present value of the assets, and Kinectrics estimation of the remaining value.

The results of this analysis reveal a number of significant facts.

First, the number of assets and the age distributions reported are consistent with the reported book value. For instance, the number of poles, transformers etc and their reported age distribution is commensurate with the depreciated book value.

Furthermore, the observed condition of the assets is as expected for assets of the age found in the field.

As illustrated in Table 4, the actual remaining values of the assets in the field were estimated to be about 31% higher than the net book values. The main cause of the difference from net book value is that the expected service life predicted by Kinectrics is longer than the actuarial life assumption required by the OEB in the rate setting process. Based on the asset condition assessment, it is expected that all equipment will reach the normal end of its service life.

For substations, the Kinectrics estimates were higher than book value since the anticipated asset life is greater than the 30 year period assumed in the accounting analysis. Kinectrics considers that a 40 to 80 year lifetime is a better estimate of expected performance given the present condition of the assets and how they are used and maintained.

The loading on transformer stations is well within the capability of the transformer and will not lead to accelerated loss of life. The normal service life values for transformer and breakers did not require adjustment for utilization.

Table 4 Oshawa PUC Networks Asset Values

Asset Type	Original Cost	Net Book Value	Kinectrics Estimate of Remaining Value	Difference in Value	Percent of Total Value
	k$	k$	k$	%	%
Stations	9,166	2,747	5,825	53	7.8
OH Primary Conductor	3,011	1,373	2,053	33	2.8
OH Poles and Hardware	18,339	12,939	14,847	13	20.0
OH Switches and Cutouts	2,882	576	1,441	60	1.9
Arresters	2,396	1,729	1,973	12	2.7
UG Primary Cables	9,599	7,013	7,959	12	10.7
UG Trench and Conduit	23,516	11,010	19,545	44	26.3
UG Misc	5,990	2,967	4,687	37	6.3
OH Dist Trans	1,591	819	1,084	25	1.5
UG Dist Trans	13,858	6,395	9,092	30	12.2
Secondary	4,598	1,468	2,881	49	3.9
Meters	2,392	1,122	1,255	11	1.7
Total	100,130	51,213	74,327	31	100.0

4. REVIEW OF RELIABILITY STATISTICS

As a component of the asset condition assessment, a review of the reliability statistics provided by Oshawa PUC Networks was conducted. Reliability statistics are an indicator of the condition of assets, the effectiveness of maintenance, and often the existence of any operational issues.

Table 6 below provides the standard reliability indices utilized by power utilities, indicating the duration, frequency and customer impact of power outages. Data on the cause of outages, particularly the % caused by equipment failure, would be useful in determining the effectiveness of the maintenance program and the general condition of the assets but it was not available.

Table 5 Reliability Statistics

Index	Value (4 year average to August 2005)
SAIFI	1.01
SAIDI	1.36
CAIDI	1.35
MAIFI (SAARI)	Unavailable

MAIFI Momentary Average Interruption Frequency Index
SAARI System Average Automatic Recloser Index

In general, all of the reliability indices are in the normal range for distribution companies of this size and customer mix. From the data provided, it was also noted that the variation in frequency of outages on a year-over-year basis was within the normal range.

Failure rate data was available for some of the asset types. The failure rates being experienced are low compared with industry wide expectations.

These reliability figures do not identify any problems with the effectiveness of the maintenance program which is discussed further in the following section.

5. REVIEW OF UTILITY MAINTENANCE PROGRAM

A review of the maintenance program at Oshawa PUC Networks was conducted in order to identify any expected impact of these programs on asset value and to determine if these programs might be responsible for any future risks or asset condition adjustments.

When maintenance programs are reviewed it is important to note that higher frequency of maintenance is not necessarily better. Appropriate frequencies depend on the number problems found during inspections and on the failure rates experienced. Appropriate frequencies also vary with different types of equipment and different service conditions of load and environment. Over-maintaining equipment is an inefficient use of resources and has been shown to actually increase failure rates in some instances.

Table 8, summarizes the maintenance activities and maintenance frequency planned by Oshawa PUC Networks. The maintenance practices are in line with the OEB Distribution Code. The maintenance schedule however provides little indication of whether the maintenance has been conducted and has been effective. The reliability statistics and visual observations discussed in the previous sections provide additional evidence of the actual maintenance practices at the utility. Based on these observations the maintenance program appears to be conducted as planned and is effective.

The summary table indicates that Oshawa PUC Networks has adopted several higher technology inspection tools, such as ultra-sound and resistograph tests of poles but not partial discharge and vibro-accoustical inspections or a computer maintenance management system to implement reliability centered maintenance. The cost of these more advanced techniques may not be justifiable at Oshawa and a strategy of waiting to see what other utilities experience may be the most prudent option.

At the present time in Oshawa PUC Networks most equipment replacement is based on equipment condition or in response to failure. This is a common strategy because it maximizes the service life of the equipment and minimizes costs. . However, it also makes long term maintenance cost planning difficult. A larger planned replacement program, such as all poles more than 75 years old, or breakers more than 60 years old, allows for better long term planning of the costs and inclusion in the rate setting process. Because the system has grown in the past the amount of equipment replacement each year will grow in the future, but the timing of the increase is unpredictable when condition based maintenance is used.

Planned replacement programs have been made in response to particular maintenance issues, such as removal of all PCB oil filled equipment, conversion from 4 kV to 13.8 kV, replacement of many types of porcelain components with polymer, and replacement of underground cable.

It was noted that at the present time all of the maintenance records are kept on paper based cards and files. The accessing of this information is somewhat inhibited by the difficulty of information retrieval. Oshawa PUC Networks could consider the benefits of a modern electronic record keeping system in which the maintenance crews enter data in the field directly into electronic devices that automatically update a central data base. The increased ease of access to information often makes these systems cost effective.

Table 6 Summary of Maintenance Program

Maintenance Procedure	Frequency
Station inspection	1 month
Station breaker operation count	1 month
Station transformer oil tests and DGA	1 year
Station transformer insulation test	6 years
Station tap changer - filter oil, operate, megger	2 years
Station and feeder load check and balance	1 year
Station infra red thermography inspection	1 year
44 kV breaker oil test	1 year
44 kV breaker oil filter	4 years
Station insulator wash	6 months or 1 year
Feeder breakers (insulation test, lubrication)	4 years
Station batteries visual, voltage	4 months
Station batteries load test	1 year
Station metal clad heater and vent	6 months
Station metal clad bus megger	8 years
Down town vault inspection	6 months
Underground vault inspection	1 year
Building vault inspection	3 years
Manhole inspection	10 years
Infra-red inspection of three phase lines	1 years
Infra-red inspection of one phase lines	3 years
Tree trimming on primary lines	3 years
44 kV switch clean, lube, align, adjust	3 years
44 kV porcelain insulators wash	6 months or 1 year
UG switch visual and infra-red	3 years
Wood pole testing visual, sound, ultrasound, resistograph	15 years
Planned replacement program	PCB equipment 44 kV porcelain insulators on concrete poles Porcelain station bus insulators Porcelain station arresters Porcelain potheads and terminations 44 kV station airbreak switches Underground cable

The values in Table 6 were obtained from the maintenance plan document. The wood pole testing on a 15 year cycle is not slated to start until 2007, after completion of the initial testing program now underway.

6. REVIEW OF CAPITAL AND MAINTENANCE BUDGETS

As part of the review, the capital and maintenance budgets of Oshawa PUC Networks were reviewed to ascertain that they were reasonable in light of the asset populations and ongoing maintenance activity.

Table 9 provides a summary of the capital and maintenance budget information. The following paragraphs provide some observations on the budget and comments.

Table 7 Summary of Maintenance and Capital Budgets

	Oshawa	Typical
Historic Cost (k$)	109,000	
Net Capital Assets (k$)	48,000	
Equipment Replacement Budget (k$)	5,446	
O&M Budget (k$)	2,195	
Annual Depreciation (k$)	3,338	
Cap Replacement as % of Depreciation	163	100 - 140
O&M as % of Capital Replacement	40	45-55
Historic cost /customer ($)[1]	2,200	1,000 - 4,000
Capital Replacement per customer ($)[1]	111	80 - 160
O&M cost per customer($)[1]	45	45 - 65

Note 1 Based on 49,000 customers

Most of the comparison figures for Oshawa PUC networks are within the range expected. This indicates that the cost of purchasing and maintaining the systems are similar to other utilities in southern Ontario. The one exception is the size of the equipment replacement budget.

Previous studies have indicated that a typical utility of the size and type of Oshawa PUC Networks would have a capital replacement budget between 100 and 140% of the annual depreciation of equipment. At Oshawa PUC the capital replacement budget is somewhat higher than this. The equipment replacement capital expenditure budget is 5.4 million dollars per year, which is 160% of the 3.3 million dollars depreciation. The slightly higher rate of capital replacement is to catch up from years when it was performed at less than the optimal rate. The O&M cost per customer is at the low end of the typical range.

7. CALCULATION OF THE HEALTH INDEX

The health index is calculated based on the results of the asset condition assessment that have been presented above. It includes an assessment of the equipment age, physical condition, maintenance, utilization, and original quality. Each of these factors is assigned a weight in an overall average. A separate health index has been calculated for each group of assets and then the groups are weighted by their contribution to the total replacement value to determine an overall heath index for the system.

A health index of 1 would indicate a new component, of good quality, with an excellent maintenance program, and not loaded close to its capacity. The health index can be both higher or lower than desirable. High values may indicate that too much capital or maintenance money is being spent on the system. However, high values could also indicate that the system has grown quickly in recent years. Low values may indicate that not enough capital or maintenance money is being spent. An old stable system with little growth should have a health index of about 0.5. A growing system should have a health index of about 0.7.

The asset condition assessment results have been given a value between zero and one for each group of assets in the following table. The age result is the fraction of the expected service life that remains in the group on average. The other results are based on the qualitative assessments being given an approximate quantitative value. If the qualitative assessment is normal then the quantitative result is set equal to the age result. Numbers above the age result indicate that the qualitative evaluation is adjusting the result up. For example, a better than average maintenance program would produce a maintenance result higher than the age result.

The first row of the table, labeled "weight", is the weight that has been assigned that column in the health index presented in final column.

Table 8 Asset Condition Assessment Results and Health Index

	Age	Condition	Maintenance	Utilization	Quality	Health Index
Weight	**0.7**	**0.1**	**0.05**	**0.1**	**0.05**	
Stations	0.53	0.9	0.9	1	0.53	0.63
OH Primary Conductor	0.76	0.76	0.76	0.76	0.76	0.76
OH Poles and Hardware	0.53	0.4	0.4	0.53	0.53	0.51
OH Switches and Cutouts	0.53	0.53	0.53	0.53	0.53	0.53
Arresters	0.75	0.75	0.75	0.75	0.75	0.75
UG Primary Cables	0.63	0.63	0.63	0.63	0.63	0.63
UG Trench and Conduit	0.75	0.75	0.75	0.75	0.75	0.75
UG Misc	0.58	0.58	0.58	0.58	0.58	0.58
OH Dist Trans	0.53	0.53	0.70	0.53	0.45	0.53
UG Dist Trans	0.58	0.58	0.70	0.58	0.45	0.58
Secondary	0.58	0.58	0.58	0.58	0.58	0.58
Meters	0.60	0.60	0.60	0.60	0.60	0.60
Total						**0.62**

8. ESTIMATE OF CAPITAL EXPENDITURE PLAN FOR POWER SYSTEM EQUIPMENT REPLACEMENT AT END OF LIFE

Based on information provided by Oshawa PUC Networks, an estimate of the Replacement Capital Plan for power system equipment only, was prepared for the next 40 years. The estimated Capital Plan provides an indication of the likely capital expenditures for equipment replacement. These estimates were obtained by applying the known distribution of ages of equipment and planning to replace it at the end of its normal service life. Since Oshawa PUC Networks uses condition based replacement, the actual equipment replacement may not occur exactly according to this plan, but it is a general indication of trends that can be expected.

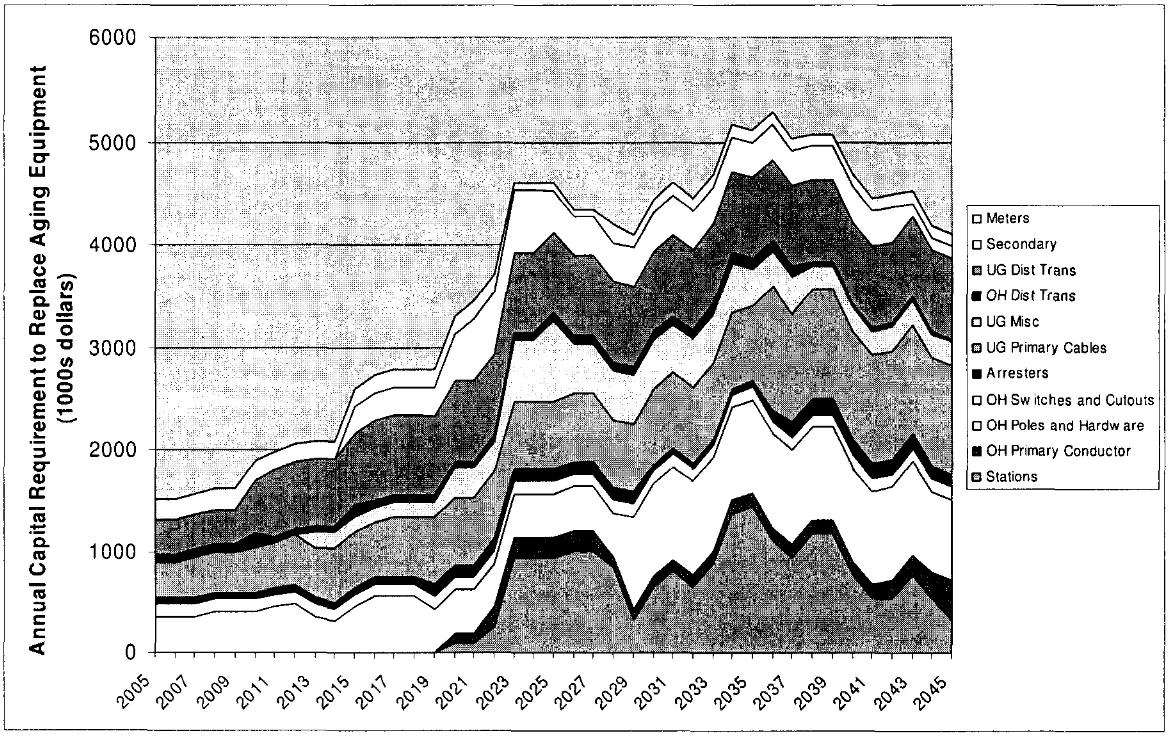


Figure 2 Estimated Capital Plan for Power System Equipment Aging Only

It can be seen from Figure 2 that the present Capital Enhancement budget is larger (5.4 Million) than that predicted by the Kinectrics analysis (1.5 million). This is because the Kinectrics estimate only includes capital spent to replace equipment failing at the end of its expected service life and the age data provided lumped everything older than 30 years. Also there are other reasons for capital replacements in addition to equipment reaching end of life such as road widening, load growth, equipment obsolescence and improving safety.

The figure shows that Oshawa PUC Networks can expect the total annual capital requirements to replace aging equipment to increase by about 3 million dollars over the next 20 years. The main causes of the expected increase are replacement of aging overhead conductor, underground cable, secondary cable, and, near the end of the twenty years, the station transformers.

There is only a slow gradual increase expected in the replacement rate of underground cable. At the present time the underground cable is being replaced at the rate of 3 km per year at a cost of $500,000. This can be expected to increase to $700,000 over the next twenty years. An acceleration of the cable replacement program is not recommended at the present time. The existing practice of replacement on the basis of failure rate should be continued, unless the reliability figures are severely impacted, which is not likely.

It must be stressed that this plan only applies to aging power system equipment and does not include vehicles, tools, buildings, office equipment, or equipment needed for system growth.

APPENDIX A Information Requirements for Asset Condition and Value Assessment

The following information would provide a basis for asset condition assessment and valuation. In some cases a priority level is identified. P1 indicates essential information. P2 indicates that estimation or exclusion of this information will affect the overall assessment by less than 20%.

1. **Maps and Diagrams**
    - Geographic map of system
    - Geographic line and station locations
    - System line diagrams

2. **Asset Listings, Populations, Inventories, Lengths etc**
    - lands
    - vehicles and equipment (line trucks, fleet vehicles, safety equipment)
    - number of transformer stations (P1)
    - number, size, voltage class, of station transformers (P1)
    - number, size, of voltage regulators and tap changers (P1)
    - number, V and I ratings of breakers/reclosers (P1)
    - description of central SCADA system (P1)
    - number of SCADA points (P1)
    - number and rating of controlled switches (P1)
    - number of manual 3 phase switches (P2)
    - number of manual 1 phase switches (P2)
    - km of overhead 3 phase line by conductor size and type(P1)
    - km of overhead 1 phase line by conductor size and type(P1)
    - insulators by voltage class and material (porcelain, polymer)
    - km of underground 3 phase line (P1) for each cable type and size (ie jacketed\unjacketed, encapsulated jacked, XLPE, tree-retardant TRXLPE) (P2)
    - km of underground 1 phase line (P1) for each cable type and size (P2)
    - km of cable in duct and km of direct buried
    - number of polemounted, padmounted, submersible distribution transformers (P1) for each kVA size (P2)
    - number and type of arresters (polymer, porcelain, gapped, ZnO), cutouts, CLFs
    - number and size of station and line capacitor banks
    - number of meters (P1)
    - km of secondary cable (P2)
    - number of wood poles of various species and treatments (P2)
    - number of concrete poles (P2)
    - number of direct buried steel poles (P2)
    - underground vaults

3. ***Age of major assets and age-distribution of minor assets***
   - station transformers (P1)
   - voltage regulators and tap changers (P1)
   - breakers/reclosers (distribution P1) (individually P2)
   - SCADA system (P1)
   - controlled switches (distribution P1) (individually P2)
   - manual switches (distribution P1) (individually P2)
   - overhead line (distribution P1) (individually P2)
   - underground line (distribution P1) (individually P2) by cable type (P2)
   - distribution transformers (distribution P1) (individually P2)
   - meters (distribution P1) (individually P2)
   - secondary cable (distribution P2)
   - wood poles (distribution P1) (individually P2)
   - arresters, cutouts, capacitors
   - concrete poles (distribution P1) (individually P2)
   - direct buried steel poles (distribution P1) (individually P2)
   - underground vaults

4. **Reliability Statistics**
   - SAIFI, SAIDI, CAIDI for entire system (P2)
   - SAIFI, SAIDI, CAIDI for local areas (P2)
   - SAIFI, SAIDI, CAIDI for individual circuits (P2)
   - SAIFI, SAIDI, CAIDI for individual cable sections, number of splices
   - Number of failures, outages, and outage minutes per year by cause of failure (P2)
   - Particular reliability issues with individual customers

5. **Operation history of major assets and historic operation distribution of minor assets**
   (operation history is the peak and average loading for transformers, # operations per year for regulators, breakers/reclosers and switches)
   - station transformers (P1)
   - voltage regulators and tap changers (P2)
   - breakers/reclosers (distribution P2)
   - controlled switches (distribution P2)
   - manual switches (distribution P2)
   - overhead line (distribution P1) (individually P2)
   - underground line (distribution P1) (individually P2) by cable type (P2)
   - distribution transformers (distribution P2)

6. **Information on Potential Problem Issues**
   - PCB testing
   - Use of non-tree-retardant cable
   - Padmount transformers with drywell canisters
   - Porcelain gapped arrester population and failures
   - Bolted as opposed to wedge ground connectors
   - Loadbreak elbows with aluminum and copper connections and aluminum threaded eye
   - Inline switches with polymer insulators prone to failure
   - Cable terminations and splices

7. Maintenance Records

- station transformers
    i. individual oil test result trends (P1)
    ii. list of maintenance performed and dates (P1)
    (oil changes, refurbishment, bushing replacement, tank painting)
- *voltage regulators and tap changers*
    i. list of maintenance performed and dates (P2)
- breakers/reclosers
    i. number maintained each year (P2)
- controlled switches
    i. number maintained each year (P2)
- wood pole inspections, testing, and replacement program
- station ground grids and line grounding inspections and maintenance
- inspection program description
    i. type of inspection and frequency (P1)

8. Design Standards and Purchasing Specs

- Overhead and underground design standards and purchasing specs

9. Financial Information

- Any existing book value of assets (and depreciation method used)
- *purchase price and date for major assets*
- replacement cost for major assets or asset groups
- annual capital replacement budget
- itemized annual maintenance budget

APPENDIX B Valuation Method

B.1 Condition-Adjusted Valuation Methodology

This Appendix describes the Kinectrics method used to consider the financial impact of asset condition for the operations review.

The current value of electric distribution system assets are generally based strictly on a straight-line depreciation of each asset over its expected service life. The present condition and use history of the assets can be used to determine an adjusted and more realistic valuation. The amount of asset value remaining must be determined by methods that are specific to the individual type of asset. The service life of some assets, such as insulators, is determined mainly by the passage of time, so that the asset age is a good indicator of remaining life. Other assets, such as wood poles, have very different life under different operating conditions, so that a condition assessment needs to be done and compared to the installation date to determine remaining life. The service life of some assets, such as transformers, is more dependent on how much they are used than the passage of time since they were installed. A heavily loaded transformer can deplete its useful life at 10 or even 100 times the rate of a moderately loaded transformer. The service life of some assets, such as breakers and reclosers, depends on the utilization and the maintenance that has been performed in the past. The service life of a new unit can be restored to an almost new condition by maintenance that is much less expensive than the initial capital cost.

Valuation can be based on historical costs and depreciation, on a market value based on recent sales of similar assets, or on the basis of the present value of the estimated future revenue and cost streams. The market value approach is difficult to apply to power system components because of limited similar sales. The income approach is not applicable to individual assets because it is not possible to separate out the contributions of each asset to the revenue stream.

The method used in this review to evaluate the current value of electric distribution assets involves the following:

- List the assets including number in service for each
- Determine the expected service life of each asset
- Estimate the age or age distribution for each asset
- Obtain the initial capital cost for the asset and estimate replacement cost.
- Determine the age, condition, previous use, planned use and maintenance history, and functional obsolescence of each asset
- Use the condition and history to estimate an adjusted service life for the asset.
- Calculate the remaining value of the asset based on the age, the adjusted service life, the capital cost and straight-line depreciation.

The use of straight-line depreciation is standard in the industry. It is not technically accurate for all types of assets, since many lose their value in a non-linear manner, often maintaining their condition through their early life and then experiencing rapid deterioration near the end. However, the value to the purchaser is decreased linearly even if the condition of the asset has not, since it is closer to the time when its condition will deteriorate rapidly.

B.2 Assumptions

Replacement capital cost or original capital cost can be used as a starting value for this analysis.

The age distribution of many assets is utilized.

For assets that have not experienced large growth in recent years the average age was assumed to be half of the service life.

Economic obsolescence, the loss of value due to factors external to the asset, was not considered. (for example, all the equipment may not be worth much if customers install natural gas fuel cells in their basements). Functional obsolescence, the loss of value due to new equipment having better features, was included.

B.3 Condition Assessment and Adjusted Valuation

The information available to Kinectrics on the value of assets consisted of book values.

Kinectrics reviewed these and computed independent values for some of the major asset categories to determine if there were any concerns with the assigned values. Kinectrics also searched for factors that would lead to modification of the valuation or depreciation of the distribution assets.

In Table 4 Column 1, the "Original Cost" is an estimate of the original equipment cost based on the replacement cost modified by inflation adjustment factors for the age of the equipment. The "Net Book Value", is based on straight line depreciation over the 25 or 30 year life that the OEB requires utilities to use in the rate setting process.

The "Kinectrics Estimate of Remaining Value", is Kinectrics estimate of the depreciated value of the assets using the "normal service life" adjusted to take into account the condition information obtained during the project.

APPENDIX C Inspection Forms

Visual Inspection Report - **Stations**

Location ______________________________

Date ________________ Inspector ________________

Transformer Designation ____________ Rating _____/______/______

Transformer Designation ____________ Rating _____/______/______

Transformer Designation ____________ Rating _____/______/______

Check to indicate completion, circle or highlight deficiency if any

Parameter	**Deficiency**	**Comments**
General appearance	housekeeping, spills	
Safety concerns	fences, locks, signs	
Vegetation	trees, weeds	
Grounds	corroded, loose	
Bus Insulation	flashed, damaged, dirty, cracked	
Transformers	load high, medium, low, hot, noise	
Gauges, meters	no access, not working	
Transformer bushings	flashed, cracked, chipped, dirty	
Transformer Tanks	corroded, leaking	
Isolation switches	corroded, overheated, loose leads	
Counters on tap changers and reclosers	not present, not working	
Capacitors	bulged, blown fuses	
Cables/terminations	deterioration, broken neutral wires	
CTs PTs	damaged, leaks,	
Lattice Structure	corroded, loose	
SCADA	not working,	

Visual Inspection Report – **Overhead Lines**

Location ____

Date ____________________ Inspector ____________________

Check to indicate completion, circle or highlight deficiency if any

Parameter	**Deficiency**	**Comments**
Poles	rotted, damaged, cracked, burnt, holed, leaning	
Cross arms	rotted, damaged, cracked, loose, steel grounded, birds nests	
Insulators	flashed, damaged, cracked, leaning, loose	
Conductors	worn, damaged, frayed, rubbing, too low, too close, sagging	
Guy Wires	worn, damaged, slack, tight, frayed, close to conductors, tails loose	
Guy Insulators	damaged, sharp edges cutting guy, wrong size, wrong location	
Guy guards	missing, damaged, too high/low	
Anchors	corroded , loose	
Cable guards	missing, damaged, cracked	
Terminators	flashed, damaged, cracked, loose, missing ground connection or phase tape	
Switches	flashed, damaged, labels, overheated, loose connections or leads	
Fuses	flashed, damaged, cracked porcelain	
Arresters	flashed, damaged, disconnector blown,	
Transformer	damaged, rusting, leaking, flashed, cracked, labels, bird nest	
Grounds	damaged, exposed, rod above ground	
Capacitors	bulged, fuse blown	
Trees	low clearance, overhanging branch, weak tree nearby, vines	
Structures	3m for LV , 5m for HV, distance to fall from flagpoles and towers	
Swimming pools	4.5m radial clearance to LV power lines	

Visual Inspection Report – **Underground Lines**

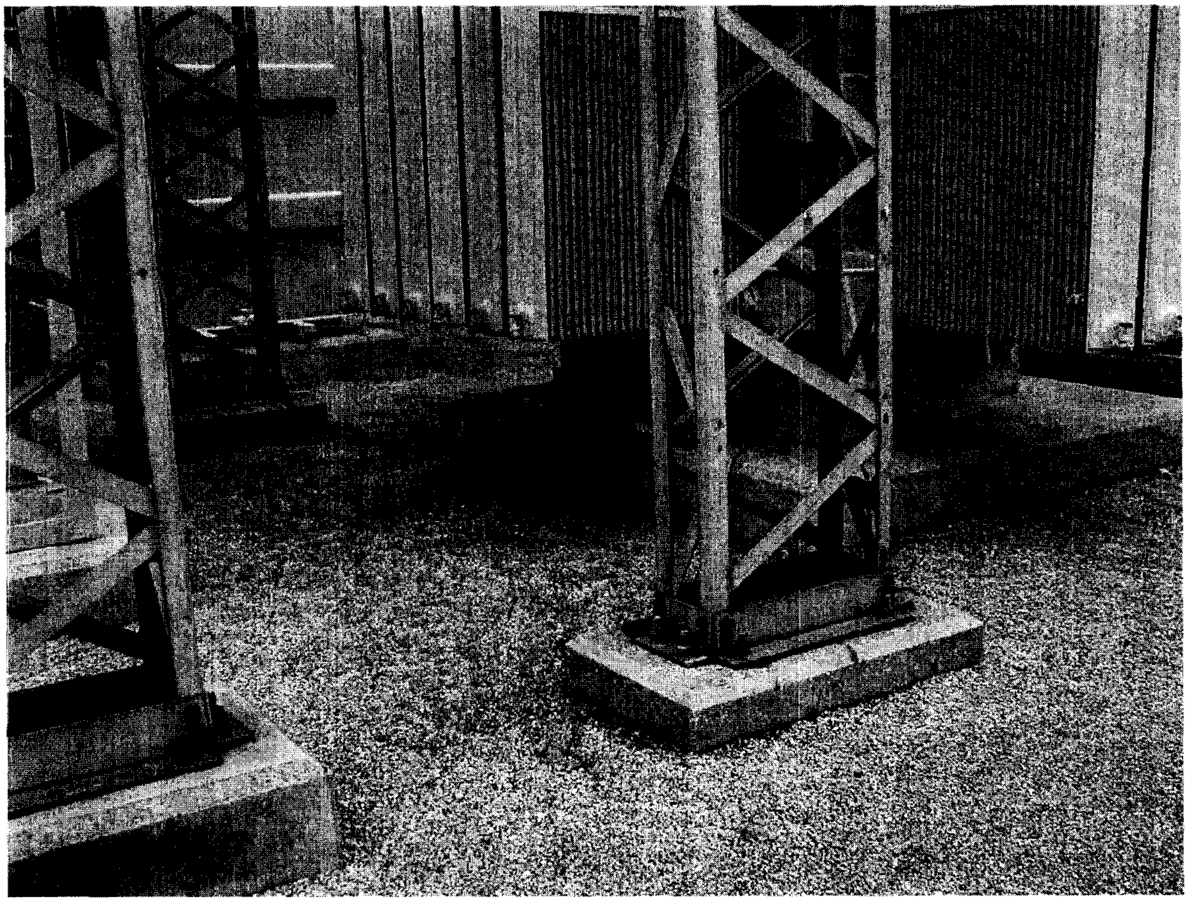
Location ____

Date ____________________ Inspector ____________________

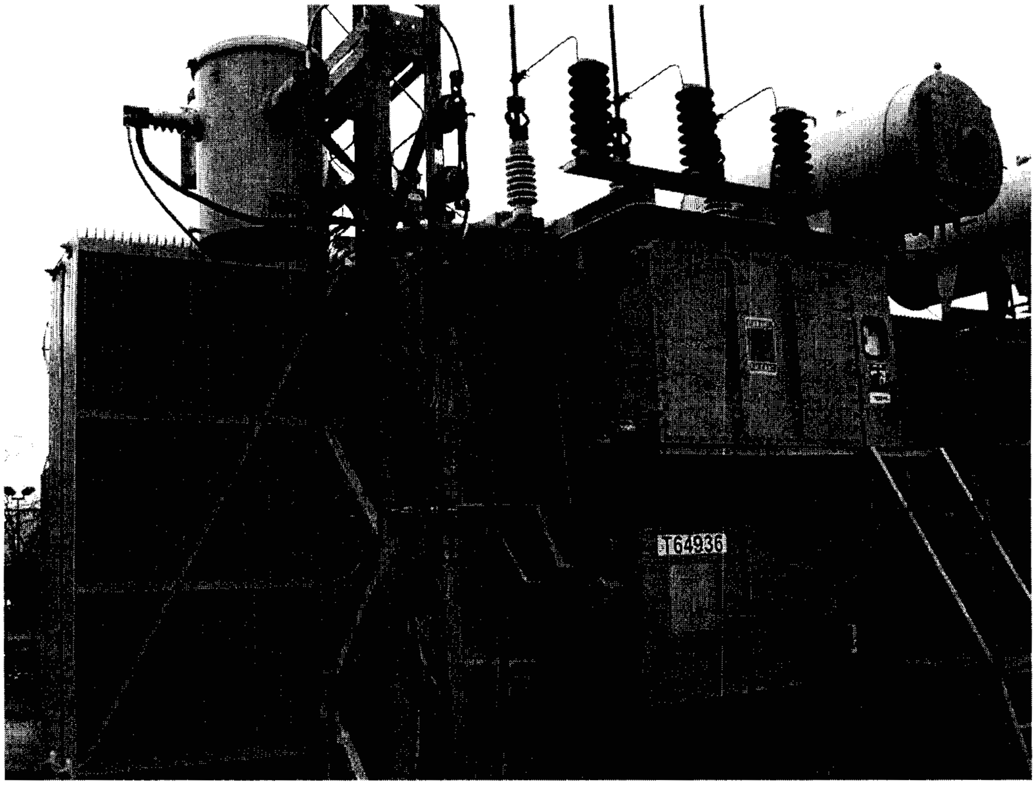
Check to indicate completion, circle or highlight deficiency if any

Parameter	***Deficiency***	**Comments**
Vaults and chambers	dirt, debris, damaged, not locked	
Grounds	corroded, loose	
Cable neutrals	corroded, damaged	
Cables	not supported, tight bends, leaking, not labeled	
Cables sheath	corroded, damaged	
Junction boxes	cracked, broken, inaccessible	
Vault Transformers	corrosion, leaking, leaning, crumbling concrete, hot	
Pad Mount Transformers	footings shifted, corroded, hot, paint peeling, crumbling concrete, leaking	
Elbows/bushings	no grease, damaged	
Pad Mount Switches	footings shifted, corroded, hot, paint peeling, crumbling concrete	

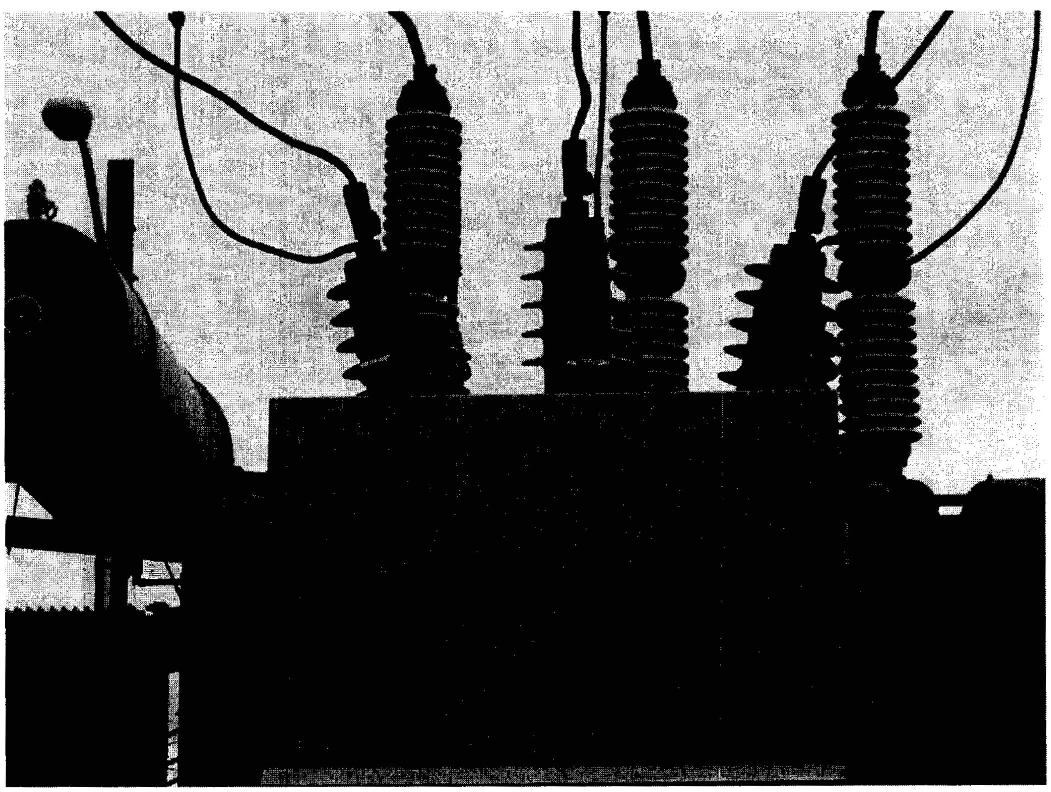
APPENDIX D Photographs from Visual Inspections



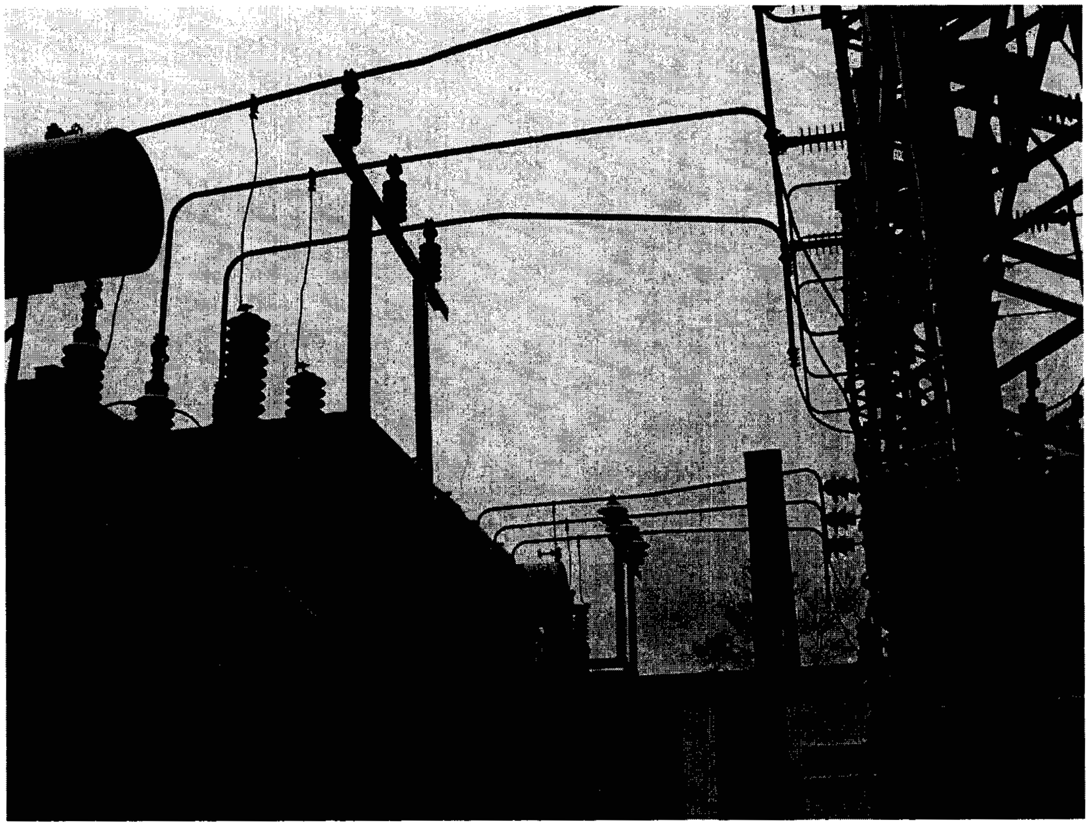
Transformer Oil Leak, good vegetation control



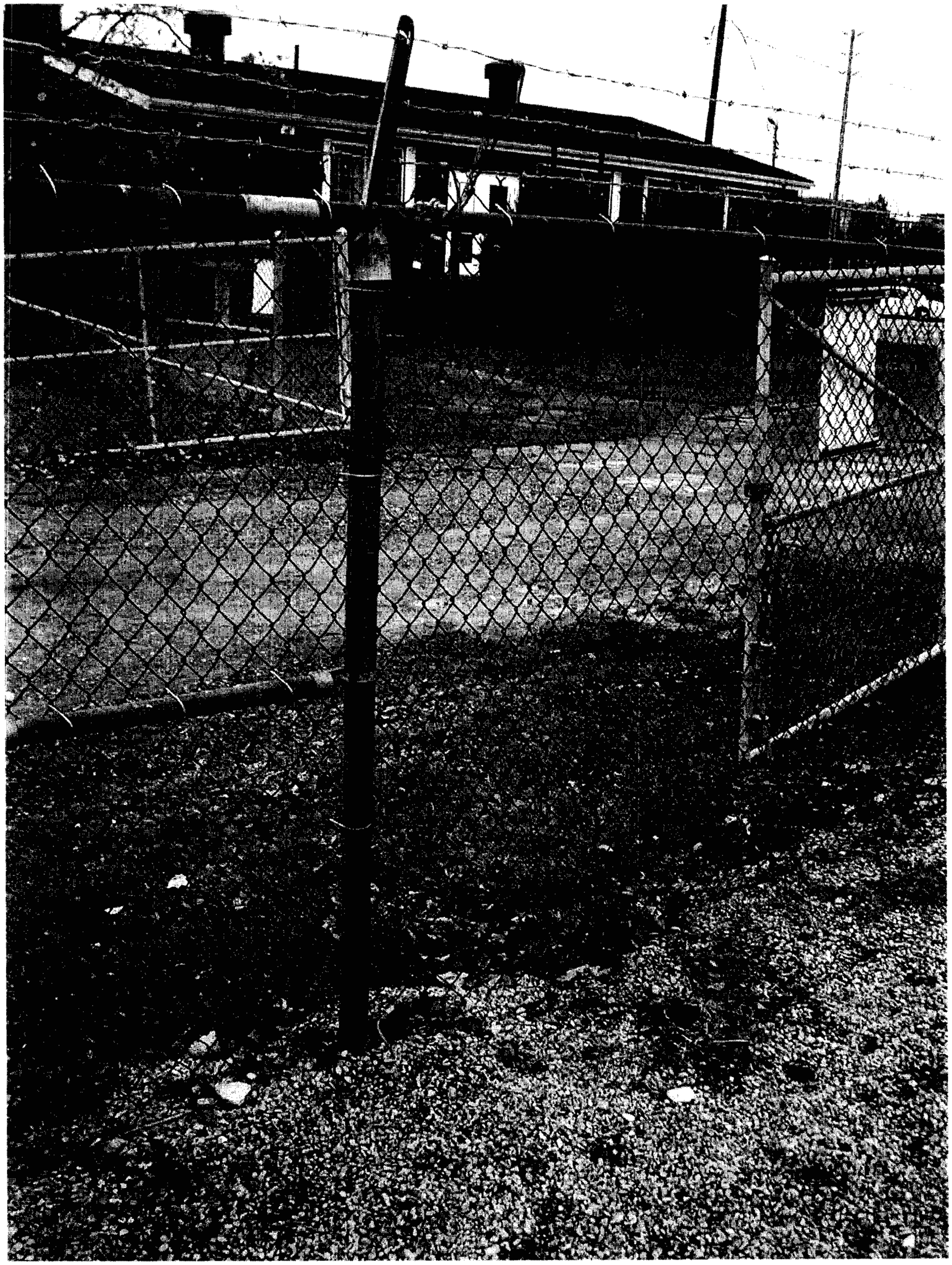
Well Maintained Older Transformer



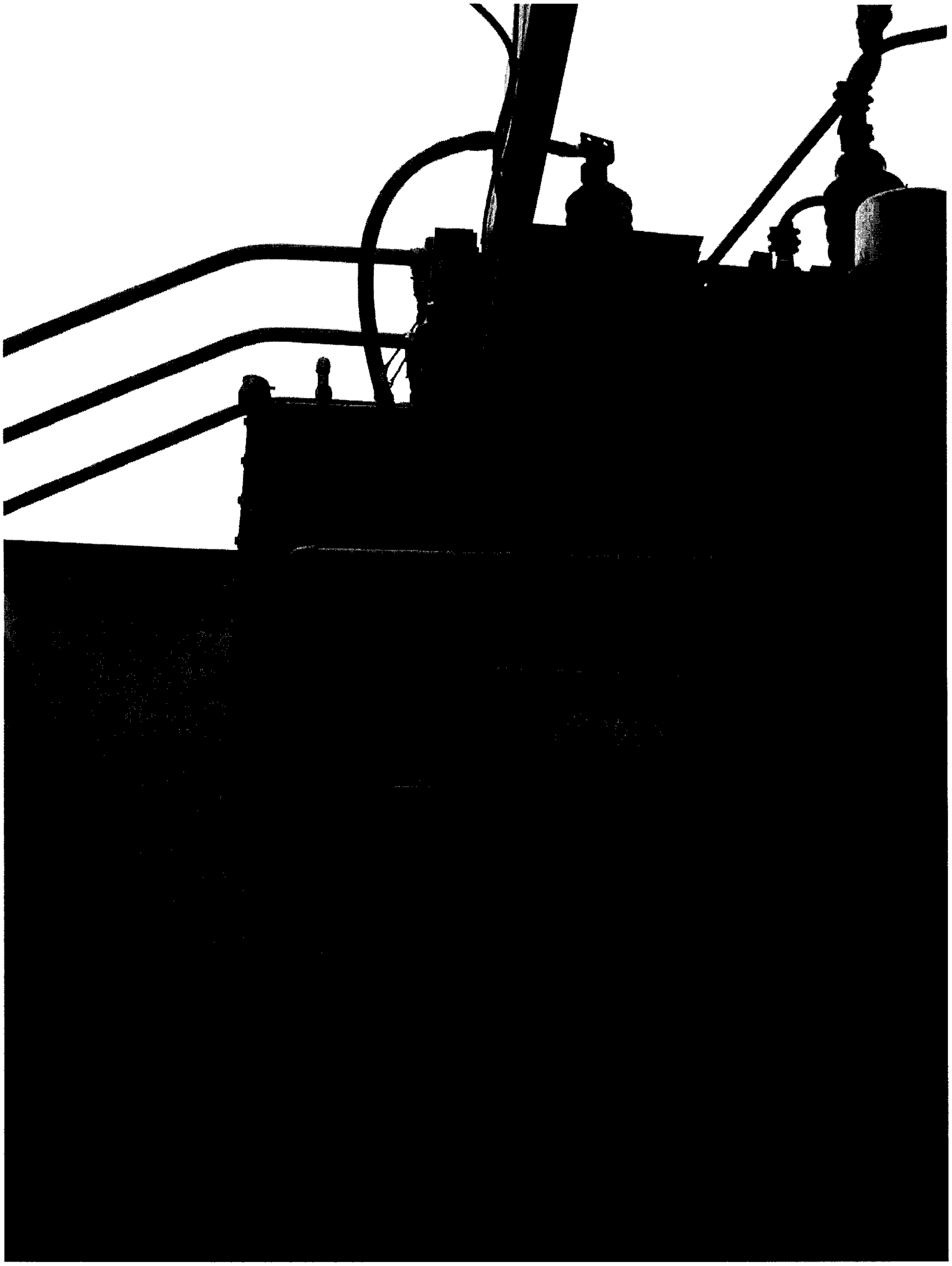
Chipped Bushings



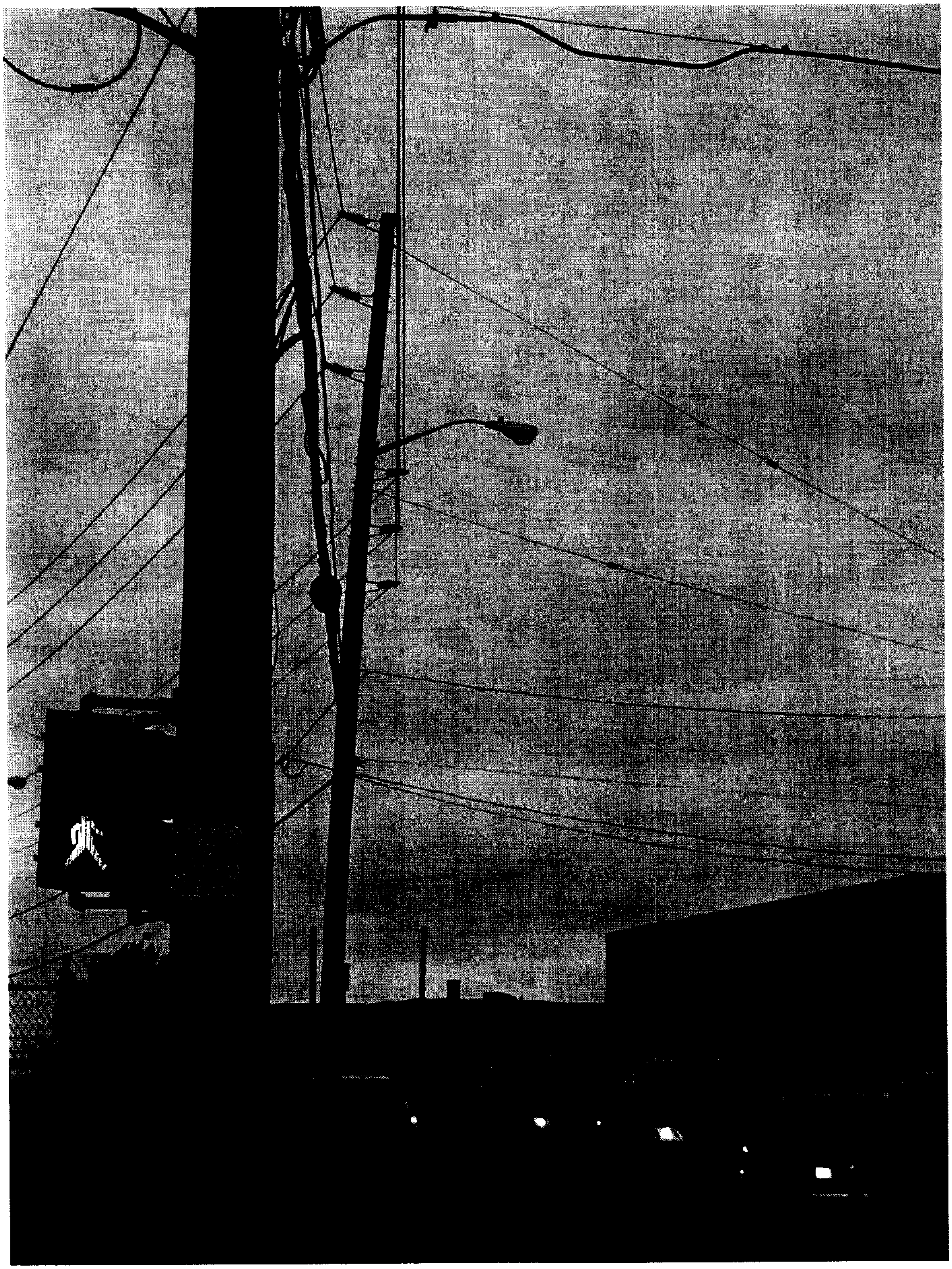
Partial Replacement of Station Porcelain Bus Insulators with Polymer



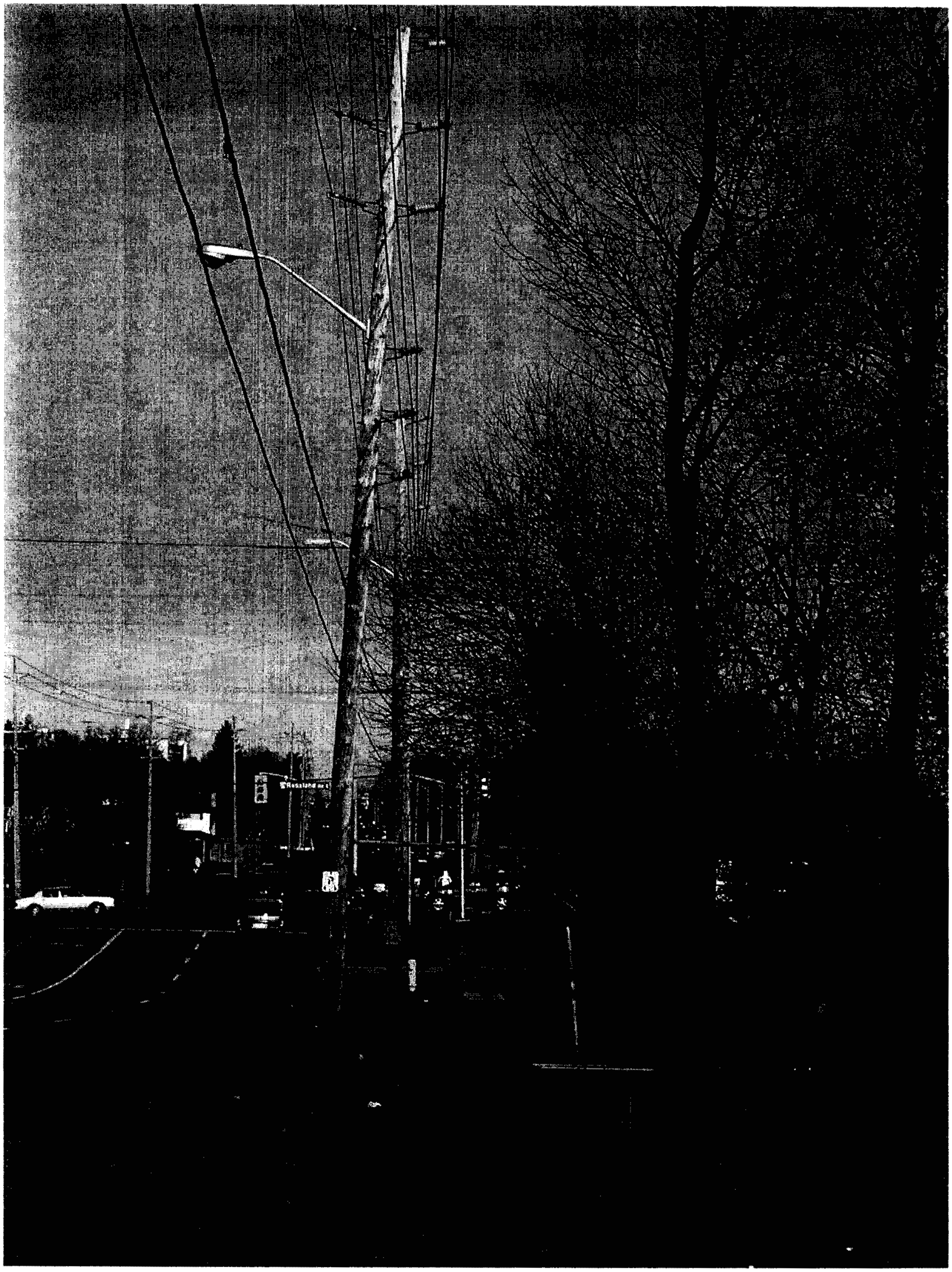
Missing (stolen) Station Fence Ground



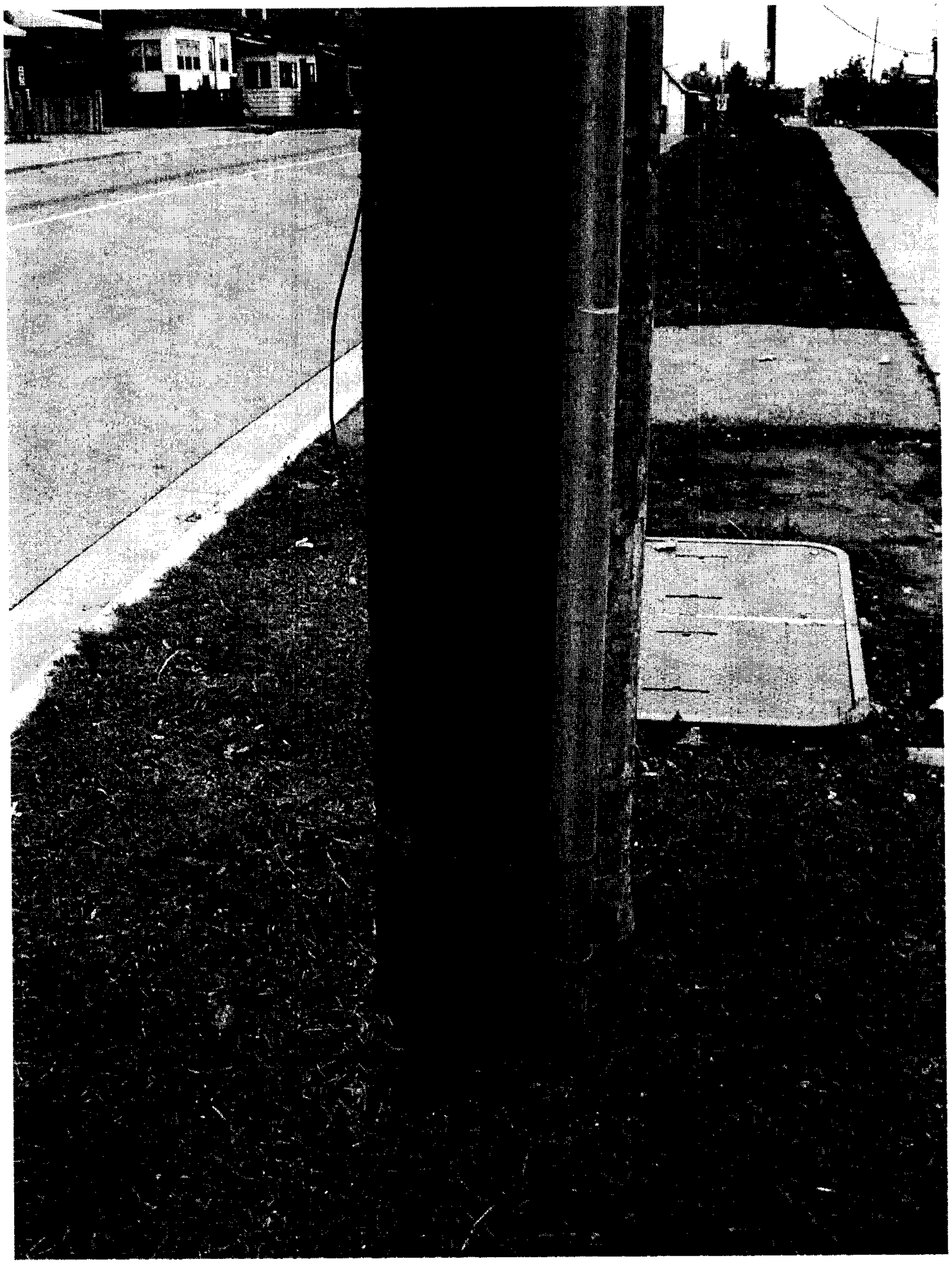
New On-Line Tap Changer Oil Filter



Leaning Pole Caused by Over Tight Guy

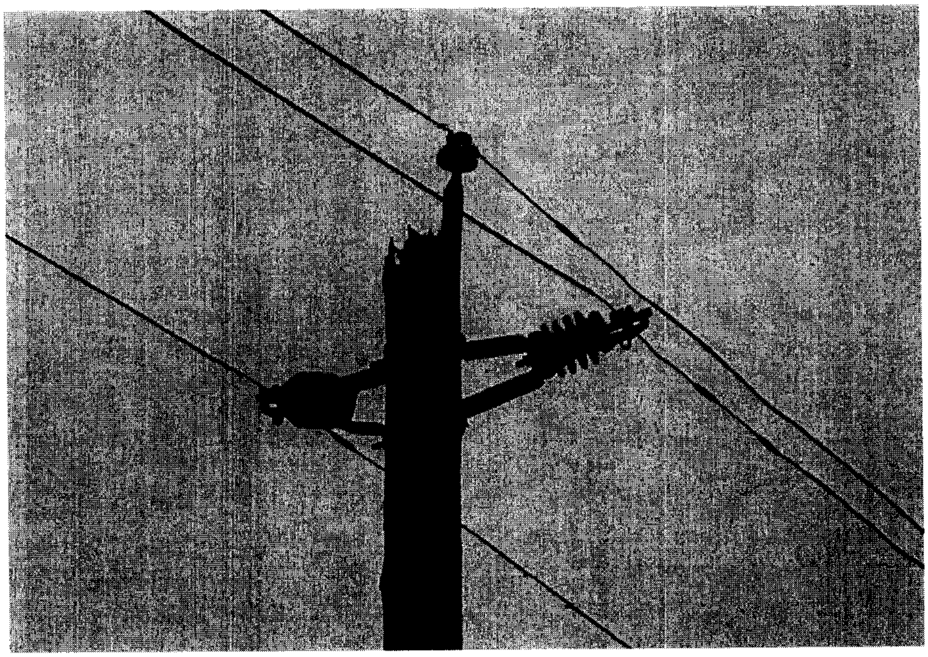


Leaning Pole Caused by Slack Guy (across the road)

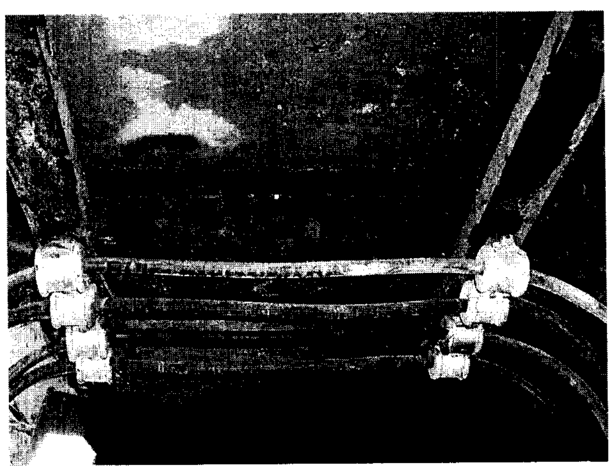


Exposed Ground Lead

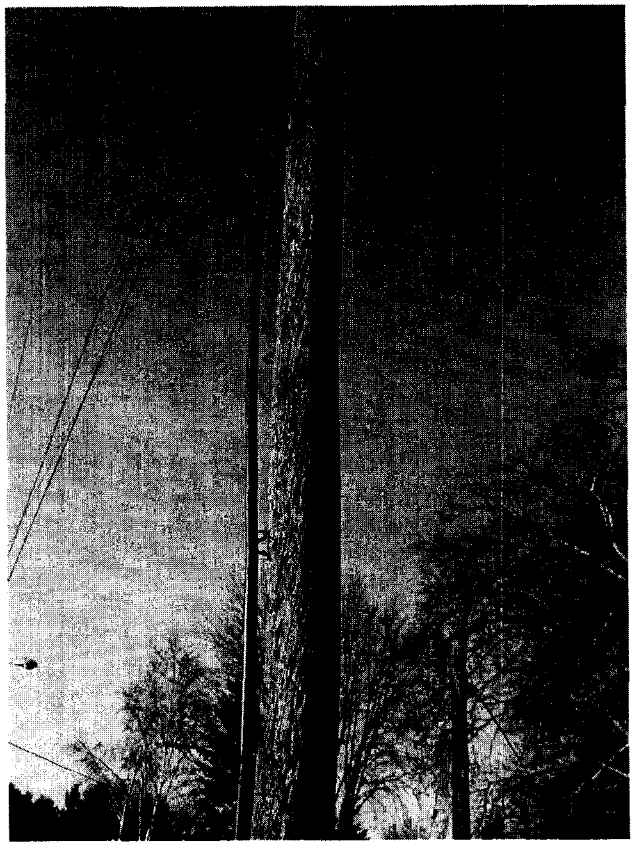
Pole Rotting at Base



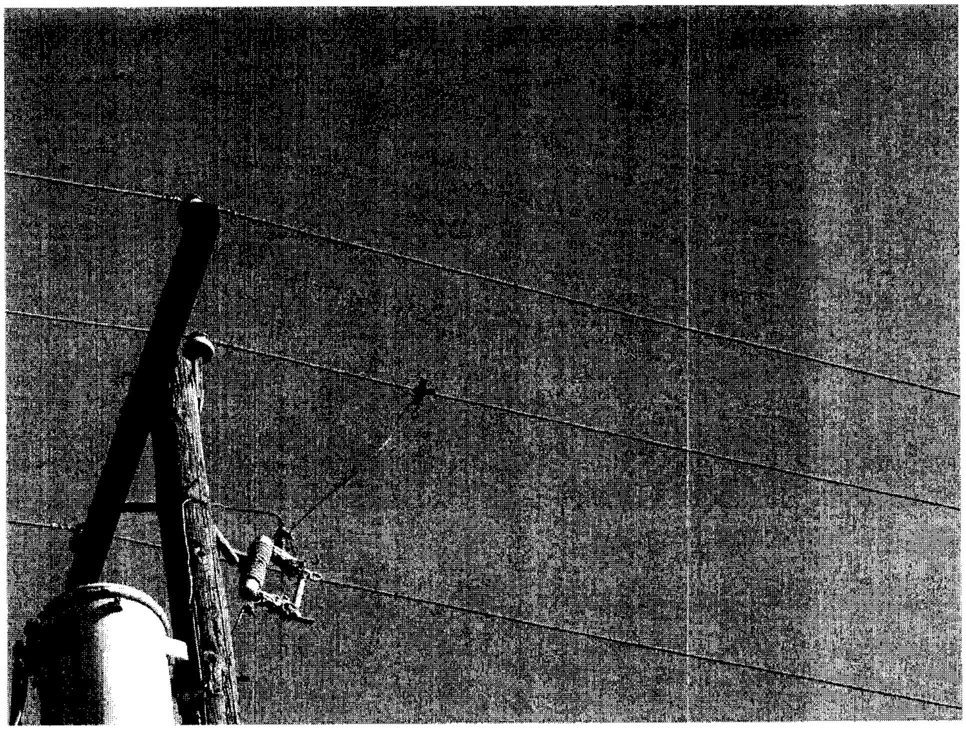
Pole Rotting at Top



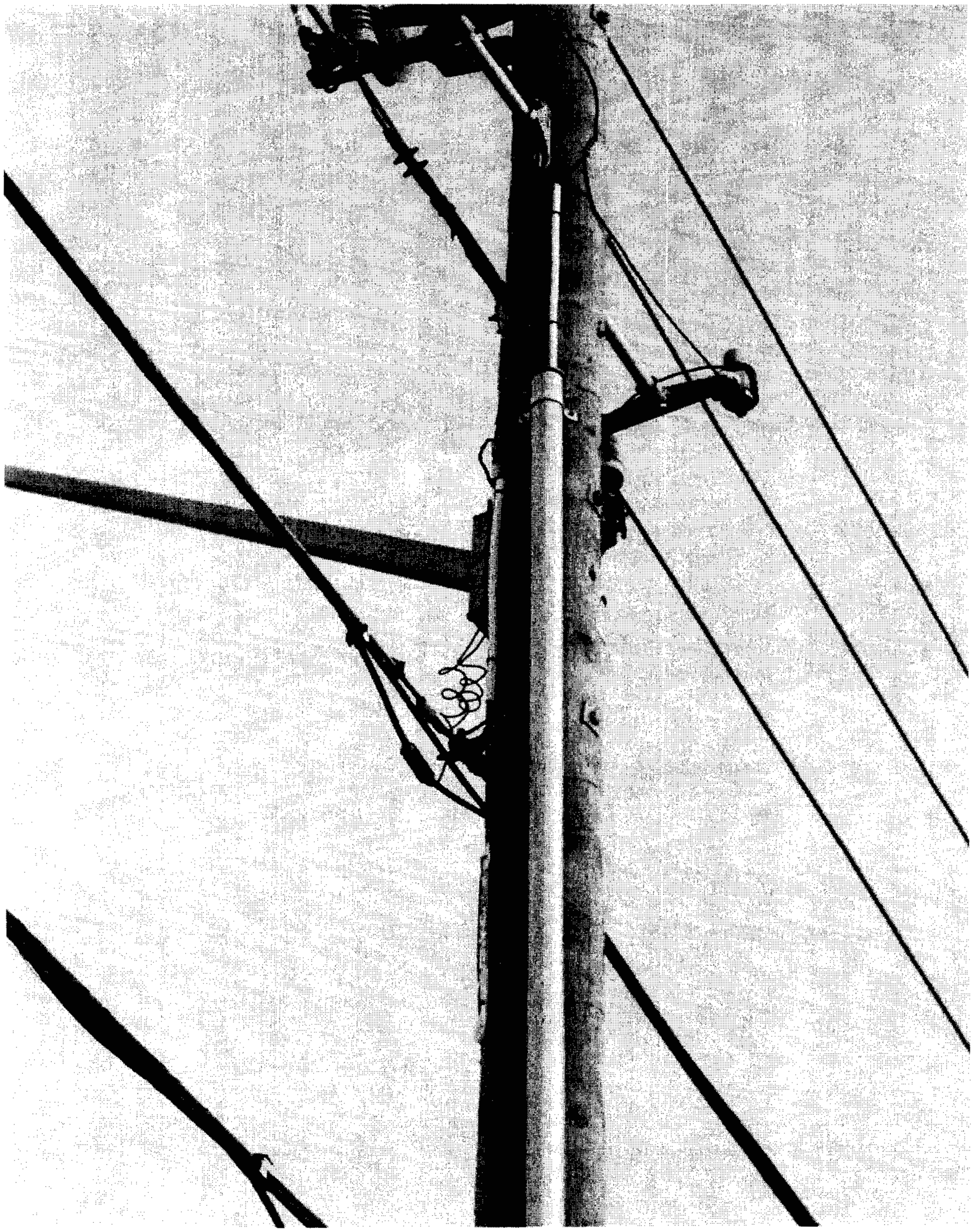
Ceiling I-beam Issues in Vault 2



Pole with Surface Damage



Live Line Clamp Directly on Conductor



Arrester Lead Not Connected to Cable Neutral

APPENDIX E Asset Condition Information from Staff Interviews

Information was solicited in each of the interviews on the historical condition, present condition, maintenance activity, and future issues for Oshawa PUC assets on both Overhead and Underground systems. The notable issues related to asset condition and management are detailed below. This information is a compilation of responses from the group of individuals. The information has provided the contractor with insight into a number of asset issues that were not readily apparent from site inspection and documentation. Topics are discussed below in the general categories of Stations, Overhead and Underground distribution plant. In general, OPUC is aware of the impact of most asset issues and is taking systematic steps to solve problems as they arise.

Station assets were reported to be in good condition. With two transformers in each station, each unit had rarely been loaded above 50%. In prior years the station transformers had experienced tap changer burn-off problems, particularly at MS11, as well as leaking gaskets. A recent program of refurbishing station transformers had included repainting, gasket replacement, oil testing, insulation testing, tap changer overhaul, winding inspection and in 2 cases re-winding and/or replacement. A spare unit had been purchased for a future station and has been used to allow removal and refurbishment of other units. Low voltage tap changers are being equipped with on-line oil filtering. Replacement of tap changer controls on some units is still considered necessary.

Station 44kV high side KSO oil circuit breakers were reported in good condition despite some issues regarding parts for older vintage breakers. Feeder breaker maintenance had been reduced in the 1990s but an upgraded maintenance plan has been in place for about 3 years with maintenance scheduled every 4 years. IR thermography has been utilized effectively to determine hot spots. Earlier breaker failure problems at MS5 and MS14 had been rectified. A program has been put in place to replace older electro-mechanical feeder relays with electronic GE Multilin relays which have reduced maintenance requirements, provide improve feeder protection and act as a source of monitoring data.

Porcelain potheads on the station egress dip pole had caused eventful failures particularly at MS7 and MS10. Potheads are being replaced with polymer terminations.

It was reported that station grounding grids appear to be one asset that has not received particular attention at OPUC.

Small conductor sizes (#2, #4) in rural areas have experienced breakage generally related to tree contact. The opinion was expressed that breakage of the small conductors may have avoided damage to the pole structures whereas larger conductors may have led to pole breakage. Arterial feeder circuits are being systematically rebuilt.

OPUC has experienced ongoing problems whereby the porcelain on a distribution cutout breaks at the mid-point. Porcelain cutouts are being replaced with polymer cutouts. The replacement program also includes utilizing a fiber bracket and arrestor replacement. Porcelain arresters have been replaced with polymer since the 1990's as some arrester failures have also been experienced. Some failures of polymer in-line switches have also been experienced. Some distribution transformers have been replaced during a PCB removal program. Some conflicting reports were received regarding the condition of the remaining population of distribution transformers. There were also reports that some of the ground operated air break switches are closed in and locked but inoperable. One action to address material problems has been the institution of an equipment approval process and standard committee.

Issues with overhead secondaries have included pull down incidents and failures of Insulink compression connectors.

As per several assets categories at OPUC, pole testing was not done rigorously in the 80's and 90's. It was reported that pole failures have generally occurred during wind storms. OPUC has now instituted a pole testing program for their approximately 12,000 wood poles. Approximately 4000 poles are being tested per year over a 3 year period to be completed in 2007, the first set were selected on a geographic area basis. A minimal number of pole fires have been experienced, notably on the pressure treated poles. Anecdotally, treated poles were believed to split more readily and are less favored than cedar poles. Older concrete poles have experienced re-bar deterioration and replacements are being made in the downtown area utilizing decorative poles.

OPUC had experienced a significant number of failures of EPAC insulators, which is an industry wide problem, and these have been changed in stations. 44kV porcelain insulator failures on cross arms have also led to ongoing replacement with polymer insulators until complete change-out has been accomplished. It has been noted that flashovers of wet or contaminated insulators have been more pronounced on concrete poles.

A large portion of OPUC's URD system was built in the 1960s. Primary cable was direct buried #2 XLPE, non-jacketed concentric neutral cross-link poly-ethylene. Failures apparently have occurred in the cable, at splices, and there have been corrosion problems with the concentric neutral. More recently OPUC has utilized #2 XLPE jacketed tree-retardant cable-in-duct. A cable replacement program is proceeding with re-cabling in approximately 5 sub-divisions which were targeted as having higher failure rates based on failure logs that are now being kept for cables to prioritize replacement. Secondary underground services were and still are direct buried and according to one staff have experienced a high failure rate including burn-offs, and breakage at older splices. A secondary cable replacement program may be in order as well. Downtown primary cable is 2/0 copper which is reportedly in good shape with a reasonable number of faults. Sections of 500MCM are utilized for station egress.

Downtown cable vaults and manholes had been inspected and structurally refurbished over an earlier 3 year period by a contractor. Cracks in concrete were filled. Work was done on 4 of the 6 main OPUC vaults. Although load bearing is apparently adequate it is acknowledged that there is additional structural refurbishment to be done on vaults and manholes including improved sealing and repair of crumbling around collars and lids. No vault fires or methane build up were reported.

In general comments on maintenance, the staff interviewed felt that the utility had a good new 4-year cycle maintenance program. There was interest expressed in proceeding to a Reliability Centered Maintenance program.

As an indicator of asset condition the question of outages was raised with those interviewed. The general consensus was that storms, tree contact, animal and bird contact, vehicle accidents and cable failures were the most prevalent sources of the outages. Perception was that unscheduled outages were down and trouble calls were down. Tree trimming programs appeared to be effective in reducing contact outages. A considerable effort to reduce animal contact had been made by the use of items such as line coverings, bushing boots, fiber cutout supports, and insulating drop leads, and these appear to have had a positive effect. These improvements were evident in a reported reduced number of momentary outages. Equipment condition related outages such as station breaker problems appeared to be reduced. Ongoing equipment related outages included cutout failures, insulator failures, switch failures and cable failures, all of which are being addressed with some action by OPUC. Cable faults are ongoing at a rate expected for this aging asset.

Opportunities to improve asset condition or management discussed in the interviews included: improvements in the SCADA and monitoring systems as well as outage data, addition of automated switches in rural areas, moving back-lot construction to front-lot for better access and maintenance, the need to continue fleet replacement and inclusion of computers in vehicles. Staff expressed the concern that high work levels may have some negative impact on asset condition since not all problems can be affectively addressed. There were some concerns expressed regarding the potential loss of large customers and the impact which that could have on the ability of OPUC to maintain asset condition levels and optimize the utilization of existing assets. Also concerns were expressed about the aging workforce, reduction of expertise, and the lack of fully trained staff to address all of the asset maintenance needs. Also the security of OPUCs assets from vandals was also raised as an asset management concern.

Through the interview process Kinectrics was satisfied that OPUC staff are knowledgeable, vigilant and in a continuous improvement mode regarding distribution assets.

DISTRIBUTION

Mr. Mark Turney	Oshawa PUC Networks
S. Cress	Kinectrics Inc., KL206
R. Piercy	Kinectrics Inc., KL206

APPENDIX E

MANAGER'S SUMMARY OF COST ALLOCATION STUDY

(Excerpt from January 15, 2007 filing)

Oshawa PUC Networks Inc.

Oshawa PUC Networks Inc. (OPUCN)

MANAGER'S SUMMARY FOR COST ALLOCATION INFORMATIONAL FILING JANUARY 15, 2007

COST ALLOCATION FILE NO: EB-2006-0247 EDR 2006 FILE NO: EB-2005-0402

1. Introduction

On September 29, 2006 the Ontario Energy Board (the "OEB") issued the Board Directions on Cost Allocation Methodology for Electricity Distributors ("the Directions"). On November 15, 2006 the OEB also issued the Cost Allocation Information Filing Guidelines for Electricity Distributors ("the Guidelines"), the Cost Allocation Model ("the Model") and User Instruction (the Instructions") for the Model. OPUCN has prepared this information filing consistent with OPUCN's understanding of the Directions, the Guidelines, the Model and the Instructions.

The main purpose of this cost allocation filing is to provide evidence to show the OPUCN rate classifications that are being subsidized by other classes and those rate classifications that are over contributing based on the assumptions of the Model.

In the mid 1980's, Ontario Hydro, the regulator at the time, completed the last cost allocation study that reflected the distribution function but this was an integrated cost study. An integrated study reviewed the full costs of providing electricity to customers which included energy, transmission and distribution. Distribution represented only around 15% of the total costs reviewed. The results of this study assisted Ontario Hydro in developing the Rate Setting Guidelines that were used by Municipal Electric Utilities to develop the bundled rates they charged customers up until around 2000.

Under the Energy Competition Act, 1998, the electricity industry in Ontario was separated into Generation, Transmission and Distribution companies. Along with this separation the rates also needed to be unbundled to reflect the structure of the new companies. The unbundling of distribution from generation and transmission was completed in the 2000 to 2001 timeframe using the Electricity Distribution Rate Handbook Rate and the Rate Unbundling and Design Model (i.e. the RUD model). The Rate Handbook and RUD model provided a method to unbundle distribution rates from the other rates by rate classification but it did not determine whether the unbundled rates collected the cost of providing service to the rate classification. The current cost allocation process is the first time a cost allocation study has been conducted in Ontario that focuses completely on distribution to determine whether or not the distribution rates are collecting the cost of providing service to the rate classifications.

In accordance with the Directions, OPUCN expects the OEB will give significant weight to the results of these filings when deciding upon specific cost allocation matters in future rate hearings. OPUCN understands that after reviewing the results of the cost allocation filings from all distributors, and considering the overall regulatory context including results from the forthcoming distribution rate design consultations, the OEB will decide upon the priorities for, and timing of, any adjustments to future cost allocations, rate classifications or rate design. OPUCN also understand the information in this filing will be made public.

OPUCN is in the 1st tranche of filers, due by January 15, 2007. This filing comprises a Run 1 and a Run 2. An optional Run 3 was conducted for the purposes of proposing cost allocation changes for Streetlights. For OPUCN, Run 1 reflects the rate classifications as they were prior to May 1, 2006. Prior to May 1, the Unmetered Scattered Load ("USL") customers were included in the General Service < 50 kW rate classification. Run 2 has the USL customers pulled out of the General Service < 50 kW class to form a class of their own which is consistent with the current rate classifications used by OPUCN.

In order to prepare this cost allocation filing, OPUCN used the services of Hydro One to prepare load data profiles by rate classification. OPUCN conducted its own residential appliance saturation survey, during the months of May and June 2006. The results of this survey were used by Hydro One to prepare the load data profiles for OPUCN.

The cost/financial data used in the Model is consistent with the cost data that supports the current approved distribution rates for OPUCN. Based on the Guidelines, OPUCN assets were broken out into primary and secondary distribution functions. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available from OPUCN's customer and financial information systems.

2. Summary of Results

2.1 Revenue to Cost Ratios

The results of a cost allocation are typically presented in the form of revenue to cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage shows the rate classifications that are being subsidized and those that are over contributing. A percentage of less than 100% means the rate classification is under collecting and is being subsidized by other classes. A percentage of greater than 100% indicates the rate classification is over collecting the cost assigned to the classification and is subsidizing other classes.

The following outlines the revenue to cost ratios for the Run 2. The results for Run 1 are similar. In Run 1, the USL rate classification is combined with the General Service < 50 kW rate classification. As a result, the cost to revenue ratio in Run 1 for General Service < 50 kW customers is 130.59% and there is no ratio for USL. All other ratios in Run 1 are approximately the same as Run 2.

Rate Classification	Revenue to Cost Ratio	($Being Subsidized)/ $Over Contributing
Residential	88.54	(1,313,529)
General Service <50 kW	129.77	707,222
General Service >50 kW < 200 kW	95.30	(152,308)
General Service >200 kW < 1,000 kW	157.58	177,902
General Service >1,000 kW < 5,000 kW	333.66	677,033
General Service >5,000 kW	257.45	527,148
Street Lights	23.16	(638,268)
Sentinel Lights	55.33	(2,837)
USL	131.76	17,635
Total	100.0%	0

Since the unbundled distribution rates have never been based on costs it is expected the Residential class would be the rate class being subsidized based on the method used to previously design the bundled rates for customers of a Municipal Electric Utility ("MEU"). Prior to the passing of Bill 35 by the Ontario Government on October 30, 1998, a MEU was regulated by Ontario Hydro. In order to assist a MEU with setting the retail rates for their customers, Ontario Hydro provided the MEU Rate Setting Guidelines. These guidelines provided guidance to a MEU on how to develop the bundled retail rates for their customers. However, the guidelines allowed the utility to charge a kWh rate for General Service customers that was up to 10% higher than the Residential customers. The rationale for this differential is unknown to OPUCN. A review of OPUCN rates prior to unbundling indicated General Service customers pay a kWh rate 12% higher than Residential customers. It is unclear why this was higher than 10%.

In the unbundling process, the unbundled distribution rates were determined by subtracting an estimate of the cost of power (i.e. generation and transmission) from the bundled rates. Assuming the cost of power is the same for all customers the unbundled distribution rates for General Service customers would be higher than Residential rates because the bundled General Service rates were 12% higher. However, there is no cost justification for this differential especially in regards to distribution costs. This means the above results for Residential and General Service rate classifications appear to be reasonable.

With regards to Street Lights and Sentinel Lights, it is assumed in the cost allocation study that a street light or sentinel light connection is equivalent to a customer. This appeared to be reasonable because in the case of other rate classifications each connection is essentially a customer. This means the customer costs allocated to street lights and sentinel lights are based on 10,076 and 77 connections, respectively which are the biggest driver that is causing the results for these two classes.

The question is: should streetlights, in particular, be allocated costs based on the number of connections or customers? There are arguments for both sides. On one hand, it could be argued that it should be connections because it would be consistent with the other rate classifications. On the other hand, it could be justified that a streetlight is like any other appliance or outside light on a home. It just happens to be outside on the street. In this case, a streetlight would be incremental load much like a stove or refrigerator and it would attract very little customer costs if any at all. The only customer costs it might attract would be the cost of sending a bill to the customer. OPUCN understand that very low revenue to cost ratio for street lights has occurred with other distributors. With the Model assuming full connection as a basis for allocation Streetlights reflect revenue to cost ratio of 23%. Using an one-tenth of connection total as suggested by Toronto Hydro to drive for equable apportionment the results are Streetlights revenue to cost ratio of 95%. In OPUCN's view, this is a provincial issue that needs to be discussed with the OEB and other market participants. As a result, changes should not be made to streetlight or sentinel light pricing until this issue has been resolved.

Regarding the USL results, these are also expected as there are most likely cost associated with meter capital and meter reading in the current rates that should be removed since these customers are not metered.

2.2 Monthly Fixed Charge Comparison

The Model produces customer unit costs per month for each rate classification. To assist with reviewing the range of current fixed monthly service charges, the Model generates three scenarios of reasonable cost-based customer unit costs for each rate classification. These unit costs are determined by the Model and compared to the current approved monthly service charge.

Scenario 1: Avoided Costs

With a strict "avoided cost" approach, only meter related costs, billing and collection costs are included. This approach has the advantage of focusing on the immediate costs of an additional customer. But no administration and general overhead are applied.

Scenario 2: Directly Related Customer Costs

The directly related customer costs are those cost included in the avoided cost version but an allocation of administration and general overhead is included.

Scenario 3: Minimum System Approach

The minimum system approach assumes that a minimum-size distribution system can be built to serve the minimum load requirements of the customer. For the purposes of this filing the minimum load requirement is assumed to be 400 watts per customer. The minimum system method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the distributor. Once determined for each plant account, the minimum size distribution system is classified as customer-related costs and then used to define the monthly unit customer cost.

There are various approaches to define the minimum system. Moreover, judgment is required to address various implementation details with this methodology. The OEB cost allocation project did not seek to develop a common minimum system methodology for use by the Ontario electricity distribution sector. Instead, the results of numerous past Ontario minimum system studies were examined and approved for use in the Model.

The minimum system results are applied to the following accounts:

- Line Transformers (Account 1850)
- "Distribution" which includes poles and conductors, and is defined as Accounts 1830 -1845
- Related O&M accounts.

The density of the distributor (i.e. customers/route kilometer of line) is the major factor that determines the percentage of the above costs which are included in the customer costs. The density of OPUCN is 46 customers/km. This means OPUCN is classified as an urban distributor. As a result, 40% of OPUCN's distribution costs (i.e. lines and poles) and 40% of OPUCN's line transformers are defined to be customer related cost.

The monthly customer unit cost under the minimum system approach includes the directly related customer costs plus 35% of distribution costs and 30% of line transformers along with any administration and general overhead associated with distribution and line transformers.

The following outlines the monthly fixed cost comparison.

Rate Classification	Approved Fixed Charge	Minimum System Fixed Charge	Directly Related Fixed Charge	Avoided Cost Fixed Charge
Residential	7.29	12.23	5.98	2.62
General Service <50 kW	8.75	25.21	18.87	8.80
General Service >50 kW<200 kW	40.23	140.90	122.82	59.72
General Service >200kW<1,000 kW	40.23	191.04	174.51	83.66
General Service >1,000 kW<5,000 kW	1,934.86	510.82	500.58	225.43
General Service >5,000 kW	10,418.47	2,081.73	2,040.71	1,063.13
Street Lights	0.47	6.87	0.00	0.00
Sentinel Lights	2.45	6.87	0.01	0.00
USL	4.38	7.46	0.07	0.02

Although the above results suggest the monthly fixed charge should be reduced for all General Service Rate Classifications that are over 50 kW this is a reasonable outcome. Under the three scenarios provided by the Model, the main cost drivers that produce a difference in the monthly unit customer cost is the difference in cost between rate classifications for meters, meter reading, billing and collecting. In other words, it would be hard to justify a monthly fixed charge that is ten times higher for General Service > 50 kW customer compared to a General Service < 50 kW customer, when the only significant difference between the two rate classifications is the cost to install and maintain meters, read the meter, send out a bill and collect the bill.

2.3 Transformer Ownership Allowance

Currently, OPUCN provides a transformer ownership allowance to those customers that own their transformation facilities. OPUCN's present transformer ownership allowance is $0.60 per kW and this same charge is applied consistently across the province. The amount of the allowance has not been reviewed on a generic basis in recent years. The filings will be used by the OEB to review this allowance from a cost based perspective.

The present allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since it is assumed that the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides the step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

In OPUCN's case, the customers that currently receive a transformer ownership allowance are all in the General Service > 50 kW rate classifications. The Model is suggesting the allowance for General Service > 50 kW < 200 kW rate class should be $0.49 per kW. However, it should be indicated that the total current transformer ownership allowance of around $289,000 has not been applied to the revenue which means the revenues in the Model could be overstated for this rate classification. This is in turn would reduce the 'over contributing' amount (and so effect the revenue to cost ratio of all classes). In OPUCN's view, the transformer allowance study amounts appear to be reasonable but suggests the OEB review this issue on a provincial basis before the current the transformer ownership allowance is adjusted.

APPENDIX F

OSHAWA PUC NETWORKS INC

LRAM AND SSM ASSESSMENT (ENERSPECTRUM GROUP)

EnerSpectrum
Group

Mr. Michael Chase
Corporate Controller
Oshawa PUC Networks Inc.
100 Simcoe Street South
Oshawa, ON
L1H 7M7

September 26, 2007

Re: Application for SSM and LRAM for OPUC CDM Programs

Dear Mr Chase:

As requested in our meeting with you on September 17, 2007, we have reviewed your application for Shared Savings Mechanism (SSM) based on Oshawa PUC Network Inc's CDM program results to the end of 2006, and the costs provided by your LDC.

Based on our review of your data and calculations, and information from similar filings with the OEB, we have adjusted the eligible amounts and arrived at a slightly higher SSM calculation, as noted in the spreadsheet and report submitted to you.

Additionally as requested, we have completed LRAM calculations for some of Oshawa PUC Network Inc.'s CDM programs that we believe qualify for consideration by the OEB. Those calculations are also submitted to you in the report.

Please call me if you have any questions about our review of your SSM and LRAM applications.

Thank you for this opportunity to assist you.

Sincerely,

Bart Burman M.B.A., BA Sc, PEng
Managing Partner

98 Archibald Road, RR2, Kettleby Ontario L0G 1J0
416-219-9976 www.enerspectrum.com

EnerSpectrum
Group

Oshawa PUC Networks Inc.

LRAM and SSM Assessment

E1073

September 7, 2007

As an incentive to LDCs to participate in Conservation and Demand Management (CDM) programs, the Ontario Energy Board (OEB) introduced rates-based applications to recover revenues lost to customer energy conservation, and to share in gains from effective CDM programs. The mechanisms developed by the OEB to calculate lost revenue or savings are the Lost Revenue Adjustment (LRAM) and the Shared Savings Mechanism (SSM).

The underlying basis for LRAM and SSM applications, is information from CDM program results, or other documented results that qualify. Therefore, it is incumbent on the distributor that sufficient time needs to have passed to ensure measurable results and information have accumulated before LRAM and SSM application is made.

Thus far, three LDCs have formally submitted application for LRAM and SSM to the OEB: Toronto Hydro; Enersource; and Halton Hills Hydro. Thus far, an order has been issued for the Toronto Hydro application allowing some $3.1 million in compensation for LRAM, and $7.2 million under SSM, based on the results reported in the LDC's 2005 and 2006 Annual CDM Reports. However, the OEB has asked Toronto Hydro to resubmit its SSM application without PILS, and to reduce its LRAM amount to reflect free ridership.

Oshawa PUC Networks Inc. has determined that it will file application for LRAM and SSM adjustments based on its 2006 CDM results, reported to the OEB in March, 2007 in its 2006 CDM Annual Report.

Required

Oshawa PUC Networks Inc. has asked EnerSpectrum Group to assist the LDC with its LRAM and SSM applications on three levels:

1. Review the SSM calculations and underlying data, and assess if the application complies with OEB requirements and make recommendations for improvement as appropriate
2. Assess available lost revenue information associated with Oshawa PUC Networks Inc.'s 2006 CDM results; determine if an LRAM application is feasible based on OEB requirements; and prepare LRAM calculations suitable for submission
3. Provide a letter of verification of SSM and LRAM calculations and assumptions for inclusion Oshawa PUC Networks Inc.'s rates application

About SSM

Under the SSM regime, a distributor may recover 5% of the net benefits created by the approved CDM portfolio, through a rate rider. An SSM claim requires all of the information as required for LRAM, and it applies only to customer focused initiatives that reduce the demand for electricity and/or reduce the amount of energy used, and only where the costs of the initiatives are expensed. The distributor must calculate the net benefits of a program using the Total Resource Cost (TRC) test that is applied for CDM program annual reporting.

Methodology

To optimize the calculation of LRAM and SSM amounts, EnerSpectrum Group proposes that it:

1. Review existing LRAM and SSM guidelines and LDC submissions to the OEB, and the OEB order issued to Toronto Hydro, to identify the most prudent course for Oshawa PUC Networks Inc. to complete its LRAM and SSM applications.
2. Seek counsel within the OEB to verify the appropriate assumptions and processes to complete LRAM and SSM submissions
3. Review Oshawa PUC Networks Inc. CDM program results and SSM submission, verify assumptions and calculations, and recommend improvements where appropriate
4. Provide LRAM calculations based on prudent assumptions, CDM results and appropriate rate classes within OEB guidelines
5. Prepare report and recommendations related to LRAM and SSM calculations
6. Prepare a letter of verification by EnerSpectrum Group to be included in the Oshawa PUC Networks Inc. application

Review of Oshawa PUC Networks Inc. SSM Application

EnerSpectrum Group has reviewed Oshawa PUC Networks Inc.'s SSM application and calculations against the OEB's RP-2004-0203 Report, calculated net TRC benefits (or in the case of program support, costs) for each CDM program. The LDC has confirmed to EnerSpectrum Group that appropriate documentation is on file in support of the costs used in the TRC calculations.

As set out in the TRC Guide, program net benefits are determined by the present value of the benefits (avoided electricity costs minus the present value of program costs over the program's life). On a program basis, gross load reductions are in turn calculated based on TRC guidelines, and then further reduced to recognize free ridership of customers who would have undertaken load and energy consumption reductions regardless of CDM incentives.

The TRC Guide prescribes the calculations as well as the use of such parameters as the unit savings per measure for different measures, free-rider rates, and avoided electricity costs. Moreover, utility-side programs, such as loss reduction initiatives, are not eligible for SSM treatment.

As the spreadsheet in Appendix 1 details, EnerSpectrum Group has reviewed Oshawa PUC Networks Inc.'s TRC calculations for each of its CDM programs and has identified any inconsistencies in the application of program costs, TRC calculations, or assumptions. In some cases, costs or assumptions adjusted, as noted in the spreadsheet comments. Based on these revisions, EnerSpectrum Group arrived at a slightly higher TRC value of $1,242,300 vs $1,229,600 as originally calculated by Oshawa PUC Networks Inc.

The Shared Savings Mechanism allows for 5% of portfolio net TRC values to be retained by the LDC. In this case, that amount computes to $62,115 to be applied for SSM purposes.

About LRAM

The OEB prescribed in its RP-2004-0203 decision of December 2004, and outlined in the subsequent 2006 EDR Report of the Board, that a distributor is expected to calculate the energy savings by customer class and to value those energy savings using the Board-approved variable distribution charge appropriate to the class. This amount is entered into a deferral account, which may be claimed in a subsequent rate year as compensation for lost revenue.

Lost revenue is calculated using the variable distribution rate (kW or kWh) for each affected class and does not include any Regulatory Asset Recovery rate riders, as these funds have their own independent true-up process in place. In addition, lost revenues are only accruable until new rates (new revenue requirement and load forecast) are set by the Board, as the savings are assumed to be incorporated in the load forecast at that time. LRAM information for an application should include:

- kW or kWh impacts (both gross and net of free riders) of each program and for each class;
- A calculation of the impact of the CDM program on distribution revenues in each class;
- Verification of the participation levels;
- Where savings information is not provided in the TRC Guide, the distributor must comply with the requirements set out in the TRC Guide respecting custom projects;
- Duration of the program in years or months.
- All information filed for the LRAM proposal should correspond to program information used in the calculation of the cost/benefit analysis.

Oshawa PUC Networks Inc. LRAM Considerations and Calculations

EnerSpectrum Group has reviewed Oshawa PUC Networks Inc.'s CDM program results with respect to completing an LRAM application by class in a manner consistent with the OEB's RP-2004-0188 Report. Input has also been sought directly from OEB personnel.

Determination of LRAM Amount

Unlike SSM evaluation, LRAM accounts for variances between actual CDM results and the corresponding energy or load reductions, rather than net present value. For LRAM reductions in customer demand and energy due to CDM programs are applied to the specific rate class and adjusted to reflect free riders, and applied to the appropriate customer class to determine lost revenue.

Consistent with OEB guidelines, and input, EnerSpectrum applied the following steps to assess and calculate eligible LRAM amounts:

1. Obtain kW or kWh savings from 2006 CDM Annual Report
2. Obtain appropriate customer class rate(s)to annual savings
3. Multiply savings by appropriate class rate(s)
4. Reduce amount of lost revenue by applicable free ridership rate to obtain to obtain eligible lost revenue
5. Sum classes of lost revenue to obtain forgone revenues

Calculated LRAM amounts for the reported 2006 CDM program results are shown in the following table:

2005 Residential Load and Revenue Impacts

Program	Load Impact		Rate/ kWh	Revenue Impact
	kWh	kW		
Library Watt Reader Program	13,154	3	$0.0119	$157
Every Kilowatt Counts (Spring)	1,674,492	107	$0.0119	$19,926
Every Kilowatt Counts (Fall/Winter)	2,452,998	48	$0.0119	$29,191
Residential 155 Colbourne Replace Bulk with Individual Meters	43,200	2	$0.0119	$514
Total	4,183,845	160		$49,788

A residential class rate rider would be suggested to recover SSM and LRAM amounts over the next 6 months. However, Oshawa PUC Networks Inc. is advised to first assess the magnitude of the required rider based on the total residential energy delivered in 2006.

Although Oshawa PUC Networks Inc. has focused on its 2006 CDM Annual Report as the basis for its application, EnerSpectrum Group has found some applicable program expenditures and results from 2005 that also qualify.

Recommendations

After reviewing Oshawa PUC Networks Inc.'s SSM and LRAM calculations and amounts, recommends:

- In support of a submission to the OEB, ensure consistency of TRC calculation by using one calculation tool. Revised TRC values are included in Appendix 1.
- Use OEB data tables for inputs to TRC calculations wherever possible to ensure compliance. Use custom or non-table data only where it can be verified or substantiated beyond a reasonable doubt. Revised TRC values are all based on OEB published tables.
- Maintain a bound paper audit for CDM costs and results as a backup to annual CDM filings, and for inquiries related to specific program details.
- Consider the extension of existing CDM programs or the selection of future CDM programs based on potential SSM and LRAM returns.
- Consider the magnitude and resulting materiality of rate riders required to recover SSM and LRAM amounts.