

ALGONQUIN POWER INCOME FUND

ANNUAL INFORMATION FORM

May 16, 2003

Trust Units of Algonquin Power Income Fund are not “deposits” within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation.

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ALGONQUIN POWER INCOME FUND

THE FUND

Algonquin Power Income Fund is an unincorporated open ended trust created by a declaration of trust dated September 8, 1997 in accordance with the laws of the Province of Ontario. The principal office of the Fund is located at 2845 Bristol Circle, Oakville, Ontario L6H 7H7.

The Declaration of Trust was amended on: (1) December 18, 1998, to provide the Fund with greater flexibility to borrow monies, which borrowings may be secured by the Fund's assets; (2) on June 1, 2000, to clarify that Fund indebtedness may be secured by some or all of the assets of the Fund, to increase the amount of permitted monthly cash redemptions from \$10,000 to \$250,000 and to expand the types of permitted investments which the Fund may make to include investments in energy-related assets and such other investments as the Trustees consider reasonable and appropriate; (3) on May 24, 2001, to provide that a quorum at a meeting of Unitholders shall, except in specified circumstances, consist of two or more individuals present in person or represented by proxy; and (4) on May 23, 2002, to make clear the ability of the Fund to complete certain transactions in connection with any internal reorganization of the Fund's assets, without Unitholder approval. In addition, Unitholders will be asked at the upcoming annual and special meeting of Unitholders to be held on June 26, 2003 to consider and if thought fit, pass an Extraordinary Resolution approving certain additional amendments to the Declaration of Trust, as described in the management information circular of the Fund dated May 12, 2003, which amendments include clarifying the ability of the Fund to dispose of certain assets of the Fund and provide guarantees of the obligations of the Fund's related entities, without Unitholder approval, permitting fractional Units and certain other housekeeping amendments.

The Fund has direct or indirect interests in the following corporations: Algonquin Power Fund (Canada) Inc., Donnacona Holdings Inc., Algonquin Holdco Inc., KMS Peel Inc. and Peel Resource Recovery Operations Inc., Ontario corporations, Lakeport Hydroelectric Corporation, an S Corporation under United States law, Algonquin Power Fund (America) Inc., Algonquin Power Fund (America) Holdco Inc., Algonquin Water Resources of America, Inc., CSI Oswego Corp., KMS America, Inc. and KMS Crossroads, Inc., Delaware corporations, SFR Hydro Corporation, a New Hampshire corporation, Clement Dam Hydroelectric LLC and Franklin Power LLC, New Hampshire limited liability companies, Worcester Hydro Company, Inc, a Vermont corporation, Court Street Investments, Inc., Oswego Power Company, Inc. and Oswego Energy Corp., Massachusetts corporations, Tug Hill Energy Inc., a New York corporation, Black Mountain Sewer Corporation, Gold Canyon Sewer Company, Bella Vista Water Company, Inc. and Litchfield Park Service Company, Arizona corporations, Great Falls Energy, L.L.C., a Maryland limited liability company, Sanger Power, L.L.C., a California limited liability company, Woodmark Utility Company and Tall Timbers Utility Company Inc., Texas corporations, and Algonquin Windsor Locks L.L.C., a Connecticut limited liability company. In addition, Algonquin Power Acquisition Inc. and Algonquin Energy Services Inc., both Delaware corporations, were incorporated as acquisition vehicles for proposed acquisitions by the Fund in the United States.

The Fund also has direct or indirect interests in the following partnerships: Société Hydro-Donnacona S.E.N.C., a Québec general partnership; Hollow Dam Power Company and Burt Dam Power Company, New York general partnerships, Hadley Falls Associates, HDI Associates III, Avery Hydroelectric Associates, Gregg Falls Hydroelectric Associates Limited Partnership, Pembroke Hydro

Associates Limited Partnership and Mine Falls Hydroelectric Limited Partnership, New Hampshire limited partnerships, Moretown Hydro Energy Company, a Vermont partnership, HDI Associates I, an Indiana general partnership, Algonquin Power (Mont Laurier) Limited Partnership, a Québec limited partnership; Great Falls Hydroelectric Company Limited Partnership, a Maryland limited partnership, Oswego Hydro Partners, L.P., a Delaware limited partnership and KMS Joliet Power Partners, L.P. and KMS Bakery Power Partners, L.P., Illinois limited partnerships.

The Fund is the sole beneficiary of the Algonquin Power Trust, an unincorporated open ended trust created by a declaration of trust dated June 30, 2000 in accordance with the laws of the Province of Ontario. Algonquin Power Trust owns all of the outstanding units of Drayton Valley Power Income Fund, an unincorporated open ended trust created by an amended and restated trust indenture effective January 2, 1997, in accordance with the laws of the Province of Alberta. Algonquin Power Trust owns all of the outstanding trust units and approximately 47.3% of the outstanding convertible debentures of KMS Power Income Fund, an unincorporated open ended trust created by a declaration of trust dated February 18, 1997, in accordance with the laws of the Province of Alberta.

All of the above-noted entities are wholly-owned, directly or indirectly, by the Fund, subject to the Manager's Interest. See *"General Development of the Business – Other Developments in Fiscal 2002"*.

All information contained in this Annual Information Form is presented as at May 16, 2003, unless otherwise specified. Reference is made to the glossary attached as Schedule A for the meanings of certain defined terms.

GENERAL DEVELOPMENT OF THE BUSINESS

General

The Fund was created to acquire direct or indirect equity interests in hydroelectric generating facilities located in Canada and the United States. The Fund has since expanded its mandate and will consider investment opportunities which provide stable cash flow from renewable resource facilities; potential candidates could include wind, biomass or natural gas powered generating stations or facilities within a regulated utility.

The Fund, through its interests in the Fund Businesses, is engaged, indirectly, primarily in the business of generating and marketing electrical energy within the independent power generation industry. The Fund currently holds equity interests, directly and indirectly, in 47 hydroelectric generating facilities located in Ontario (5), Québec (12), Newfoundland (1), Alberta (1), New York State (12), New Hampshire (13), Vermont (2) and New Jersey (1) representing aggregate installed generating capacity of approximately 140 MW. The Fund holds equity interests in one energy from waste facility in Ontario with an installed generating capacity of 10 MW, one landfill gas-fired facility in Illinois with an installed generating capacity of 1.6 MW and three natural gas-fired cogeneration facilities in each of Connecticut, New Jersey and California with an installed capacity of approximately 113 MW. In addition, the Fund owns partnership, share and debt interests in three bio-mass fired generating facilities with combined installed capacity of approximately 70 MW located in Alberta, Québec and Nova Scotia. The Fund holds minority term investments in two natural gas/wood waste-fired generating facilities with joint installed capacity of approximately 138 MW located in northern Ontario and one 150MW natural gas powered

combined cycle cogeneration plant located in south-eastern Ontario. In addition to its electricity generating assets, Algonquin owns six regulated water distribution and wastewater handling facilities in Arizona and Texas. The facilities are grouped into four business segments: hydroelectric segment, natural gas cogeneration segment, alternative fuel segment and infrastructure segment. See “*Description of the Business – The Developments*”.

The Fund may, where practical and economic, expand its current operations. All investment opportunities must meet established guidelines and are subject to review by the Trustees. Such facilities will only be acquired if the Fund believes that the acquisition will likely result in an increase in Distributable Cash per Trust Unit, otherwise meet the Fund’s acquisition guidelines and is in accordance with the Fund’s objectives, as set out in the Declaration of Trust. The Trustees believe that the stability and sustainability of cash flows to Unitholders may be enhanced through the diversification of the current asset portfolio. Opportunities providing long term, statistically predictable future cash flows whose risk profile is generally consistent with the existing portfolio of energy and infrastructure assets will be considered. See “*Acquisition Guidelines*”.

The management of the Manager has extensive experience and contacts in the independent power industry in Canada and the United States and is expected, but is not obligated, to continue presenting appropriate acquisition opportunities to the Fund. Under the terms of the recently revised management compensation structure implemented between the Manager and the Fund, the Manager will **not** be paid any acquisition or transaction related fees in respect of acquisitions by the Fund. See “*Governance, Management and Operations*”.

Acquisition Guidelines

After consultation with and approval by the Trustees of the Fund, who have established certain acquisition guidelines which may change depending on circumstances, the Manager uses an acquisition strategy which targets energy and/or infrastructure facilities and employs the following guidelines in the review and evaluation of possible acquisitions:

- (a) each facility, development or group of developments will only be acquired if the Fund believes that the acquisition will provide a forecast internal rate of return that is greater than 200 basis points above the yield of long-term (20 year) Government of Canada bonds over the expected life of the facility after deducting operating costs, general, administrative and management expenses and incorporating the impact of debt financing, but before income taxes;
- (b) each facility, development or group of developments will only be acquired if the Fund believes that the acquisition will likely result in an increase in Distributable Cash per Trust Unit;
- (c) facilities or a group of facilities for which no existing debt financing is in place will be preferred;
- (d) facilities where Power Systems or Newspring will become the operator will be preferred;

- (e) facilities in respect of which long term power purchase agreements with major electrical utilities exist or facilities within a regulated utility will be preferred and in other cases, commodity price forecasts and exchange rate assumptions used in acquisition evaluations will reflect market expectations;
- (f) the acquisition of each facility, or development, will be based on an independent engineering report confirming the condition of each facility or each of the facilities within the development or group, as applicable, and the technical assumptions utilized in the acquisition evaluation;
- (g) for each facility in which an interest with an indefinite term is being acquired, the expected useful life of such facility and associated structures will, with regular maintenance, overhauls and upkeep, be not less than 25 years; and
- (h) the acquisition of each facility, or development, will be reviewed and approved by the Trustees.

All acquisitions must be in accordance with the Declaration of Trust.

The Manager and the Operator

The Fund is managed by Algonquin Power Management Inc. Management of the Manager has extensive experience and contacts in the independent power industry in Canada and the United States and may, but is not obligated to, present appropriate acquisition opportunities to the Fund. The Manager is owned by the shareholders of Algonquin Power Corporation Inc. The Manager and its affiliates provide design, financing, construction, management, operation and maintenance of independent hydroelectric power facilities ranging in size from 130 to 18,000 kilowatts. The principals of the Manager together have over 50 years of experience in the industry.

Algonquin Power Systems Inc., an affiliate of Algonquin Power, provides operations-related services in respect of the facility interests indirectly owned by the Fund. In addition to operating the hydroelectric generating facilities in which the Fund has an interest, Power Systems is responsible for the operation of 200,000 kilowatts of generating capacity across Canada and the United States and is one of the largest operators of independent hydroelectric generating facilities in Canada. Power Systems supplies both direct operations services to the various facilities and operations supervisory services to Algonquin Canada and its related entities.

In addition to the principals of the Manager, the human resources of Power Systems, Newspring and various subsidiaries of the Fund of over 240 individuals is comprised of engineers, technicians, biologists, professional managers and administrative support staff, including a field team of trained plant operators and field supervisors. The head office of Power Systems, located in Oakville, Ontario, provides technical and management support, regulatory compliance and budget and accounting control for field personnel undertaking plant improvements and repairs. Field staff are organized into regional groups, each with its own trained supervisor. Most of the facilities are outfitted with remote computer controls and systems which allow the plants to be operated remotely in the field or by head office personnel. Power Systems also has data management systems to track the performance of the facilities, with a view to optimizing facility output. See *“Governance, Management and Operations”*.

Public Offerings Since January 1, 2000

On September 26, 2000, the Fund completed the sale of 3,000,000 Trust Units at an issue price of \$9.15 per Trust Unit pursuant to a prospectus-qualified offering. The Fund used the proceeds to pay off the revolving line of credit and to complete the acquisitions of the Milton Facility, the Mine Falls Facility and the Great Falls Facility.

On January 25, 2001 and February 15, 2001 the Fund completed the sale of 6,600,000 and 990,000 Trust Units respectively at an issue price of \$9.85 per Trust Unit pursuant to a prospectus-qualified offering. The Fund utilized approximately \$27.5 million of the net proceeds to complete the acquisition of an interest in the Campbellford Facility, the Kings Falls Facility, the Otter Creek Facility, the Worcester Facility, the Phoenix Facility, the Arthurville Facility and the Black Mountain Facility.

On July 3, 2001 and July 26, 2001, the Fund completed the sale of 6,500,000 and 975,000 Trust Units respectively at an issue price of \$10.05 per Trust Unit pursuant to a prospectus-qualified offering. The Fund utilized \$49.4 million to complete the acquisition of interests in the Dickson Dam Facility, the Drayton Valley Facility and the Gold Canyon Facility.

On October 18, 2001 and November 2, 2001 the Fund completed the sale of 7,750,000 and 1,040,300 Trust Units respectively at a price of \$9.70 per Trust Unit pursuant to a prospectus-qualified offering. The Fund utilized the proceeds to acquire share and debt interests in six generating facilities.

On March 15, 2002 and July 4, 2002 the Fund issued 6,099,557 Trust Units and 713,616 Trust Units, respectively, to Algonquin Power Trust to deliver to unitholders and debentureholders of KMS Power Income Fund to acquire all of the outstanding trust units and approximately 47.3% of the outstanding convertible debentures of KMS Power Income Fund.

On May 1, 2002, the Fund issued 248,667 Trust Units to Sanger Power LLC to deliver as part of the consideration for its purchase of the Sanger Facility.

On October 16, 2002, the Fund completed the sale of 9,950,000 Trust Units at a price of \$9.90 per Trust Unit pursuant to a prospectus-qualified offering. Of the net proceeds of the offering, the Fund utilized \$66.9 million to repay debt, \$18.0 million of the net proceeds to complete the acquisition of interests in the Tall Timbers, Woodmark and the Windsor Locks Facilities and the balance for general corporate purposes.

Acquisitions of Generating Facilities in Fiscal 2000

During 2000, the Fund indirectly acquired a 100% interest in three hydroelectric generating facilities from Algonquin Power for total consideration of approximately \$12,978,000.

The purchase price paid for each facility, the nature of the acquisition and the date of acquisition are set out in the table below:

<i>Facility</i>	<i>Purchase Price (in thousands)</i>	<i>Nature of Acquisition</i>	<i>Date of Acquisition</i>
Milton Facility	\$ 2,618	Shares and management agreement interests	July 11, 2000

Mine Falls Facility	4,905	Partnership interests	September 6, 2000
Great Falls Facility	5,455	Partnership interests	September 15, 2000
Total	<u>\$ 12,978</u>		

Acquisitions of Facilities in Fiscal 2001

During 2001, the Fund acquired two wastewater treatment facilities, six hydroelectric generating facilities, a note receivable and a 50% interest in a hydroelectric generating facility and 50% ownership of a biomass-fired generating facility for total consideration of approximately \$76,885,000.

The purchase price paid for the facilities, the nature of the acquisitions and the dates of acquisition are set out in the table below:

<i>Facility</i>	<i>Purchase Price (in thousands)</i>	<i>Nature of Acquisition</i>	<i>Date of Acquisition</i>
Phoenix, Kings Falls, Otter Creek and Worcester Facilities	\$ 11,614	Shares	March 21, 2001
Campbellford Facility	8,151	Partnership interest and note receivable	March 9, 2001 and April 1, 2001
St. Raphaël de Bellechasse Facility	905	Shares	April 11, 2001
Black Mountain Facility	6,782	Shares	March 16, 2001
Gold Canyon Facility	7,315	Shares	July 9, 2001
Dickson Dam Facility and 50% of Drayton Valley Facility	42,118	Trust units and partnership units	July 27, 2001
Total	<u>\$ 76,885</u>		

Acquisition of Notes Receivable and Other Interests in 2001

In May 2001, Algonquin Power Trust purchased the senior loan outstanding against the Côte Ste-Catherine Facility for a purchase price of \$21,998,000. The loan was provided by a syndicate comprised of the Clarica Life Insurance Company, The Standard Life Assurance Company and the Caisse de Dépôt et Placement du Québec. The loan has a term of 23.25 years commencing on October 31, 1994 and bears interest varying from 9.91% to 11.05% during the term, compounded monthly. This transaction resulted in the Fund eliminating all external debt on the facility. In addition to the purchase price, Algonquin Power Trust paid a prepayment fee of \$6,751,000 to the syndicate.

In September 2001, the Fund acquired certain notes receivable and equity in companies which own six generating facilities for a total of \$74,534,000. These facilities include a biomass-fired facility in each of Alberta, Québec and Nova Scotia and three natural gas-fired cogeneration facilities located in Ontario. Subsequent to the completion of this transaction, the owner of the biomass-fired facility located in Alberta, repaid the outstanding loan plus a prepayment penalty. The Fund has no further interest in such facility.

Other Developments in Fiscal 2001

In 2001, the Fund caused certain of its indirect subsidiaries to be wound up into other Fund entities and caused Algonquin Canada to amalgamate with certain other indirect subsidiaries of the Fund, so as to streamline the corporate structure of the Fund and reduce administrative expenses.

Acquisitions of Facilities in Fiscal 2002

During 2002, the Fund indirectly acquired a 100% interest in two cogeneration and one landfill gas-fuelled facility and three water distribution and wastewater reclamation facilities for total consideration of approximately \$ 185.6 million.

The purchase price paid for the facilities, the nature of the acquisitions and the dates of acquisition are set out in the table below:

<i>Facility</i>	<i>Purchase Price (in thousands)</i>	<i>Nature of Acquisition</i>	<i>Date of Acquisition</i>
Peel, Crossroads and Joliet Facilities	109,484	Trust units and convertible debentures of KMS Power Income Fund	March 15, 2002 and July 4, 2002
Sanger Facility	49,035	Assets	May 1, 2002
Bella Vista Facility	21,600	Shares	May 23, 2002
Tall Timbers Facility	3,419	Shares	November 5, 2002
Woodmark Facility	2,096	Shares	December 18, 2002
Total	<u>\$ 185,634</u>		

Other Developments in Fiscal 2002

The KMS Bakery cogeneration facility, located near Chicago, Illinois, was acquired in 2002 in connection with the acquisition by the Fund of KMS Power Income Fund. This facility was sold in August

2002, to Entenmann's Inc., the owner of the bakery supplied by the facility, for aggregate proceeds of \$920,000 (US\$588,000)

In September 2002, the Fund paid \$1,311,000 (US\$862,000) in cash in connection with the acquisition of Gold Canyon which was acquired in the third quarter of 2001. This additional contingent consideration was required as a rate case which was in progress at the time that the acquisition was completed.

In October 2002, as approved by the Unitholders by Extraordinary Resolution at the annual and special meeting of Unitholders held on May 23, 2002, the Fund completed a reorganization (the "**Reorganization**") under which Algonquin Canada and Algonquin America issued special voting shares (the '**Special Shares**') to the Manager. The effect of the issuance of the Special Shares and the Governance Agreement is to confer on the Manager as the holder thereof the right to elect two of the three directors of Algonquin Canada and all of the directors of Algonquin America. Pursuant to the Governance Agreement, two of the three directors of Algonquin Canada were and continue to be nominees of the Manager. In addition, all of the directors of Algonquin America have been, since its incorporation, principals of the Manager. The Special Shares do not confer any material economic benefit on the Manager, as they are not entitled to receive dividends or other distributions of the assets of Algonquin Canada or Algonquin America, as the case may be. The Special Shares only carry the right to vote with respect to the election of directors and are not transferable by the Manager except to a successor manager of the Fund. The terms and conditions of the Special Shares include a right of Algonquin Canada and Algonquin America, as applicable, and the Fund has directly received a right, in the event of the termination or expiry of the Management Agreement, to purchase the Special Shares for their issue price.

At the annual and special meeting of Unitholders to be held on June 26, 2003, Unitholders will be asked to approve a reorganization substantially the same as the Reorganization with respect to KMS Peel and KMS America. Upon completion of such reorganization, the Manager will be entitled to elect two of the three directors of KMS Peel and all of the directors of KMS America. The Fund intends to complete such reorganization, subject to Unitholder approval, in fiscal 2003.

Acquisitions of Facilities in 2003

In February 2003, the Fund acquired the Litchfield Facility, located outside of Phoenix, Arizona, for \$34.9 million (U.S.\$23.4 million). The facility currently services approximately 18,000 water reclamation and distribution customers.

In March 2003, the Fund acquired the Windsor Locks Facility for \$43.2 million (U.S. \$29.5 million). The facility produces electricity sold to Connecticut Light and Power Company pursuant to a long-term power purchase agreement ending in 2010. In addition, the facility delivers steam energy and a small portion of the electricity produced to a specialty fiber composites mill located adjacent to the facility.

Other Developments in 2003

In February 2003, the Fund announced that it had entered into an agreement to purchase a 40% partnership interest in an 80 MW biomass-fired electric generating facility located in Virginia. Under the terms of the purchase and sale agreement the Fund cannot disclose the details of the transaction prior to closing. Closing of the acquisition of the partnership interest is subject to, among other things, obtaining

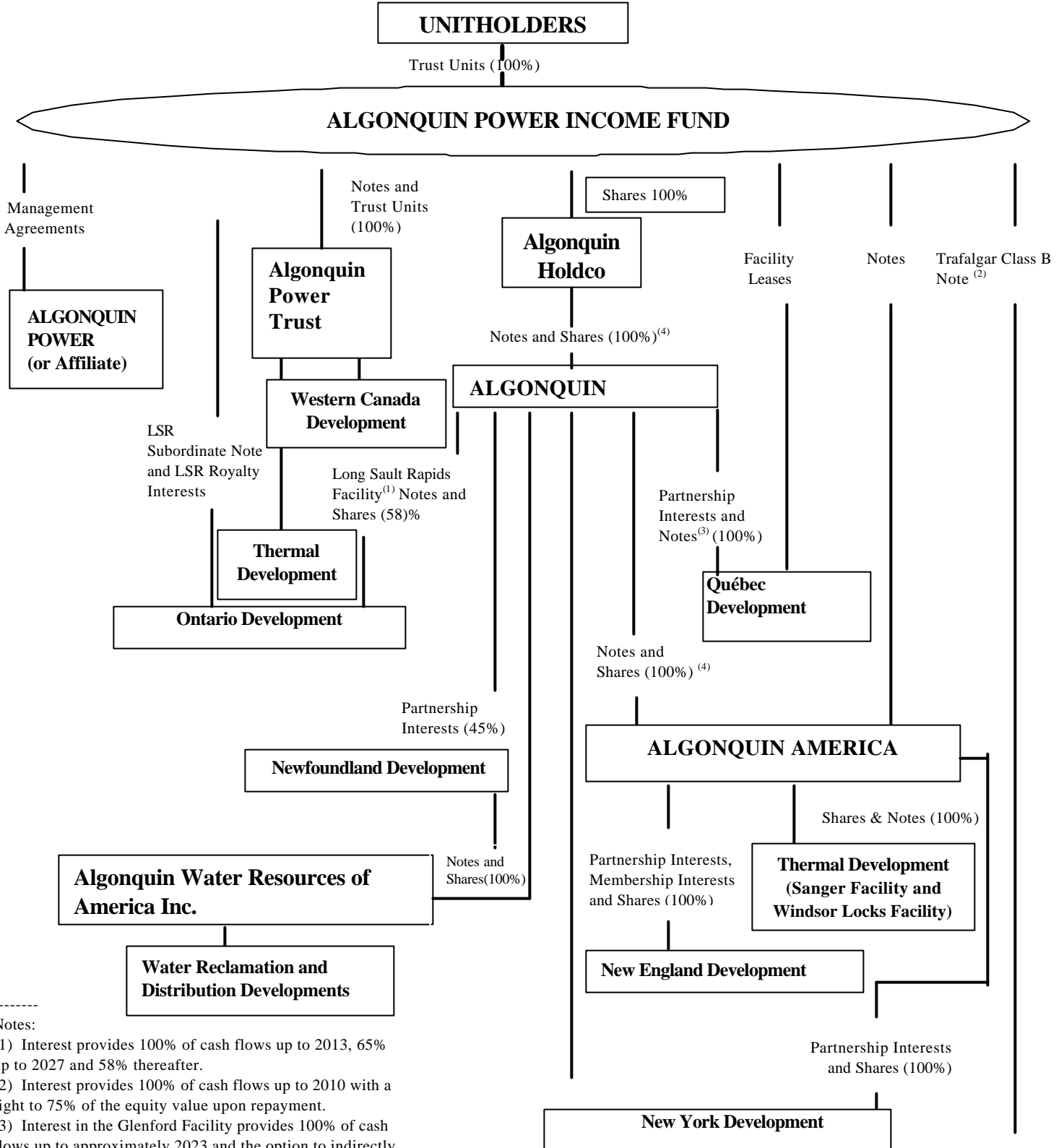
certain required transfer approvals.

In February 2003, the Fund renegotiated with the Public Service Company of New Hampshire (“PSNH”) the pricing terms of the power purchase agreements associated with 13 small hydroelectric generating facilities in New Hampshire in which the Fund has an interest. Subject to certain approvals and adjustments, as consideration for a reduction in the above-market rates stipulated in these power purchase agreements, the Fund is expected to receive approximately \$30.6 million (US\$20.4 million). After completion of these transactions, PSNH will continue to purchase the energy produced by these generating stations at the New England power pool market price.

DESCRIPTION OF THE BUSINESS

Structure of the Fund

Diagram



Notes:

- (1) Interest provides 100% of cash flows up to 2013, 65% up to 2027 and 58% thereafter.
- (2) Interest provides 100% of cash flows up to 2010 with a right to 75% of the equity value upon repayment.
- (3) Interest in the Glenford Facility provides 100% of cash flows up to approximately 2023 and the option to indirectly acquire the facility.
- (4) Subject to Manager's Interest.

THE DEVELOPMENTS

The Fund owns, directly or indirectly, debt, equity and royalty and other interests in 58 power generation facilities and six regulated water distribution and reclamation facilities.

Power Development

Generating Facility	Generating Capacity (kilowatts)	Location	2003 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Ontario Development						
Long Sault Rapids Facility (Hydroelectric)	18,000	Abitibi River near Cochrane, Ontario	Summer Energy \$0.0370/kW-hr Summer Capacity \$0.0572/kW-hr Winter Energy \$0.0455/kW-hr Winter Capacity \$0.0755/kW-hr	113,943	2047	2001 ⁽²⁾
Hurdman Dam Facility (Hydroelectric)	570	Mattawa River near Mattawa, Ontario	Winter Peak \$0.0896 /kW-hr Winter Off-Peak \$0.0354 /kW-hr Summer Peak \$0.0831 kW-hr Summer Off-Peak \$0.0254 /kW-hr	4,429	2005	2004
Drag Lake Dam Facility (Hydroelectric)	225	Trent River near Haliburton, Ontario	Winter Peak \$0.0934 /kW-hr Winter Off-Peak \$0.038 /kW-hr Summer Peak \$0.0757 /kW-hr Summer Off-Peak \$0.0338 /kW-hr	1,219	2012	Owned
Burgess Dam Facility (Hydroelectric)	130	Muskoka River near Bala, Ontario	Winter Peak \$0.0809 /kW-hr Winter Off-Peak \$0.0319 /kW-hr Summer Peak \$0.0752 /kW-hr Summer Off-Peak \$0.0228 kW-hr	932	2009	1998 ⁽³⁾
Campbellford Facility (Hydroelectric)	4,000	Trent River near Campbellford, Ontario	Winter On-Peak \$0.0961/kW-hr Winter Off-Peak \$0.0373/kW-hr Summer On-Peak \$0.0797/kW-hr Summer Off-Peak \$0.0326/kW-hr	27,834	2019	2019
Québec Development						
Saint-Alban Facility (Hydroelectric)	8,200	Ste-Anne River near the Village of Saint-Alban, Québec	\$0.06006/kW-hr (Jan-Nov) \$0.06186/kW-hr (Dec)	37,260	2016	1998 ⁽⁶⁾
Glenford Facility (Hydroelectric)	4,950	Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec	\$0.06006/kW-hr (Jan-Nov) \$0.06186/kW-hr (Dec)	24,593	2020	Owned

Generating Facility	Generating Capacity (kilowatts)	Location	2003 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Rawdon Facility (Hydroelectric)	2,500	Ouareau River near the Village of Rawdon, Québec	\$0.06006/kW-hr (Jan-Nov) \$0.06186/kW-hr (Dec)	13,900	2014	2014
Côte Ste-Catherine Facility (Hydroelectric)	11,120	St. Lawrence River near the Town of Ste.-Catherine, Québec	Phase I Energy \$0.04924/kW-hr Phase II Energy \$0.05124/kW-hr Capacity \$125.77/kilowatt (over the average kilowatt output over the period December to March) Phase III Energy \$0.05335/kW-hr Capacity \$131.87/kilowatt (over the average kilowatt output over the period December to March)	Phase I: 16,616 Phase II: 37,625 Phase III: 37,247	Phase I: 2009 Phase II: 2018 Phase III: 2021	2009
Ste-Raphaël Facility (Hydroelectric)	3,500	Rivière de Sud near Québec City, Québec	\$0.06006/kW-hr (Jan-Nov) \$0.06186/kW-hr (Dec)	25,035	2014	2013
Mont Laurier Facility (Hydroelectric)	2,725	Rivière-du-Lièvre in the Town of Mont Laurier, Québec	\$0.06006/kW-hr (Jan-Nov) \$0.06186/kW-hr (Dec)	20,824	2007	2023
Rivière-du-Loup Facility (Hydroelectric)	2,600	Rivière-du-Loup near the Town of Rivière-du-Loup, Québec	\$0.06006/kW-hr (Jan-Nov) \$0.06186/kW-hr (Dec)	16,059	2015	2015
Hydraska Facility (Hydroelectric)	2,250	Yamaska River near the Town of St.-Hyacinthe, Québec	Summer Energy \$0.0505/kW-hr Winter Energy \$0.09262/kW-hr	9,910	2014	2014
Ste-Brigitte Facility (Hydroelectric)	4,200	Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec	\$0.06006/kW-hr (Jan-Nov) \$0.06186/kW-hr (Dec)	12,367	2014	Owned
Belleterre Facility (Hydroelectric)	2,200	Winneway River in the Municipality of Laforce, Québec	Summer Energy: \$0.04262/kwh Winter Energy: \$0.09268/kwh Capacity: \$123.74/kilowatt (over the average kilowatt output over the period December to March)	14,743	2013	2011
Donnacona Facility (Hydroelectric)	4,800	Jacques Cartier River near Donnacona, Québec	\$0.06006/kW-hr (Jan-Nov) \$0.06186/kW-hr (Dec)	20,970	2022	2017
St. Raphaël de Bellechasse Facility (Hydroelectric)	650	Rivière du Sud downstream from Ste-Raphaël	\$0.06006/kW-hr (Jan-Nov) \$0.06186/kW-hr (Dec)	2,782	2013	Owned
Newfoundland Development						

Generating Facility	Generating Capacity (kilowatts)	Location	2003 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Rattle Brook Facility (Hydroelectric)	4,000	Rattle Brook near Jackson's Arm, Newfoundland	Summer Energy \$0.04262/kwh Summer Capacity \$0.02237/kwh Winter Energy \$0.04262/kwh Winter Capacity \$0.04782/kwh	17,470	2024	2048
New York Development						
Ogdensburg Facility, Hydroelectric)	3,675	Oswegatchie River near Ogdensburg, New York	US\$0.03 /kW-hr (est)	10,596	2007	2038
Forestport Facility, Hydroelectric)	3,300	Black River near Boonville, New York	US\$0.029 /kW-hr (est)	10,016	2007	Owned
Herkimer Facility, Hydroelectric)	1,680	West Canada Creek near Herkimer, New York	US\$0.031 /kW-hr	4,363	2007	Owned
Hollow Dam Facility, Hydroelectric)	900	Oswegatchie River near Gouverneur, New York	US\$0.03 /kW-hr (est)	4,400	2000 ⁽⁵⁾	2026
Christine Falls Facility, Hydroelectric)	850	Sacandaga River near Clifton, New York	US\$0.2473 /kW-hr (est)	3,065	2028	Owned
Burt Dam Facility, Hydroelectric)	600	18 Mile Creek near Newfane, New York	US\$0.03 /kW-hr (est)	2,300	2000 ⁽⁵⁾	2036
Cranberry Lake	500	Oswegatchie River near Clifton, New York	US\$0.03 /kW-hr (est)	2,154	2025	2035
Kayuta Lake Facility, Hydroelectric)	400	Black River near Boonville, New York	US\$0.0929/kW-hr (Jan-Sep) US\$ 0.025/kw-hr (Oct-Dec)	2,089	2028	Owned
Adams Facility, Hydroelectric)	350	Sandy Creek near Adams, New York	US\$ 0.0967/kw-hr (Jan-Mar, Oct- Dec) US\$ 0.025/kw-hr (Apr-Sep)	648	2028	Owned
Kings Falls Facility, Hydroelectric)	1,750	Deer River near Copenhagen, New York	US\$ 0.03775/kw-hr Flat Rate	3,680	2003	Owned
Otter Creek Facility, Hydroelectric)	530	Otter Creek in Craig, New York	US\$ 0.03/kw-hr Flat Rate	1,944	2003	Owned
Phoenix Facility, Hydroelectric)	3,500	Oswego River in Phoenix, New York	US\$ 0.09205/kw-hr Flat Rate	11,760	2026	Owned
New England Development						
Gregg Falls Facility, Hydroelectric)	3,500	Piscataquog River near the Town of Goffstown, New Hampshire	Energy Block 1 US\$0.1362/kW-hr Block 2 US\$0.1195/kW-hr Block 3 US\$0.1028/kW-hr Block 4 US\$0.0848/kW-hr Block 5 US\$0.0681/kW-hr Energy: US\$ 0.040/kw-hr (est) (8)	10,083	2020 (8)	2031

Generating Facility	Generating Capacity (kilowatts)	Location	2003 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Pembroke Facility, Hydroelectric)	2,600	Suncook River near the Town of Pembroke, New Hampshire	Energy Block 1 US\$0.1362/kW-hr Block 2 US\$0.1195/kW-hr Block 3 US\$0.1028/kW-hr Block 4 US\$0.0848/kW-hr Block 5 US\$0.0681/kW-hr Energy: US\$ 0.040/kw-hr (est) (8)	8,272	2020 (8)	Owned
Clement Facility, Hydroelectric)	2,400	Winnipisauhee River near the Town of Tilton, New Hampshire	US\$0.09000/kW-hr Energy: US\$ 0.040/kw-hr (est) (8)	11,288	2004 (8)	2032
Franklin Facility, Hydroelectric)	River Bend 1,600 Steven's Mill 200	Winnepesaukee River near the Town of Franklin, New Hampshire	On Peak US\$0.1282/kW-hr Off Peak US\$0.9690/KW-hr Capacity US\$90.34/ Average kW Energy US\$0.11040/kW-hr Capacity US\$90.34/ Average kW Energy: US\$ 0.040/kw-hr (est) (8)	River Bend 7,550 Steven's Mill 1,020	2006 (8)	Owned
Moretown Facility, Hydroelectric)	1,200	Mad River near Moretown, Vermont	Winter On-Peak US\$0.1078/kW-hr Winter Off-Peak US\$0.0682/kW-hr Summer On-Peak US\$0.0978/kW-hr Summer Off-Peak US\$0.0539/kW-hr Capacity Adder US\$0.0243/kW-hr	2,778	2018	Owned
Lochmere Facility, Hydroelectric)	1,200	Winnepesaukee River near Lochmere, New Hampshire	US\$0.09/kW-hr Energy: US\$ 0.040/kw-hr (est) (8)	4,083	2006 (8)	2033
Lower Robertson Facility, Hydroelectric)	960	Ashuelot River near Hinsdale, New Hampshire	On-Peak US\$0.1678/kW-hr Off-Peak US\$0.1248/kW-hr Capacity US\$106.58/Average kW Energy: US\$ 0.040/kw-hr (est) (8)	3,729	2015 (8)	Owned
Ashuelot Facility, Hydroelectric)	900	Ashuelot River near Hinsdale, New Hampshire	On-Peak US\$0.1678/kW-hr Off-Peak US\$0.1248/kW-hr Capacity US\$106.58/Average kW Energy: US\$ 0.040/kw-hr (est) (8)	3,629	2015 (8)	2040
Lakeport Facility, Hydroelectric)	600	Winnepesaukee River near Laconia, New Hampshire	On-Peak US\$0.1283/kW-hr Off-Peak US\$0.0970/kW-hr Capacity US\$90.35 /Average kW Energy: US\$ 0.040/kw-hr (est) (8)	2,650	2005 (8)	2032

Generating Facility	Generating Capacity (kilowatts)	Location	2003 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Avery Facility, Hydroelectric)	260	Winnepesaukee River near Laconia, New Hampshire	On-Peak US\$0.1678/kW-hr Off-Peak US\$0.1248/kW-hr Capacity US\$106.58/Average kW Energy: US\$ 0.040/kw-hr (est) (8)	1,834	2015 (8)	2035
Hadley Falls Facility, Hydroelectric)	250	Piscataquog River near Goffstown, New Hampshire	On-Peak US\$0.1035/kW-hr Off-Peak US\$0.0761/kW-hr Capacity US\$96.40/Average kW Energy: US\$ 0.040/kw-hr (est) (8)	1,007	2006 (8)	2016
Hopkinton Facility, Hydroelectric)	250	Contoocook River near Hopkinton, New Hampshire	US\$0.0900/kW-hr Energy: US\$ 0.040/kw-hr (est) (8)	920	2006 (8)	2023
Milton Facility, Hydroelectric)	1,335	Salmon River near the Town of Milton, New Hampshire	US\$0.0771 / kW-hr Energy: US\$ 0.040/kw-hr (est) (8)	6,166	2012 (8)	Owned
Mine Falls Facility, Hydroelectric)	3,000	Nashua River near the City of Nashua, New Hampshire	US \$ 0.0900 / kW-hr Energy: US\$ 0.040/kw-hr (est) (8)	10,717	2005 (8)	2024
Great Falls Facility, Hydroelectric)	10,950	Passaic River near the City of Paterson, New Jersey	US \$ 0.03 / kW-hr (est)	19,322	2002	2021
Worcester Facility, Hydroelectric)	180	Winooskie River in Worcester, Vermont	Winter On-Peak US\$0.1573/kW-hr Winter Off-Peak US\$0.0864/kW-hr Summer On-Peak US\$0.0844/kW-hr Summer Off-Peak US\$0.0386 / kW-hr Capacity Adder US\$0.0192 / kW-hr	438	2016	Owned
Western Canada Development						
Drayton Valley (Biomass)	12,000	Drayton Valley, Alberta	Energy: \$0.0655/kW-hr	87,600	2014	Owned
Dickson Dam (Hydroelectric)	15,000	Innisfail, Alberta	Energy: \$0.0619/kW-hr	67,248	2012	2030
Thermal Development						
Joliet Facility (Landfill Gas)	3,200	Joliet, Illinois	Municipal Average Rate US\$0.0668/kW-hr	12,633	Perpetual Renewals	2007
Crossroads Facility (Cogeneration)	10,000	Mahwah, New Jersey	Energy Rate Fixed US\$0.09362/kW-hr + a variable rate Onpeak - US\$0.0995/kW-hr Midpeak - US\$0.077/ kW-hr Offpeak – US\$0.0270/kW-hr	OR 34,012 CDA 17,609	2008 – 2017 – Industrial	2016

Generating Facility	Generating Capacity (kilowatts)	Location	2003 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Peel Facility (Energy from Waste)	10,100	Brampton, Ontario	Winter Peak - \$0.0969/kW-hr Winter Offpeak - \$0.0373/kW-hr Summer Peak - \$0.0823/kW-hr Summer Offpeak - \$0.0326/kW-hr All rates subject to CPI Increases	54,511	2012	Owned
Sanger Facility (Cogeneration)	43,500	Sanger, California	\$0.0537/ kW-hr Capacity Payment- \$190 per kW/year	109,512	2021	Owned
Windsor Locks Facility (Cogeneration)	56,000	Windsor Locks, Connecticut	Utility – Peak - US\$0.0218 Off peak – US\$0.0058 Variable - US\$0.0222 x Gas Index Industrial – Electrical Capacity -US\$52,938 + US\$107,480xCPI per month - Energy - US\$33.83 / MWr Steam -US\$33,138+ US\$67280 x CPI +US\$5.05 /000 lbs x fuel index	353,700	2010	2018

Water Reclamation and Distribution Developments

Utility	Location	Type of Utility	Current Connections	Rates
Black Mountain Sewer Company	Carefree, Arizona	Water Reclamation	1,752	US\$38.00/ month
Gold Canyon Sewer Company	Gold Canyon Arizona	Water Reclamation	4,190	US\$35.00/Month
Bella Vista Water Company	Sierra Vista, Airzona	Water Distribution	7,204	US\$2.88/Avg. Rate Per 1000 gallons
Tall Timbers Utility Company	Tyler, Texas	Water Reclamation	939	US\$40.08/Month
Woodmark Utility Company	Tyler, Texas	Water Reclamation	682	US\$32.60/Month
Litchfield Park Services Company	Litchfield, Park, Arizona	Water Reclamation Water Distribution	9,883 10,165	US\$2.00/Avg Rate per 1000 gallons US\$32.36/Month

Notes:

- (1) 2002 power purchase rates have been rounded to four decimals and are not representative of long term power purchase rates under the applicable power purchase agreements. Long term rates under different agreements will be both higher and lower than current rates. Seasonal periods and daily periods vary from project to project.

- (2) Interim lease to be replaced by a long term lease of 50 years less a day.
- (3) Lease has been extended on a month-to-month basis during negotiations for the renewal of the lease. Long term lease to be entered into will be for twenty years.
- (4) These rates changed to the Avoided Costs of Niagara Mohawk effective January 1, 2001.
- (5) Agreement has been extended on a month-to-month basis during negotiations for the renewal of the agreement.
- (6) A long term lease is currently being finalized.
- (7) The Fund also has notes receivable and equity in companies which own five generating facilities. See "*Other Interest in Energy-Related Developments*".
- (8) The Fund has renegotiated with the Public Service Company of New Hampshire ("PSNH") the pricing terms of the power purchase agreements, subject to certain approvals and adjustments. After completion of these transactions, PSNH will continue to purchase the energy produced by these generating stations at the New England power pool market price.

Ontario Development - Long Sault Rapids, Hurdman Dam, Drag Lake Dam, Burgess Dam and Campbellford Facilities

Long Sault Rapids Facility

The Long Sault Rapids Facility is an 18,000 kilowatt hydroelectric generating facility located on the Abitibi River, 19 kilometers north of the Town of Cochrane, in northern Ontario. The facility was commissioned on April 1, 1998.

The facility was developed by a joint venture between Algonquin Power (Long Sault) Partnership and N-R Power Partnership. The facility is owned by the Co-Owners as tenants-in-common and not as joint tenants, with the Co-Owners each having an undivided 50% interest in the facility. The partners in the Algonquin Power (Long Sault) Partnership, Algonquin Power (Long Sault) Corporation Inc. and Energy Acquisition (Long Sault) Ltd., are wholly-owned subsidiaries of Algonquin Power. The partners in the N-R Power Partnership are Nicholls Holdings Inc. and Radtke Holdings Inc., companies controlled by two independent businessmen. There are two non-recourse loans outstanding which are secured against the facility and the Co-Owners' interest therein (see "Credit Agreements" below).

The facility includes a 125 meter long rock filled dam that crosses the Abitibi River. The dam has created a narrow headpond approximately ten kilometres in length. The facility is a run-of-the-river facility and the headpond will not be utilized for storage and peaking purposes. The powerhouse is an integrated structure, housing four pit turbine generating units each rated at 4,500 kilowatts of generating capacity which were manufactured by Sulzer Canada Inc.

Electricity produced by the facility is sold directly to OEFC for distribution to its customers by means of a 23.5 kilometre 115 kV transmission line, which crosses both private property and provincially owned land pursuant to easements, rights of way and land use permits. Rights to all necessary lands have been obtained in order to construct, operate and maintain the transmission line.

Power Purchase Agreement

Pursuant to the terms of the power purchase agreement, the Co-Owners sell power produced by the facility exclusively to OEFC and OEFC purchases all power delivered at the delivery point, approximately 23.5 kilometres from the facility site. The power purchase agreement terminates 50 years from the commercial in-service date, April 1, 1998, and may be renewed for a further term upon request by either party on terms and conditions to be mutually agreed. OEFC has the option to terminate the

agreement upon 60 days' written notice if the Co-Owners fail to deliver power to OEFC for 24 consecutive months and, in OEFC's opinion, the Co-Owners are not taking appropriate steps to remedy the situation. In addition, OEFC has the right to discontinue the receipt of power, by written notice, should the Co-Owners fail to perform any obligation under the agreement or under an operations agreement between OEFC and the Co-Owners outlining operating procedures for the facility, until the obligation is fulfilled.

The agreement provides that the payment made by OEFC for power produced by the facility is calculated as the sum of the monthly capacity payment and the monthly energy payment. The monthly capacity payment is calculated as the product of the number of On-peak hours for the month and the sum of the applicable energy and capacity rates. The monthly energy payment is the product of Off-peak hours and the applicable energy rate. The rates are escalated annually based on an index figure tied to the greater of OEFC's all customer rate or direct customer rate. The agreement provides that the rates will not decrease based on this index.

The Co-Owners will not receive a monthly capacity payment unless the facility delivers an average of at least 1,800 kilowatts of power to OEFC during at least 85% or more of the On-peak period fifteen minute intervals for that month. The monthly payment from OEFC will not include an amount for any monthly capacity power delivered in excess of target generation specified in the agreement and will not include an amount for any monthly energy in excess of 115% of target generation specified in the agreement.

Waterpower Lease

The Co-Owners have entered into a Crown Lease with the Province of Ontario in respect of the dam site for a term expiring on June 30, 2003. The Crown Lease provides that the parties will enter into a long-term waterpower lease upon certain matters being completed, including approval of the long-term lease by the Lieutenant Governor in Council. The long-term lease will be for a term of 50 years, comprised of an initial term of 30 years, a 10-year extension on the same terms and conditions and an additional 10-year extension on the terms and conditions to be approved by the Province. The long-term waterpower lease will provide for an annual land rental and an annual water rental charge. The water rental charge will not commence until 10 years after the long-term lease comes into effect.

Partnership Agreements

There are partnership agreements governing the affairs of both Co-Owners. The provisions of each partnership agreement are virtually identical. The partnerships were formed for the purpose of carrying on the business of financing, holding and operating undivided interests in the facility.

Co-Owners Agreement and Management Agreement

The Co-Owners have entered into an agreement concerning, among other things, their holding of undivided interests in the facility. Upon the occurrence of specified events of default, the non-defaulting Co-Owner may purchase the defaulting Co-Owner's interest for 90% of fair market value. The Co-Owners have entered into a management agreement with NR-Algonquin Energy Management Inc. to manage the facility on their behalf for nominal consideration.

Credit Agreements

There is an outstanding senior loan against the facility in the amount of \$44,071,000 at December 31, 2002. The loan was provided by a syndicate comprised of The Clarica Life Insurance Company ("Clarica"), The Canada Life Assurance Company and The Maritime Life Assurance Company. Clarica acts as agent for the syndicate. The loan has a term of 30 years commencing upon completion of construction and conversion of the loan to long-term financing (which conversion occurred effective January 31, 1999) and an identical amortization period with an interest rate of 10.16% for the first 15 years and 10.21% thereafter, compounded annually. Blended payments of principal and interest are made monthly. The loan is non-recourse and is secured by the facility and the ownership interests therein.

The credit agreement contains certain events of default, including: (i) the sale of assets and property covered by the lenders' security without the lenders' consent; (ii) certain changes in ownership; (iii) any amendment, waiver, termination, renewal or extension or breach continuing for 30 days after written notice of any of the material facility agreements, without the prior written consent of a majority of the lenders; or (iv) if there is a change in the manager or operator from Power Systems.

Under the terms of the credit agreement, a debt reserve is required. At December 31, 2002, the debt reserve was fully funded and contained a balance of \$1.4 million.

The LSR Subordinate Note is also an outstanding loan against the facility which the Fund currently owns.

Hurdman Dam, Drag Lake Dam and Burgess Dam Facilities

The Drag Lake Dam facility, with a generating capacity of 225 kilowatts is located on the Trent River at the Drag Lake Dam, in Haliburton, Ontario. The Burgess Dam facility, with a generating capacity of 130 kilowatts, is located at the outlet of Lake Muskoka River at Moon River, in Bala, Ontario.

The Hurdman Dam facility, with a generating capacity of 570 kilowatts, is located on the Mattawa River, two kilometres upstream from the Town of Mattawa, Ontario. These three facilities are owned by Algonquin Canada.

Power Purchase Agreements

Pursuant to the terms of the power purchase agreements, each facility will sell all power produced at such facility exclusively to OEFC and OEFC agrees to purchase all such power. The initial term of the agreement for the Hurdman Dam facility is 20 years commencing January 1, 1985, for the Drag Lake Dam facility is 20 years from the commencement of commercial operations, which occurred on March 9, 1992 and for the Burgess Dam facility is 20 years from the commencement of commercial operations, which occurred on August 14, 1989.

The agreements contain typical non-utility generator obligations to OEFC. There are no minimum contractual delivery quantities. The power purchase rates applicable to the facilities are currently based on On-peak versus Off-peak hours and summer (April 1 to September 30) versus winter.

Land and Water Rights

For the Hurdman Dam facility, a waterpower renewal lease agreement was entered into with the Province of Ontario in respect of the facility site dated January 1, 1994. The agreement provides for both waterpower and land usage rights. The term of the agreement is for 10 years, with a right to three further 10 year renewal terms upon the request of the lessee. The annual rent is: (i) an amount determined in accordance with a formula based on energy produced multiplied by the increase in the consumer price index; (ii) \$15,000; and (iii) 9% of gross revenues generated by the facility. The Province may terminate the lease if amounts owing under the lease remain unpaid for 90 days or if taxes or other assessments remain unpaid. Upon expiry or termination of the lease, improvements on the site become the property of the Province upon payment of the value of such improvements. Water levels must be maintained as specified in the lease. The lease is subject to termination if the power purchase agreement with OEFC is terminated.

With respect to the Drag Lake Dam facility, the land on which the powerhouse and penstock are located is owned by Algonquin Canada. The dam site is licenced from the Trent-Severn Waterway.

The Burgess Dam facility has a lease for the facility site with The Corporation of the Township of Muskoka Lakes (the "Township") that commenced on May 1, 1988 for an initial term of ten years. The lease has four 10 year renewal terms on terms to be mutually agreed. The lease expired on April 30, 1998 and the Manager is currently negotiating a renewal with the Township. The Township has agreed to extend the lease on a month-to-month basis during the negotiations. The lease may be terminated for non-payment of rent, failure to maintain the site, vacancy for 20 or more days or other breaches on the part of the lessee, upon notice and after an opportunity to cure has expired. The lease includes the water rights owned by the Township and under the direction of the Ontario Ministry of Natural Resources.

Rights to all necessary lands have been obtained in order to operate and maintain the transmission lines for the facilities.

Campbellford Facility

The Campbellford Facility is a 4,000 kilowatt hydroelectric generating facility located at Lock No. 14 on the Trent-Severn Waterway approximately four kilometers north of Campbellford, Ontario. This facility was an expansion project by the Town of Campbellford and Algonquin Power to the existing 2,100 kilowatt generating station owned by the town. The expansion was completed in late 1993 and commissioned in January 1994.

The facility is a run-of-the-river facility that consists of a shared 240 meter power canal leading to a concrete powerhouse housing two S-Kaplan double regulated turbines.

Land and Water Rights

The Town of Campbellford has a lease from the Government of Canada which gives the municipality the rights to all the available water in excess of that required for navigation at Lock No. 14 on the Trent-Severn Waterway. In addition to the water, the Town of Campbellford also has a lease for the land adjacent to Lock No.14 where the Campbellford Facility was developed.

In 1991, the Town of Campbellford entered into an arrangement with an Algonquin Power entity to develop the under-utilized water resources at the Lock No.14 site on the Trent-Severn Waterway. The Town of Campbellford subleased the necessary lands and water rights to the Algonquin Power entity to allow it to build the Campbellford Facility. The arrangement is for 25 years from the commencement of the agreement, being March 8, 1994. At the conclusion of the term, the plant and equipment will be turned over to the Town of Campbellford.

On November 15, 1994, the Campbellford Facility was granted by Environment Canada – Parks Services, under the Dominion Water Act, a licence to operate a low head hydro power facility at Lock No. 14 on the Trent River. The term of the approval is 30 years, commencing July 1, 1994 and ending June 30, 2024.

Power Purchase Agreement

The agreement has a term of 25 years commencing March 10, 1994. The specified settlement rates set out in the agreement will be paid to the producer.

Québec Development — Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup, Hydraska, Ste-Brigitte, Belleterre, Donnacona, and Arthurville Facilities.

Saint-Alban Facility

The facility is an 8200 kilowatt hydroelectric generating facility located on the Ste-Anne River approximately one kilometre from the Village of Saint-Alban, Québec and approximately 200 kilometres east of Montréal. The facility is located at the site of a decommissioned hydroelectric generating facility previously owned by Hydro-Québec. The facility consists of a newly gated spillway and the existing dam and spillway, which were rehabilitated and reconditioned in 1996, two penstocks, a powerhouse structure and a tailrace canal and has been designed as a run-of-the-river facility.

Land and Water Rights

The land upon which the facility is located is currently owned by the Government of Québec, although certain hydraulic rights are owned by Shawinigan Electric Company, a wholly-owned subsidiary of Hydro-Québec. The Government of Québec is in the process of acquiring all outstanding hydraulic rights from Shawinigan Electric Company. Once this process is complete, it is anticipated that the Government of Québec will enter into a final 20 year lease agreement with SLI from the Facility's commissioning date in 1996. SLI is presently negotiating the terms of the final lease agreement with the Government of Québec. The facility operates under an Order-in-Council of the Government of Québec.

In addition to contractual lease payments and other amounts payable to the Government of Québec, an agreement exists for the payment of an annual royalty of approximately \$11,500 in 2002 (increasing by \$500 per year) including electricity use reimbursement to a maximum of \$500 per year in respect of the Saint-Alban municipal park.

Approval from the Government of Québec to the transfer of the leasehold interests from SLI to Algonquin Canada has been sought and should be obtained following signature of the final lease agreement.

Acquisition of legal title to this facility interest will be completed following the Saint-Alban Transfer Date.

Glenford Facility

The facility is a 4950 kilowatt hydroelectric generating facility located on the Ste-Anne River approximately one kilometre from the Village of Ste-Christine d'Auvergne, Québec and approximately 230 kilometres east of Montréal. The facility is located at the site of a decommissioned hydroelectric generating facility previously owned by Hydro-Québec. The facility consists of the existing dam and spillway, which were rehabilitated and reconditioned in 1995, an intake, powerhouse and tailrace structure and has been designed as a run-of-the-river facility.

Land and Water Rights

The Glenford Facility has been constructed on certain lands purchased by the Glenford Partnership and which lands include the existing structures associated with the historic generating facility. In addition, certain easements were granted to the former owner in respect of flooding rights and the access road. The land owned by the Glenford Partnership includes the bed of the river upon which the existing dam structure is located and certain lands on either side of the river. Accordingly, no lease from the Province of Québec is required.

Credit Agreement

The Glenford Senior Debt is an outstanding senior loan provided to the Glenford Partnership in the amount of \$5.7 million at December 31, 2002. The loan was provided by Corpfinance International Limited and has a term of 25 years which commenced in April 1995. The loan is to be repaid in equal monthly payments of \$63,591 representing blended interest and principal during its term. The loan is secured solely by the facility and the ownership interests therein.

The credit agreement contains certain events of default, including: (i) the sale of assets and property covered by the lender's security without the lender's consent; (ii) certain changes in ownership; (iii) any amendment, waiver, termination, renewal or extension or breach continuing for 15 days after written notice of any of the material facility agreements, without the prior written consent of the lender; or (iv) if there is a change in the manager or operator from Power Systems.

A hydrology reserve fund with a balance as at December 31, 2002 of \$137,186 has been established to provide additional security in respect of the payment of interest and principal on the Glenford Senior Debt. Under the terms of the credit agreement, such reserve is required to be increased at the rate of 9% on an annual basis. A maintenance reserve fund with a balance as at December 31, 2002 of \$166,450 has been established in respect of major capital expenditures which may be incurred by the Glenford Partnership.

Rawdon Facility

The facility is a 2500 kilowatt hydroelectric generating facility located on the Ouareau River approximately one kilometre from the Village of Rawdon, Québec and approximately 70 kilometres north of Montréal. The facility consists of an existing dam (which was rehabilitated and reconditioned in 1986 by

Hydro-Québec), intake, spillway, penstock, powerhouse and tailrace structure and has been designed as a run-of-the-river facility.

Land and Water Rights

The land upon which the facility is located and the hydraulic rights necessary for the operation of the facility have been leased by SLI from the Ministry of Natural Resources, Québec pursuant to a 20 year lease agreement, as assigned by SLI to the Fund in June, 1999. The Government of Québec has consented to the assignment. The lease expires in June 2014 and includes a renewal option for an additional 20 year period, exercisable by the lessee upon mutually acceptable terms. The lease may be terminated by the Province of Québec upon, among other events, termination of the power purchase agreement for the facility with Hydro-Québec or transfer of the leasehold interest without approval of the landlord.

Saint-Alban, Glenford and Rawdon Power Purchase Agreements

As part of the transfer of title to the Saint-Alban Facility to the Fund, right, title and interest in the power purchase agreement is to be transferred to the Fund. Under the terms of the power purchase agreement, the consent of Hydro-Québec (which consent may not be unreasonably withheld) is required to complete the acquisition of the Saint-Alban Facility and the acquisition of the Glenford Facility by the Fund. The consent of Hydro-Québec has been obtained with respect to the acquisition of the Rawdon Facility.

Under the power purchase agreement, Hydro-Québec has agreed to purchase all power made available to it from the Saint-Alban, Glenford and Rawdon Facilities. The standard Hydro-Québec power purchase agreement stipulates a minimum energy production during each 12 consecutive months commencing December 1 in each contract year. If a facility produces less energy than the minimum, a penalty of approximately 1.1 cents per kilowatt hour for each kilowatt hour that the actual production is below the minimum annual production is payable to Hydro-Québec.

The term of the power purchase agreement for the Rawdon Facility and the Saint-Alban Facility is 20 years from the commercial start-up date and is 25 years from the commercial start-up date for the Glenford Facility. The power purchase agreements expire in 2014, 2016 and 2020 for the Rawdon, Saint-Alban and Glenford Facilities, respectively. The agreements may be renewed at the option of the generator for a period not exceeding the original term upon mutually acceptable terms.

For the Saint-Alban and Rawdon Facilities, power purchase rates under the agreement for each contractual year will be increased in accordance with the percentage increase in the Consumer Price Index for the Montréal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%. For the Glenford Facility, the power purchase rate is fixed at \$0.0504 per kW-hr until December 1, 1999, after which time the rate will be escalated in a manner similar to the rates for the Saint-Alban and Rawdon Facilities as set out above.

Côte Ste-Catherine Facility

The Côte Ste-Catherine Facility is located at the Côte Ste-Catherine lock of the Lachine section of the St. Lawrence Seaway. The bypass canal upon which the facility is located was constructed as part of the St. Lawrence Seaway in 1958. The facility has a total installed capacity of 11,120 kilowatts and

was constructed in three separate phases, each phase having a total installed capacity of 2,120 kilowatts, 4,500 kilowatts and 4,500 kilowatts, respectively, and each phase was commissioned in 1989, 1993 and 1996, respectively. Due to the year round, high volume water flows of the St. Lawrence River, the Manager expects there to be sufficient water to operate the Côte Ste-Catherine Facility at full capacity throughout the year. The Côte Ste-Catherine Facility uses approximately 2% of the river flow at any given time.

Land and Water Rights

The land and water rights necessary for the construction and operation of the Côte Ste-Catherine Facility have been obtained from the St. Lawrence Seaway Authority by way of a lease agreement dated March 1, 1988, as amended. The lease agreement will expire on February 28, 2009. The lease can be extended for an additional period of 21 years upon the lessee giving 6 months notice. The facility is located on a federal waterway. However, the Province of Québec has asserted jurisdiction over the water rights to this facility.

Ste-Raphaël Facility

The Ste-Raphaël Facility is a 3,500 kilowatt facility located on the Rivière de Sud approximately 60 km. east of Québec City, Québec. The site was formerly developed by Hydro Québec and then released by the Ministry of Energy Québec, for private development in 1991. The site was rebuilt by a former owner and placed back into operation in January 1994.

Land and Water Rights

The land and hydraulic rights necessary for the operation of the facility have been leased by the Ministry of Natural Resources and the Ministry of Environment, Québec pursuant to a lease agreement dated December 14, 1993. The lease terminates on December 14, 2013 and may be renewed for an additional period of 20 years at the option of the lessee upon terms imposed by the government.

Mont Laurier Facility

The Mont Laurier Facility is a 2,725 kilowatt facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The site has been historically utilized for the production of power and was refurbished in 1989. The rehabilitation included extensive repairs to the civil works, rebuilding of all three turbines and replacement of all electrical and control works.

Land and Water Rights

The facility is constructed on lands owned by MTL Partnership. Water rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources, Québec pursuant to a lease agreement dated March 23, 1988 and assigned to the MTL Partnership on October 31, 1994. The term of the lease expires on December 31, 2023.

Rivière-du-Loup Facility

The Rivière-du-Loup Facility is located on the Rivière-du-Loup in close proximity to the downtown section of the Town of Rivière-du-Loup, Québec. The site has been historically utilized for the production

of power and was decommissioned in 1977. A major refurbishment undertaken in 1995 included complete rehabilitation of the civil works, installation of a new turbine, rebuilding of two existing turbines and replacement of all electrical and control works. The installed capacity of the plant has been increased to 2,600 kilowatts.

Land and Water Rights

The land and hydraulic rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources and the Ministry of the Environment, Québec pursuant to a lease agreement dated November 20, 1997. The lease terminates on October 22, 2015. The lease can be extended for an additional period of 20 years at the option of the lessee upon terms imposed by the government.

Hydraska Facility

The Hydraska Facility is located on the Yamaska River at Penmans Dam near the Town of St-Hyacinthe, Québec. Construction on the site commenced in 1993 and commissioning was successfully completed in May 1994. The civil works include a 250 meter long tailrace canal and have been designed to be attractively integrated into the park in which the site is located. The capacity of the plant is established at 2,250 kilowatts.

Land and Water Rights

The land rights and existing structures on the site are leased from the City of St-Hyacinthe pursuant to a 20 year lease agreement dated August 30, 1993, the term of which commenced in May 1994. The lease can be extended on the same terms for an additional period of 20 years at the option of the lessee. The hydraulic rights necessary for the operation of the facility have been leased by the lessee from the Ministry of Natural Resources and the Ministry of the Environment, Québec pursuant to a lease agreement dated March 24, 1994. The lease terminates on May 23, 2014 and may be renewed for an additional period of 20 years at the option of the lessee upon terms imposed by the government.

Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup and Hydraska Power Purchase Agreements

Under the power purchase agreements, Hydro-Québec has agreed to purchase all power made available to it from the Côte Ste-Catherine, Rivière-du-Loup, Hydraska, Ste-Raphaël, and Mont Laurier facilities. The standard Hydro-Québec power purchase agreement stipulates a minimum energy production during each 12 consecutive months commencing December 1 in each contract year. If a facility produces less energy than the minimum, a penalty of approximately 1.1 cents per kilowatt hour for each kilowatt hour that the actual production is below the minimum annual production is payable to Hydro-Québec. The power purchase agreement for Hydraska does not include any penalty provisions.

The term of the power purchase agreements for each of the Côte Ste-Catherine – Phase I, Hydraska, Ste-Raphaël, Mont Laurier and Rivière-du-Loup facilities is 20 years from the commercial start-up date and is 25 years from the commercial start-up date for the Côte Ste-Catherine – Phase II and Côte Ste-Catherine – Phase III facilities. For the Côte Ste-Catherine Facility Phases I, II and III, the power purchase agreements expire in 2009, 2018 and 2021, respectively. The expiry dates for the power purchase agreements for the Mont Laurier, Hydraska, Ste-Raphaël, and Rivière-du-Loup facilities are

2007, 2014, 2014 and 2015, respectively. The agreements may be renewed at the option of the producer for a period not exceeding the original term upon terms imposed by Hydro-Québec.

For all facilities except Mont Laurier and Côte Ste-Catherine – Phase I, power purchase rates under the agreements for each contractual year will be increased in accordance with the percentage increase in the Consumer Price Index for the Montreal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%. For the Mont Laurier Facility, the power purchase rates will be increased in accordance with the percentage increase in the Montreal Consumer Price Index with a maximum annual escalation of 5.2%. In addition to escalation due to inflation, the rates paid under the Mont Laurier Facility power purchase agreement will be escalated by \$0.01/kW-hr in 2002. For the Côte Ste-Catherine Facility – Phase I, the power purchase rates will be increased in accordance with the percentage increase in the Montreal Consumer Price Index with a maximum annual escalation of 6%.

Ste-Brigitte Facility

The Ste-Brigitte Facility is a 4,200 kilowatt hydroelectric generating facility located on the Nicolet River, in the Municipality of Ste-Brigitte-des-Saults, Québec. The facility is located at the site of an historic mill, but none of the original structures have been utilized for the new powerhouse. The site layout involves an intake canal equipped with a gate structure, a powerhouse containing a single 4200 kilowatt turbine generator and a tailrace canal which conveys the waterflow back to the natural watercourse. It has been designed as a run-of-the-river facility.

The facility incorporates a 1.1 metre high movable dam utilized to increase available water level differential. The original movable dam was damaged and was replaced in the summer of 1998 by and at the expense of Algonquin Power.

Land and Water Rights

The Ste-Brigitte Facility has been constructed on certain lands purchased by a former owner. In addition, certain easements were granted to the former owner in respect of the access road, transmission line and Hydro-Québec interconnection. The land includes the bed of the river upon which the existing weir structure is located and certain land on either side of the river. Accordingly, no lease with the Province of Québec is required.

On May 10, 2002, certain upstream residents of the Ste-Brigitte Facility commenced an action in the Québec Supreme Court against certain Fund entities and others claiming in excess of \$5 million as a result of a flood event which occurred on April 13, 2001. The flood apparently resulted from an ice jam upstream from the facility that flooded properties near the river. In addition to the claim for damages, the plaintiffs are seeking an order requiring that the facility cease operation and that it be removed. The Fund entities are vigorously defending the action.

Belleterre Facility

The Belleterre Facility is a 2,200 kilowatt hydroelectric generating facility located on the Winneway River, in the Municipality of Laforce, Québec. The facility is located at the point of discharge of the Winneway River into Lac Simard/Lac des Quinzes. Commissioning of the Belleterre Facility involved the rehabilitation of a generating facility constructed in the 1930's to supply power to local mining

operations. The rehabilitation work included replacement of the turbine-generating equipment, restoration of site structures, including the penstock and gates, and replacement/recommissioning of the electrical interconnection to the Hydro-Québec grid. The rehabilitation and recommissioning was completed and the facility was brought into commercial service with Hydro-Québec in March 1993.

Land and Water Rights

The land and water rights necessary for the Belleterre Facility were originally leased from the Province of Québec to the Town of Belleterre pursuant to a lease dated July 17, 1991. The lease expires in December 2011 and includes a renewal option for an additional 20 year period, exercisable by the lessee upon terms imposed by the Province of Québec. The lease may be terminated by the Province of Québec upon, among other events, termination of the power purchase agreement for the facility with Hydro-Québec.

The Town of Belleterre transferred its interest in the lease to a former owner pursuant to a deed of sale dated May 31, 1992. Consideration paid under the deed of sale included granting the Town of Belleterre a royalty interest which provides an annual payment equal to two percent of the gross revenues earned by the facility from the sale of energy to Hydro-Québec. Certain easements required for the transmission line were granted by the Town of Belleterre under the deed of sale. Under the lease with the Province of Québec, a shareholder of a former owner was required to provide a guarantee of the lessee's obligations thereunder. Following the acquisition of the Belleterre Facility, Algonquin Canada provided an indemnity to such shareholder in respect of its obligations under the guarantee.

Ste-Brigitte and Belleterre Power Purchase Agreements

Under the power purchase agreements, Hydro-Québec has agreed to purchase all power made available to it from the facilities. The standard Hydro-Québec power purchase agreement stipulates a minimum energy production during each 12 consecutive months commencing December 1 in each contract year. If a facility produces less energy than the minimum, a penalty of approximately 1.1 cents per kilowatt hour for each kilowatt hour the actual production is below the minimum annual production is payable to Hydro-Québec.

As a result of unrealistic energy production forecasts and poor operating procedures by a former owner of the Ste-Brigitte Facility and the Belleterre Facility, the facilities failed to meet the minimum production obligations under the Hydro-Québec power purchase agreements. As a result, Hydro-Québec reduced the minimum annual production obligation for the Belleterre Facility to 10,249,200 kilowatt hours and reduced the minimum annual production obligation for the Ste-Brigitte Facility to 10,818,600 kilowatt hours. Under the agreement of purchase and sale in respect of all of the issued and outstanding shares of BCL Energy (Belleterre) Inc. and all the issued and outstanding shares of BCL Energy (Ste-Brigitte) Inc., the Fund is liable for the payment of the fees charged by Hydro-Québec for such reductions in the amounts of \$65,509 during 2003 for the Ste-Brigitte Facility. The Manager fully expects to be able to meet the revised minimum annual production obligations set out in the power purchase agreements with Hydro-Québec for both facilities over the remaining term of the contracts.

The term of each of the agreements is 20 years from the commercial start-up date and the Ste-Brigitte Facility agreement expires in 2014 and the Belleterre Facility agreement expires in 2013. The agreements may be renewed at the option of the producer for a period not exceeding the original 20 year term upon terms imposed by Hydro-Québec.

Power purchase rates under the agreements for each contractual year will be increased in accordance with the percentage increase in the Consumer Price Index for the Montréal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%.

Donnacona Facility

The Donnacona Facility is a 4,800 kilowatt hydroelectric generating facility located on the lower portion of the Jacques Cartier River, near the Town of Donnacona, Québec. The Jacques Cartier River flows south and empties into the St. Lawrence River approximately 60 kilometres west of Québec City, Québec. The facility was constructed at the site of an existing dam and is located on property purchased from Alliance Forest Products Inc./Produits Forestiers Alliance Inc. ("Alliance"). The powerhouse houses eight identical 600 kilowatt turbine generators. Construction commenced in April 1996 and the facility was commissioned in December 1996. Electricity produced by the facility is delivered to the Hydro-Québec distribution system.

Power Purchase Agreement

Under the power purchase agreement, Hydro-Québec has agreed to purchase all power made available to it from the facility and the Donnacona Partnership has agreed to supply a minimum of 18,790,200 kilowatt hours of energy during each period of 12 consecutive months commencing December 1 in each contract year. If the facility produces less energy than the minimum, a penalty of approximately 1.1 cents per kilowatt hour for each kilowatt hour the actual production is below the minimum annual production is payable to Hydro-Québec. The term of the agreement is 25 years and it expires in 2022. The agreement may be renewed at the option of the Donnacona Partnership for a period not exceeding the original 25 year term upon terms to be negotiated. Hydro-Québec can veto the renewal, but only if the Donnacona Partnership is in default of a material term of the agreement.

Power purchase rates for contract year 2001 and thereafter will be increased in accordance with the percentage increases in the Consumer Price Index for the Montréal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%.

Land and Water Rights

The real property interest required for the construction and operation of the facility consists of a deed of transfer of certain land and easement rights obtained from Alliance in April 1996. In addition to the land, the existing dam structure, the bed of the Jacques Cartier River upstream of the facility and the natural hydraulic forces of that part of the river were transferred to the Donnacona Partnership. Under the deed of transfer, the Donnacona Partnership agrees to allow water flows in the Jacques Cartier River of up to 2.25 cubic metres per second to be utilized by Alliance for the Donnacona paper mill located approximately one kilometre from the facility site until such time as a permanent pumping system is conveyed by the Donnacona Partnership to Alliance. During construction, the deed of transfer required the partnership to design and install a temporary water pumping system to supply the Alliance mill with water if there was a problem with the existing gravity water supply system. This temporary pumping equipment was then transferred to Alliance and the equipment is located in a building on the site. The Donnacona Partnership also has the obligation to construct a permanent pumping station in the unlikely event there is a permanent failure of the existing dam and the existing gravity water supply system is permanently disrupted.

The deed of transfer grants the Donnacona Partnership certain easements across land retained by Alliance, which easements are required to allow access to the dam and other structures located near the powerhouse. Under the terms of the deed of transfer, the Donnacona Partnership has agreed, among other things, to maintain the dam in good condition and maintain certain insurance which will protect Alliance against loss of water caused by negligence of the Donnacona Partnership until completion of a permanent pumping facility.

The Donnacona Partnership has entered into a lease with the Province of Québec in respect of a section of the bed of the river upstream from the facility and water rights relating to the Jacques Cartier River necessary for the operation of the facility which expires on February 6, 2017. The lease includes a renewal option for an additional 20 year period, exercisable at the request of the Donnacona Partnership upon terms imposed by the Province of Québec. The lease may be terminated by the Province upon, among other events, termination of the power purchase agreement with Hydro-Québec. Notice of any change of control of the Donnacona Partnership or its partners must be given to the Québec Minister of Natural Resources and the Québec Minister of the Environment within 30 days of the change of control. The Ministers have the discretion to approve such change of control or terminate the lease.

Rights to all necessary lands have been obtained in order to operate and maintain the transmission line for the facility.

St. Raphaël de Bellechasse Facility

The St. Raphaël de Bellechasse Facility is a 650 kilowatt hydroelectric generating facility located on the Du Sud River near Saint-Raphaël de Bellechasse, approximately 40 kilometers east of Québec City. The site was originally developed in the late 1700's as a sawmill, and later, in the early 1900's as a flourmill. It was not until September 15, 1993 that the structure was commissioned as a hydroelectric generating facility by Énergie DLS Inc. The powerhouse building is estimated to be approximately 230 years old.

This run-of-the-river facility consists of a concrete gravity dam and spillway that spans the river, an intake, two penstocks, a stone masonry powerhouse and a tailrace canal.

Land and Water Rights

The St. Raphaël de Bellechasse Facility is constructed on private land, such that the generator owns the land and the associated hydraulic forces. The land owned includes the bed of the river upon which the existing spillway is located. Accordingly, no water lease with the Province of Québec is required.

Power Purchase Agreement

Under the power purchase agreement, Hydro-Québec has agreed to purchase all power made available. The agreement is for a 20 years, commencing September 15, 1993, which was the commissioning date of the facility. The established minimum contractual energy production during each 12 consecutive months commencing December 1st in each contract year is 3,313 megawatt hours. As a result of lower than forecast energy production, the former owner lowered the minimum contractual energy production in 1994 to 2,847 megawatt hours and again in 1999 to 2,568 megawatt hours.

Under the agreement, if the facility produces less than the established minimum contractual energy, a penalty of approximately 1.13 cents per kilowatt hour for each kilowatt hour the actual production is below the minimum annual production is payable to Hydro-Québec. The Manager fully expects to be able to meet the revised minimum annual production.

Power purchase rates under the agreement will be increased in accordance with the percentage increase in the Consumer Price Index for the Montreal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%.

Newfoundland Development - Rattle Brook Facility

Rattle Brook Facility

The facility is a 4,000 kilowatt hydroelectric generating facility located on Rattle Brook, approximately four kilometres north of the Town of Jackson's Arm, in the Province of Newfoundland. Construction commenced in September 1997 and the facility was commissioned in December 1998.

The facility is a run-of-the-river facility and there will be no storage of water for peaking purposes. A penstock runs 1,100 metres from a small dam to the powerhouse. The powerhouse is a single storey building which houses a single horizontal turbine attached to a synchronous air cooled generator. The interconnection point for delivery of electricity to the power purchaser is adjacent to the facility and therefore no transmission line is included.

Land and Water Rights

All necessary land and water rights and environmental approvals have been obtained by the Rattle Brook Partnership, including a 50 year lease from the Province of Newfoundland for use of the land required by the facility.

Power Purchase Agreement

Electricity produced by the facility is sold directly to Newfoundland and Labrador Hydro. Pursuant to the power purchase agreement, Newfoundland and Labrador Hydro agrees to purchase all power delivered to the interconnection point and the Rattle Brook Partnership agrees to sell all power produced by the facility to Newfoundland and Labrador Hydro.

The power purchase agreement is for a term of 25 years from the commercial in-service date, which occurred on October 23, 1998, and may be renewed for a further term of 25 years upon terms mutually agreed. Newfoundland and Labrador Hydro has the option to terminate the supply or receipt of power upon reasonable notice if the Rattle Brook Partnership is in default of any obligation under the agreement. If the Rattle Brook Partnership continues in default after receiving reasonable notice thereof (at least 60 days), Newfoundland and Labrador Hydro has the option to terminate the agreement.

The power purchase agreement provides that payments made by Newfoundland and Labrador Hydro consists of two components: a capacity component and an energy component, for each of the winter period and the summer period. The energy component is adjusted annually by the change in the Consumer Price Index for Canada, provided that any escalation does not exceed 6% year over year. The capacity component is fixed and is not escalated over the term of the power purchase agreement.

Partnership Agreement

The partnership agreement dated October 14, 1997 between Algonquin Power Corporation (Rattle Brook) Inc. and Algonquin Canada governs the affairs of the Rattle Brook Partnership. The partnership agreement specifies, *inter alia*, that income allocations, cash distributions and voting rights at meetings of the partners will be divided as to 55% to be equally divided among the four shareholders of the Manager and 45% to Algonquin Canada. Generally, management decisions for the partnership are made by majority vote of the partners. Certain matters, including capital expansion of the facility, disposition of the facility by the partnership and dissolution of the partnership, require unanimous consent of the partners.

New York Development - Ogdensburg, Forestport, Herkimer, Hollow Dam, Christine Falls, Burt Dam, Cranberry Lake, Kayuta Lake, Adams, Kings Falls, Otter Creek and Phoenix Facilities

Trafalgar Power, Inc. and Christine Falls Corporation

Trafalgar Power, Inc., a Delaware corporation, and Christine Falls Corporation, a New York corporation, own seven hydroelectric generating facilities located in upper New York State. The Trafalgar Companies are each controlled by the same independent businessman. The Ogdensburg Facility, Forestport Facility, Herkimer Facility, Cranberry Lake Facility, Kayuta Lake Facility and the Adams Facility are owned by Trafalgar and the Christine Falls Facility is owned by Christine Falls Corporation. Each of the facilities has received a licence or a licence exemption from FERC and each sell electricity to Niagara Mohawk Power Corporation pursuant to separate power purchase agreements. Such agreements are either front-end loaded, whereby the rate paid by Niagara Mohawk is high in the early years to enable the developer to recoup its capital costs and is adjusted downward in later years to compensate for the overpayment based on the balance in a tracking account set up for such purpose, or specified rate, whereby the rate is as set out in the agreement in the early years and thereafter is set as a percentage of Niagara Mohawk's Avoided Costs. Niagara Mohawk has the right to suspend its obligations under such agreements if its transmission system is unable to accept power generated from the facilities. It also retains a right of first refusal to negotiate the acquisition of a facility in the event of a proposed disposition thereof. The Trafalgar Companies must maintain such facilities in good working order, maintain the interconnection with Niagara Mohawk's transmission system and provide insurance coverage.

Trafalgar Operations Subcontract

Algonquin Power entered into the Trafalgar Operations Contract with the Trafalgar Companies, pursuant to which Algonquin Power agreed to provide the Trafalgar Companies with certain services in respect of the Trafalgar Facilities. Algonquin Canada entered into the Trafalgar Operations Subcontract on December 23, 1997 pursuant to which Algonquin Canada provides to Algonquin Power services required in respect of the operation of the Trafalgar Facilities. In addition to receiving certain monthly payments in respect of the operating costs incurred by Algonquin Canada in providing such services, Algonquin Canada is entitled to the Trafalgar Contingency Participation as a bonus payment based on achieving certain target revenue generation and payments on the above-noted note.

Algonquin Canada entered into a services agreement (the "Trafalgar Services Agreement") on December 23, 1997 pursuant to which Power Systems has assumed responsibility for providing the operations services required by the Trafalgar Facilities. Compensation to Power Systems under the Trafalgar Services Agreement does not include any portion of the Trafalgar Contingency Participation.

On an annual basis, the Trafalgar Contingency Participation will be equal to 50% of Trafalgar Operating Cashflows in amounts up to certain annual targets and 10% of the amount of Trafalgar Operating Cashflows which is in excess of those targets. Prior to the holder of the Trafalgar Class B Note having received aggregate payments exceeding a certain cumulative target, the Trafalgar Contingency Participation will be equal to 50% of Trafalgar Operating Cashflows up to certain annual targets and 10% of cash flows in excess of those targets. After the holder of the Trafalgar Class B Note has received aggregate payments exceeding such certain cumulative target, the Trafalgar Contingency Participation will be equal to 33% of Trafalgar Operating Cashflows.

Trafalgar Class A and B Notes

Algonquin Canada acquired the Trafalgar Class A Note on December 23, 1997. The Trafalgar Class A Note has subsequently been repaid.

The Fund acquired the Trafalgar Class B Note on December 23, 1997. The Trafalgar Class B Note was issued jointly and severally by the Trafalgar Companies pursuant to the Trafalgar Indenture, bears interest at the rate of 6.10% per annum. It is secured by a charge against all assets of the Trafalgar Companies including, without limitation, the generating equipment comprising the Trafalgar Facilities and the interest in the key contracts held by the Trafalgar Companies for the operation of the Trafalgar Facilities.

Under the terms of the Trafalgar Indenture, prior to the holder of the Trafalgar Class B Note having received aggregate payments exceeding a certain cumulative target, 50% of Trafalgar Operating Cashflows in amounts up to certain annual targets, and 90% of cash flows in excess of those targets, will be paid to the holder of the Trafalgar Class B Note in respect of interest and principal payments on the note. After the holder of the Trafalgar Class B Note has received aggregate payments exceeding such cumulative target, 33% of Trafalgar Operating Cashflows will be paid to the holder of the Trafalgar Class B Note in respect of interest and principal payments on the note.

Under the terms of the various securities purchased and agreements entered into by the Fund and Algonquin Canada, the Fund is indirectly entitled to a 100% interest in the cash flows generated from the Trafalgar Facilities up to the year 2010 and thereafter until all amounts outstanding under such note are repaid if the Trafalgar Companies elect not to repay the Trafalgar Class B Note.

If the Trafalgar Companies fully repay the Trafalgar Class B Note upon its maturity on December 31, 2010, the Fund will receive a payment equal to 75% of the equity value of the Trafalgar Facilities which is expected by the Fund to be satisfied by delivery of a 75% equity interest in the Trafalgar Companies

In August 1999, the Fund and Algonquin Canada declared the Trafalgar Class A Note and the Trafalgar Class B Note in default and accelerated the indebtedness represented by the Notes. The outstanding balance of the B Note as at December 31, 2002 was approximately US\$ 21.8 million.

In a separate action, Trafalgar obtained a judgment against a third party and received an award of approximately US\$10 million. The Fund has made a claim against this award. These funds are being held in escrow pending the outcome of the litigation referred to below.

Trafalgar Power, Inc. commenced an action in New York District Court against the Fund,

Algonquin Canada and Algonquin Power with respect to the Fund's and Algonquin Canada's purchase of certain promissory notes. Trafalgar has alleged that Aetna Life Insurance Company breached an agreement with Trafalgar by selling the Trafalgar Class A Note and the Trafalgar Class B Note to the Fund and Algonquin Canada. Trafalgar has also alleged that the Fund, Algonquin Canada and Algonquin Power tortiously interfered with the agreement between Aetna and Trafalgar and that the Fund, Algonquin Canada and Algonquin Power converted Trafalgar's assets. The Manager believes that this action was a result of the Fund taking steps towards initiating foreclosure proceedings against Trafalgar with respect to the Trafalgar Class B Note and pursuant to a loan agreement and a trust agreement with Trafalgar. The Manager believes that this case is without merit.

On August 27, 2001, Trafalgar Power, Inc., Christine Falls of New York, Inc., Marina Development, Inc. (the sole shareholder of the Trafalgar Companies) (collectively the "Trafalgar Entities") filed for bankruptcy protection in the United States Bankruptcy Court in Raleigh, North Carolina. At that time, all legal actions involving the Trafalgar Entities were stayed by the bankruptcy court in North Carolina. Included in the bankruptcy filings by the Trafalgar Entities was an adversarial proceeding which named the Fund, the Manager and certain Fund entities in a number of complaints. The complaints filed by the Trafalgar Entities are identical to the complaint filed by Trafalgar Power, Inc.

On December 13, 2001, the bankruptcy court in North Carolina transferred the bankruptcy proceedings to the United States Bankruptcy Court, Northern District of New York, in Utica, New York.

As a result of the bankruptcy procedures, all revenue generated by the Trafalgar facilities are being held as part of the estate of Trafalgar together with the amount of approximately US\$ 10 million previously held in escrow. All operating expenses are being paid from these amounts. Based on the current power rates, the facilities are operating at a small positive operating cash flow.

During the fiscal year ended December 31, 2002, the Fund reimbursed the Manager for one half of the external legal fees incurred up to July 1, 2002 with respect to the above legal actions. The Fund will fund the litigation of the action from July 1, 2002. In the event of a recovery by the Fund of all or part of the funds held in escrow, the Fund and the Manager will divide such amounts in proportion to the amount of legal fees funded, after reimbursement of expenses.

Ogdensburg Facility

The facility is located on the Oswegatchie River, in the City of Ogdensburg, New York. The facility was built at an existing concrete dam located immediately upstream of the St. Lawrence River. The dam is owned by the City of Ogdensburg (the "City") and Trafalgar entered into an agreement with the City to utilize the structures. It is a run-of-the-river facility. The facility is rated at 3,675 kilowatts. The facility has five bevel geared, double regulated Kaplan turbines manufactured by Sulzer Hydro.

Power Purchase Agreement

The agreement is for a term of 20 years from the commencement of commercial operations, which occurred on December 15, 1987. For the period January 1, 2001 through December 31, 2007, the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs.

FERC Licence

The facility received a licence (Major Project) for a hydroelectric generating facility from FERC on June 15, 1987 (FERC Project No. 9821). The licence is for a 3675 kilowatt facility. The facility was commissioned on December 18, 1987 and the licence expires in May 2027. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) the FERC licence requires a complex and strict minimum flow regime. The first 183 cubic feet per second through the site is spilled over the dam. River flow between 183 to 733 cubic feet per second is discharged through turbine No. 5 which is directed towards the base of the dam and maintains a minimum flow along the downstream reach of the facility. Flows greater than 733 cubic feet per second are discharged through the remaining four turbines, but Turbine No. 5 must always discharge the maximum 733 cubic feet per second.

Agreement with the City of Ogdensburg

In March 1987, Trafalgar entered into an agreement for the development of the facility with the City, pursuant to which Trafalgar is required to pay the City: (i) certain payments relating to the issuance of municipal bonds in the amount of \$143,000 (US\$100,000) plus interest; (ii) repayment of a loan in the amount of \$641,000 (US\$450,000) plus interest; (iii) \$36,600 (US\$25,000) annually, commencing on December 1, 1988 to December 1, 2007; (iv) \$99,800 (US\$70,000) annually, commencing on December 1, 2008 and ending on December 1, 2027; and (v) during the period from January 1, 2028 through to December 31, 2037, Trafalgar is required to pay the City 40% of the net revenues from the facility and during the period from January 1, 2038 to the expiration of the agreement, 50% of the net revenues from the facility. As security for its obligations under the agreement, Trafalgar granted the City a mortgage over the facility. Trafalgar must give notice to the City of its intent to sell, lease or assign control or ownership of the facility to any entity other than an affiliate of Trafalgar. If the City does not object by written notice given to Trafalgar within 30 days of delivery of Trafalgar's notice, the City is deemed to have approved the transaction.

The City has an option to purchase the facility after January 1, 2038. If the City exercises this option, the purchase price will be two-thirds of the facility's value capitalized at 8.5% of the net return after normal operating and maintenance expenses, based on the average of the net facility revenues over the three years immediately preceding the date of purchase. Trafalgar cannot place a mortgage on the property after December 31, 2028 without the consent of the City.

Forestport Facility

The facility is rated at 3,300 kilowatts and is located on an existing canal system along the Black River, near the Town of Boonville, which is located about 30 kilometres north of Utica, New York. The canal system is owned and maintained by the New York State Thruway Authority/Canal Corporation ("NYSTA/CC") and is used mainly by recreational canoers. The facility generates electricity from flows from both the Black River and Alder Creek. The powerhouse is located adjacent to the canal and water is diverted to it by a steel penstock. The powerhouse includes a conventional, horizontal "S" type Kaplan turbine generator set manufactured by Sulzer Hydro. After passing through the turbine, water is discharged into the Black River.

Power Purchase Agreement

The agreement is for a term of 20 years from commencement of commercial operations which occurred on December 30, 1987. From the period January 1, 2001 through the remainder of the term ending on December 31, 2007, the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs.

FERC Licence

The facility received a licence (Major - Existing Dam) for a hydroelectric facility from FERC on March 20, 1987 (FERC Project No. 4900). The licence is for a 3,300 kilowatt generating facility producing power from one turbine. The facility was commissioned in October 1988 and the licence expires in February 2027. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; a gate on the barge canal, upstream of the powerhouse, enables the facility to operate in an instantaneous run-of-the-river mode; and (ii) a minimum flow of 140 cubic feet per second must be released downstream of the dam at all times. The minimum flow is required for fisheries and water quality and was based on recommendations from federal and state regulatory agencies. The NYSTA/CC operates the barge canal system and has required an additional minimum flow within the canal for recreation. Presently, approximately 30 cubic feet per second is discharged into the canal during the summer months.

Herkimer Facility

The facility is located on West Canada Creek, upstream of the Village of Herkimer, New York. The facility is rated at 1,680 kilowatts. The facility is located at a new concrete dam and overflow structure. There are four siphon-type, semi-kaplan ESAC turbine generators and one vertical Flygt turbine generator installed at the facility.

Power Purchase Agreement

The power purchase agreement with Niagara Mohawk is for a term of 20 years from the commencement of commercial operations, which occurred on December 29, 1987. From the period January 1, 2001 through the remainder of the contract term on December 31, 2007, the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs.

FERC Licence

The facility received a licence (Major Project) for a hydroelectric generating facility from FERC on April 22, 1987 (FERC Project No. 9709) for a 1,680 kilowatt facility. The facility was commissioned in February 1988 and the licence expires in March, 2027. The main compliance conditions associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility. The producer is required to install and maintain stream gauging stations for the purpose of measuring the stage and flow of the river; and (ii) the FERC licence requires a minimum flow of 160 cubic feet per second be released downstream of the dam at all times. The minimum flow is required for fisheries and water quality and was based on recommendations from applicable regulatory agencies. A portion of this flow, however, is first passed through the 80 kilowatt Flygt turbine before being discharged back into the stream. The remainder is passed directly over the spillway. In the event that the Flygt turbine is not available, a by-pass gate is opened to pass the minimum flow.

Hollow Dam Facility

The facility is located on the West Branch of the Oswegatchie River in the Town of Fowler, New York, approximately 16 kilometres south of Gouverneur, New York. The facility is rated at 900 kilowatts. The facility was constructed in 1987 and is located at an existing dam of 100 metres in length and includes a 70 metre spillway. The facility is equipped with two submersible Flygt turbine/generators, each capable of generating 450 kilowatts. The facility is owned by the Hollow Dam Partnership.

Power Purchase Agreement

The power purchase agreement with Niagara Mohawk for the Hollow Dam Facility expired on December 31, 2000. An arrangement has been made for a short term extension of the power purchase agreement. The Fund is looking to enter into a longer term agreement with Niagara Mohawk.

Land and Water Rights

The facility was built in 1987 on land leased to Lavalin Hydro Corporation by Barbara and Robert Sullivan pursuant to a long term lease agreement dated December 13, 1988. The lease has been assigned to the Hollow Dam Partnership. A term of the agreement states that all lands and facilities revert back to the landlord on April 26, 2026.

FERC Licence

The facility received a licence (Minor Project) from FERC on May 30, 1986 (FERC Project No. 6972) for a period of 40 years effective May 1, 1986. The licence was issued for a 1,000 kilowatt generating facility. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) pursuant to an amending order dated February 27, 1990, the facility must maintain a minimum flow of 21 cubic feet per second by ensuring the water levels within the headpond are not lower than an elevation of 630.8 feet above sea level. The amending order also required continuous recording of the water levels within the headpond.

Christine Falls Facility

The facility is located on the Sacandaga River approximately eight kilometres east of the Town of Specular, which is located within the Adirondack Mountain State Park, in upper New York State. The facility is rated at 850 kilowatts and consists of two horizontal shaft, Francis turbine/generators. The site was previously developed by Niagara Mohawk and was rehabilitated by Christine Falls Corporation. Water from the Sacandaga River is diverted to the plant at an existing concrete dam through a small intake structure and steel penstock. The total head at the site is 15 metres. It is a run-of-the-river facility. Power is delivered to the utility grid at Highway 30.

Power Purchase Agreement

The agreement is for a term of 40 years from the commencement of commercial operations and ends January 2028. The facility commenced commercial operations on April 15, 1988. For years 1 through 15, the specified settlement rates set out in the agreement will be paid to the producer. For years 16 through 18, the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs.

For years 19 through 30, the producer will be paid a rate equal to 90% of Niagara Mohawk's Avoided Costs. For the remainder of the term, the producer will be paid a rate equal to 80% of Niagara Mohawk's Avoided Costs.

FERC Licence

The facility received a licence (Minor Project) for a hydroelectric generating facility from FERC on October 18, 1983 (FERC Project No. 4639). The original licence was for a 725 kilowatt generating facility from two turbines and was amended to 850 kilowatts on February 15, 1989 when the developer purchased two used machines. The facility was commissioned in April 1988 and the licence expires in September 2023. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) a minimum flow of 25 cubic feet per second must be released downstream of the dam during March, April and May and ten cubic feet per second must be released at all other times of the year. The minimum flow is required for fisheries and water quality and is controlled through a small valve in the dam.

Burt Dam Facility

The facility is a 600 kilowatt hydroelectric generating facility located on the Eighteen Mile Creek in the Town of Newfane, New York. The facility consists of an existing dam with an integrated intake structure, powerhouse and tailrace and the facility is designed to operate as a run-of-the-river facility. The facility was reconstructed in 1987 from an old hydroelectric generating facility at the site of an existing dam. The facility is owned by the Burt Dam Partnership.

Power Purchase Agreement

A power purchase agreement with Niagara Mohawk for the Burt Dam Facility expired on December 31, 2000. An arrangement has been made for a short term extension of the power purchase agreement. The Fund is looking to enter into a longer term agreement with Niagara Mohawk.

Land and Water Rights

The land and certain facility structures are rented from the Olcott Harbor Board of Trade, Inc. pursuant to a lease agreement dated December 5, 1986. The lease agreement is for a term equal to the greater of 50 years or the term of the FERC licence and payment is based on a percentage of net income from the facility.

The Eighteen Mile Creek has been identified as one of six areas of concern in New York State by the Water Quality Board of the International Joint Commission due to high levels of chemicals in the sediments within the river, mainly PCBs and dioxins. A Remedial Action Plan ("RAP") has been jointly developed by the New York State Department of Environmental Conservation ("NYDEC") and SLI, the former owner, to provide environmental protection at this site. The RAP does not affect day-to-day operations of the facility, but the program will have to be considered if major works are required to be constructed with respect to the facility in and around the watercourse.

FERC Licence

The facility received an exemption from licensing for a small hydroelectric generating facility from FERC on May 15, 1986 (FERC Project No. 7477). The exemption order is for a generating facility of less than 5,000 kilowatts and the facility was commissioned in 1988. The major compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) if the NYDEC proceeds with a salmon stocking program, the Burt Dam Partnership must provide a flow over the dam to provide for downstream passage of fish. NYDEC has stated that it presently has no plans to stock Eighteen Mile Creek.

Cranberry Lake Facility

The facility is located on the Oswegatchie River, at the outlet of Cranberry Lake, in the Town of Clifton. The facility is located on land and utilizes water that is leased pursuant to a long term agreement with the Oswegatchie River Cranberry Reservoir Regulating District ("OR-CRRD") dated October 19, 1987 and expires in 2035. The facility is rated at 500 kilowatts and is a run-of-the-river facility using flow available from Cranberry Lake. The facility was constructed within the existing dam structure at the outlet of the lake. The facility configuration is similar to the Adams and Kayuta Lake facilities and includes an ESAC bulb-type turbine generator set in a small powerhouse. The facility is interconnected to Niagara Mohawk's grid immediately at the facility gate.

Power Purchase Agreement

The agreement is for a term ending December 31, 2025. Commercial operations commenced on December 31, 1987. From the period January 1, 2001 through December 31, 2010, the producer will be paid a rate equal to 90% of Niagara Mohawk's Avoided Costs. For the remainder of the term, the producer will be paid a rate equal to 80% of Niagara Mohawk's Avoided Costs.

FERC Licence

The Cranberry Lake Facility received a licence (Minor Project) for a hydroelectric generating facility from FERC on April 27, 1987 (FERC Project No. 9685). The facility is licensed to generate 595 kilowatts. The facility was commissioned in May 1988 and the licence expires in March 2027. The facility is required to operate according to the direction of the OR-CRRD, which determines the water level of Cranberry Lake and, therefore determines the water flow available for generation. The main compliance condition associated with the facility is that it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility.

Kayuta Lake Facility

The facility is rated at 400 kilowatts. The facility is located on the Black River at the outlet of Kayuta Lake. The site is immediately upstream of the Forestport facility, in the Town of Boonville. The site was developed at an existing concrete control structure at the outlet of Kayuta Lake. It is a run-of-the-river facility with a configuration very similar to the Adams and Cranberry Lake facilities. The powerhouse is built around an ESAC bulb-type turbine generator set located adjacent to the dam. The facility interconnects with the utility grid immediately at the facility fence.

Power Purchase Agreement

The agreement is for a term of 40 years ending January 2028. Commercial operations commenced on January 1, 1988. Power purchase rates are front-end loaded. The front-end loaded rate for the first 15 years is fixed at \$0.1324/kW-hr (US\$0.0929/kW-hr). Pursuant to its right to review the power purchase rate based on the balance of the tracking account, on January 8, 1999, Niagara Mohawk determined that an excessive Advance Payment Account balance was being created and the stabilized rate was decreased to \$0.0991/kW-hr (US\$0.0696/kW-hr). Niagara Mohawk has the right to continue such reviews on an annual basis for the remainder of the first 15 year period. The producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs for years 16 through 22 and a rate equal to 95% of Niagara Mohawk's Avoided Costs for years 23 through 30. The rate paid during this period will be adjusted positively or negatively to eliminate any balance in the Advance Payment Account by the end of the 30th year. The balance in the Advance Payment Account as at December 31, 2002 was \$1,183,143 (US\$749,014) and given the high balance of the Advance Payment Account, a further reduction in rates paid during this 15 year period may occur. During the period following the 31st year, the producer will be paid a rate equal to 90% of Niagara Mohawk's Avoided Costs, without adjustment. The agreement specifies that, at the end of the 30th year, the unrepaid balance of the Advance Payment Account must be paid to Niagara Mohawk, if the balance is positive, or to the producer, if the balance is negative, as the case may be. Niagara Mohawk has a lien on the facility to secure any positive balance in the Advance Payment Account, which lien is subordinate to the security under the Trafalgar Indenture.

FERC Licence

The facility received a licence (Minor Project) for a hydroelectric generating facility from FERC on September 12, 1984 (FERC Project No. 5000). The facility is built at the outlet of Kayuta Lake at the site of an existing control structure. The facility was commissioned in March 1988 and the FERC licence expires in August 2024. The main compliance condition associated with the facility is that it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility.

Adams Facility

The facility is a 350 kilowatt hydroelectric generating facility located on Sandy Creek, in the Village of Adams, New York. Sandy Creek discharges to the east side of Lake Ontario, south of the City of Watertown. It is a run-of-the-river facility located at an existing concrete dam structure. The dam is 41 metres long. A small powerhouse located at the dam houses an ESAC bulb-type turbine generator set. Electricity produced by the facility is connected to the Niagara Mohawk grid at the facility fence.

Power Purchase Agreement

The power purchase agreement for the Adams facility is for a term of 40 years ending January 2028. The facility commenced commercial operations on January 1, 1988. Power purchase rates under the agreement are front-end loaded. The front-end loaded rate for the first 15 years was initially set at \$0.1391/kW-hr (US\$0.0976/kW-hr). Pursuant to its right to review the power purchase rate based on the balance of the Advance Payment Account, on January 8, 1999 Niagara Mohawk determined that an excessive tracking account balance was being created and the stabilized rate was changed to \$0.1378/kW-hr (US\$0.0967/kW-hr). Niagara Mohawk has the right to continue such reviews on an annual basis for the remainder of the first 15 year period.

The agreement provides that the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs for years 16 through 22 and a rate equal to 95% of Niagara Mohawk's Avoided Costs for years 23 through 30. The rate paid during this period will be adjusted positively or negatively to eliminate any balance in the Advance Payment Account by the end of the 30th year. The balance in the Advance Payment Account as at December 31, 2002 was \$651,171 (US\$412,238) and given the high balance of the Advance Payment Account, a further reduction in rates paid during this 15 year period may occur.

During the period following the 31st year, the producer will be paid a rate equal to 90% of Niagara Mohawk's Avoided Costs, without adjustment. The agreement provides that, at the end of the 30th year, the unrepaid balance of the Advance Payment Account must be paid to Niagara Mohawk, if the balance is positive, or to the producer, if the balance is negative, as the case may be. Given the current status of the Advance Payment Account, it can be expected that a large payment will have to be made to Niagara Mohawk at the end of the 30th year. Niagara Mohawk has a lien on the facility to secure any positive balance in the Advance Payment Account, which lien is subordinate to the security under the Trafalgar Indenture.

FERC Licence

The facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on July 12, 1983 (FERC Project No. 6878). The exemption order is for a 358 kilowatt generating facility and the facility was commissioned in December 1987. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) a minimum flow of 15 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Taxes

The Trafalgar Companies are responsible for the payment of municipal taxes with respect to the Trafalgar Facilities. The municipal tax burden at each facility, other than the Ogdensburg facility, is based on the market value of such facility. The market value of the facility is based on the capitalization of the projected revenue stream of the facility from energy sales to Niagara Mohawk. The Manager has renegotiated or is in the process of renegotiating the existing assessments for municipal taxes to reflect the reduced market valuation based on the reduction in power rates.

Under an agreement for the development of the Ogdensburg facility with the City of Ogdensburg, the City is responsible for payment of the City's portion of the municipal taxes for the site. Trafalgar in turn pays the City an annual royalty. In addition to the agreement, the Ogdensburg facility is located in an Economic and Development Zone and therefore, Trafalgar was able to obtain relief from the school and county portion of the taxes for a period of time. These taxes were reduced to zero for the first seven years and then phased in starting in 1995. Currently, Trafalgar is responsible for payment of all school and county taxes. Trafalgar is also responsible for payment of the Cranberry Lake-Oswegatchie River Commission tax, which amounts to approximately \$4,950 (US\$3,159) per annum.

Transmission Lines

Rights to all necessary lands have been obtained in order to operate and maintain the transmission lines for the Trafalgar Facilities.

Kings Falls Facility

The facility is located on the Deer River, near Copenhagen in Lewis County, New York. The facility dam is located approximately 300 feet upstream from Kings Falls. It is a run-of-the-river facility and is rated at 1,750 kilowatts. The facility has one Waplins Vertical Kaplan turbine.

Power Purchase Agreement

A new agreement was entered into on April 12, 2000 with Niagara Mohawk for a term of five years. From January 1, 1999 until December 31, 2003, the specified settlement rates set out in the agreement will be paid to the producer.

Land and Water Rights

Tug Hill Energy Inc. acquired all land necessary for the operation of the facility. As a result of its ownership of the generating station site, Tug Hill Energy Inc. was granted the water rights for the facility.

FERC Licence

The facility received a licence (Minor Project) for a hydroelectric generating facility from the FERC on September 30, 1986. An order approving transfer of licence to Tug Hill Energy Inc. was granted by the FERC on June 30, 2000. The facility was commissioned in 1988.

The main compliance conditions associated with the facility are that: (1) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) the FERC licence requires a minimum flow of 8 cubic feet per second year round. The minimum flow is required for fisheries and water quality and was based on recommendations from applicable regulatory agencies.

Otter Creek Facility

The facility is located on the Otter Creek, near Craig, New York. The facility is located at a rehabilitated stone and masonry dam with a concrete overlay about 115 feet long. It is a run-of-river facility and is rated at 530 kilowatts. The facility has one Ossberger Cross- Flow turbine.

Power Purchase Agreement

A new agreement was entered into on June 22, 2000 with Niagara Mohawk for a term of two years. From May 1, 2000 until October 31, 2001, the specified settlement rates set out in the agreement were paid to the producer. With respect to the Burt Dam, Hollow Dam and Otter Creek Facilities, each is currently operating under an extension agreement to the original power purchase agreement granted by Niagara Mohawk through April 30, 2002 and each facility received 100% of the spot market price as per the load zone for which it is located and is also able to claim ancillary costs. Each site is no longer able to claim capacity power with these extensions. The April 2002 agreement has been extended until December 31, 2003, with the same contractual terms noted above.

Land and Water Rights

Tug Hill Energy Inc. acquired all land necessary for the operation of the facility. As a result of its ownership of the generating station site, Tug Hill Energy Inc. was granted water rights for the facility.

FERC Licence

The facility received an exemption from licensing for a small hydroelectric generating facility from FERC on September 9, 1985. The exemption order is for a generating facility of less than 5,000 kilowatts. The facility was commissioned in 1986.

The main compliance conditions associated with the facility are that: (1) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; (ii) there is a minimum flow requirement of 52 cubic feet per second year round to the natural streambed; the minimum flow is required for fisheries and water quality and was based on recommendations from applicable regulatory agencies; and (iii) there is a fish bypass pipe which must pass water at 44 cubic feet per second to the natural streambed.

Phoenix Facility

The facility is located on the Oswego River, in the Town of Phoenix, Onondaga County, New York. The facility is located at an 866 foot long concrete ogee spillway which is owned by the New York State Thruway Authority/ Canal Corporation (“NYSTA/CC”). It is a run-of-the-river facility and is rated at 3,500 kilowatts. The facility has two ESAC single regulated turbines.

Power Purchase Agreement

The original agreement was dated September 19, 1989 and had a term of 40 years from the date of issuance of the project licence by FERC. Therefore, from March 28, 1986 until March 28, 2026, the specified settlement rates set out in the agreement will be paid to the producer. The agreement requires maintenance of an adjustment account based on the difference between the specified rate and 90% of the long run Avoided Cost. The agreement states that the obligation to repay this balance in the adjustment account expires on expiry of the term of the agreement.

Land and Water Rights

The generating station is located on land formerly owned by the Onondaga County Industrial Development Agency. A Fund entity, Oswego Hydro Partners, holds certain permanent easements on land and buildings used by the facility. The Phoenix Facility is located at the Oswego Canal Lock No. 1 on the Oswego River. The dam, reservoir and navigation lock are owned by the State of New York and are operated and maintained by the New York State Thruway Authority/Canal Corporation (NYSTA/CC). The lock is operated by the NYSTA/CC and is open from April through October. However, the NYSTA/CC and Oswego Hydro Partners have an agreement to allow the facility operator to operate and be responsible for three Rodney-Hunt gates at the center of the dam.

FERC Licence

The facility received a licence for a hydroelectric generating facility from FERC on March 28, 1986. The licence is for a 3,500 kilowatt generating facility producing power from two turbines. The facility was commissioned in December 1990.

The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) the FERC licence requires a complex and strict minimum flow regime. On March 26, 2003, FERC provided an order amending the minimum flow requirements, which requires certain discharges over the flashboards, spillway crest or from the tainter gates to maintain dissolved oxygen below the Phoenix dam. Whenever the flow in the river falls below 1,900 cubic feet per second (cfs) during the June 1 through October 31 period, early morning dissolved oxygen and temperature monitoring must be conducted. If the average tailwater dissolved oxygen is at 5 mg/l or greater, a minimum flow of 300 cfs must be directed through the flashboards. If the average tailwater dissolved oxygen is less than 5 mg/l, flow release operations must be modified to increase tailwater dissolved oxygen to levels equal to or greater than 5.5 mg/l. At inflows less than 1500 cfs, the facility must reduce turbine release and increase flashboard/spillway/tainter gate flow until the average tailwater dissolved oxygen equals or exceeds 5.5 mg/l or all inflows are released. The facility must maintain this release scheme until the tailwater dissolved oxygen remains consistently greater than 5.5 mg/l. As subsequent dissolved oxygen levels permit, releases for dissolved oxygen augmentation may be reduced and turbine output correspondingly increased.

At inflows of 1500 to 1900 cfs, the facility follows the same procedure for inflows less than 1500 cfs, with the exception that the maximum total non-turbine release (if needed) for dissolved oxygen augmentation includes all inflow except 700 cfs. At inflows greater than 1900 cfs, no dissolved oxygen and temperature monitoring is required and thus no minimum flow release is required other than the 300 cfs over the flashboards.

The minimum flow from November 1 through May 31 is as follows: with inflows in excess of 300 cfs, the bypass flow is 300 cfs and for flows of less than 300 cfs, the requirement is the inflow. There is a downstream fish passage which is required to pass fish continuously; this bypass discharges water at a rate of 75 cubic feet per second.

New England Development — Gregg Falls, Pembroke, Clement Dam, Franklin, Moretown, Lochmere, Lower Robertson, Ashuelot, Lakeport, Avery Dam, Hadley Falls, Hopkinton, Milton, Mine Falls, Great Falls and Worcester Facilities

Gregg Falls Facility

The Gregg Falls Facility is located on the Piscataquog River near the Town of Goffstown, New Hampshire. The site was historically used for the generation of electrical energy and was decommissioned in the 1970's. A major refurbishment was undertaken in 1985, which included the installation of two new turbines and generators and the replacement of all electrical and control works. The installed capacity of the facility is 3,500 kilowatts.

Land and Water Rights

The former owner obtained the rights to the existing structures located at the facility site pursuant to a lease agreement dated December 29, 1982, as amended in May 24, 1985, with the New Hampshire Water Resources Board. The lease was assigned to Algonquin America. The leased premises include all physical structures and the water rights necessary for the operation of the facility. The lease expires on December 29, 2032.

FERC Licence

The Gregg Falls Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on July 21, 1983 (FERC Project No. 3180) for a 3,820 kilowatt facility. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; and (ii) a minimum flow of 20 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Pembroke Facility

The Pembroke Facility is located on the Suncook River near the Town of Pembroke, New Hampshire. The site consists of a 500 foot power canal and a 480 foot penstock leading to a concrete powerhouse housing a single turbine generator. The site was constructed in 1986 and has an installed capacity of 2,600 kilowatts.

Land and Water Rights

The land necessary for the operation of the facility is owned and the water rights for the Suncook River available at the facility site for the operation of the facility have been granted to the owner. The terms of the use of such water rights are governed by the New Hampshire Water Resources Board.

FERC Licence

The Pembroke Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC in February, 1983 (FERC Project No. 3185) for a 2,600 kilowatt facility. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; and (ii) a minimum flow of 10 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Gregg Falls and Pembroke Power Purchase Agreements

Both the Gregg Falls and Pembroke Facilities sell all electrical energy to PSNH pursuant to separate agreements both dated May 11, 1994. Both agreements terminate on December 31, 2020. Prior to December 31, 2011, the rates paid by PSNH for the energy are indexed to certain increases in the general rate of inflation. After January 1, 2012, the rates paid for energy and capacity are based on the then current PSNH avoided costs. As discussed under “*General Development of the Business - Other Developments in 2003*”, after the completion of the transaction which renegotiated the power purchase

rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Clement Dam Facility

The facility is located on the Winnepesaukee River approximately five miles upstream from its confluence with the Pemigewasset River and near the Town of Tilton, New Hampshire. The facility is rated at 2,400 kilowatts and was constructed in 1984 at the location of an existing 120 foot wide dam and includes a 275 foot steel penstock which is 12 feet in diameter.

Power Purchase Agreement

The power purchase agreement with the Public Service Company of New Hampshire for all electrical energy produced at the Clement Dam Facility has a term of 20 years and it will terminate at the end of 2004. Under the terms of the agreement, PSNH is required to purchase all energy for US\$0.09/kW-hr, plus 50% of the positive amount of PSNH's incremental energy cost in excess of US\$0.09. Since incremental energy costs have not risen above this level, payments have been made at the rate of US\$0.09/kW-hr since commissioning of the facility. As discussed under "*General Development of the Business - Other Developments in 2003*", after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

The land upon which the Clement Dam Facility is located is leased from the former owners. Payments under the lease commenced on January 1, 2000 and are equal to 10% of the revenues earned by the facility from the sale of energy. The lease terminates in the year 2032 and the Fund has the right to purchase the lands upon the termination of the lease for US\$300,000. The former owners have been granted the option to require the Fund to purchase the lands at any time after January 1, 2010 upon thirty days written notice for US\$200,000, increasing by US\$10,000 each year after 2010 to a maximum of US\$300,000.

Water rights for the site have been obtained from the New Hampshire Water Resources Board pursuant to a water user's agreement dated July 7, 1986. Semi-annual payments under the water user agreement are based on energy production and are expected to be approximately US\$17,691 per year. Currently the facility is operating on the old water user agreement while the state establishes a new water user agreement. Although the original term of the water user's agreement has expired, the parties continue to operate under the terms of the water user's agreement pending negotiation of a new agreement. The State of New Hampshire, Department of Environmental Services – Water Resources Department is the administrator of State water user agreements and is currently reviewing all expired water user agreements and will be commencing discussions with all stakeholders. There has been no schedule developed by the State to commence these discussions.

Pursuant to an agreement dated June 24, 1985 for payment in lieu of property taxes with the Town of Tilton, the owner is obligated to pay the Town of Tilton 3.75% of gross revenues per annum generated by the facility until June 24, 2000 and 4% of gross revenues per annum generated by the facility from June 25, 2000 until June 24, 2005. As well, pursuant to an agreement dated February 8, 1990 with the Town of Northfield for payment in lieu of taxes, the owner is required to pay to the Town of Northfield

US\$2,000 per year for a period of sixteen years or until the owner receives gross revenues from hydroelectric power generated by facilities in the Town of Northfield.

FERC Licence

The Clement Dam Facility received an exemption from the licencing of a small hydroelectric generating facility from the Federal Energy Regulatory Commission ("FERC") on May 17, 1982 (FERC Project No. 2966) for a 1,200 to 1,400 kilowatt facility. An amendment was issued on March 18, 1983 which amended the rated capacity to 2,400 kilowatts. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; and (ii) a minimum flow of 30 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Franklin Facility

The Franklin Facility consists of two independent powerhouses located on the Winnepesaukee River in the Town of Franklin, New Hampshire, and located several kilometers downstream from the Clement Dam Facility. The River Bend Turbine-Generator is rated at 1,600 kilowatts and is located in a powerhouse which was constructed in 1985. The facility is constructed at the location of an existing 70 foot wide dam and includes a 1,000 foot long concrete penstock. The Steven's Mill Turbine-Generator, rated at 228 kilowatts, is housed in a powerhouse located immediately adjacent to the dam. In October 1998, the Steven's Mill building was damaged by fire and the Steven's Mill Turbine-Generator was returned to service in January 2000. Subsequent to coming back in service, the generator malfunctioned and the facility was off-line until February 2000, when the turbine was repaired.

On August 27, 2001, Franklin Industrial Complex, Inc. ("Franklin") filed for bankruptcy protection in the United States Bankruptcy Court in Raleigh, North Carolina. In December 2001, the bankruptcy court granted the Manager's request for relief from the automatic stay of proceedings against the company. In December 2001, the Fund noticed a foreclosure and secured party sale of the collateral securing the Trafalgar Class B Note which included the two generating facilities and Franklin's rights under an interconnection agreement and a rate order. The foreclosure sale was held on January 25, 2002 and the Fund, through its indirect subsidiary, Franklin Power LLC, purchased the facilities for US\$3,000,000. The Fund has filed an action in the District Court in New Hampshire for the balance of the amount owing on the Trafalgar Class B Note.

Franklin, Marina Development Inc. and Arthur Steckler have filed a complaint against Algonquin Canada, Power Systems, Algonquin Power and others alleging, among other things, that the Algonquin entities conspired against Franklin, mismanaged the facility and breached fiduciary duties owed to Franklin. The Manager believes that this claim lacks substance.

Power Purchase Agreement

Pursuant to an interconnection agreement, together with a long term rate filing issued by the Public Utilities Commission of New Hampshire on December 20, 1984, all electrical energy produced by each of the Steven's Mill Turbine-Generator and the River Bend Turbine-Generator will be sold to PSNH. The term of the rate order is for 20 years, commencing January 1986, which was the commissioning date of the facility. The rate order expires in 2006. The amount payable under the agreement is based on a time differentiated energy payment plus a capacity payment. As discussed under "*General Development of*

the Business - Other Developments in 2003”, after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

The Franklin Facility is located on lands owned by the Franklin Industrial Complex Inc. The subsurface penstock which connects the intake to the powerhouse is located on an easement granted by the Town of Franklin. There is no transmission line associated with the facility as the interconnection with PSNH is located on the owned lands. The hydraulic rights necessary for the operation of the facility are leased from the New Hampshire Water Resources Board pursuant to a lease dated May 28, 1987. The lease expires in August 2002 and is renewable on a year-to-year basis. Currently the facility is operating on the old water user agreement while the state establishes a new water user agreement.

Pursuant to an agreement with the Town of Franklin dated September 1, 1987 for payment in lieu of property taxes, the owner is obligated to pay the Town of Franklin 4% of gross revenues per annum generated by the facility until March 31, 2002 and 5% of gross revenues per annum generated by the facility from April 1, 2002 to March 31, 2006.

FERC Licence

The Franklin Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on June 14, 1983 (FERC Project No. 3760) for a 1,940 kilowatt facility. The FERC exemption order was amended on April 16, 1991 to increase the stipulated capacity to 2,161 kilowatts. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; (ii) a minimum flow of 100 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality; and (iii) at the time of issuance of the FERC exemption order, the US Fish and Wildlife Service requested a downstream passage for Atlantic salmon seeded by the resource agencies. The cost of installing such fish passage, if required, is not expected to be significant. In addition, protection measures at the intake will also be required during the downstream migration of smolts, the cost of which is not significant.

Moretown Facility

The facility is a 1,200 kilowatt hydroelectric generating facility located on the Mad River in the Town of Moretown, Vermont. The facility includes a 12 metre dam, forebay, intake structure, penstock, powerhouse and tailrace. The powerhouse includes one Kaplan type turbine generator rated at 1,250 kilowatts. The facility was constructed in 1989 and is owned by the Moretown Partnership.

Power Purchase Agreement

A power purchase agreement was executed between Vermont Power Exchange, Inc. and the Moretown Partnership on July 29, 1988, whereby Vermont Power Exchange, Inc. agreed to purchase all the electrical energy produced from the facility. The term of the contract is 30 years and the power purchase rates include an energy rate, a capacity rate and a payment lag adder rate. Vermont Power Exchange, Inc. is a purchasing agent authorized by the Vermont Public Service Board. As purchasing agent for the utility, the Vermont Power Exchange, Inc. is paid a commission by the producer for the

energy sales. On March 15, 1996, the Vermont Electric Power Producers, Inc. ("VEPPI") was designated as the purchasing agent to replace the Vermont Power Exchange, Inc. Moretown Partnership entered into an interconnection agreement with Washington Electric Cooperative, Inc. on June 22, 1988, so that the facility may interconnect with the electrical system in Moretown, Vermont.

Land and Water Rights

All land and water rights required for the construction and operation of the facility are owned by the Moretown Partnership. The Town of Moretown and the Town School District executed a tax stabilization agreement with the Moretown Partnership dated October 25, 1990. The agreement limited the municipal and school taxes to be paid with respect to the property to a certain amount which may be increased if there is an increase in the power purchase rates paid by the Vermont Power Exchange, Inc. The term of the agreement is approximately 18 years, expiring March 31, 2008.

FERC Licence

The facility received a licence (Minor Project) for a hydroelectric generating facility from FERC on December 7, 1982 (FERC Project No. 5944) and the term of the licence is for a period of 40 years. The main compliance condition associated with the facility is that the facility must maintain an instantaneous minimum flow of 25 cubic feet per second over the dam, when available, to protect the Mad River.

Lochmere Facility

The facility is a 1200 kilowatt hydroelectric generating facility located on the Winnepesaukee River, in the Village of Lochmere, within the city limits of Tilton, New Hampshire. The facility consists of a dam, intake canal, intake, powerhouse and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was reconstructed from an old hydroelectric generating facility at the site of an existing dam at the outlet of Winnisquam Lake. The Lochmere Facility is owned by the HDI Partnership.

Power Purchase Agreement

A power purchase agreement was executed between PSNH and the HDI Partnership on August 5, 1983 for all electrical energy produced at the facility. The term of the contract is 20 years commencing January 1986. As discussed under "*General Development of the Business - Other Developments in 2003*", after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

The land for the facility site was leased by the Town of Belmont from the New Hampshire Water Resources Board pursuant to an agreement dated August 10, 1983. The lease was assigned to the HDI Partnership for development of the facility. The term of the lease is 50 years and payments under the agreement are based on a percentage of adjusted gross revenues generated by the facility, which payments are in lieu of property taxes.

Since the existing dam at this site was once used to generate electricity and is a State-owned structure, there is a water use licence granting the facility the right to utilize the hydraulic resources for hydroelectric generation purposes by the State of New Hampshire. It has a term of 15 years ending March 2000. The lease may be renewed upon mutual agreement. The lease has expired, however, the arrangement is being continued on the same basis as the original lease. Payments are made on a semi-annual basis in accordance with a simple formula contained in the licence. The payment rate escalates by ten percent on every fifth anniversary of the agreement.

Rights to all necessary lands have been obtained in order to operate and maintain the transmission line for the facility.

FERC Licence

The facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on March 15, 1984 (FERC project No. 3128) for a 1,200 kilowatt facility. The main compliance conditions associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; (ii) from October to March, a minimum flow of 35 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality. During the months of April to September, the minimum flow is 50 cubic feet per second for the benefit of small mouth bass and anglers; and (iii) a series of inexpensive, hand-built check dams constructed of natural river bed material are to be maintained annually downstream of the dam for the creation of fish and macroinvertebrate habitat. The cost of maintaining such check dams is not significant.

Lower Robertson Facility

The facility is a 960 kilowatt hydroelectric generating facility located on the Ashuelot River approximately one kilometre upstream of the Highway bridge at Hinsdale, New Hampshire. The facility consists of a dam, intake, powerhouse and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was constructed in 1988 at the site of an existing concrete dam, which was rebuilt to facilitate the generating facility. The facility is operated in conjunction with the Ashuelot Facility, due to the close proximity of the sites (less than one kilometre away).

Power Purchase Agreement

In 1984, the NHPUC approved a rate order which requires PSNH to purchase from the former owner the entire electrical output from the Lower Robertson Facility at specified rates. The rate order was subsequently assigned to HDI III Partnership. The amount paid by PSNH for electrical output is based on an energy payment plus a capacity payment. The term of the rate order is for a period of 29 years commencing September 1, 1987 and expires in September 2016. As discussed under “*General Development of the Business - Other Developments in 2003*”, after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

The real property interest required for the construction and operation of the facility was obtained pursuant to a warranty deed from Paper Service Mills, Inc. on December 29, 1986. Under the terms of

the warranty deed, the HDI III Partnership obtained title to the land on which all structures associated with the facility are located, including the dam structure, as well as access to both sides of the Ashuelot River required for the operation and maintenance of the facility. The warranty deed provides an interest in the riparian rights at the site, including all water power rights and privileges on the Ashuelot River.

Hydroelectric Development, Inc. ("HDI") has entered into an agreement with the Town of Winchester for payment in lieu of property taxes for the facility. This agreement was subsequently assigned by HDI to the HDI III Partnership. The agreement requires HDI III Partnership to pay to the Town within 90 days following the end of each fiscal year the greater of two and one-half percent of the gross revenues for that fiscal year or two and one-half percent of the average gross revenues for the previous fiscal year. The term of the agreement is for 30 years commencing on the initial date of commercial operation, which occurred in June 1987.

FERC Licence

The facility received an exemption from licensing for a hydroelectric generating facility of five megawatts or less from FERC on July 31, 1986 (FERC Project No. 8235). The main compliance conditions associated with this facility are that: (i) the facility must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; (ii) a minimum flow of ten cubic feet per second has to be released downstream of the dam, when available, to maintain the instream fisheries and water quality; and (iii) at the time of issuance of the FERC exemption order, the US Fish and Wildlife Service and New Hampshire Department of Fish and Game indicated that there may be a future requirement for the installation of an upstream fish by-pass at the facility, estimated by the Manager to cost approximately \$150,000. To date, no such by-pass system has been installed. The government agencies are reconsidering the necessity for this structure.

Ashuelot Facility

The facility is a 900 kilowatt hydroelectric generating facility located on the Ashuelot River near the highway bridge at Hinsdale, New Hampshire. The facility consists of a dam, intake, powerhouse and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was constructed in 1988 at the site of an existing concrete dam which was rebuilt to facilitate the generating facility.

Power Purchase Agreement

In 1985, the NHPUC approved a rate order which requires PSNH to purchase from Ashuelot River Partners the entire electrical output from the Ashuelot Facility at specified rates. The rate order was subsequently assigned to HDI III Partnership. The amount payable is based on an energy payment plus a capacity payment. The term of the rate order is for a period of 29 years commencing September 1, 1986 and expires in September 2015. As discussed under "*General Development of the Business - Other Developments in 2003*", after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

The land and water rights for the site are leased from the Ashuelot Paper Company pursuant to an agreement dated January 14, 1985. The term of the lease is 55 years commencing on January 14, 1985

and terminating on December 31, 2040 and payments under the agreement are structured as a percentage of gross revenues from the facility.

HDI has entered into an agreement dated August 13, 1986 with the Town of Winchester for payment in lieu of property taxes for the facility. This agreement was subsequently assigned by HDI to HDI III Partnership. The agreement requires HDI III Partnership to pay to the Town within 90 days following the end of each fiscal year the greater of two and one-half percent of the gross revenues for that fiscal year or two and one-half percent of the average gross revenues for the previous fiscal year. The term of the agreement is for 30 years commencing on the initial date of commercial operation, which occurred in June 1987.

FERC Licence

The Ashuelot Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on July 31, 1986 (FERC Project No. 7791) for an 850 kilowatt generating facility. The main compliance conditions associated with this facility are that: (i) the facility must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; (ii) a minimum flow of ten cubic feet per second has to be released downstream of the dam, when available, to maintain the instream fisheries and water quality; and (iii) at the time of issuance of the FERC exemption order, the US Fish and Wildlife Service and the New Hampshire Department of Fish and Game indicated that there may be a future requirement for the installation of an upstream fish by-pass at the facility, estimated by the Manager to cost approximately \$150,000. To date, no such by-pass system has been installed. To date, no such by-pass system has been installed. The government agencies are reconsidering the necessity for this structure.

Lakeport Facility

The facility is a 600 kilowatt hydroelectric generating facility located on the Winnepesaukee River near the Town of Lakeport, New Hampshire. The facility consists of a dam, powerhouse and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was constructed in 1984 at the site of an existing concrete dam.

Power Purchase Agreement

In 1985, the NHPUC approved a rate order which requires PSNH to purchase from Lakeport Corporation the entire electrical output from the Lakeport Facility at specified rates. The amount payable is based on an energy payment plus a capacity payment. The term of the rate order is for a period of 20 years commencing September 1, 1985 and expires in September 2005. As discussed under "*General Development of the Business - Other Developments in 2003*", after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

The facility is constructed on certain lands purchased by Lakeport Corporation. Certain additional land and water rights necessary for the operation of the facility are leased from the New Hampshire Water Resources Board pursuant to an agreement dated December 29, 1982. The term of the lease is

50 years and payments under the agreement are structured as a percentage of gross revenues from the facility.

As a condition under the lease with the New Hampshire Water Resources Board, Lakeport Corporation has entered into a water user's agreement dated August 30, 1985 with the New Hampshire Water Resources Board in respect of certain water management services provided by the New Hampshire Water Resources Board to users located on the Winnepesaukee River. Payments under the water user's agreement are structured based on energy production from the facility.

Lakeport Corporation has entered into an agreement with the City of Laconia for payment in lieu of property taxes for the facility. The agreement requires Lakeport Corporation to pay to the City of Laconia following the end of each fiscal year an amount equal to five percent of the gross revenues from the facility for that fiscal year. The term of the agreement is for 20 years commencing on October 9, 1985.

FERC Licence

The Lakeport Facility received a licence for a small hydroelectric generating facility from FERC on September 8, 1983 (FERC Project No. 6440) for a 600 kilowatt generating facility. The main compliance conditions associated with this facility are that: (i) the facility must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) a minimum flow of 180 cubic feet per second has to be released downstream of the dam, when available, to maintain the instream fisheries and water quality. The term of the FERC licence is 40 years commencing on the date of issue.

Avery Dam Facility

The facility is a 260 kilowatt hydroelectric generating facility located on the Winnepesaukee River in the City of Laconia, New Hampshire. The facility was constructed in 1985 at an existing site that was used for power generation and consists of a dam, intake structure, powerhouse and tailrace. The generating equipment includes two Flygt submersible turbine/generators. The facility is owned by the Avery Dam Partnership.

Power Purchase Agreement

The NHPUC issued a rate order to Avery Hydroelectric, Inc., on June 20, 1985. This rate order was subsequently assigned by Avery Hydroelectric, Inc. to the Avery Dam Partnership. The rate order requires PSNH to purchase all output from the facility at specified rates. The amount payable is based on an On-peak and Off-peak energy payment and a capacity payment. The term of the rate order is for a period of 29 years commencing September 1, 1986 and expires in September 2015. On August 27, 1986, Avery Dam Partnership signed an interconnection agreement with PSNH concerning operational matters relating to the facility. As discussed under "*General Development of the Business - Other Developments in 2003*", after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

Avery Dam Partnership has entered into a lease agreement with the New Hampshire Water Resources Board, a public corporation and an agency of the State of New Hampshire, for the water rights, land and associated facilities of the Avery Dam on the Winnepesaukee River. The lease agreement was amended and restated on November 27, 1985. The term of the lease agreement is the earlier of 50 years or the termination of the FERC licence and the rental payments are five percent of the adjusted gross revenue ("AGR") for years 1 to 5, 10% of AGR for years 6 to 10, 15% of AGR for years 11 to 15 and 20% of AGR for years 16 to 50.

The Avery Dam Partnership entered into a contract with water users with the New Hampshire Water Resources Board dated November 27, 1985. The term of the agreement is 15 years and can be extended after that period on a yearly basis upon mutual agreement. The rent includes both a base fee and an incentive fee.

The Avery Dam Partnership entered into an agreement for payment in lieu of taxes with the City of Laconia pursuant to an agreement dated October 9, 1985. The agreement provides for the owner to pay the City of Laconia an amount equal to five percent of gross revenues from the facility in lieu of municipal taxes. The agreement has a term of 20 years.

FERC Licence

The facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on March 22, 1985 (FERC Project No. 6752). The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility; and (ii) it must maintain a minimum flow of 30 cubic feet per second from April to September and 20 cubic feet per second during the remainder of the year.

Hadley Falls Facility

The facility is a 250 kilowatt hydroelectric generating facility located on the Piscataquog River near the Town of Goffstown, New Hampshire. The facility consists of a dam, intake canal, powerhouse and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was commissioned in 1986 at the site of an existing concrete dam which was rebuilt to facilitate the generating facility.

Power Purchase Agreement

In 1986, the NHPUC approved a rate order which requires PSNH to purchase the entire electrical output from the Hadley Falls Facility at specified rates. The amount payable is based on an energy payment plus a capacity payment. The term of the rate order is for a period of 20 years commencing September 1, 1986 and expires in September 2006. As discussed under "*General Development of the Business - Other Developments in 2003*", after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

Hydro Dynamic Corp. entered into a lease agreement dated July 30, 1981 with Heritage Door Company for the land and facilities required in order to construct and operate the Hadley Falls Facility. This agreement was assigned to the Hadley Falls Partnership on December 14, 1981. The term of this lease is for 35 years commencing in 1981 and the rent is a negotiated fee based on competitive rents. Hydro Dynamic Corp. also entered into a lease agreement dated September 8, 1981 with the New Hampshire Water Resources Board for the water rights at this location. This agreement was assigned to the Hadley Falls Partnership on October 26, 1981.

FERC Licence

The facility received an exemption from licensing for a small hydroelectric generating facility of five megawatts or less from FERC on January 19, 1982 (FERC Project No. 5379). The main compliance issue is that the facility must operate as an instantaneous run-of-the-river facility.

Hopkinton Facility

The facility is a 250 kilowatt hydroelectric generating facility located on the Contoocook River, in the Village of Contoocook, New Hampshire. The layout of the facility consists of a dam, intake, powerhouse and tailrace structure and is designed and operated as a run-of-the-river facility. The facility was constructed at the site of an existing concrete dam which was rebuilt to facilitate the new generating facility. The Hopkinton Facility is owned by the HDI Partnership.

Power Purchase Agreement

A power purchase agreement was executed between the Public Service Company of New Hampshire and the HDI Partnership on August 5, 1983 for all electrical energy produced at the Hopkinton Facility. The term of the agreement is 20 years, commencing January 1986, which was the commissioning date of the facility. Under the terms of the agreement, PSNH is required to purchase all energy for \$0.1242/kW-hr (US\$0.09/kW-hr), plus 50% of the positive amount of PSNH's incremental energy cost in excess of \$0.1242 (US\$0.09). Since incremental energy costs have not risen above this level, payments have been made at the rate of \$0.1242/kW-hr (US\$0.09/kW-hr) since commissioning of the facility. As discussed under "*General Development of the Business - Other Developments in 2003*", after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

Land and water rights for the site are leased from the Town of Hopkinton pursuant to an agreement dated September 2, 1983. The term of the lease is 40 years and payments under the agreement are based on a step-rated percentage of annual gross revenues from the facility. The lease makes provision to significantly reduce lease payments in the event that dam repairs exceed \$345,000 (US\$250,000). A separate agreement with the Town of Tilton provides for payments in lieu of property taxes based on gross revenues generated by the facility.

Rights to all necessary lands have been obtained in order to operate and maintain the transmission line for the facility.

FERC Licence

The Hopkinton Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on March 14, 1984 (FERC project No. 5735) for a 250 kilowatt facility. The main compliance conditions associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; (ii) a minimum flow of two cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality; and (iii) at the time of issuance of the FERC exemption order, the US Fish and Wildlife Service requested a downstream passage for Atlantic salmon seeded by the resource agencies. If there is a successful arrival of naturally migrating salmon, an upstream fish ladder will be required. The cost of installing such fish ladder, if required, is unknown at this time.

Milton Facility

The Milton Facility is located on the Salmon River on the Maine-New Hampshire border, approximately 70 km from Manchester, New Hampshire with an installed capacity of 1,335 kilowatts. The facility is located at a site which was historically utilized for electrical and mechanical energy production for mill purposes. The facility was substantially rehabilitated and expanded in 1986 and includes a 3,800 foot penstock leading from the intake to the powerhouse. The Milton facility is owned by SFR Hydro Corporation.

Power Purchase Agreement

The Milton Facility sells all energy produced to PSNH pursuant to a power purchase agreement dated July 17, 1982. The agreement terminates on July 1, 2012 and stipulates a fixed rate for the sale of energy over its term. As discussed under “*General Development of the Business - Other Developments in 2003*”, after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

SFR Hydro Corporation acquired all land necessary for the operation of the Milton facility from Iron Mountain Records Management Inc. In addition to direct ownership of certain parcels of land, SFR Hydro Corporation holds certain permanent easements on land and buildings employed by the facility. As a result of its ownership of the facility site, SFR Hydro Corporation was granted the water rights for the Salmon River available at the facility site for the operation of the facility.

FERC Licence

The Milton Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC in June 30, 1981 (FERC Project No. 3984). The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility; and (ii) a minimum flow of 25 cubic feet per second must be released downstream of the dam between April and June, when available, to maintain the instream fisheries and water quality.

Mine Falls Facility

The Mine Falls Facility is a 3,000 kilowatt hydroelectric generating station located on the Nashua River near the City of Nashua, New Hampshire. The site is comprised of two turbine-generators housed in a new concrete powerhouse located at the site of a historic concrete dam. The site was commissioned in 1986. The Mine Falls facility is owned by the Mine Falls Limited Partnership.

Power Purchase Agreement

A power purchase agreement dated March 25, 1984 was entered into between Seaward Development-Mine Falls Inc. and PSNH. The agreement was amended on November 14, 1985 and was assigned to the Mine Falls Partnership on December 10, 1985. The agreement expires on December 31, 2005. Under the amended terms, PSNH continues to purchase all electrical energy from the facility at a fixed rate of US\$0.09/kW-hr over the remainder of the term. As discussed under "*General Development of the Business - Other Developments in 2003*", after the completion of the transaction which renegotiated the power purchase rate to market, PSNH will continue to purchase the energy produced by the facility at the New England power pool market price.

Land and Water Rights

The land, physical structures and water rights associated with the facility are leased from the City of Nashua pursuant to a lease dated May 2, 1984. The lease has a term of 40 years and expires in 2024. Payments pursuant to the lease are based on a percentage of gross revenues earned from the sale of energy from the facility.

FERC Licence

The City of Nashua and Seaward Construction Company Inc. received a FERC Licence (FERC Project No. 3442) for a small hydroelectric generating facility on March 26, 1985 with installed capacity of 3,032 kilowatts. The interest of Seaward Construction Company Inc. was assigned to the Mine Falls Partnership on November 5, 1985. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility; (ii) a minimum flow of 20 cubic feet per second must be released over the dam plus a minimum flow of 10 cubic feet per second must be released into an adjacent watershed, when available, to maintain the instream fisheries and water quality, and (iii) the existing upstream fish hoist system, while it appears to function properly, has not received final acceptance by FERC.

Great Falls Facility

The Great Falls Facility is a 10,950 kilowatt hydroelectric generating station located on the Passaic River near the City of Paterson, New Jersey. The site was originally utilized for the production of electrical energy and was decommissioned in January 1969. The powerhouse was declared a National Historic Landmark in 1971. In 1986, the facility underwent a major rehabilitation with the installation of three new turbine-generators and new electrical and control equipment and was recommissioned in December 1986. The Great Falls facility is owned by the Great Falls Hydroelectric Company (the "Great Falls Partnership"), a Maryland limited partnership.

Power Purchase Agreement

A power purchase agreement dated September 6, 1985 was entered into between the Great Falls Hydroelectric Company and Public Service Electric and Gas Company ("PSE&G"). The agreement was amended on February 9, 1998 and expires in 2002. Under the amended terms, PSE&G continues to purchase all electrical energy from the facility. The rates paid for such energy and capacity are based on the local marginal energy pricing paid by PSE&G for energy and capacity. In 2002, the average blended energy price was approximately US\$0.026 /kW-hr.

Land and Water Rights

The land, physical structures and water rights associated with the facility are leased from the Paterson Municipal Utilities Authority pursuant to a lease dated September 10, 1984. The lease expires on March 10, 2021. Payments pursuant to the lease are based on a percentage of gross revenues earned from the sale of energy from the facility, with a minimum annual payment.

FERC Licence

The Great Falls Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on March 1, 1981 for a 7,500 kilowatt facility, which exemption was amended on September 6, 1985 (FERC Project No. 2814) to allow for a 10,950 kilowatt facility. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; and (ii) (ii) As of January 1, 2002 a minimum flow of 200 cubic feet per second must be released over the dam for aesthetic purposes, when available, to maintain the instream fisheries and water quality.

Worcester Facility

The Worcester Facility is located on the North Branch of Winnooskie River, in the Town of Worcester, Vermont approximately 10 miles north of Montpelier, Vermont. The facility is located at a concrete gravity dam 80 feet long and 21 feet in height. It is a run-of-the-river facility and is rated at 180 kilowatts. The facility has one Ossberger Cross- Flow turbine.

Power Purchase Agreement

The agreement with Vermont Power Exchange, Inc. is for a term of 30 years. From August 15, 1986 until August 15, 2016, the specified settlement rates set out in the agreement will be paid to the producer.

Land and Water Rights

A Fund entity, Worcester Hydro Company, Inc., owns all land necessary for the operation of the facility. Certain permanent easements on land and buildings are also held by the Worcester Hydro Company, Inc. As a result of its ownership of the generating station site, Worcester Hydro Company, Inc. was granted the water rights for the facility.

FERC Licence

The facility received an exemption from licensing for a small hydroelectric generating station facility from FERC on June 11, 1985. The exemption order is for a generating facility of less than 5,000 kilowatts. The facility was commissioned in 1985.

The main compliance conditions associated with the facility are that: (1) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) a minimum flow of ten cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Western Canada Development – Dickson Dam and Drayton Valley Facilities

Dickson Dam Facility

The Dickson Dam Facility is located 20 kilometres west of the Town of Innisfail, Alberta. The Dickson Dam Facility is a 15.0MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the waterflows of the Red Deer River. The facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992.

Power Purchase Agreement

The Dickson Dam power purchase agreement was entered into with TransAlta Utilities Corporation (“TransAlta”) on December 7, 1990 and was approved by the Alberta Public Utilities Board on January 16, 1991. It has a term of 20 years ending on January 16, 2012. Under this agreement, TransAlta is obligated to accept delivery of all electricity in amounts up to 115% of the 12.7MW capacity which is allocated to the facility at rates stipulated by the *Small Power Research and Development Act* (Alberta) (the “Small Power Act”). The price paid by TransAlta during 2002 was \$0.062/kw-hr.

Use of Works Agreement

The original owner of the Dickson Dam Facility entered an agreement with the Government of Alberta under which it obtained the right to construct the Dickson Dam Facility and utilize the available waterflows for generating power until March 31, 2030. This agreement has been transferred to a Fund entity. Under the Use of Works Agreement, such Fund entity has accepted the obligation to operate the Dickson Dam Facility in accordance with the requests of the Minister of Environment (Alberta) to accommodate water release changes. Following commercial operation in 1992, the Dickson Dam Facility has been operated in accordance with the terms of the Use of Works Agreement. Under the Use of Works Agreement, the Minister does not guarantee any reservoir water level or any supply of water to the Dickson Dam Facility, which is dependent upon water flows in the Red Deer River. The Minister also reserves the right to control releases and direct that the Dickson Dam Facility be operated to meet certain water management objectives relating to flood control, water quality levels and inter-provincial treaty obligations. The owner of the Dickson Dam Facility is obligated to make annual payments to the Minister of Environment (Alberta) of \$50,000 (measured in 1992 dollars) throughout the term of the Use of Works Agreement and which payments escalate annually by the Alberta Consumer Price Index. In 2002, the annual payment (inclusive of water rental) was \$61,300.

Drayton Valley Facility

The Drayton Valley Facility is a 12.0MW bio-mass fired generating facility which produces electricity from burning wood waste provided by Weyerhaeuser Canada Ltd. ("Weyerhaeuser") using a single steam turbine. The facility was commissioned in 1994 and has operated satisfactorily since its commissioning.

Drayton Valley Power Income Fund and Algonquin Power Trust own, directly and indirectly, a 50% interest in the partnership which owns the Drayton Valley Facility. The Fund's partner in the Drayton Valley Facility is also the operator. The operator has extensive experience in operating biomass-fired generating facilities.

Power Purchase Agreement

The Drayton Valley Facility has entered into a 20 year agreement with TransAlta dated December 13, 1994, pursuant to which TransAlta is obligated to purchase all electricity produced at the Drayton Valley Facility up to 10.5MW at prices stipulated by the Small Power Act. Electricity generated at the Drayton Valley Facility is delivered to TransAlta through interconnection facilities erected on and adjacent to the facility site.

Fuel Supply

The Drayton Valley Facility entered into an agreement with Weyerhaeuser on January 30, 1995 pursuant to which Weyerhaeuser is obligated to supply, without charge, all wood waste produced at the Weyerhaeuser sawmill plant which is co-located with the Drayton Valley Facility. The agreement, which expires in 2017, requires the Drayton Valley Facility to establish a storage pile of wood waste in an amount which will enable the Drayton Valley Facility to operate at an 87% capability factor for more than six months without further wood waste deliveries. The Drayton Valley Facility operating at approximately 95% of maximum annual capacity consumes approximately 84,000 oven dried tonnes (odt) of wood waste each year. The Weyerhaeuser mill currently delivers approximately 90,000 odt of wood waste each year. Weyerhaeuser is one of Canada's largest forest products companies and the Drayton Valley sawmill and strandboard plant is a core asset. This plant currently produces approximately 113 million feet of lumber board from the sawmill and approximately 390 million feet from the strandboard facility. Weyerhaeuser plans to operate the Drayton Valley plant beyond the term of the fuel agreement with the Drayton Valley Facility. If Weyerhaeuser fails to fulfil its obligations under the fuel supply agreement with the Drayton Valley Facility, it is estimated that there is approximately 100,000 odt of alternative bio-mass wood waste available within a 160 kilometre radius of the Drayton Valley Facility. No assessment has been made of the impact of transportation costs for such alternative bio-mass fuel upon the economics of the Drayton Valley Facility.

Thermal Development - Peel Facility, Joliet Facility, Crossroads Facility, Sanger Facility and Windsor Locks Facility

KMS Power Income Fund

At the beginning of March 2002, Algonquin Power Trust, a trust of which the Fund is the sole beneficiary, completed the acquisition of approximately 86.7% of the outstanding trust units and approximately 47.3% of the outstanding convertible debentures of the KMS Power Income Fund. The

debentures were issued in 1999 by KMS, in the aggregate principal amount of \$30,000,000, at a price of \$1,000 per debenture. The debentures have a five year term (maturing on June 30, 2004) with a coupon of 10%, and are currently convertible into trust units of KMS at \$11.00 per unit until maturity. In July 2002, Algonquin Power Trust completed the compulsory acquisition of the remaining trust units of KMS that were not deposited to the Algonquin Power Trust's take-over bid. As a result of the compulsory acquisition pursuant to the KMS declaration of trust, the Algonquin Power Trust is now the sole unitholder of KMS.

KMS Power Income Fund owns the following generating facilities, through its subsidiary entities:

Peel Facility

The Peel Facility is a 10.0 MW generating station which produces electricity from incinerating non-recyclable materials, including municipal solid waste, using steam to drive a turbine generator to produce electricity.

Power Purchase Agreement

KMS Peel Inc. and OEFC have entered into a power purchase agreement which expires in 2012. Pursuant to the power purchase agreement, OEFC is required to purchase all the electricity produced by the facility. The current electricity rates are as follows (escalating price based on changes in the consumer price index): (1) winter peak - \$0.0961/ kWhr, (2) winter off-peak - \$0.0373/ kWhr, (3) summer peak - \$0.0797 /kWhr, (4) summer off-peak - \$0.0326/kWhr.

Fuel Supply

KMS Peel Inc. and the Regional Municipality of Peel (the "Regional Municipality") have entered into a "tip or pay" waste supply agreement and an expanded capacity agreement which expire in 2012. Pursuant to these agreements, the Regional Municipality supplies the facility with a minimum of 127,000 tonnes and up to 36,000 tonnes per year of acceptable municipal solid waste, respectively. At the end of the waste supply agreement the Regional Municipality has the option to renew the agreement for an additional five year term. The current agreement requires the Regional Municipality to pay a "tipping fee" for each tonne of acceptable waste delivered. This fee is adjusted monthly throughout the term of the agreement based on changes in the Toronto-area consumer price index. Additional volumes of waste may be supplied by the Regional Municipality at the request of either party, subject to the agreement of the other.

The waste supply agreement provides that if certain taxes are imposed or revised standards are set for certain environmental or operating matters affecting the facility, the tipping fees paid by the Regional Municipality will be increased to reflect the increased capital or operating costs so imposed on KMS Peel Inc. by the taxes or revised standards.

Joliet Facility

The Joliet Facility is a landfill gas to electricity facility at the CDT landfill located near Joliet, Illinois. KMS Joliet Power Partners, L.P. ("KMS Joliet") owns and operates the electrical generating facility at the landfill. The facility is designed to generate approximately 1.6 MW of electrical power.

Power Purchase Agreement

KMS Joliet has entered into an electrical purchase agreement with Commonwealth Edison Company ("CECo"), a major mid-western utility company. Pursuant to the agreement, CECo has agreed to purchase all electricity produced by the facility under a one year contract, automatically renewable yearly thereafter.

Fuel Supply

The CDT landfill occupies approximately 20.2 hectares. Gas from 20 wells drilled in the CDT landfill flows into an underground pipeline system where it is compressed. The pressurized gas then fuels two Caterpillar reciprocating engines to generate electricity. Mank, L.P. owns the rights to extract gas from the CDT landfill. Pursuant to a gas sales agreement, KMS Joliet purchases landfill gas necessary to operate the generating facility at a fixed price of US \$0.70 per MMBTU through December 31, 2007. Under the gas sales agreement, KMS Joliet is obliged to make an annual minimum purchase of gas in an amount not to exceed \$65,000. KMS Joliet is obligated under an agreement with CDT to make payments of US \$25,000 per year during the term of the agreement, commencing upon commercial production. In addition, KMS Joliet must pay to CDT a royalty of 25% of the revenue received by Mank, L.P. for the gas sold to KMS Joliet, but in no event less than US \$0.40 per one million British Thermal Units of landfill gas sold. A production royalty of 1% of gross revenues from electricity sales is also payable to CDT.

Crossroads Facility

KMS Crossroads, Inc. operates the Crossroads Facility located in an office building complex in Mahwah, New Jersey and utilizes one 7.0 MW Solar Taurus 70 natural gas fired turbine to produce electricity and thermal energy.

Power Purchase Agreement

KMS Crossroads, Inc. has entered into a power sales agreement with Orange and Rockland Utilities Inc. ("O&R") for the purchase of up to 3.88 MW of capacity. The power sales agreement expires on December 31, 2008. The sales price of electricity under the power sales agreement includes both a variable and a fixed component. The variable component is redetermined once each calendar quarter for the term of the power sales agreement. The variable component is based on the weighted average price at which O&R transfers natural gas to its electric department for the purpose of generating electricity, as ordered by the New York Public Service Commission, in the previous calendar quarter. In the event no natural gas is transferred in a calendar quarter, the variable component will be based on the weighted average price of number six fuel oil burned by O&R at its Lovett and Bowline generating facilities in that calendar quarter. The fixed component is US \$0.0995 /kW-hour for on peak hours, US \$0.0770 for mid-peak hours and US\$0.02704 for off-peak hours. Effective for the second quarter of 2002, the variable component is US\$0.0166 /kW-hour. The variable component remains constant regardless of the hour during which the kilowatts are generated.

Pursuant to an energy services agreement, Crossroads, Inc. is obliged to use reasonable efforts to provide firm electrical and thermal energy to the Crossroads Corporate Park, owned by Crossroads Developers Associates L.L.C ("CDA") and CDA must purchase all of its required electricity from the KMS Crossroads, Inc. and all thermal power produced by KMS Crossroads, Inc. Pursuant to the energy services agreement the sales price paid by CDA for electricity for the year ended December 31, 2002

was an average price of US\$0.094 /kW-hr. for each kilowatt hour generated and US\$5.87 / million British Thermal Unit of thermal energy sold.

Sanger Facility

The Sanger Facility is a 43.5 MW natural gas-fired generating facility located in Sanger, California. The Sanger Facility is a combined cycle generating station comprised of a 32 MW Westinghouse natural gas fired turbine and a 11.5 MW General Electric steam turbine, commissioned in 1991.

Power Purchase Agreement

Output of the facility is governed by the terms and conditions of a firm capacity and energy power purchase agreement between Sanger Power, L.L.C. and Pacific Gas and Electric Company. The original agreement was signed in 1984 and has been amended five times, the last amendment occurring in July 2001. The agreement is for a term of 30 years and calls for delivery of 38,000 kW of firm capacity and is effective through April 2022.

Capacity payments are based on a fixed amount of \$190 per kW/ year and is paid monthly on the basis of a capacity allocation factor and a transmission loss factor which is fixed. To qualify for the full capacity payment, the facility must maintain a capacity factor of 80% during the peak and/ or partial-peak hours of each monthly billing period. Annual capacity payments are estimated to be \$7,140,000 for 2002.

In July 2001 there was a fifth amendment to the power purchase agreement. This change fixes the energy price at an annual average of \$0.0537 per kWhr. Actual energy prices vary depending on a time-of-day adjustment as well as a seasonal adjustment. The fixed price arrangement remains in place until July 15, 2006. After this date, barring any decision to revise Pacific Gas and Electric Company's short-term avoided cost pricing by the California Public Utility Commission, energy pricing will revert back to the existing short term avoided cost transition formula.

The power purchase agreement requires that the facility meet and maintain its status as a FERC Qualifying Facility under PURPA. PURPA requires that a Qualifying Facility be owned by an entity which is not primarily engaged in the sale or generation of electric power. In order to meet the ownership criteria, the applicant must demonstrate that no more than 50% of the equity interest in a Qualifying Facility site is held, directly or indirectly, through subsidiaries, by electric utilities and/or electric utility holding companies. The Manager is of the view that the Sanger Facility qualifies as a Qualifying Facility.

Fuel Supply

Natural gas for the facility is delivered under the terms of a gas supply agreement with Sempra Energy Trading Corp. Deliveries under the agreement take place weekdays between September 1, 2001 and July 31, 2006. The agreement provides for a fixed price for all quantities below a base amount. All natural gas required above the base amount is purchased at the spot price available on the day burned.

Energy Lease

Pursuant to a lease, energy supply and common services agreement between Sanger Power, L.L.C. and Dyna Fibers Inc., Dyna Fibers Inc. leases a portion of the facility site in order to carry on its

hydro mulch business and purchases certain energy at a cost equal to 3% of the fuel costs incurred by the facility, to offset the incremental cost of fuel to supply such energy. The water consumption, exhaust heat and steam consumption by the hydro mulch operations are metered and recorded for FERC qualifying facility calculations that are submitted to Pacific Gas and Electric Company on an annual basis.

Windsor Locks Facility

The Windsor Locks Facility is a 56 MW (gross) natural gas-fired generating facility located in Windsor Locks, Connecticut. The Windsor Locks Facility is a combined cycle generating station comprised of a 40 MW General Electric natural gas fired turbine and a 16 MW General Electric steam turbine and was commissioned in 1990.

Power Purchase Agreement

The majority of the output of the Windsor Locks Facility is governed by the terms and conditions of a power purchase agreement with Connecticut Light and Power Company. The original agreement was signed in 1986 and expires in April 2010.

The agreement calls for delivery of 38 MW summer and 39 MW winter firm capacity. Energy payments are based on a fixed amount of \$2.18 per kW/hour during peak hours and US\$0.0058 per kW/hour for off-peak hours. In addition, a variable payment of US\$0.022 per kW/hour multiplied by the ratio of the buyer's gas cost divided by \$2.66 MMBtu is payable, insulating the Facility from changes to the price of natural gas.

The power purchase agreement requires that the facility meet and maintain its status as a FERC Qualifying Facility under PURPA or rate reductions will result. PURPA requires that a Qualifying Facility be owned by an entity which is not primarily engaged in the sale or generation of electric power. In order to meet the ownership criteria, the applicant must demonstrate that no more than 50% of the equity interest in a Qualifying Facility site is held, directly or indirectly, through subsidiaries, by electric utilities and/or electric utility holding companies. The Manager is of the view that the Windsor Locks Facility qualifies as a Qualifying Facility.

Fuel Supply

Natural gas for the facility is delivered under the terms of a gas supply agreement with Yankee Gas Service Company. Gas is supplied by Yankee Gas at 73% of its weighted average cost of gas (WACOG) for the month. The gas contract contains minimum annual consumption requirements with associated penalties for shortfalls.

Energy Services Agreement and Ground Lease

Pursuant to a Ground Lease and an Energy Services Agreement between Algonquin Windsor Locks LLC and Ahlstrom Windsor Locks, LLC ("Ahlstrom"), Ahlstrom leases to Algonquin Windsor Locks, LLC the facility site, and utilizes thermal steam energy and a small portion of electrical generation of the Windsor Locks Facility for use at its specialty fibres composites mill located adjacent to the Windsor Locks Facility. Both the Ground Lease and the Energy Services Agreement expire in January 2018, subject to certain early termination rights in favour of Ahlstrom and rights of renewal in favour of both parties. Payments under the Energy Services Agreement are also fully indexed to the cost of natural gas

consumed by the facility.

Other Interests in Energy-Related Developments

Pursuant to an agreement with Confederation Life Insurance Company, in liquidation dated September 5, 2001 (the "Confederation Life Agreement"), Algonquin Power Trust acquired note and share interests in certain companies which own the following generating facilities:

Kirkland Lake Facility

The Kirkland Lake Facility is a 102 MW combined cycle co-generation facility located in Kirkland Lake, Ontario owned by Kirkland Lake Power Corporation ("Kirkland") which burns natural gas and wood waste to generate electricity using three 23MW gas turbines and two steam turbines. The facility was commissioned in 1991 by Northland Power Inc. ("Northland") and Northland remains the operator of the facility. Electricity produced by the facility is sold to OEFC pursuant to a 40 year contract executed in 1989. Amendments to such power purchase agreement have been made so that electricity in excess of that committed to OEFC under the power purchase agreement may be sold into the deregulated market in Ontario. Natural gas used by the facility is supplied by Gulf Canada Resources Limited and Chevron Canada Resources under supply contracts with 20 year terms commencing in 1991. Price increases under such gas supply agreements are generally tied to price increases under the power purchase agreement with OEFC. Wood waste consumed by the facility is supplied by local forest product companies under contracts of varying terms with the longest being 31 years. The capital structure of Kirkland is comprised of approximately \$87.5 million of senior debt outstanding and 3,562,963 Class A voting shares and 37,000,000 Class B non-voting shares. The Class A and Class B shares are identical in all respects except the Class A shares have voting rights.

Under the Confederation Life Agreement, Algonquin Power Trust acquired 32.4% of the Class B non-voting shares issued by Kirkland. The management agreement between Northland and Kirkland contemplates that Kirkland will achieve specified target operating profits from the operation of the Kirkland Lake Facility, failing which, among other things, Kirkland may terminate the management agreement. It is Kirkland's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income, and the amount of dividends to date have been consistent with the targeted operating profits (net of applicable tax) established in the management agreement. Northland has granted Kirkland a put option to sell the Kirkland Facility to Northland with an exercise date of February 28, 2011 at exercise price of \$10 million. Under the management agreement, 90% of operating income of the facility will be paid to Northland after the exercise date and, accordingly, it is anticipated that Kirkland will exercise such put option and the proceeds of such sale will be utilized to repay debt and make distributions to shareholders.

Cochrane Facility

The Cochrane Facility is a 35.8 MW combined cycle co-generation facility located in Cochrane, Ontario owned by Cochrane Power Corporation ("Cochrane") which burns natural gas and wood waste to generate power using a 26.5MW gas turbine and a steam turbine. The facility was commissioned in 1990 by Northland and Northland remains the operator of the facility. Electricity produced by the facility is sold to OEFC pursuant to a 25 year contract executed in 1989. Amendments to such power purchase agreement have been made so that energy in excess of that committed to OEFC under the power purchase agreement may be sold into the deregulated market in Ontario. The majority (90%) of the natural

gas used by the facility is supplied by Canadian Natural Resources Limited under a supply contract with a 20 year term which expires in 2012. Price increases under such gas supply agreement are generally tied to price increases under the power purchase agreement with OEFC. Wood waste consumed by the facility is supplied by local forest product companies under contracts of varying terms with the longest being 30 years. The capital structure of Cochrane has no debt and consists of 6,000,000 Class A voting shares representing 11.54% of the equity interests and 46,000,000 Class B non-voting shares representing approximately 88.46% of the equity interests.

Under the Confederation Life Agreement, Algonquin Power Trust acquired 25.0% of the Class B non-voting shares issued by Cochrane. The management agreement between Northland and Cochrane contemplates that Cochrane will achieve specified target operating profits from the operation of the Cochrane Facility, failing which, among other things, Cochrane may terminate the management agreement. It is Cochrane's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income, and the amount of dividends to date have been consistent with the targeted operating profits (net of applicable tax) established in the management agreement. Northland has granted Cochrane a put option to sell the Cochrane Facility to Northland with an exercise date of February 28, 2011 at exercise price of \$3.0 million. Under the management agreement, 90% of operating income of the facility will be paid to Northland after the exercise date and, accordingly, it is anticipated that Cochrane will exercise such put option and the proceeds of such sale will be distributed to shareholders.

Cardinal Facility

Cardinal Power of Canada L.P. ("Cardinal") owns the Cardinal Facility which is a 150 MW combined cycle co-generation facility fuelled by natural gas located in Cardinal, Ontario and which generates and sells electricity exclusively to OEFC at contracted rates for a minimum of 20 years commencing in 1992. In addition to electricity, the facility generates and sells steam to Canada Starch Operating Company pursuant to a 20 year steam sales agreement. The Cardinal Facility purchases natural gas from Husky Oil Limited under a 20 year gas supply agreement maturing in 2014 and under which the facility is provided with all required natural gas at predetermined prices, subject to pricing changes within fixed ranges. Natural gas for the facility is transported by TransCanada PipeLines Limited and Centra Gas Ontario, Inc. pursuant to 20 year and three year firm service agreements, respectively. The facility is operated by Sithe Energies Canada Power Service Inc. and the operator is paid a monthly fee for operations services, which fee is subject to annual escalations equivalent to changes in the consumer price index. The capital structure of Cardinal includes \$145.5 million of senior debt maturing October 1, 2014 and paying 9.68% per annum, compounded quarterly. Pursuant to the credit agreement entered into in respect of the senior debt, a debt service escrow account has been established to provide continued debt service payments in the event of unforeseen business disruptions.

Under the Confederation Life Agreement, Algonquin Power Trust acquired a 16.9% interest in the senior debt issued by Cardinal. The outstanding principal amount of the interest in the senior debt acquired by Algonquin Power Trust as at December 31, 2002 was approximately \$19.9 million.

Chapais Facility

Chapais Energie, Societe en Commandites ("Chapais") owns an electricity generating facility which burns wood waste and is located in the Town of Chapais, Québec. The Chapais Facility was placed into commercial operation after significant commissioning difficulties and delays in August 1995. The Chapais Facility sells electricity to Hydro Québec pursuant to a power purchase agreement with a 20

year term expiring December 1, 2015, with a 5 year renewal option. Wood waste is purchased from local sawmills in the area with transportation expense being the principal cost incurred to obtain the wood waste supply. The Chapais Facility is operated by a third party operator. As part of a restructuring which occurred as a result of commissioning delays and difficulties, the original debt incurred by Chapais in the construction of the facility has been temporarily exchanged for certain preferred shares until July 31, 2004. The capital structure of Chapais is comprised of 50 common shares, 400 Class A non-voting shares and 336 Class B non-voting preferred shares. Chapais is also the debtor under a term loan held by CHEL Subco Inc. ("CHEL"). The authorized capital of CHEL consists of common shares (all of which are held by Chapais), as well as Class A preferred shares (the "Tranche A Shares"), Class B preferred shares (the "Tranche B Shares") and Class C preferred shares. There are approximately \$47.5 million of Tranche A Shares and \$15.3 million of Tranche B Shares outstanding. Both tranches of preferred shares are expected to pay dividends at the rate of 6.5% per annum. On July 31, 2004, the Tranche A and Tranche B Shares are expected to be exchanged for term loan interests issued by Chapais, which loans will bear interest at the rate of 10.789% and 4.91%, respectively.

Under the Confederation Life Agreement, Algonquin Power Trust acquired a 12.1% interest in both the Tranche A and Tranche B Shares and a 33.9% interest in the Class B non-voting preferred shares of Chapais.

Brooklyn Facility

Brooklyn Power Corporation ("Brooklyn") owns a 28.0 MW bio-mass-fired electric generating facility located in Queen's County, Nova Scotia. The Brooklyn Facility was commissioned in December 1995 and consumes the wood waste produced by the Bowater Mersey Paper Company Limited ("Bowater") facility in addition to certain wood waste purchased from several local sawmill operators in southern Nova Scotia. Brooklyn sells electricity to Nova Scotia Power Inc. ("NSPI") pursuant to a power purchase contract expiring in 2028, the pricing under which is based on NSPI's avoided costs. Brooklyn delivers steam to Bowater in exchange for a portion of the wood waste fuel. The capital structure of Brooklyn is comprised of approximately \$54.0 million of senior debt and 1,000,000 common shares.

Under the Confederation Life Agreement, Algonquin Power Trust acquired a 13.6% interest in the senior debt issued by Brooklyn and a 13.6% interest in the outstanding common shares of Brooklyn. The outstanding principal amount of the interest in the senior debt acquired by Algonquin Power Trust as at December 31, 2002 was approximately \$8.1 million.

Wastewater Treatment Development – Black Mountain, Gold Canyon, Tall Timbers, Bella Vista and Woodmark Facilities

Black Mountain Facility

The Black Mountain Sewer Company ("BMSC") was established in 1971 to support the development of the Boulders Resort and golf course (currently owned by Wyndham International). This resort is located ten miles north of Scottsdale Arizona, in the town of Carefree, Arizona. BMSC currently serves approximately 1,800 customers in the Town of Carefree.

The existing plant is located in the residential portion of the Boulders Resort, in the immediate vicinity of residences and the Boulders golf course. The plant owned by the utility treats 120,000 gallons per day and presently runs at capacity every day. The reclaimed water produced by the plant is delivered

by pipe to a lake on the Boulders golf course. The BMSC plant is an activated sludge plant and produces an effluent which exceeds quality standards for effluent discharge and reuse and which is used for irrigation of the Boulders golf course and surrounding vegetation. Excess wastewater is delivered by pipe to the City of Scottsdale Wastewater Treatment Plant under an agreement entered into in 1996.

BMSC provides sewer services for a flat tariff rate of US\$38 per month. The utility operates under a perpetual regulated agreement called a Certificate of Convenience and Necessity (“CC&N”) and is regulated by the Arizona Corporation Commission or ACC. The facility operates under Arizona Department on Environmental Quality – Aquifer Protection Permits and Reuse Permits.

Gold Canyon Sewer Company

The Gold Canyon Sewer Company (“GCSC”) was established in 1984 to serve a number of residential developments in the City of Gold Canyon area, approximately 25 miles east of downtown Phoenix, Arizona. GCSC currently serves over 4,000 residential customers. During 2002, GCSC experienced a 25% growth rate in the number of connections to the utility. GCSC provides sewer services at a flat tariff of US\$35 per month. GCSC operates under a CC&N and is regulated by the ACC.

The treatment process is comprised of an extended aeration facility combined with a sequencing batch reactor. The facility has a peak treatment capacity of 1.0 million gallons per day. The facility is currently operating at 750,000 gallons per day and is expected to be expanded to its approved capacity of 1.9 million gallons per day. The facility is expected to ultimately serve approximately 9,000 customers.

The facility is a consumptive re-use facility and sells its reclaimed water for use as irrigation water on five neighbouring golf courses. The treatment facility operates under Arizona Department on Environmental Quality – Aquifer Protection Permits and Reuse Permits.

Bella Vista Water Company

Bella Vista Water Company (“BVWC”) was formed in 1952 to serve a new motel and several small commercial buildings developed in the Town of Sierra Vista, Arizona. The utility currently serves approximately 7,000 connected water customers and has experienced long term growth at the rate of 3% per year.

All potable water supplied by the utility is obtained from deep well groundwater. There are 29 wells supplying the Bella Vista infrastructure and water from all wells is disinfected at the source prior to distribution.

In 2002, the average water bill for each connection to this utility was approximately US\$39 per month. The utility operates under a CC&N and is regulated by the ACC. The facilities operate under Arizona Department on Environmental Quality – Aquifer Protection Permits and Reuse Permits.

BVWC currently has outstanding indebtedness to the Water Infrastructure Finance Authority evidenced by two 25 year fully amortizing notes (“BVW Notes”). The first BVW Note, issued in 1995, bears interest at the rate of 6.10% and has a remaining balance as at December 31, 2002 of US\$153,090.74. The other BVW Note bears interest at the rate of 6.26% and has an outstanding balance of US\$1,997,527.40 as at December 31, 2002.

Tall Timbers Utility Company

Tall Timbers Utility Company (“TTUC”) was formed in 1983 to serve subdivision developments in the City of Tyler, Texas approximately 90 miles east of Dallas. The utility now serves approximately 1,000 connected customers consisting of 11 commercial/light industrial connections and the balance representing residential connections. The utility experienced growth of approximately 5% in 2002. A new highway is under construction through the CC&N service area which is anticipated to result in increased growth.

The current approved customer rate is US\$40.08 per month. TTUC operates under a CC&N and is regulated by Texas Commission on Environmental Quality (“TCEQ”). The facility discharges to the nearby Mud Creek.

Woodmark Utility Company

Woodmark Utility Company (“WUC”) was formed in 1990 to serve a small subdivision under construction near the Town of Tyler, Texas approximately 90 miles east of Dallas, Texas. The utility currently serves 850 connected customers.

Currently approved rates are US\$32.60 per month. WUC is currently pursuing a rate case with the TCEQ and has requested an increase to a customer rate of approximately \$40 per month. WUC operates under a CC&N and is regulated by the TCEQ. The facility discharges to the nearby Mud Creek.

Litchfield Park Service Company

Litchfield Park Service Company (“LPSCo”) is a water distribution and wastewater reclamation utility located in the West Valley of Maricopa County, 15 miles west of Phoenix, Arizona whose service area includes sections of the Cities of Goodyear, Avondale and Litchfield Park, Arizona. According to the 2000 census data, Maricopa County is the fastest growing county in the United States.

LPSCo presently serves approximately 9,000 water and 9,000 wastewater customers located in its CC&N. The LPSCo water infrastructure includes a total of eight active wells and a 6.3 million gallon reservoir which provides water to the current customer base through a single pressure zone. LPSCo recently completed construction and commissioning of a 4.2 million gallon per day water reclamation facility. This facility now operates at 40% capacity and supplies Class “A+” reclaimed water to a number of local golf courses in the area.

Approved rates for LPSCo are US\$32 per month for sewer services and the average customer bill for water is approximately US\$32 per month. LPSCo operates under a CC&N and is regulated by the ACC. The company operates under Arizona Department of Environmental Quality – Aquifer Protection Permits and Reuse Permits.

The Litchfield Park Service Company currently has outstanding indebtedness to the City of Goodyear in the amount of US\$12,590,000 in respect of which the City of Goodyear has acted as a conduit issuer of a like amount of Industrial Development Authority bonds (“LPSCo Bonds”). The LPSCo Bonds consist of two series, both fully amortizing over a 30 year term. The first series was issued in 1999, has a principal amount as of December 31, 2002 of US\$5,090,000 bearing interest at the rate of 5.87%. The second series was issued in 2000 with a principal amount as of December 31, 2002 of US\$7,500,000

and bearing interest at the rate of 6.71%.

DECLARATION OF TRUST

The Fund was created on September 8, 1997 pursuant to the Declaration of Trust with a view to the completion of an initial public offering of its Trust Units and the acquisition of direct or indirect equity interests in certain of the Fund Businesses.

The following is a summary of certain provisions of the Declaration of Trust. For a complete description of the Trust Units and the Declaration of Trust, reference should be made to the Declaration of Trust.

Sole Undertaking

The Declaration of Trust provides that, notwithstanding any other provision thereof, the only undertaking of the Fund is (a) the investing of its funds in property (other than real property or an interest in real property), (b) the acquiring, holding, maintaining, improving, leasing or managing of any real property (or an interest in real property) that is capital property of the Fund, or (c) any combination of the activities in (a) and (b).

Trustees

The Trustees are entitled to compensation for services rendered to the Fund in their capacity as Trustees. Compensation has been established at \$15,000 per year plus \$1,000 for each meeting attended in person and \$500 for each meeting attended by telephone per Trustee.

The Declaration of Trust provides that, subject to the terms and conditions of the Declaration of Trust, the Trustees may, in respect of the trust assets and the business and affairs of the Fund, exercise any and all rights, powers and privileges that could be exercised by a legal and beneficial owner thereof. The number of Trustees will be not less than one nor more than seven. The Declaration of Trust prohibits non-residents of Canada (as that term is defined in the *Tax Act*), among others, from being Trustees. The Trustees are responsible for, among other things: (i) acting for, voting on behalf of and representing the Fund as a shareholder of Algonquin Holdco, an indirect shareholder and noteholder of Algonquin Canada, a unitholder of Algonquin Power Trust and a noteholder of Algonquin America; (ii) maintaining records and providing reports to Unitholders; (iii) supervising the activities and managing the investments and affairs of the Fund; and (iv) effecting payments of Distributable Cash from the Fund to Unitholders.

A Trustee may resign upon written notice to the Fund and may be removed by a majority of the votes cast at a meeting of Unitholders and the vacancy created by such removal may be filled at the same meeting, failing which it may be filled by the Trustees.

A quorum of the Trustees, being one Trustee at any time there is only one Trustee duly appointed or two Trustees at any time there are two or more Trustees duly appointed, may fill a vacancy in the Trustees, except a vacancy resulting from an increase in the number of Trustees or from a failure of the Unitholders to elect the required number of Trustees. In the absence of a quorum of the Trustees, or if the vacancy has arisen from a failure of the Unitholders to elect the minimum number of Trustees, the Trustees will forthwith call a special meeting of Unitholders to fill the vacancy. If the Trustees fail to call

such meeting or if there are no Trustees then in office, any Unitholder may call the meeting.

The Trustees may, between annual meetings of Unitholders, appoint one or more additional Trustees to serve until the next annual meeting of Unitholders, but the number of additional Trustees will not at any time exceed one-third of the number of Trustees who held office at the expiration of the immediately preceding annual meeting of Unitholders.

The Declaration of Trust provides that the Trustees will act honestly and in good faith with a view to the best interests of the Fund and in connection therewith will exercise the degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. The Declaration of Trust provides that the Trustees will be entitled to indemnification from the Fund in respect of the performance of their duties under the Declaration of Trust in the absence of a breach of their duties and standard of care. The Declaration of Trust states that the duties and standard of care of the Trustees provided in the Declaration of Trust are intended to be similar to, and not greater than, those imposed on a director of a corporation governed by the Business Corporations Act.

Trust Units

An unlimited number of Trust Units may be issued pursuant to the Declaration of Trust. Each Trust Unit is transferable and represents an equal undivided beneficial interest in any distribution from the Fund, whether of net income, net realized capital gains or other amounts, and in any net assets of the Fund in the event of the termination or winding-up of the Fund. All Trust Units will rank among themselves equally and rateably without discrimination, preference or priority. Trust Units are not subject to future calls or assessments except that future offerings of Trust Units may be issuable for consideration payable in instalments, in which case the Fund may take security over any such Trust Units, and each Trust Unit entitles the holder thereof to one vote for each whole Trust Unit held at all meetings of Unitholders. Except as set out under *Declaration of Trust — Redemption Right*’ below, the Trust Units have no conversion, retraction, redemption or pre-emptive rights. Additional Trust Units may be issued in the future.

Issuance of Trust Units

The Declaration of Trust provides that Trust Units may be issued at the times, to the persons, for the consideration and on the terms and conditions that the Trustees determine. Trust Units may be issued in satisfaction of any non-cash distribution of the Fund to Unitholders on a pro rata basis. The Declaration of Trust also provides that immediately after any pro rata distribution of Trust Units to Unitholders in satisfaction of any non-cash distribution, the number of outstanding Trust Units will be consolidated such that each Unitholder will hold after the consolidation the same number of Trust Units as the Unitholder held before the non-cash distribution. In this case, each certificate representing a number of Trust Units prior to the non-cash distribution is deemed to represent the same number of Trust Units after the non-cash distribution and the consolidation.

Restrictions on Debt

The Declaration of Trust precludes the Fund from incurring indebtedness for borrowed money absent the passage of an Extraordinary Resolution, except in connection with the acquisition of additional facilities, provided certain criteria are met, and except for amounts in respect of previous acquisitions of facilities and amounts outstanding up to \$1.5 million incurred for capital expenditures and operations

related purposes for facilities in which the Fund has an interest.

Distributions

The amount of Distributable Cash to be distributed annually per Trust Unit will be equal to a pro rata share of interest, royalty and dividend income, taxable deemed dividends, lease payments or other income from the Leases received by the Fund in the year less: (i) administrative expenses of the Fund; (ii) amounts which may be paid by the Fund in connection with any cash redemptions of Trust Units; (iii) amounts required for the business and operations of the Fund, including amounts required to pay the deferred portion of the purchase price for any assets acquired by the Fund, directly or indirectly; and (iv) capitalized interest with respect to any notes held by the Fund. Any income of the Fund which is applied to any cash redemptions of Trust Units or is otherwise unavailable for cash distribution will be distributed to Unitholders in the form of additional Trust Units. Such additional Trust Units will be issued pursuant to exemptions under applicable securities laws, discretionary exemptions granted by applicable securities regulatory authorities or a prospectus or similar filing. In addition, on December 31 of each year, Unitholders will be entitled to receive a distribution of the amount, if any, by which the income of the Fund including any net capital gains for purposes of the Tax Act in respect of the year (calculated without reference to paragraph 82(1)(b) and to subsection 104(6) of the Tax Act) less any deductible non-capital or capital losses of prior years exceeds all amounts otherwise distributed or made payable in respect of the year. Certain adjustments may apply.

The Trustees of the Fund have determined to have the Fund make distributions monthly and not quarterly. The Fund will include in its monthly distributions cash dividends, distributions or returns of capital, if any, received from Fund Businesses. Monthly distributions are due and payable to Unitholders of record on the last day of each month and are expected to be paid on or before 45 days thereafter without interest or penalty.

Revenues from the hydroelectric facilities operated by the Fund Businesses are higher in the spring due to the spring run-off and in the fall due to higher levels of rainfall and, as a result, it is anticipated that distributions of Distributable Cash will be greater during the month's ending in the spring and the fall. In an effort to assist in the equalization of distributions throughout the year, funds have been set aside to be used at the discretion of the Trustees to help compensate for seasonal fluctuations in waterflows.

Redemption Right

Trust Units are redeemable at any time at the option of the holders thereof upon delivery to the Fund of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requesting redemption. Upon receipt of the redemption request by the Fund, all rights of the holders with respect to the Trust Units tendered for redemption will cease and the holder thereof will only be entitled to receive a price per Trust Unit ("Cash Redemption Price") equal to the lesser of: (i) 95% of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the ten trading day period commencing immediately after the date on which the Trust Units were tendered to the Fund for redemption (the "Redemption Date"); and (ii) the "closing market price" on the principal market on which the Trust Units are quoted for trading on the Redemption Date.

For the purposes of this calculation, "market price" will be an amount equal to the weighted

average trading price of the Trust Units for each of the trading days on which there was a closing price, provided that if the applicable exchange or market cannot provide a weighted average trading price, but only provides the highest and lowest prices of the Trust Units traded on a particular day, the “market price” will be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the ten trading days, the “market price” will be the simple average of the following prices established for each of the ten trading days: (i) the average of the last bid and last ask prices of the Trust Units for each day on which there was no trading, (ii) the weighted average trading price of the Trust Units for each day that there was trading if the exchange or market provides a weighted average trading price; and (iii) the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The “closing market price” will be: (i) an amount equal to the closing price of the Trust Units if there was a trade on the date; (ii) an amount equal to the average of the highest and lowest prices of Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; or (iii) the average of the last bid and ask prices of the Trust Units if there was no trading on the date.

The aggregate Cash Redemption Price payable by the Fund in respect of any Trust Units tendered for redemption during any calendar month will be satisfied by way of a cash payment on the last day of the following month, provided that the entitlement of Unitholders to receive such cash payment upon the redemption of their Trust Units is subject to the limitations that: (i) the total amount payable by the Fund in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month will not exceed \$250,000 (provided that such limitation may be waived at the discretion of the Trustees); (ii) at the time such Trust Units are tendered for redemption, the outstanding Trust Units will be listed for trading on the Toronto Stock Exchange or traded or quoted on any other market which the Trustees consider, in their sole discretion, provides representative fair market value prices for the Trust Units; and (iii) the normal trading of Trust Units is not suspended or halted on any stock exchange on which the Trust Units are listed for trading (or, if not listed on a stock exchange, on any market on which the Trust Units are quoted for trading) on the Redemption Date or for more than five trading days during the ten day trading period commencing immediately after the Redemption Date.

If a Unitholder is not entitled to receive cash upon the redemption of Trust Units as a result of the foregoing limitations, then the redemption price for such Trust Units will be the fair market value thereof as determined by the Trustees, taking into account any taxes payable by the Fund arising from such redemption. The redemption price will, subject to any applicable regulatory approvals, be paid and satisfied by way of distribution in specie of an interest in Fund Assets. No fractional shares, notes (based on increments of \$100) or other securities, if any, will be distributed and, where the number of shares, notes and/or other securities, if any, to be received by a Unitholder includes a fraction, such number will be rounded to the next lowest whole number.

Meetings of Unitholders

The Declaration of Trust provides that Unitholders may pass resolutions that bind the Trustees or the Fund only with respect to: the appointment or removal of Trustees (except filling casual vacancies); the appointment or removal of the auditors of the Fund; the approval of amendments to the Declaration of Trust (except as described under “*Declaration of Trust - Amendments to the Declaration of Trust*”); the appointment of an inspector; the sale of all or substantially all of the assets of the Fund (other than as

part of an internal reorganization); and the termination of the Fund. Such resolutions must be passed by Extraordinary Resolution, except for the appointment or removal of Trustees or auditors of the Fund, which requires the approval of a majority of votes cast at a meeting of Unitholders. Meetings of Unitholders will be called and held annually for the election of Trustees and the appointment of auditors of the Fund.

A special meeting of Unitholders may be called at any time by the Trustees and must be convened if requisitioned by the holders of not less than 10% of the Trust Units then outstanding (not including Units beneficially owned by the Manager) by written requisition. A requisition must state in reasonable detail the business proposed to be transacted at such meeting.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder. Two individuals present in person or represented by proxy constitute a quorum for the transaction of business at all such meetings.

The Declaration of Trust contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders.

Exercise of Voting Rights attached to Algonquin Canada Shares

The Declaration of Trust provides that the Fund will not authorize, either by agreement or by voting the Algonquin Canada Shares:

- (a) any amendment to the articles of Algonquin Canada or its subsidiaries to change or remove any restriction on the business of Algonquin Canada or its subsidiaries or change the authorized share capital or change or amend the rights, privileges, restrictions and conditions attaching to any class of shares of Algonquin Canada or its subsidiaries, as applicable;
- (b) any sale, lease or other disposition of all or substantially all of the property and assets of Algonquin Canada, except in the ordinary course of business or as part of an internal reorganization of Algonquin Canada and any one or more of its wholly-owned subsidiaries;
- (c) any issue of shares in the capital of Algonquin Canada or its subsidiaries other than to the Fund or Algonquin Canada, as applicable;
- (d) any amalgamation or other merger of Algonquin Canada or its subsidiaries with any other corporation, except with one or more wholly-owned subsidiaries of such entity; or
- (e) any amendment to any unanimous shareholders' agreement entered into in respect of Algonquin Canada or its subsidiaries,

except in the ordinary course of business or as part of an internal reorganization of Algonquin Canada and anyone or more of its subsidiaries, without the approval of the Unitholders by Extraordinary Resolution at a meeting of Unitholders called for that purpose.

Limitation on Non-Resident Ownership

In order for the Fund to maintain its status as a mutual fund trust under the Tax Act, the Fund must not be established or maintained primarily for the benefit of non-residents of Canada within the

meaning of the Tax Act. Accordingly, the Declaration of Trust provides that at no time may non-residents be the beneficial owners of a majority of the Trust Units. If the Trustees or the transfer agent become aware that the beneficial owners of 49% of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, the Trustees or the transfer agent may make a public announcement thereof and will not accept a subscription for Trust Units from, or issue or register a transfer of Trust Units to, a person unless the person provides a declaration that the beneficial owner is not a non-resident. If, notwithstanding the foregoing, the Trustees or the transfer agent determine that a majority of the Trust Units are held by non-residents, the transfer agent may, or the Trustees may cause the transfer agent to, send a notice to non-resident Unitholders, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustees or the transfer agent may consider equitable and practicable, requiring them to sell their Trust Units or a portion thereof within a specified period of not less than 60 days. If the Unitholders receiving such notice have not sold the specified number of Trust Units or provided the transfer agent with satisfactory evidence that the beneficial owners are not non-resident within such period, the transfer agent may on behalf of such Unitholder, sell such Trust Units and, in the interim, will suspend the voting and distribution rights attached to such Trust Units. Upon such sale, the affected holders will cease to be holders of Trust Units and their rights will be limited to receiving the net proceeds of sale upon surrender of the certificates representing such Trust Units.

Amendments to the Declaration of Trust

The Declaration of Trust may be amended or altered from time to time by Extraordinary Resolution. The Trustees may, without the approval of Unitholders, authorize certain amendments to the Declaration of Trust, including amendments:

- (a) for the purpose of ensuring continuing compliance with the applicable laws, regulations, requirements or policies of any governmental authority having jurisdiction over the Trustees or the Fund;
- (b) which, in the opinion of the Trustees, provide additional protection for the Unitholders;
- (c) to remove any conflicts or inconsistencies in the Declaration of Trust or to make corrections that are, in the opinion of the Trustees, necessary or desirable and not materially prejudicial to the rights of Unitholders; or
- (d) which, in the opinion of the Trustees, are necessary or desirable as a result of changes in or in the administration or interpretation of taxation laws.

Termination of the Fund

The Fund has been established for a term ending 21 years after the date of the death of the last surviving issue of Her Majesty, Queen Elizabeth II, alive on September 8, 1997. The Declaration of Trust requires the Trustees to commence to wind-up the affairs of the Fund not more than two years prior to the end of the term of the Fund. In addition, at any time prior to the expiry of the term of the Fund, Unitholders may pass an Extraordinary Resolution to terminate the Fund, following which the Trustees are obligated to commence to wind-up the affairs of the Fund.

Take-over Bids

The Declaration of Trust contains provisions to the effect that if a take-over bid is made for Trust Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust Units held by Unitholders who did not accept the offer on the terms offered by the offeror.

Foreign Property

The Fund has been registered by the Canada Customs and Revenue Agency (the "CCRA") as a "registered investment" under the Tax Act and has not been notified by the CCRA that such registration has been revoked. Provided the Fund continues to be so registered, Trust Units of the Fund will not be foreign property for Unitholders who are subject to Part XI of the Tax Act.

Reporting to Unitholders

The Fund will furnish to the Unitholders such financial statements (including quarterly and annual financial statements) and other reports as are from time to time required by applicable law, including prescribed forms needed for the completion of Unitholders' tax returns under the Tax Act and equivalent provincial legislation. Each of the Fund Businesses controlled by the Fund has undertaken to provide the Fund with: (i) a report of any material change that occurs in its affairs in form and content that it would file with applicable regulatory authorities if it were a reporting issuer; and (ii) all financial statements that it would be required to file with applicable regulatory authorities if it were a reporting issuer under applicable securities laws. All such reports and statements will be provided to the Fund in a timely manner so as to permit the Fund to comply with the continuous disclosure requirements relating to reports of material changes in its affairs and the delivery of financial statements as required under applicable securities laws.

Prior to each meeting of Unitholders, the Fund will provide Unitholders with information similar to that required to be provided to shareholders of an Ontario public company, along with notice of such meeting.

GOVERNANCE, MANAGEMENT AND OPERATIONS

Administration Agreement

The Manager administers the Fund pursuant to the Administration Agreement entered into between the Fund and the Manager and is responsible for the administration and management of the affairs of the Fund. The Manager is reimbursed for its reasonable out-of-pocket expenses incurred in administering the Fund. The agreement is coterminous with the Management Agreement.

Management Agreement

Algonquin Canada and the Manager entered into the Management Agreement on December 23, 1997, pursuant to which the Manager provides management services (the "Management Services") for the Fund Businesses. As announced at last year's annual and special meeting of Unitholders on May 23, 2002, the Management Agreement was amended in fiscal 2002, as described in more detail below.

The Management Services provided include, without limitation, advice and consultation concerning business planning, support, guidance and policy making and general management services. Senior officers of the Manager also act as senior officers of the Fund. Specific functions performed by the Manager include: (i) accounting and financial services; (ii) assisting in the preparation of financial statements; (iii) negotiating and communicating with third parties with respect to contractual and other matters; (iv) arranging external professional and non-professional services; (v) assisting in providing human resources; and (vi) advising on major acquisitions and sales of subsidiaries and/or businesses.

In exercising its powers and discharging its duties under the Management Agreement, the Manager is required to exercise the degree of care, diligence and skill that a reasonable, prudent advisor or manager having responsibility for management of a similar business would exercise in comparable circumstances.

Algonquin Canada or the Manager may terminate the Management Agreement immediately in the event of the insolvency or receivership of the other party or in the case of default by the other party in a material obligation under the Management Agreement which is not remedied within 30 days, other than a failure of performance which results from an event of force majeure. The Manager may terminate the Management Agreement at any time on 12 months' notice.

As mentioned above, the Manager holds special voting shares of Algonquin Canada and Algonquin America entitling it to elect two of the three directors of Algonquin Canada and all of the directors of Algonquin America. These shares carry no other right to vote and no material economic benefit and may be purchased by the Fund, or Algonquin Canada or Algonquin America, as applicable, at their issue price upon termination or expiry of the Management Agreement.

The Management Agreement contains provisions to regulate any conflicts of interest which may arise and provides for indemnification by the Manager of Algonquin Canada in certain circumstances. The Management Agreement may be assigned by the Manager only with the consent of Algonquin Canada.

The head office of the Manager is located at 2845 Bristol Circle, Oakville, Ontario L6H 7H7.

The compensation arrangements with the Manager have been amended to reflect the evolving governance and incentive fee arrangements in the income trust sector, while accommodating unique aspects of the Fund's business and structure. In 2002, the Trustees have agreed with the Manager as follows: (i) except for incentive fees, the Manager will be paid on a cost reimbursement basis only; (ii) the Manager will be paid incentive fees based on 25% of Distributable Cash per Trust Unit in excess of \$0.92 per annum (there will be no further acquisition-based incentive fees paid to the Manager); (iii) Power Systems, which is owned by the same shareholders as the Manager and which operates most of the facilities owned directly or indirectly by the Fund, will be paid on a cost reimbursement basis only; (iv) the Management Agreement's term has been extended by five years and on expiry of the initial term, is renewable for rolling five (5) year terms; and (v) no fees will be paid to the Manager as compensation for the Manager's consent to these amendments, including the Manager forgoing its entitlement to a quarterly fee and energy production fee under the Management Agreement.

Under the new structure, the four principals of the Manager will perform their respective management functions effectively as employees of the Fund. The Manager is entitled to reimbursement of its reasonable out-of-pocket expenses incurred in connection with its duties under the Management

Agreement, including an amount of \$600,000, adjusted annually based on changes in the Consumer Price Index, for providing senior executive services (the "Senior Executive Amount"), together with employee benefits expenses for such principals.

Prior to the implementation of such revised compensation structure, the Fund completed the provision of debt financing to and the acquisition of all trust units and certain convertible debentures issued by the KMS, the acquisition of the Sanger Facility and the Bella Vista Facility for an aggregate transaction value of approximately \$180 million. In respect of these transactions, an affiliate of the Manager was paid fees in the aggregate of approximately \$3.0 million. Such acquisition related fees were calculated solely on the basis of the amount by which the cash distributions anticipated to be provided to the Fund from these facility interests exceeded the minimum accretion criteria of \$0.97 per Trust Unit established by the Trustees of the Fund.

For the fiscal period ended December 31, 2002, the Fund, directly or indirectly, paid to the Manager a total of \$3.7 million, including the Senior Executive Amount and the other amounts referred to above, plus reimbursement of sundry expenses in an aggregate amount not exceeding \$100,000.

Operations Supervisory Agreement

Algonquin Canada and Power Systems entered into the Operations Supervisory Agreement on December 23, 1997, pursuant to which Power Systems provides certain operations related services for the Facilities (the "Operations Supervisory Services") which are beyond the scope of the operations and maintenance services agreements which have been entered into between the entities which own the various facilities and Power Systems. Senior officers of Power Systems also act as senior officers of Algonquin Canada. Specific functions include: (i) planning of capital repairs; (ii) compliance monitoring for environmental permits; and (iii) administration of power purchase agreements.

As mentioned above, in connection with the amendments to the Management Agreement, Power Systems has forgone any payment of fees in connection with its services under the Operations Supervisory Agreement and is now paid on a cost reimbursement basis only.

The Operations Supervisory Agreement will terminate on termination of the Management Agreement.

The head office of Power Systems is located at 2845 Bristol Circle, Oakville, Ontario L6H 7H7.

Direct Operations Agreements

Direct operations and maintenance services are generally comprised of those services necessary for a facility to continue to operate under typical circumstances. Such services include the provision of direct operating labour, management of available water/fuel resources, monitoring and reporting on facility performance, performance of scheduled maintenance tasks and completion of minor repairs as required. Power Systems has entered into agreements with Fund entities which own generating Facilities to provide such services. The Fund, directly or indirectly, paid to Power Systems an aggregate amount of approximately \$10.2 million during 2002, which amount was paid on a cost reimbursement basis pursuant to the amended Operations Supervisory Agreement and the direct operations agreements. In addition, Newspring has entered into agreements with the entities which own the water distribution and wastewater

treatment facilities to provide similar services for an aggregate amount totalling approximately \$1,847,000 during 2002, which amount was paid on a cost reimbursement basis.

Contingency Repair and Capital Improvement Projects

Power Systems also manages the contingency repair and capital improvement projects for the owners of certain generating Facilities. The annual repair and maintenance expenditures during 2002 were approximately \$2.2 million, which amount was paid to Power Systems on a cost reimbursement basis and is included in the \$10.2 million paid to Power Systems under the Operations Supervisory Agreement and the direct operations agreements referred to above.

Governance Agreement

Pursuant to the Governance Agreement, the Manager is entitled to appoint two directors to Algonquin Canada's board of directors, with the Fund being entitled to appoint one director. The articles of Algonquin Canada provide that the number of directors is fixed at three.

The Governance Agreement will remain in force for so long as the Management Agreement remains in force and will provide that the Fund will not vote for any amendment to Algonquin Canada's articles, including an amendment with respect to the number of directors, without the Manager's approval. The Governance Agreement further provides that the Fund will comply with the Manager's instructions with respect to the appointment, removal and replacement of the Manager's nominees to the board of directors of Algonquin Canada. Notwithstanding the foregoing, the Fund will be entitled to remove the Manager's nominees as directors of Algonquin Canada or amend Algonquin Canada's articles if:

- (a) Algonquin Canada does not comply with or prevents the implementation of Algonquin Canada's distribution policy;
- (b) any of the Fund Businesses does not comply with or prevent the implementation of its distribution policy;
- (c) any amendment is made to the partnership agreement in respect of any of the Fund Businesses which are partnerships without the consent of the Fund;
- (d) there is a change of control of the Manager (other than a change of control to which the Fund consents);
- (e) other than in the ordinary course of business and without the prior written consent of the Fund, any of the Fund Businesses undertakes a material change in its business, incurs any material debt or issues any securities other than to another such entity or the Fund;
- (f) an offer is made for 100% of the Trust Units and the offeror acquires more than 50% of the Trust Units under that offer; or
- (g) the Management Agreement expires or is terminated.

TRUST UNIT AND LOAN CAPITAL OF THE FUND

Trust Unit Capital of the Fund

The Fund presently has 67,887,612 Trust Units outstanding. See “*Declaration of Trust*” for a description of the rights, attributes, privileges and conditions attaching to the Trust Units.

Loan Capital of the Fund

The Fund has available a line of credit (the “Credit Line”) provided by a major Canadian bank in the maximum principal amount of \$100,000,000 (plus a temporary \$15,000,000 facility) to be utilized in respect of the acquisition of facilities by the Fund, plus an additional \$15,000,000 working capital facility. As security for repayment of such line of credit, the Fund has, among other things, pledged the shares of certain Fund entities. As of May 7, 2003, the Fund had \$64.2 million outstanding under the Credit Line. In addition, the Fund has used the Credit Line to post (i) a letter of credit in the approximate amount of U.S.\$19.4 million in respect of bond liabilities assumed in connection with the acquisition of the Sanger Facility, (ii) a \$1 million letter of credit to the Minister of the Environment (Alberta) pursuant to the Use of Works Agreement in respect of the Dickson Dam Facility; and (iii) letters of credit for the Peel Facility totaling \$4.5 million. The Fund is in material compliance with the terms of the agreements governing the Credit Line and no waiver of any breach has occurred thereunder.

Interest

Any amounts outstanding under the Credit Line bears interest at a rate equal to bank prime rate plus 25 basis points, payable monthly. An annual standby fee equal to 37.5 basis points of the undrawn portion of the Credit Line is payable monthly.

Redemption

The credit agreement in respect of the Credit Line stipulates that the amount outstanding under the Credit Line is due and payable as of the maturity of the Credit Line, which is April 26, 2004.

THE INDEPENDENT POWER GENERATION INDUSTRY

As mentioned above, the Fund is primarily engaged indirectly in the business of generating and marketing electrical energy within the independent power generation industry.

General

Description of a Hydroelectric Facility

A hydroelectric generating facility consists of a number of components, including a dam, headrace canal or penstock, intake structure, electromechanical equipment consisting of a turbine(s), a generator(s), draft tube and tailrace canal. In addition, there are electrical switchgear and controls equipment which are necessary to interconnect the facility with the receiving electrical grid system.

A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace (referred to as “head”), as well as to provide sufficient

depth within the reservoir for an intake. Dam structures are also used to create an upstream reservoir which allows water to be stored within a headpond. Virtually all dam structures used for hydroelectric generation purposes have spillways for discharging water which is surplus to the demand of the generating station. A spillway dam can be either an overtopping section of the dam (uncontrolled spillway) or an opening within the dam itself (sluiceway). Sluiceway structures must be equipped with a mechanism for blocking the opening(s) during periods when the hydroelectric generating facility can adequately handle the river flow. This can be accomplished using a variety of methods ranging from simple wooden logs (referred to as stoplogs) to automatically controlled and sophisticated steel gates.

Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal. A penstock is a pipeline capable of operating under pressure, and is normally constructed of steel or other suitable materials. A headrace canal is a channel which conveys water from the reservoir to the intake in a hydraulically efficient manner.

The intake structure is a water intake located at the entrance to a penstock or at the end of a headrace canal. The purpose of the intake structure is to collect water from the upstream reservoir. Intake structures are normally equipped with steel or plastic screens (referred to as trashracks) which prevent debris and ice found in the reservoir from entering into the turbine equipment. Intake structures must be adequately submerged to prevent the entrainment of air into the water passages.

The electromechanical equipment consists of the turbine(s) and generator(s) used to transform the hydraulic energy into electrical energy. A turbine is a series of blades which rotate a shaft as a result of water flowing over or through the blades. A variety of turbines are used depending on the site. The generator is connected to the turbine (sometimes using a gearbox) and converts mechanical energy into electrical energy.

The electromechanical equipment is typically contained within a powerhouse building. The purpose of the powerhouse is to provide a solid structural foundation for the equipment and protect the equipment from the environment.

The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse through a draft tube and tailrace. The purpose of these two components is to return the flows back to the environment in a "hydraulically smooth" fashion.

The electrical equipment consists of switchgear, controls, a transformer substation and frequently a transmission line. The purpose of the electrical equipment is to transform the electrical energy produced by the generator into a form which is acceptable to the receiving electrical grid. This usually involves increasing the voltage and controlling the electrical frequency. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location.

Energy from Waste

In North America and elsewhere, the combination of increasing population and stricter environmental regulations has imposed increasing limitations upon the development of new municipal landfills and on the expansion of existing landfills. To reduce the total tonnage of municipal waste being directed to landfills and to extract greater value from existing landfills, considerable effort is being directed

toward the establishment of energy from waste facilities. The establishment of energy from waste facilities is now a licenced process in certain states of the United States, Canadian provinces and in other countries.

Cogeneration

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. Often natural gas is used to produce both electricity and steam. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility. Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods. Examples of industries using cogeneration facilities include food processing, pulp and paper and chemical plants.

Where both electrical and thermal energy are generated separately, typically one third to one half of the fuel's energy content is converted into useful energy output such as steam or electricity. The remainder is wasted energy which escapes as unused heat. By producing electricity and steam simultaneously, cogeneration uses a higher proportion of the fuel's energy content. Depending on the degree of steam and/or useful heat utilization, 55% to 80% of the fuel's energy content is converted into useful energy output, which produces significant fuel savings over conventional arrangements.

Cogeneration compared to conventional processes also has environmental benefits as it results in burning less fuel and producing less carbon dioxide. Furthermore, in cogeneration facilities which use fuels such as natural gas or oil, sulphur dioxide and nitrous oxide emissions are greatly reduced compared to other technologies and fuels.

Landfill Gas Generation

Many landfill sites produce gas which can be burned to produce energy. Typically, an underground pipe system is installed and the gas produced is compressed and the pressurized gas is then piped off to engines or turbines to be burned to generate electricity.

Canada

In Canada, the provinces have legislative authority over the supply of energy. In the past, the majority of the electrical supply within the Canadian provinces was provided by large Crown corporations such as Ontario Hydro and Hydro-Québec or smaller, investor owned utilities. These large utilities have been primarily responsible for the generation, transmission and distribution of electricity. In the mid-1980's, however, the rapid growth of projected energy demand, projections of dramatic increases in energy rates and advances in new generation technology led provincial governments to develop policies to encourage independent power generation. These policies were meant to encourage larger utilities to purchase power from independent power producers pursuant to long term power purchase agreements which would supply power to the provincial power grid in parallel to the utilities' own generation. In the late 1980's and early 1990's, British Columbia, Alberta, Ontario, Québec, Nova Scotia and Newfoundland established programs to actively seek independently produced power. By the late 1990's, many of the large utilities started the process of restructuring the energy market. To date British Columbia, Alberta, and Ontario have made progress on restructuring and introducing competition into the energy market.

Ontario

By the mid-1980's, the majority of energy produced in Ontario was the responsibility of Ontario Hydro. In 1987 however, the provincial utility and the provincial government developed policies and programs to encourage the addition of new generation by independent power generators. Over 90 of these independent generators or non-utility generators entered into long term power purchase agreements with Ontario Hydro. These projects represent over 1,225 megawatts of energy from a variety of fuels, such as water, natural gas and wood wastes.

In 1998, the provincial government started the process of restructuring the energy market in Ontario. This restructuring includes the elimination of the large provincial utility, Ontario Hydro, that had enjoyed a monopoly in Ontario and the introduction of new generators and retailers of electricity into a competitive market.

Ontario has continued this process of reshaping the electricity industry throughout 1999 and into the year 2000. Following the passage of the Energy Competition Act, 1998 (the "Energy Act") in October, 1998, Ontario Hydro has been successfully restructured and separated into a number of new, successor companies such as Ontario Power Generation Inc. and OEFC, among others. The regulatory framework for wholesale and retail competition has been developed by the Ontario government through the Ontario Energy Board (the "OEB"). While transitional issues such as pricing and metering continue to be considered by the OEB, full competition in the wholesale and retail electricity market commenced on May 1, 2002.

Immediately following the opening of the Province's wholesale and retail energy market, in July, August and September of 2002, Ontario experienced dramatic increases in the wholesale price of electricity and charges for imported power. This was primarily due to a sharp increase in demand for electricity and lower than expected sources of electrical generation. In response to growing public concerns with respect to the unexpected high costs of electricity, the Government of Ontario passed the *Electricity Pricing, Conservation and Supply Act, 2002* on December 9, 2002 which included a price freeze of 4.3 cents per kilowatt hour for the electricity market until May 1, 2006 for low volume and other designated consumers.

The restructuring of Ontario Hydro and the Ontario energy market and the current decisions of the Ontario Government has not had a material impact on the long term purchase agreement for each generating facility located in Ontario in which the Fund has an interest. OEFC now holds all rights, obligations and liabilities under such power purchase contracts. This Ontario government agency will continue to purchase the energy generated by the Ontario facilities in which the Fund has an interest pursuant to the existing contracts. The Fund has also received a licence to generate from the OEB as required by the Energy Act.

Québec

In September 1990, the Québec government adopted a policy allowing private power producers to build, operate and manage hydroelectric generating facilities with a capacity of less than 25 megawatts, as well as the development of larger cogeneration facilities. The program set out the terms and conditions of long term waterpower leases with the Québec government and power purchase agreements with Hydro-Québec which would apply to all private power producers. Between 1991 and 1993, Hydro-Québec negotiated and signed agreements with private producers for the purchase of a total of 474 megawatts

from hydroelectric generating facilities, wind powered facilities and cogeneration plants fuelled by biomass and natural gas.

In July, 2001, the Regie de l'energie of Québec approved a call for tenders for new generation by Hydro- Québec. On November 26, 2002, the Québec Government announced that two sites were selected for development as a result of the call for proposals. At that time, the Government also announced that there would be no new dams built for small hydroelectric projects.

Alberta

The government of Alberta passed the *Electric Utilities Act* (the "EU Act") in 1996 and the EU Act was amended in 1998 and 2000 to separate generation, transmission and distribution of electrical power in Alberta for regulatory purposes. The EU Act permits the development of a competitive marketplace for electricity in Alberta. The EU Act also created the Alberta Power Pool (the "Power Pool") through which all electrical power must be traded in Alberta.

The amendments to the EU Act and corresponding regulations in 2000 created the Alberta Balancing Pool (the "Balancing Pool"). The amended legislation provides that the relevant utility is to purchase power at the prices set out in the power purchase agreement entered into pursuant to the *Small Power Research and Development Act* (Alberta) and sell the power into the Power Pool. All revenues associated with the sale of such power into the Power Pool are to be paid into the Balancing Pool and all costs associated with such power purchase agreements are to be paid out of the Balancing Pool. The effect of the amendments is to render a utility that is a party to such a power purchase agreement a flow through for the rights and obligations under the power purchase agreement.

Newfoundland

In anticipation of an increase in electricity demand in the Province of Newfoundland, Newfoundland and Labrador Hydro began seeking generating capacity from independent power producers in 1990. In April 1990, a new policy was developed stating that Newfoundland and Labrador Hydro was prepared to relinquish its franchise rights to private developers on any hydroelectric project up to ten megawatts or greater under certain conditions. By 1992, however, the energy demand forecast for the province changed significantly and the utility indicated that it would limit the number of private generators that could sell power to the utility pursuant to long term power purchase agreements. In April 1992, the utility issued a request for proposals from private generators for a total of 50 megawatts of new generation. In December 1993, Newfoundland and Labrador Hydro announced that it would issue power purchase agreements to four small hydroelectric projects located on the island of Newfoundland totalling 38 megawatts. The utility also announced that it would purchase electricity from these facilities commencing on October 1, 1998. In 1998, the provincial government announced a moratorium on the development of small hydroelectric projects in Newfoundland. The government announced a review of environmental issues associated with such development and a review of the need for additional generation capacity. The government cancelled two of the four facilities that were proceeding to construction. The Rattle Brook and Star Lake facilities were the two facilities completed and commissioned in 1998.

United States

In 1978, The United States Congress enacted the Public Utility Regulatory Policies Act ("PURPA") in response to a belief that the electric generation industry in the United States was too

heavily dependent on foreign oil. Energy production in the United States is regulated by the Federal Energy Regulatory Commission. By enacting PURPA, Congress enabled private power producers to supply electricity to the large utilities throughout the country. FERC, pursuant to the PURPA legislation, mandated the development of policies by state utility commissions and utilities themselves that enable private producers to build power facilities. The key policy issue was the development of long term power purchase agreements with fixed, long term power purchase rates. The long term rates were based on projections of the utilities' Avoided Costs. Today, due to market forces and economic changes, many of these long term agreements are priced far above current market rates. While these higher costs are burdensome to the utilities, most have recognized these costs as Stranded Costs.

In 1992, the United States Congress empowered FERC to begin opening up the wholesale electric marketplace to competition. Order 888 issued by FERC on April 24, 1996 established the rules associated with wholesale market competition. It is projected by FERC and others that the United States and Canada will evolve to the point where the generating component of electricity will be open to competition and no longer be subject to price regulation.

New York State

Following the implementation of PURPA in 1978, New York State aggressively pursued the development of independent power production. There are currently over 300 independent power facilities now in operation in New York State and independent power producers have added more than 6,000 megawatts of new electric generating capacity.

New Hampshire

New Hampshire has one large, investor-owned utility, Public Service Company of New Hampshire, which is a subsidiary of Northeast Utilities ("NU"), as well as a number of smaller regional utilities. With the passing of PURPA in 1978, the New Hampshire legislature passed the Limited Electrical Energy Producers Act which directed the New Hampshire Public Utilities Commission to encourage the State's utilities to purchase independently produced power from a variety of sources. The state legislature also granted the NHPUC authority to set long term rates for renewable energy sources and beginning in 1984, the PSNH issued power purchase agreements with long term fixed power purchase rates that helped stimulate the development of small hydroelectric generating facilities. While these rates were based on PSNH's own projected energy costs at that time, the contracted rates are now well above today's market rates for electricity. The NHPUC also issued rate orders to utilities such as PSNH to purchase electricity from certain power producers at stipulated power purchase rates.

In March 2002, PSNH approached all the existing holders of power purchase agreements and rate orders with an offer to buy down or buy out the existing contracts that contained over market power purchase rates. By the end of the year, PSNH either bought out or bought down twelve contracts or rate orders.

Vermont

Following the implementation of PURPA in 1978, the State of Vermont agreed to encourage the development of independent power production. The electrical distribution system of the State is comprised of approximately 26 small, local utilities and for efficiency it was determined that one purchaser, the Vermont Electrical Exchange, Inc., should act as purchasing agent for all State utilities. Consequently,

Vermont Electrical Exchange, Inc. has entered into a number of contracts with private producers under which it purchases power from these independent power producers and, in turn, delivers such power to member utilities. In August 1999, 18 electric utilities petitioned the Vermont Public Service Board requesting the board to alter, modify and construe existing power purchase agreements, including the one power purchase contract held by the Fund. The independent power producers affected by the petition, including the Fund, are aggressively opposing the utilities' position before the board.

New Jersey

In the late 1970's, with an energy crisis emerging, the federal government enacted the Public Utility Regulatory Policies Act. This government legislation was intended to encourage private power producers to develop generating facilities using renewable energy (for example, small hydro). Under the new PURPA regulation, the Federal Energy Regulatory Commission was allowed to implement its own directives to ensure utilities purchase energy under long term contracts produced by PURPA "Qualifying Facilities". In 1981 and 1983 the New Jersey Board of Public Utilities ordered the PURPA be executed, which in turn authorized State utilities and Qualifying Facilities to negotiate long term contracts.

In 1992, the federal Energy Policy Act was passed, which brought competition to the wholesale electric marketplace. This legislation bestowed upon the FERC the authorization to ensure fair competition, more specifically open access, non-discriminatory transmission and access to information in the wholesale marketplace. In the early 1990's, as a result of the new bulk energy market, the New Jersey Board of Public Utilities challenged in court the validity of the long term contracts with independent power producers. The intention was to necessitate the buy-out of uneconomical independent power producer contracts. However, in 1995, the legal dispute was overruled by the United States Court of Appeals for the Third Circuit. The basis of the decision was that the New Jersey Board of Public Utilities disobeyed the FERC and PURPA regulations.

Further changes to the New Jersey energy marketplace have taken place over the last few years. In February 1999, the State of New Jersey enacted the Electric Discount and Energy Competition Act. This regulation encourages competition in the energy markets, including electricity generation, in New Jersey. On August 1, 1999, New Jersey finally deregulated the electric and gas utility business throughout the State.

California

The California Legislature passed Assembly Bill 1890 ("AB 1890") in 1996 to restructure the electricity industry. The State restructuring law dramatically changed the market system that was in place for more than eighty years. The intent of the restructuring was to ensure a transition to a more competitive electricity market by creating a new market that provided competitive low-cost and reliable electric service. While municipal utilities were not required participate in the restructured market, customers of investor-owned electric utilities were free to choose their electricity provider. The market was controlled by the Power Exchange, which was to provide market services and control, and the Independent System Operator, which was given control over the transmission grid.

The restructured electricity industry took form in early 1998 and the new market appeared to be off to a good start. Initially, as expected, electricity prices tracked closely the marginal cost of power production. Ultimately, however, many implementation problems developed, which eventually elevated to an "energy crisis" in 2000. Problems that began to appear were extremely high costs of electricity,

decreased reliability, very high profits by generators and large debts incurred by utilities.

Customers of the investor-owned utilities had their rates frozen as part of the overall legislative design and did not see the high wholesale costs reflected in their utility bills. Because of the rate freeze, utilities could not pass these expenses on to their customers, leaving utilities, such as Pacific Gas and Electric Company, with negative balances in their revenue accounts. Pacific Gas and Electric Company ultimately declared bankruptcy on April 6, 2001.

The California Legislature addressed the crisis by implementing a number of changes to restructure the electricity market. A key component of the changes was to ensure that there was and is an adequate supply of electricity to meet market demands. Currently, while still under bankruptcy protection, Pacific Gas and Electric Company is profitable and is paying its obligations. In September 2002, Pacific Gas and Electric Company filed a Plan of Reorganization which the company states will allow it to emerge from Chapter 11 protection.

Connecticut

Connecticut Light and Power Company is part of the North East Utilities System which is located in the New England Power Pool ("NEPOOL"). ISO New England Inc. was established as a not-for-profit, private corporation on July 1, 1997 following its approval by the Federal Energy Regulatory Commission (FERC). The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff.

Located in Holyoke, Massachusetts, ISO New England Inc. was formed by transferring staff and equipment from the NEPOOL. Since May 1, 1999, ISO New England Inc. has also administered the wholesale electricity marketplace for the region. Six electricity products are bought and sold by market participants on an Internet-based market system.

NEPOOL was formed in 1971 and is a voluntary association of electric utilities in New England who established a single regional network to direct the operations of the major generating and transmission (bulk power system) facilities in the region. NEPOOL built a state-of-the-art Control Center to centrally dispatch the bulk power system using the most economic generating and transmission equipment available at any given time to match the electric load of the region. This approach netted millions of dollars in savings for NEPOOL utilities and their customers, while increasing the overall reliability of the bulk power system.

NEPOOL will continue to exist as the entity representing not only traditional electric utilities but companies that will participate in the emerging competitive wholesale electricity marketplace. ISO New England Inc. has a services contract with NEPOOL to operate the bulk power system and to administer the wholesale marketplace.

Competition and Green Power Pricing

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric power is not subject to commodity fuel price volatility or risk. In addition, the generation of hydroelectric power does not involve significant ongoing capital and operating

costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Deregulation has increased demand for privately generated power from a variety of sources including fossil fuels, waste, wind and water. Taking into account capital costs, wind power is generally more expensive than traditional forms of generated power. Fossil fuels are harmful to the environment; and waste burning power generation requires producers to abide by stringent and costly environmental regulations.

With deregulation and opening of competition in the electricity marketplace, there will be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity. Over 30 utilities in the United States now offer their customers Green Power at a premium price. Green Power is electricity generated from renewable energy sources that do not contribute to greenhouse gas emissions. Green Power includes technologies such as small hydroelectric (generally defined as facilities of less than 20 megawatts in capacity), bioenergy, landfill gas, wind and photovoltaic. The US Department of Energy has suggested that in a competitive marketplace, utilities and energy marketers will utilize Green Power pricing to strengthen their image with their customers and build customer loyalty. Further, the Department has found that most utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The Department believes that as deregulation and open competition evolve, the Green Power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation.

In April 1997, Natural Resources Canada announced that, as part of the federal Green Power Procurement program, the federal government entered into an agreement to purchase up to 13,100 megawatt hours per year of Green Power from a utility to supply electricity to buildings owned by Natural Resources Canada and Environment Canada. Further, at that time, the Minister of the Environment announced that Environment Canada will be greening up to 20 per cent of its nation-wide electrical consumption before 2010 to assist the growth of the Green Power sector while reducing the greenhouse gas emissions caused by the Department's use of electricity. Natural Resources Canada has announced that the Green Power Procurement program is one of several initiatives that form a new federal strategy on renewable energy.

Recently, international environmental agreements such as the Kyoto Protocol on Climate Change have set targets for the reduction of greenhouse gas emissions. The Canadian government has announced its intention to implement the Kyoto Protocol with some changes. The United States, at both the federal and state government levels, has announced various programs and targets to reduce greenhouse gas emissions. Though programs and policies are evolving at all government levels, the trading of greenhouse gas credits created by renewable energy projects are seen as part of the eventual solution.

WATER SERVICES INDUSTRY

The Global Water Services Market

The global market for water supply and treatment equipment and services has been growing rapidly over the last decade and currently constitutes over a third of the global market for environmental products and services. The trend to market pricing for water services, combined with the growing

privatization of water and wastewater utilities, has generated an opportunity for private capital to participate in water services markets. The opportunity is enhanced by increasingly stringent enforcement of environmental regulations, worldwide consolidation of the water industry and the proliferation of e-business.

The United States, Western Europe and Japan represent over 80 percent of the total market for water services and equipment; these markets are generally mature with an average growth of approximately 3 to 4 percent consistent with the growth in population. The largest participants in serving the global water and wastewater industry are based in the United States, France, Britain, Japan and Germany.

United States Water Services Industry

The ownership of water assets and the provision of water and wastewater services around the world, including the United States, remain primarily concentrated in the public sector, typically at the municipal or community level. Rates charged by such utilities are determined in the discretion of the municipality on the premise that such services are provided at cost.

Notwithstanding the foregoing, approximately 55 million Americans living in smaller communities are served by approximately 60,000 privately owned and operated water utilities and 5,500 privately owned wastewater reclamation and treatment utilities. Rates charged by these utilities are determined by state or county regulators; rates are established to provide sufficient revenues to generate after-tax equity returns of approximately 10 to 12%.

In the continental United States, water supplies and resources for approximately one-third of the land mass are considered endangered. The Southwest United States is particularly susceptible to the effects of groundwater and surface-water withdrawals, precipitation lost through evaporation, lack of industrial water recycling and extremes of temperatures.

The connection between the water delivery and wastewater collection and reclamation industries is becoming closer with the advent of stronger re-use regulations and continuing evolution in water rights. The industry and regulators appear now to agree that high quality reclaimed water from wastewater treatment and potable groundwater credits should be considered interchangeable. In many jurisdictions in the United States, reclaimed water is being recharged by wastewater treatment utilities into the ground aquifers and then subsequently withdrawn and re-introduced into the potable water systems by water delivery utilities. The wastewater treatment utilities are awarded credits for such recharge and the water delivery utilities utilize such credits in respect of pumping and delivering water to customers.

The global market for water and wastewater services and equipment is large and growing. There is a large number of private water and wastewater companies in the United States and a large concentration of these utilities is located in the high growth areas of the arid Southern States.

It is estimated that investment of between \$25 US billion and \$40 billion will be required in the industry over the next 20 years in capital improvements and new infrastructure. Under the regulations governing private investor owned utilities, rates will be established to ensure investors of such capital earn a market return.

OTHER CONSIDERATIONS

Competition

The Fund competes for infrastructure project acquisitions with individuals, corporations and institutions (both Canadian and foreign) which are seeking or may seek infrastructure project investments similar to those desired by the Fund. Availability of investment funds and an increase in interest in infrastructure project investments may increase competition for infrastructure investments, thereby increasing purchase prices. Many of these investors have greater financial resources than those of the Fund or operate according to more flexible conditions.

The Fund will access public markets to finance infrastructure project acquisitions if funds are not immediately available. In addition, the Fund believes that the Manager in its role as administrator and manager provides the Fund with a competitive advantage with its experience in identifying strategic investment opportunities.

Significant deregulation and opening of competition is occurring in the electricity marketplace. The Fund is in a strong competitive position since, for new generation, small hydroelectric is the lowest cost producer, after industrial co-generation, in relation to total costs and is the lowest cost producer with respect to variable production costs. Reference is made to "The Independent Power Generation Industry - Competition and Green Power Pricing".

Environmental Matters

The Facilities encompass operations which require adherence to environmental standards imposed by regulatory bodies through licences, permits, policies and legislation. Failure to operate the Facilities in strict compliance with these regulatory standards may expose the Facilities to claims, clean-up costs and loss of operating licences and permits.

The Manager has an environmental management program including environmental policies and procedures that involve long term environmental monitoring programs, reporting, government liaison and the development and implementation of emergency action plans as related to environmental matters.

Environmental protection requirements did not have a significant financial or operational effect on the Fund's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2002. Further, such requirements are not expected to have a significant impact in future years, although, management of the Fund expects that more stringent environmental standards will continue to be implemented by various governmental agencies.

Employees

Algonquin Canada currently has 26 employees who are involved in the operation of the hydroelectric facilities and an additional 14 employees through its subsidiaries are involved in the operations of the cogeneration facilities. Algonquin Power Trust (including its subsidiaries) currently has 71 employees who are involved in the management of the Fund. In addition, the Manager, Power Systems and Newspring currently have approximately 119 employees who may in the course of their duties perform duties which would customarily be performed by employees of the Fund. Labour relations have been stable to date and there has not been any disruption in operations as a result of labour disputes with

employees. These employees are non-unionized.

Foreign Operations

For 2002, 49% of the gross revenue of the Fund was generated in the United States. Currently the Fund has interests in 31 facilities located in the United States, including six water reclamation and distribution facilities.

Currency fluctuations may affect the cash flow which the Fund will realize from its operations, as certain of the Fund Businesses sell electricity in the United States and receive proceeds from such sales in US dollars. Such Fund Businesses also incur costs in US dollars.

Intellectual Property

The “Algonquin” name and trademark and related marks and designs are licensed to the Fund by Algonquin Power under a non-exclusive, royalty-free trademark licence agreement (the “Licence Agreement”) dated December 23, 1997 between Algonquin Power and the Fund. Subject to the terms of the Licence Agreement, this licence will remain in effect for as long as the Management Agreement is in effect. The Fund, by using the “Algonquin” name, has the benefit of the goodwill and recognition associated with Algonquin Power and its affiliates’ use of the “Algonquin” name in the energy sector for the past nine years.

Seasonality

Based on the type of power purchase agreements in place at all of the facilities in which the Fund has an interest, the revenue generated by the facilities is proportional to the amount of electrical energy generated. In addition, the amount of energy generated at the facilities is dependent upon available water flows. Accordingly, the Fund’s revenues are affected by low and high water flow caused by seasonal rains and melts, with the result that revenues are higher in the spring and fall and are lower in the summer and winter. Engineering studies have been undertaken to assess the amount of energy which can be expected to be generated from each facility on an average annual basis. Furthermore, the majority of the facilities have significant operating histories with which to compare the theoretical estimates in the engineering studies. Due to geographic diversity of the facilities, the variability of total revenues is minimized.

Customers

The Fund Businesses derive their revenues from the sale of electricity to large utilities. For the twelve months ended December 31, 2002, the Fund Businesses’ revenues were derived as follows: Niagara Mohawk - approximately 7% OEFC - approximately 15%; Hydro Québec - approximately 22%; PSNH - approximately 12%; Pacific Gas and Electric 26% and others - approximately 18%.

SELECTED FINANCIAL INFORMATION

The following sets out certain selected financial information for the Fund:

	Three months ended March 31, 2000	Three months ended June 30, 2000	Three months ended September 30, 2000	Three months ended December 31, 2000	Year ended December 31, 2000
(thousands of dollars, except for per Trust Unit amounts)					
Operating Revenue	12,585	14,134	8,794	11,180	46,693
Operating Expenses	5,956	5,896	5,409	5,495	22,756
Interest Expense	2,294	2,234	2,286	2,133	8,947
Income Taxes	635	234	(103)	860	1,626
Net Income	3,700	5,770	1,202	2,692	13,364
Net Income per Trust Unit	0.15	0.24	0.05	0.10	0.54
Total Assets	321,759	319,502	343,020	328,502	328,502
Total Long Term Debt	76,260	81,961	83,584	74,115	74,115
Distributions per Trust Unit	0.2425	0.2425	0.2425	0.2425	0.97

	Three months ended March 31, 2001	Three months ended June 30, 2001	Three months ended September 30, 2001	Three months ended December 31, 2001	Year ended December 31, 2001
(thousands of dollars, except for per Trust Unit amounts)					
Operating Revenue	10,501	12,894	8,064	13,511	44,969
Operating Expenses	5,399	6,378	7,405	7,125	26,307
Interest Expense	2,111	1,669	1,447	1,473	6,700
Income Taxes	(845)	593	(2,595)	3,084	237
Net Income	3,836	(2,498)	1,807	3,719	6,864
Net Income per Trust Unit	0.12	(0.08)	0.05	0.09	0.17
Total Assets	400,583	367,998	435,527	512,384	512,384
Total Long Term Debt	72,919	50,756	50,662	50,665	50,665
Distributions per Trust Unit	0.23	0.23	0.23	0.23	0.92

	Three months ended March 31, 2002	Three months ended June 30, 2002	Three months ended September 30, 2002	Three months ended December 31, 2002	Year ended December 31, 2002
(thousands of dollars, except for per Trust Unit amounts)					
Operating Revenue	15,728	28,360	25,057	25,618	94,763

	Three months ended March 31, 2002	Three months ended June 30, 2002	Three months ended September 30, 2002	Three months ended December 31, 2002	Year ended December 31, 2002
Operating Expenses	9,181	16,128	23,288	19,440	68,037
Interest Expense	1,456	2,105	2,232	2,589	8,382
Income Taxes	(1035)	(303)	2,991	(370)	1,283
Net Income	6,146	10,292	(3,783)	3,495	16,150
Net Income per Trust Unit	0.12	0.18	-0.07	0.05	0.28
Total Assets	599,256	713,220	712,504	723,038	723,038
Total Long Term Debt	58,746	156,754	166,727	93,094	93,094
Distributions per Trust Unit	0.23	0.23	0.23	0.23	0.92

DISTRIBUTION POLICY

The following outlines the distribution policy of the Fund as contained in the Declaration of Trust, including any restrictions on the ability to make distributions.

The amount of Distributable Cash to be distributed annually per Trust Unit will be equal to a pro rata share of interest, royalty and dividend income, taxable deemed dividends, lease payments or other income from the Leases received by the Fund in the year less: (i) administrative expenses of the Fund; (ii) amounts which may be paid by the Fund in connection with any cash redemptions of Trust Units; (iii) amounts required for the business and operations of the Fund, including amounts required to pay the deferred portion of the purchase price for any assets acquired by the Fund, directly or indirectly; and (iv) capitalized interest with respect to any notes held by the Fund. Any income of the Fund which is applied to any cash redemptions of Trust Units or is otherwise unavailable for cash distribution will be distributed to Unitholders in the form of additional Trust Units. Such additional Trust Units will be issued pursuant to exemptions under applicable securities laws, discretionary exemptions granted by applicable securities regulatory authorities or a prospectus or similar filing. In addition, on December 31 of each year, Unitholders will be entitled to receive a distribution of the amount, if any, by which the income of the Fund including any net capital gains for purposes of the Tax Act in respect of the year (calculated without reference to paragraph 82(1)(b) and to subsection 104(6) of the Tax Act) less any deductible non-capital or capital losses of prior years exceeds all amounts otherwise distributed or made payable in respect of the year.

The Trustees determined in September 2002 to have the Fund make distributions monthly and not quarterly. The Fund will include in its monthly distributions cash dividends, distributions or returns of capital, if any, received from Fund Businesses. Monthly distributions are due and payable to Unitholders of record on the last day of each month and are expected to be paid on or before 45 days thereafter without interest or penalty. The Trustees declared and made distributions totalling \$55,192,000 during 2002. Such amounts were comprised of three quarterly payments of the Fund for the first three quarters of 2002 and three monthly payments for the balance of 2002 based on anticipated Distributable Cash of the Fund for those periods.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Algonquin Power Income Fund (the "Fund") is a publicly-traded Canadian income fund and an active consolidator of power generation and infrastructure facilities in Canada and the United States. Market capitalization has grown from \$80 million in 1997 to approximately \$600 million in 2002 as a result of the Fund's acquisition strategy. At December 31, 2002, the Fund had 67,887,612 units issued and outstanding and owned 62 generating and wastewater and water treatment reclamation and distribution facilities either directly or indirectly.

The Fund increased revenues to \$94.8 million in 2002 from \$45.0 million in 2001. Net income increased to \$16.2 million in 2002 from \$6.9 million in 2001. Earnings per trust unit increased to \$0.28 in 2002 from \$0.17 in 2001.

The Fund distributed \$55.2 million to unitholders during 2002, an increase of \$17.9 million from \$37.3 million distributed during 2001. Distributions per unit remained constant at \$0.92 during 2002 and 2001. During 2002, the Fund also increased its cash available for distribution to \$44.7 million from \$28.8 million in 2001. On a per unit basis, cash available for distribution increased approximately 5% to \$0.77 for 2002, compared with \$0.73 in 2001.

While the Fund was challenged by widespread below average water flows in 2002, the Fund believes that such conditions are temporary and long term average energy projections continue to be valid. Accordingly, the Fund believed it prudent to maintain current distribution levels in 2002. The Fund is confident that the portfolio is well structured to provide continuing value to unitholders through consistent distributions

2002 Financial and Operating Highlights

	Year ended December 31	
All figures in thousands of dollars except as noted	2002	2001
Revenues	94,743	44,969
Net Income	16,150	6,864
Distributions to Unitholders	55,192	37,302
Per Unit		
Net Income	0.28	0.17
Distributions to Unitholders	0.92	0.92
 Cash Available for Distribution	 44,742	 28,813
Cash Available for Distribution	0.77	0.73

The Fund's diversification strategy in 2002 continued to focus on the acquisition of non-hydroelectric, long-lived assets that have contributed to improved year-over-year results. While the Fund's hydroelectric generating facilities were impacted in 2002 by the below normal water flow conditions which have impacted hydroelectric generation in North America, the Fund realized the benefits of its diversified portfolio with increased per unit earnings (\$0.28 in 2002 against \$0.17 in 2001) and increased per unit cash available for distribution (\$0.77 in 2002 against \$0.73 in 2001).

2002 Activity Highlights

In 2002, the Fund undertook the following initiatives aimed at increasing unitholder value:

Directly aligned management interests with unitholders in July, 2002 through a restructuring of the arrangements with the Manager providing senior management with a salary and incentive compensation plan;

Completed the acquisition of the KMS Power Income Fund in March, 2002 which includes the KMS Peel energy-from-waste facility, the KMS Crossroads cogeneration facility and the KMS Joliet landfill gas facility;

Completed the acquisition of the 44 MW Sanger, California cogeneration facility in May, 2002; and

Continued the expansion of the Infrastructure Division in September, 2002 through the acquisition of three water reclamation and distribution utility companies in Arizona and Texas.

In 2002, the Fund completed acquisitions having a total value of \$186.9 million.

2003 Outlook Summary

While below average hydrologic conditions continued into the first quarter of 2003, the Fund believes that the continuing changes to the composition of its asset portfolio will allow the Fund to deliver sustainable and stable cash flows to unitholders. In early 2003, the Fund's operating divisions announced the following transactions in furtherance of achieving this objective and aimed at enhancing unitholder value. Completion of these transactions has allowed the Fund to commit fully the proceeds of previous public offerings of trust units:

- Acquisition of the 56 MW cogeneration facility in Windsor Locks, Connecticut;
- Acquisition of the 18,000 customer connection Litchfield Park, Arizona water reclamation and distribution facility;
- Agreements for the Fund to accept payment as consideration for lowering certain over-market power purchase rates stipulated in agreements in New Hampshire; and
- Agreement to acquire an interest in an 80 MW biomass fired generating facility in Virginia.

Assuming the completion of these transactions, the three generating divisions of the Fund are expected to contribute cash flows in approximately equal proportions. The Fund believes that such asset allocation, together with the Fund's current capital arrangements, will allow the Fund to deliver continued consistent distributions.

2002 Significant Transactions

During 2002, the Fund completed the acquisition of the KMS Power Income Fund (KMS). This

acquisition added the 10 megawatt Peel energy-from-waste facility in Brampton, Ontario, the 10 megawatt Crossroads cogeneration facility in Mahwah, New Jersey and the 1.6 megawatt biogas generating facility in Joliet, Illinois. Another cogeneration facility located in Chicago, Illinois was sold during the year to the energy customer through the exercise of a purchase option in the energy services agreement. The Fund acquired all the outstanding trust units and 47.3% of the outstanding convertible debentures of KMS, by issuing 6,813,173 trust units. The Fund had previously loaned \$35 million to KMS during 2001. The total transaction value of the acquisition was approximately \$109.5 million.

- The Peel Facility is a 10 MW generating facility which produces electricity from incinerating non-recyclable materials, including municipal solid waste, using steam to drive a turbine generator to produce electricity. It has a power purchase agreement with Ontario Energy Financial Corporation which expires in 2012. The facility also has a waste supply agreement with the Regional Municipality of Peel which pays the facility to take approximately 162,000 tonnes of municipal solid waste annually and which expires in 2012.
- The Crossroads cogeneration facility has entered into a power purchase agreement expiring December 31, 2008 with Orange and Rockland Utilities Inc. for the purchase of up to 3.88 MW of electrical capacity. The facility also has an energy services agreement expiring in 2016 with Crossroads Corporate Park. It requires the facility to use reasonable efforts to provide firm electrical and thermal energy.
- The Joliet biogas generating facility is a landfill gas-to-electricity facility at the CDT landfill located near Joliet, Illinois. The facility is designed to generate approximately 1.6 MW of electricity. The facility has a power purchase agreement with Commonwealth Edison Company (“Com Ed”), a major mid-western utility company, whereby Com Ed will purchase all electricity produced by the facility under a one-year contract, automatically renewable yearly thereafter. Gas from 20 wells drilled in the CDT landfill is used by the facility.

The Fund added to its cogeneration portfolio by acquiring a 44 megawatt natural gas-fired cogeneration facility in Sanger, California. The facility has demonstrated a successful operating history since it was commissioned in 1991. Electrical energy and capacity produced by the facility are sold to Pacific Gas and Electric Company pursuant to a long-term power purchase agreement ending in May, 2021. Payments under the power purchase agreement consist of a monthly capacity payment and an energy payment which are fixed until 2006 at which time they become related to the cost of natural gas consumed by the facility. The Fund paid \$46.9 million in cash, assumed \$30.8 million (US\$ 19.4 million) in tax exempt municipal bonds and issued 248,667 trust units having a value of \$2.2 million.

The Fund also added to its infrastructure portfolio during 2002 by acquiring the Bella Vista Water Company, Inc. in Sierra Vista, Arizona, for \$21.6 million (US\$ 14.1 million) as well as the Tall Timbers and Woodmark water reclamation facilities in Tyler, Texas for a total of \$5.5 million (US\$ 3.5 million). Together, these three acquisitions have a combined customer base of 8,590. The Fund now has a total of 13,500 water and reclamation and distribution customers.

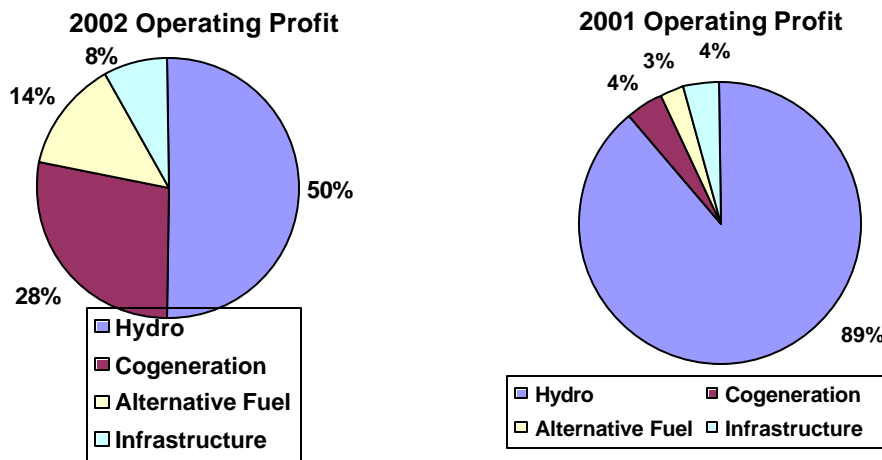
- The Bella Vista Water Company serves approximately 6800 customers in the Town of Sierra Vista, approximately 100km southeast of Tucson, Arizona. Since its inception in 1954, Bella Vista has enjoyed the benefits of the steady expansion of the Town of Sierra

Vista through growth in its customer base.

- The Tall Timbers water reclamation facility serves approximately 1,040 customers in the Town of Tyler, Texas, approximately 140 km east of Dallas, Texas.
- The Woodmark water reclamation facility serves approximately 750 customers in the Town of Tyler, Texas adjacent to the Tall Timbers facility.

Operating and Financial Review

With continued expansion of the Cogeneration, Alternative Fuels and Infrastructure Divisions, the Fund repositioned its portfolio to increase its diversification from hydroelectric facilities.



Hydroelectric Division

2002 Financial and Operating Highlights

All figures in thousands of dollars except as noted	Year ended December 31		2003 Forecast
	2002	2001	Production (1)
Performance (MW-hrs sold)			
Quebec Region	247,965	251,810	297,800
Ontario Region (2)	123,427	111,093	130,800
New England Region	48,001	66,370	76,200
New York Region (2)	66,512	45,464	76,300
Western Region (2)	48,120	18,091	67,300
Total	534,025	492,828	648,400
Revenues			
Energy sales (3)	40,681	36,270	
Interest and dividend income	674	985	
	41,355	37,255	
Expenses			
Operating Expenses (3)	14,370	12,420	
Division Operating Profit	26,985	24,835	
Average electricity sales price (\$/MW-hr)	76.21	73.6	
Percentage of 2002 Forecast Production	82%	82%	

- Note:
- (1) 2003 Forecast Production is based on the hydrology records and past plant performance.
 - (2) 2001 energy production includes the Dickson Dam facility after acquisition in July, 2001 and five hydroelectric facilities located in Ontario, New York and Vermont after acquisition in early 2001.
 - (3) 2002 revenues and operating expenses include the costs for the full year of operations for those facilities acquired during 2001 (See note 2 above).

The Hydroelectric Division is comprised of 47 hydroelectric facilities located in the United States and Canada. Most facilities are run-of-the-river from which energy production is tied directly to available river flows. As a direct result of lower than average water flows, energy production in 2002 from the Fund's hydroelectric facilities was approximately 82% of long-term averages, consistent with 2001. Inclusion of 6 hydroelectric generating facilities acquired in 2001 for a full year in 2002 added approximately \$1.3 million in revenue. The balance of the increase in revenue is the result of higher exchange rates between Canadian and U.S. currency during 2002.

Operating costs were \$14.4 million, which were slightly lower than forecast due to lower regulatory and water lease fees resulting from lower production. Continued management emphasis is being placed on controlling costs and improving operational economies of scale. Operating costs were higher than the prior year due to the additional facilities and higher repair and maintenance costs and insurance costs. Major repairs were undertaken at the Belleterre, Donnacona, Lochmere and Mine Falls generating stations, which resulted from unplanned breakdowns.

Hydroelectric Outlook For 2003

Colder than average temperatures causing below-average water flows in early 2003 have resulted in below-average energy production at the Hydroelectric Division's generating facilities. While snow pack levels are higher than average in regions in which the Fund's hydroelectric facilities are located, spring thaw characteristics will influence how effectively the Fund's facilities can capitalize on such potential.

The Fund has renegotiated with the Public Service Company of New Hampshire ("PSNH") the pricing terms of the power purchase agreements associated with 13 small hydroelectric generating facilities in New Hampshire. Subject to certain approvals and adjustments as consideration for a reduction in the above-market rates stipulated in these power purchase agreements, the Fund is expected to receive approximately \$30.6 million (US\$20.4 million) after the first quarter. After completion of these transactions, PSNH will continue to purchase the energy produced by these generating stations at the New England power pool market price. Given the relatively short period of time remaining on these original agreements and considering the recent history of high volatility in water flow, the Fund believes that such capital will be more effectively deployed elsewhere within the Fund.

Cogeneration Division

2002 Financial and Operating Highlights

Year ended December 31

All figures in thousands of dollars except as noted		2002	2001		Production (1)
Performance (MW-hrs sold)		118,433	-		442,284
Revenues					
	Capacity	11,310	-		
	Energy sales	12,256	-		
	Interest and dividend income	3,758	1,166		
		27,324	1,166		
Expenses					
	Operating Expenses	2,590	-		
	Fuel Expenses	9,665	-		
Division Operating Profit		15,069	1,166		
Average electricity sales price (\$/MW-hr)		103.48	-		

Note: (1) 2003 Forecast Production reflects forecast planned operating schedules based on existing permits and contracts and historic performance, including the March 2003 acquisition of the Windsor Locks facility.

The generating capacity of the Cogeneration Division was increased in 2002 with the acquisition of the 44 MW Sanger cogeneration facility and the 10 MW KMS Crossroads facility. The 2002 performance of the Cogeneration Division assets was generally in accordance with expectations. Strong performance at the Sanger facility offset reduced production at the KMS Crossroads facility caused by unseasonably high temperatures in July and August and lost production arising from the completion of certain repairs at KMS Crossroads in September, 2002. The Cogeneration Division completed the major overhaul of the gas turbine at the KMS Crossroads facility during the second quarter of 2002. The investments in the Kirkland, Cochrane and Cardinal facilities contributed \$3.8 million of dividends and interest compared to \$1.2 million during 2001 as the revenue was included for the full year during 2002. These investments were made in October, 2001.

Cogeneration Outlook For 2003

In March 2003, the Fund completed the acquisition of the 56 MW Windsor Locks, Connecticut cogeneration facility for \$43.2 million (US \$ 29.5 million) which delivers electricity and thermal energy pursuant to sales agreements ending in 2011 and 2018, respectively. The facility delivers electricity to the Connecticut Light and Power Company pursuant to a long-term power purchase agreement ending in 2010. In addition, the facility delivers thermal steam energy and a small portion of its electrical energy to a specialty fibre composite mill located adjacent to the generating facility pursuant to an energy services agreement ending in 2018.

While the majority of the electrical output of the KMS Crossroads facility is sold pursuant to a long-term, take-or-pay power purchase agreement, increased building vacancy rates have resulted in lower electricity and thermal energy host sales by the KMS Crossroads facility which is expected to

reduce 2003 contributions. In addition, gas supply to the facility was curtailed intermittently during the first quarter due to colder than normal temperatures in New Jersey.

Continued strong performance is expected throughout 2003 from the Sanger facility. The major overhaul for the Sanger facility will be completed in May, 2003. The projected cost of the overhaul has risen from \$2.8 million to \$4.0 million.

Alternative Fuels Division

2002 Financial and Operating Highlights

All figures in thousands of dollars except as noted	Year Ended December 31		2003 Forecast Performance (1)
	2002	2001	
Performance (MW-hrs sold)	82,724	18,421	101,000
Performance (tonnes waste processed)	130,793		173,000
Revenues			
Energy sales	4,994	1,020	
Waste disposal sales	10,697	-	
Interest and dividend income	1,470	446	
	17,161	1,466	
Expenses			
Operating Expenses	9,869	747	
Division Operating Profit	7,292	719	
Average electricity sales price (\$/MW-hr) (2)	60.37	62.10	
Average waste tipping fee (\$/tonne)	81.80		

- Note: (1) 2003 Forecast Performance reflects forecast planned operating schedules based on existing permits and contracts and historic performance, but does not include any contribution from the previously announced pending acquisition of an interest in an 80 MW Virginia biomass-fired generating station by the Alternative Fuels division.
- (2) Average electricity sale price in Canadian dollars includes the KMS Peel energy-from-waste facility and KMS Joliet landfill gas facility acquired on March 25, 2002 and a full year of operations of the Drayton Valley facility acquired in July, 2001.

Activity during 2002 in the Alternative Fuels Division was highlighted by the acquisition of the 10 MW KMS Peel 500 tonne/day energy-from-waste facility and the 1.6 MW KMS Joliet landfill gas facility. Management effort and resources were directed towards rectifying deferred maintenance problems and improving the cost control of the operation of these facilities. While in July, 2002, the KMS Peel facility commenced processing high value international airline waste, difficulties resulting from high moisture content of such waste stream reduced cash flows from this initiative through the balance of 2002. Unexpected steam turbine repairs completed in 2002 at the Drayton Valley biomass facility and the KMS Peel facility resulted in higher than expected repair/maintenance program costs.

Alternative Fuels Outlook for 2003

The handling charges levied by the KMS Peel facility for international airline waste were increased in April, 2003 to compensate for the high moisture content. The Fund anticipates that cash flows from this initiative will be in accordance with expectations through the balance of 2003.

In February, 2003, the Alternative Fuels Division announced that it had entered into an agreement to purchase a 40% partnership interest in an 80 MW biomass-fired electric generating station located in Virginia. The generating station has demonstrated a successful operating history since its commissioning in 1994 and provides peaking capacity to Virginia Electric and Power Company pursuant to a long-term capacity and energy purchase agreement ending in 2019. Closing of the acquisition of the partnership interest will be subject to, among other things, obtaining certain transfer approvals.

Investment being made in capital improvements at the Drayton Valley biomass facility is focused on improving reliability. Increased downtime and cost to complete such work is expected to reduce its contribution in 2003. Management efforts are continuing to be focused on improving operational efficiencies at the KMS Peel and Drayton Valley facilities.

Infrastructure Division

2002 Financial and Operating Highlights

All figures in	Year Ended December 31		2003 Forecast Performance (1)
	2002	2001	
Performance			
Water reclamation connections	7,210	4,600	17,850
Water distribution connections	6,971	-	18,500
Revenues			
Water Reclamation	4,827	2,522	
Water Distribution	3,147	-	
Interest and dividend income	98	30	
	8,072	2,552	
Expenses			
Operating Expenses	3,394	1,353	
Division Operating Profit	4,678	1,199	

Note: (1) 2003 Forecast Performance reflects current connections and management's assessment of current planned connection growth through a review of building permit issuance and includes the expected contribution of the Litchfield Park Service Company acquired in February, 2003.

The Infrastructure Division performed well in 2002 with customer growth and cash flows exceeding expectations. Compared with 2001, 2002 revenues increased by approximately \$5.5 million and 2002 operating profit increased by approximately \$3.5 million. These increases primarily reflect the effects of the acquisition of the Bella Vista Water Company in 2002 and the inclusion of operations of the Gold

Canyon Sewer Company and Black Mountain Sewer Company for a full year. In addition, utilities in the Infrastructure Division demonstrated strong organic growth during 2002.

Infrastructure Outlook for 2003

In February, 2003, the Fund completed the acquisition of the Litchfield Park Service Company (LPSCo) for \$52.5 million (US\$ 35.2 million). This utility provides the Fund with an additional 18,000 water reclamation and distribution connections. Recent acquisitions have propelled the Fund to its current position as the third largest investor-owned utility in Arizona.

Continued strong organic growth in the customer base of the Fund's water reclamation and distribution facilities is expected in 2003 with approximately 5,000 new connections forecast.

Administrative operations, including customer service and billing for the Fund utilities, are being consolidated at the Fund's head office in Oakville.

The Infrastructure Division was originally contemplated as a small diversification initiative to provide stable and growing cash flows to the Fund with downside protection afforded through the regulatory authorities. Opportunities in the high growth southwestern United States resulted in acquisitions that caused performance and capital requirements to exceed initial expectations. Accordingly, the Fund is actively considering a number of strategic alternatives for the Infrastructure Division, including the spin-off of this Division as a separately-traded entity.

Administration

				Year ended December 31			
				2002	2001		
All figures in thousands of dollars				2002	2001		
Administrative Expenses							
	Management costs			658	646		
	Administrative costs			4,911	792		
	Withholding taxes			558	472		
	Loss / (gain) on foreign exchange			1,643	(354)		
Interest expense				8,382	6,700		

During 2002, in recognition of the evolving governance standards in the income trust sector and the unique aspects of the Fund's business and structure, the Manager and the Fund voluntarily amended the management agreements in respect of the Fund without compensation to the Manager. Under the revised agreements, while the senior management personnel are not technically employees of the Fund, compensation for these individuals is now limited to salary and an incentive bonus based solely on increases in cash available for distribution. Other management and operations services are now provided on a cost reimbursement basis.

Administration costs in 2002 were approximately \$4.9 million, an increase of approximately \$4.1 million over 2001. Such increased costs include approximately \$1.2 million in non-recurring charges: legal costs incurred with respect to the Trafalgar Power Inc. and Franklin Industrial assets (\$0.8 million); and

additional GST due to a tax audit (\$0.4 million). In 2001, administrative costs were reduced by franchise tax recovery (\$0.8 million). The balance of the administrative cost increase over the prior year resulted primarily from the increased size of the Fund including the acquisition of the KMS Power Income Fund and associated administrative costs.

The Fund incurred a foreign exchange loss of \$1.6 million of which approximately \$1.0 million was unrealized. Foreign exchange gains and losses arise primarily from the long-term U.S. Dollar denominated debt associated with the Sanger facility of \$30.3 million (U.S. \$19.2 million).

Interest and financing fees in 2002 totaled \$8.4 million, an increase of \$1.7 million over 2001. Such increased costs are related to increased activity in the Fund including use of the acquisition line of credit provided by the Fund's banking syndicate, the inclusion of project-related debt acquired during the year and the KMS convertible debentures.

Cash Flow

	Year ended December 31	
All figures in thousands of dollars except as noted	2002	2001
Operating cash flow before working capital changes	40,611	22,173
Receipt of principal on notes receivable	2,738	8,414
Proceeds on sale of capital assets	920	-
Decrease in reserves	1,854	593
Repayment of long-term liabilities	(929)	(602)
Maintenance capital expenditures, net of capital grants	59	(1,565)
Other	(511)	(200)
Cash available for distribution	44,742	28,813
Distributions to unitholders	55,192	37,302
Per trust unit (\$/trust unit)		
Cash available for distributable per trust unit	0.77	0.73
Distributions to unitholders per trust unit	0.92	0.92

Distributions declared to unitholders are generally based on the expected sustainable cash generated using long-term average water conditions for hydroelectric facilities and planned operations for non-hydroelectric generating assets. Cash distributions were \$55.2 million in 2002 in comparison to \$37.3 million in 2001. While performance of the recent acquisitions is forecast to provide accretion to cash available for distribution, as a result of below average hydrologic conditions in 2002, the Fund determined it was prudent to maintain the 2001 distribution level of \$0.92 per unit in 2002.

Cash available for distribution does not have any standardized meaning prescribed by generally accepted accounting principles and is therefore unlikely to be comparable to similar measures presented by other companies.

Cash available for distribution generated by the Fund's portfolio increased by over 55% from \$28.8 million in 2001 to \$44.7 million in 2002. Per-unit results also increased by approximately 5% to \$0.77 per unit in 2002 from \$0.73 per unit in 2001. Management believes that such improvements can be traced directly to the Fund's diversification strategy.

Distribution Outlook for 2003

The Fund believes that current below-average hydrologic conditions are temporary. Therefore, long-term average energy production projections for the Fund's hydroelectric assets remain valid. There can be no assurances that the 2002 below-average water flow conditions will not continue into 2003. However, with the current diversification of the Fund's assets, less than 45% of 2003 cash distributions are forecast to be generated by the Hydroelectric Division. Forecast cash distributions to be provided from the other operating divisions are in excess of those amounts required to maintain current distribution levels.

Liquidity and Capital Reserves

As at December 31, 2002, the Fund had positive net working capital of \$15.4 million, compared to \$19.0 million in 2001. At the end of 2001, the Fund had \$24.8 million of cash and cash equivalents.

Long-term liabilities at December 31, 2002 were \$85.2 million compared to \$50.2 million in 2001. These long-term liabilities primarily represent the non-recourse project debt at certain facilities.

At the end of 2002, the Fund has a strong balance sheet with a debt-to-capital ratio of less than 15%.

Acquisitions completed by the fund in early 2003 and the growth-capital expenditure requirements and equipment overhauls planned for 2003 will be financed from internally generated cash flows, cash received from the renegotiation of the New Hampshire power purchase contracts, funds from the public offering completed in October, 2002 and bank financing.

Risk Management

Results from operations are affected by the exchange rate between the Canadian and U.S. dollars. The Fund has attempted to reduce the impact of exchange rate fluctuations by agreeing to pay certain of its obligations in U.S. dollars including the Municipal Bonds for the Sanger facility. The Fund also utilizes currency options as required to fix the foreign exchange rate on cash flows for quarterly distributions and protect a minimum downside position. At the end of 2002, the Fund had forward contracts for U.S. \$8.4 million or 75% of the U.S. dollar cash flow for 2003. In early 2003, the Fund entered into another U.S. \$21.5 million or 44% of the U.S. dollar cash flow of forward contracts for 2004 to 2008.

The Fund's cogeneration and alternative fuels facilities utilize natural gas in their daily operating processes. The Fund has fixed its forecast gas consumption using natural gas fixed price contracts and future purchase contracts. The Fund has fixed its forecast natural gas exposure for 2003. The Sanger facility has fixed natural gas contracts in place until 2006 at which time the natural gas becomes a pass through in the power purchase agreement. The Crossroads facility's has effectively fixed the price on its natural gas price until May 2004 at which time the natural gas be a pass through in the power purchase agreement. The Peel energy-from-waste facility has fixed the price of its forecast usage of natural gas until 2007. Total MMBtu's being hedged during 2003 are approximately 1,600 per day.

The Fund has adequate insurance on all of its facilities. This includes property and casualty, boiler and machinery and liability insurance.

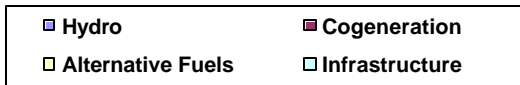
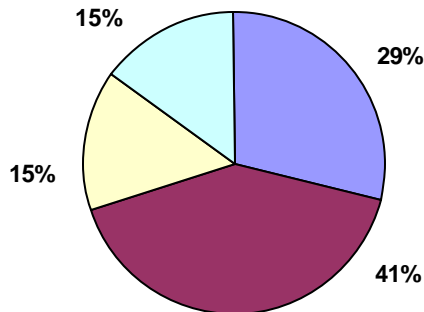
Outlook

The Fund will continue its diversification strategy to balance further and strengthen the portfolio during 2003.

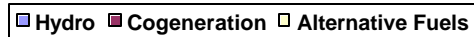
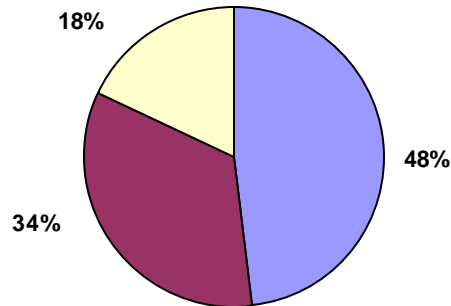
The Fund will continue to consider investment opportunities that provide stable cash flow from generating and infrastructure facilities. Opportunities which provide long-term, statistically predictable future cash flows and a risk profile generally consistent with the existing portfolio of assets, will be considered. All investment opportunities will continue to be required to meet the Fund's Acquisition Guidelines established by the Trustees. These guidelines provide that all acquisitions are expected to result in an increase in Distributable Cash per Trust Unit.

The Fund's portfolio will continue to be repositioned and balanced to further reduce the dependence on hydroelectric generation during 2003. The chart (below) shows the operating profit splits between the different groups after taking into account the transactions closed in the first quarter of 2003.

Expected Operating Profit before depreciation after completion of Litchfield Park and Windsor Locks transactions



Expected Operating Profit before depreciation after completion of Windsor Locks transaction excluding the Infrastructure Division



Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2002.

\$ millions except per trust unit amount

2002	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Total
Revenues	15.7	28.4	25.1	25.6	94.8
Net earnings (loss)	6.1	10.3	(3.8)	3.6	16.2
Net earnings per trust unit	0.12	0.18	(0.07)	0.05	0.28
2001					
Revenues	10.6	13.1	8.2	13.1	45.0
Net earnings (loss)	3.8	(2.5)	1.8	3.8	6.9
Net earnings per trust unit	0.12	(0.08)	0.05	0.08	0.17

Note: The sum of net earnings per trust unit for the four quarters ended December 31 may differ from the net earnings per trust unit for the year due to the difference in average number of trust units outstanding.

Recently Issued U.S. and Canadian Accounting Standards

In January, 2003, The Canadian Institute of Chartered Accountants (“CICA”) issued “Handbook Section 3110, Accounting for Asset Retirement Obligations” which addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Section 3110 requires the Fund to record the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development and/or normal use of the assets. The fair value of the liability is added to the carrying amount of the associated asset and this additional carrying amount is depreciated over the life of the asset. Subsequent to the initial measurement of the asset retirement obligation, the obligation will be adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The Fund is required and plans to adopt the provisions of Section 3110 as of January 1, 2004. The determination of fair value is complex and will require the Fund to gather market information and develop cash flow models. Because of the effort necessary to comply with the adoption of Section 3110, it is not practicable for management to estimate the impact of adopting this standard at the date of this report.

In December, 2002, the CICA issued Handbook Section 3063, “Impairment or Disposal of Long-Lived Assets” and revised Section 3475, “Disposal of Long-Lived Assets and Discontinued Operations”. Together, these two Sections supersede the write-down and disposal provisions of Section 3061, “Property, Plant and Equipment” as well as Section 3475, “Discontinued Operations”. Section 3063 amends existing guidance on long-lived asset impairment measurement and establishes standards for the

recognition, measurement and disclosure of the impairment of long-lived assets held for use by the Fund. It requires that an impairment loss be recognized when the carrying amount of an asset to be held and used exceeds the sum of the undiscounted cash flows expected from its use and disposal; the impairment recognized is measured as the amount by which the carrying amount of the asset exceeds its fair value. Section 3475 requires assets classified as held-for-sale to be measured at the lower of their carrying amounts or fair value, less costs to sell. The new standards contained in Section 3063 on the impairment of long-lived assets held for use are applicable for years beginning on or after April 1, 2003. The revised standards contained in Section 3475 on disposal of long-lived assets and discontinued operations are applicable to disposal activities initiated by the Fund on or after May 1, 2003.

The CICA has issued Accounting Guideline 13, "Hedging Relationships" ("AcG 13") which establishes new criteria for hedge accounting and will apply to all hedging relationships in effect for the Fund on or after January 1, 2004. On January 1, 2004 the Fund will re-assess all hedging relationships to determine whether the criteria are met or not and will apply the new guidance on a prospective basis. To qualify for hedge accounting, the hedging relationship must be appropriately documented at the inception of the hedge and there must be reasonable assurance, both at the inception and throughout the term of the hedge, that the hedging relationship will be effective. Effectiveness requires a high correlation of changes in fair values or cash flows between the hedged item and the hedging item. The Fund is in the process of reviewing all of its hedging relationships to ensure compliance with the AcG-13 and does not anticipate any material impact from adopting this guideline at the date of this report.

In January, 2003, the CICA issued AcG 14 "Guarantees" which requires certain disclosures to be made by a guarantor in its interim and annual financial statements. The Fund will be required to make such disclosures in its first quarter 2003 financial statements. AcG-14 does not impact the Fund's operating results or financial position.

Note: Certain statements contained in this information herein are forward-looking and reflect the Fund's and its Manager's views with respect to future events. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Forward-looking statements are not guarantees of the Fund's future performance or results and are subject to various factors including but not limited to assumptions such as those relating to: the performance of the Fund's assets; commodity market prices; interest rates; and environmental and other regulatory requirements. Although the Fund and its Manager believe that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of the dates hereof. The Fund and its Manager are not obligated nor do either of them intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise.

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Blake, Cassels & Graydon LLP, counsel to the Fund ("Counsel"), the following summary describes the principal Canadian federal income tax considerations pursuant to the Tax Act and the regulations thereunder generally applicable to a Unitholder who acquires Trust Units and who, for purposes of the Tax Act, is resident in Canada, holds the Trust Units as capital property and deals at arm's length with the Fund, Algonquin Power and the Manager and is not affiliated with the Fund, Algonquin Power or the Manager. Generally, Trust Units will be considered to be capital property to a Unitholder provided the Unitholder does not hold the Trust Units in the course of carrying on a business

and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. Certain Unitholders who might not otherwise be considered to hold their Trust Units as capital property may, in certain circumstances, be entitled to have them treated as capital property by making the election permitted by subsection 39(4) of the Tax Act. This summary is not applicable to a Unitholder that is a “financial institution” for purposes of the mark-to-market rules, to a Unitholder an interest in which is a “tax shelter investment” or to any such Unitholder that is a “specified financial institution”, all within the meaning of the Tax Act. Any such Unitholder should consult its own tax advisor with respect to an investment in Trust Units.

This summary is based upon the provisions of the Tax Act and the Income Tax Regulations (the “Regulations”) in force as of the date hereof, all specific proposals to amend the Tax Act or the Regulations that have been publicly announced by the Minister of Finance prior to the date hereof (the “Proposed Amendments”), certificates of the Fund, Algonquin Canada, Algonquin Power and others as to certain factual matters and Counsel’s understanding of the current published administrative and assessing policies of the Canada Customs and Revenue Agency (“CCRA”). This summary is also based on the assumption that the Fund will at all times comply with the Declaration of Trust.

This summary is not exhaustive of all possible Canadian federal income tax consequences and, except for the Proposed Amendments, does not take into account or anticipate any changes in the law or in the administrative or assessing policies of CCRA, whether by legislative, governmental or judicial action, nor does it take into account provincial, territorial or foreign tax considerations, which may differ significantly from those discussed herein. No assurance can be given that the Proposed Amendments will be enacted as currently proposed or at all.

This summary is of a general nature only and is not intended to be legal or tax advice to any prospective purchaser of Trust Units or any Unitholder. Consequently, prospective purchasers and Unitholders should consult their own tax advisors with respect to their particular circumstances.

Status of the Fund

This summary assumes that the Fund qualifies and will continue to qualify as a “mutual fund trust” as defined in the Tax Act. In order to so qualify, Trust Units representing at least 95% of the fair market value of all Trust Units of the Fund must have conditions attached thereto that include conditions requiring the Fund to accept, at the demand of the holder thereof and at prices determined and payable in accordance with the conditions, the surrender of the Trust Units, or fractions or parts thereof, that are fully paid. In addition, there must at all times be at least 150 Unitholders of the Fund each of whom owns not less than one “block” of Trust Units having a fair market value of not less than \$500. A “block” of Trust Units means 100 Trust Units if the fair market value of one Trust Unit is less than \$25. Further, the undertaking of the Fund must be restricted to the investing of its funds in property (other than real property or an interest in real property), the acquiring, holding, maintaining, improving, leasing or managing of any real property (or an interest in real property) that is capital property of the Fund, or a combination of these activities. The Fund will be deemed not to be a mutual fund trust if it can reasonably be considered that the Fund, having regard to all the circumstances, was established or is maintained primarily for the benefit of non-resident persons. While Counsel cannot provide an opinion on matters of fact such as the foregoing, Counsel understands that the Fund intends, and this summary assumes, that at all relevant times these and other applicable requirements will be satisfied and that the Fund is not established nor will it be maintained primarily for the benefit of non-resident persons, so that the Fund qualifies and will continue to qualify as a mutual fund trust at all relevant times. In the event the Fund does not qualify as a mutual fund

trust, the income tax considerations would in some respects be materially different from those described below.

If the Fund ceases to qualify as a mutual fund trust, the Fund may be required to pay a tax under Part X.2 or Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Fund may have adverse income tax consequences for certain Unitholders, including non-resident persons.

The Fund has been registered by CCRA as a registered investment for purposes of the Tax Act. Accordingly, the Fund may be subject to a special tax under Part XI of the Tax Act if it acquires or holds foreign property in excess of the limits provided in the Tax Act, or enters into certain agreements to acquire shares of a corporation at a price that may differ from the fair market value of the shares at the time of acquisition. Counsel has been advised by the Fund that it does not expect to make excessive investments in foreign property or enter into any such agreements, and accordingly the Fund should not be subject to tax under Part XI of the Tax Act.

Taxation of the Fund

The Fund is subject to taxation in each taxation year on its taxable income for the year, including net realized taxable capital gains, less the portion thereof that is paid or payable in the year to Unitholders and which is deducted by the Fund in computing its income for purposes of the Tax Act. An amount will be considered to be payable to a Unitholder in a taxation year if it is paid in the year by the Fund or the Unitholder is entitled in that year to enforce payment of the amount. The taxation year of the Fund is the calendar year.

The Fund will generally be entitled to deduct its expenses incurred to earn such income provided such expenses are reasonable and otherwise deductible, and it will be entitled to claim capital cost allowance with respect to its undepreciated capital cost in any facility equipment held by the Fund, subject to the provisions of the Tax Act in that regard. Counsel can express no opinion with respect to matters of fact, such as the reasonableness of expenses or the accuracy of capital costs. The Rawdon Facility Equipment, the Donnacona Facility Equipment, the Ste-Brigitte Facility Equipment and the Belleterre Facility Equipment are currently leasing properties and specified energy property of the Fund and, accordingly, capital cost allowance claimed in respect thereof is currently deductible by the Fund only to the extent of the Fund's income from such property (determined without reference to paragraph 20(1)(a) of the Tax Act). The Fund may deduct in computing its income for a year a portion of the reasonable expenses of the issue of Trust Units paid by the Fund from the proceeds of the public offerings of its Units. Such portion of issue expenses deductible by the Fund in a taxation year is determined pursuant to the Tax Act and is generally equal to that portion of 20% of the total issue expenses that the number of days in the Fund's taxation year is of 365 days, to the extent that the issue expenses were not otherwise deductible in a preceding year.

Under the Declaration of Trust, an amount equal to all of the income of the Fund for each year (determined without reference to paragraph 82(1)(b) and subsection 104(6) of the Tax Act), together with the taxable and non-taxable portion of any capital gains realized by the Fund in the year, (excluding income and capital gains which may be realized by the Fund upon a distribution *in specie* of the Fund Assets in connection with a redemption of a Trust Unit) net of the Fund's deductions and expenses, will be payable in the year to the holders of the Trust Units by way of cash distributions, subject to the exceptions described below.

Under the Declaration of Trust, income of the Fund may be used to finance cash redemptions of Trust Units and accordingly such income so utilized will not be payable to holders of the Trust Units by way of cash distributions but rather will be payable in the form of additional Trust Units (“Reinvested Trust Units”).

A distribution by the Fund to a Unitholder of a portion of the assets of the Fund upon a redemption of Trust Units will be treated as a disposition thereof by the Fund for proceeds equal to their fair market value (determined, in the case of an interest in the debt obligations held by the Fund, without taking into account any accrued interest) and will give rise to income (or loss) and/or a capital gain (or a capital loss) to the Fund to the extent that the fair market value of the Fund Assets so distributed exceeds (or is exceeded by) the cost amount to the Fund of the respective portion of the Fund Assets immediately prior to the distribution. In addition, the Fund will be required to include in its income any interest that had accrued on any of the Fund Notes and other accrued but unpaid income, if any, in respect of the Fund Assets so disposed of up to the date of distribution to the extent not otherwise included in its income for the year of disposition or a previous year. On a redemption of Trust Units, capital gains arising in the Fund attributable to an *in specie* distribution of Fund Assets and certain income of the Fund will be payable to the redeeming Unitholder, with the result that the taxable portion of such gains and such income should generally be taxable to the redeeming Unitholder and not the Fund. Nevertheless, the Declaration of Trust provides that income of the Fund which is required to satisfy any tax liabilities on the part of the Fund will not be payable to the Unitholders.

For purposes of the Tax Act, the Fund generally intends to deduct in computing its income the full amount available for deduction in each year to the extent of its taxable income for the year otherwise determined. Therefore, as a result of such deduction from income and the Fund’s entitlement to a capital gains refund within the meaning of the Tax Act, Counsel has been advised by the Fund that the Fund does not expect that it will be liable for any material amount of tax under Part I of the Tax Act. However, Counsel can provide no opinion in this regard.

Taxation of the Unitholders

A Unitholder will generally be required to include in computing income for a particular taxation year the Unitholder’s portion of the income of the Fund for a taxation year, including net realized taxable capital gains, that is paid or payable to the Unitholder in that particular year, notwithstanding that any such amount may be payable in Reinvested Trust Units.

Provided that appropriate designations are made by the Fund, such portions of its net taxable capital gains, taxable dividends from taxable Canadian corporations and foreign source income as are paid or payable to a Unitholder will effectively retain their character and be treated as such in the hands of the Unitholder for the purposes of the Tax Act. Accordingly, such amounts will generally be taken into account in determining the Unitholder’s foreign tax credits and, in the case of a Unitholder that is an individual, the Unitholder’s entitlement to the dividend tax credit. Such amounts will also be taken into account in determining the Unitholder’s liability, if any, for alternative minimum tax under the Tax Act.

Any amount in excess of the income of the Fund that is paid or payable by the Fund to a Unitholder in a year should not generally be included in the Unitholder’s income for the year. However, where such an amount is paid or becomes payable to a Unitholder, other than as proceeds of disposition or deemed disposition of Trust Units or any part thereof, the amount will generally reduce the adjusted cost base of the Trust Units held by such Unitholder, except to the extent that the amount represents the

Unitholder's share of the non-taxable portion of the net realized capital gains of the Fund for the year, the taxable portion of which was designated by the Fund in respect of the Unitholder.

The adjusted cost base of a Trust Unit to a Unitholder will include all amounts paid or payable by the Unitholder for the Trust Unit, with certain adjustments. Trust Units issued to a Unitholder in lieu of a cash distribution of income (including net capital gains) will have a cost equal to the amount of such income and this cost will be averaged with the adjusted cost base of all other Trust Units held as capital property in accordance with the detailed provisions of the Tax Act in that regard.

Upon the disposition or deemed disposition by a Unitholder of a Trust Unit, whether on redemption or otherwise, the Unitholder will generally realize a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition (excluding any amount payable by the Fund which represents an amount that must otherwise be included in the Unitholder's income as described above) are greater (or less) than the aggregate of the Unitholder's adjusted cost base of the Trust Unit and any reasonable costs of disposition. Where Trust Units are redeemed and any Fund Assets are distributed *in specie* to the Unitholder, the proceeds of disposition to the Unitholder of the Trust Units will be equal to the fair market value of the Fund Assets so distributed (excluding any amount that is paid or made payable in a year out of the income or capital gains of the Fund for the year or any amount that is payable by the Fund which must otherwise be included in the Unitholder's income).

One-half of any capital gain realized by a Unitholder on the disposition of a Trust Unit and the amount of any net taxable capital gains designated by the Fund in respect of a Unitholder will be included in the Unitholder's income under the Tax Act in the taxation year in which the disposition occurs or in respect of which a net taxable capital gains designation is made by the Fund. To the extent that the adjusted cost base of a Trust Unit would otherwise be less than zero in any taxation year of a Unitholder, the negative amount will be deemed to be a capital gain realized by the Unitholder in such taxation year from the disposition of the Trust Unit and the amount of such capital gain will be added to the adjusted cost base of the Trust Unit. Subject to certain specific rules in the Tax Act, one-half of any capital loss realized on the disposition of a Trust Unit may be deducted against one-half of any capital gains realized by the Unitholder in the year of disposition, in the three preceding taxation years or in any subsequent taxation years. Capital losses realized on a disposition of Trust Units by a Unitholder that is a corporation may be reduced by the amount of taxable dividends designated to the Unitholder in accordance with the detailed rules in the Tax Act in that regard.

The cost amount to a Unitholder, immediately after a redemption of Trust Units of the Unitholder, of any Fund Assets distributed to the Unitholder by the Fund upon such redemption or upon the termination of the Fund, will be equal to the fair market value of such Fund Assets at the time of the distribution excluding, in the case of a Fund Note, any accrued interest thereon. The redeeming Unitholder will be required to include in income interest on any Fund Note acquired (including interest that had accrued prior to the date of the acquisition of the interest in the Fund Note by the Unitholder) in accordance with the provisions of the Tax Act. To the extent that the Unitholder is required to include in income any interest that had accrued prior to the date of the acquisition of the Fund Notes by the Unitholder, an offsetting deduction may be available.

Taxable capital gains realized by a Unitholder that is an individual may give rise to alternative minimum tax, depending on the Unitholder's circumstances.

Holdings are advised to consult their own tax advisors prior to exercising their redemption rights.

Tax Exempt Unitholders

The Trust Units will generally be qualified investments for trusts (“Plans”) governed by registered retirement savings plans (“RRSPs”), registered retirement income funds (“RRIFs”), deferred profit sharing plans (“DPSPs”) and registered education savings plans (“RESPs”) under the Tax Act, subject however to the specific provisions of any particular Plan and the Fund maintaining its status as a mutual fund trust or continuing to be a registered investment under the Tax Act. The Trust Units will not be prohibited investments for registered pension plans, subject to the qualifications set out under the heading “Eligibility For Investment”. The Plans will generally not be liable for tax in respect of any distributions received from the Fund or any capital gains realized on the disposition of any Trust Units. Where a Plan receives Fund Assets as a result of a redemption of Trust Units, such Fund Assets will likely not be qualified investments under the Tax Act for the Plans and could give rise to adverse consequences to the Plans (and, in the case of RRSPs or RRIFs, to the annuitants thereunder) including, in the case of RESPs, revocation of such Plans. Accordingly, Plans that own Trust Units should consult their own tax advisors before deciding to exercise the redemption rights thereunder.

If the Fund ceases to qualify as a mutual fund trust and the Fund’s registration as a registered investment under the Tax Act is revoked, the Trust Units will cease to be qualified investments under the Tax Act for Plans. Where, at the end of a month, a Plan holds Trust Units or other properties that are not qualified investments, the Plan may, in respect of that month, be required to pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units or other properties at the time such Trust Units or other properties were acquired by the Plan. In addition, where a trust governed by an RRSP (or an RRIF) holds (or acquires, respectively) Trust Units or other properties that are not qualified investments, the trust will become taxable on income attributable to the Trust Units or other properties while they are not qualified investments. Where a trust governed by an RESP acquires or holds Trust Units or other properties that are not qualified investments, the Plan may become revocable and its registration may be revoked by the Minister of National Revenue. Where a trust is governed by a DPSP and acquires property that is not a qualified investment, the trust will be required to pay a tax equal to the fair market value of the property at the time of its acquisition. Where a trust governed by an RRSP or RRIF acquires property that is not a qualified investment the annuitant under the RRSP or RRIF will be required to include the fair market value of such property in income for tax purposes.

Under the Tax Act, trusts governed by RRSPs, RRIFs, DPSPs, registered pension plans, registered investments and certain other entities are subject to a special tax under Part XI of the Tax Act in respect of investments in foreign property in excess of limits specified within the Tax Act. Provided the Fund continues to be a registered investment for purposes of the Tax Act, Counsel is of the opinion that the Trust Units will not, at the time of their issue pursuant hereto, constitute foreign property for Plans, registered pension plans or other persons subject to tax under Part XI of the Tax Act.

ELIGIBILITY FOR INVESTMENT

In the opinion of Blake, Cassels & Graydon LLP (“Counsel”) as at the date hereof, eligibility of the Trust Units for investment by purchasers to whom the following statutes apply is, in certain cases, governed by criteria which such purchasers are required to establish as policies or guidelines pursuant to the applicable statute (and, where applicable, the regulations thereunder) and is subject to compliance with the prudent investment standards and general investment provisions provided therein:

Insurance Companies Act (Canada)
an Act respecting insurance (Québec) (in respect of insurers other than guarantee fund corporations, mutual associations and professional corporations)
Trust and Loan Companies Act (Canada)
Loan and Trust Corporations Act (Alberta)
an Act respecting trust companies and savings companies (Québec) (for a trust company investing its own funds and deposits it receives and a savings company (as defined therein) investing its funds)
Pension Benefits Standards Act, 1985 (Canada)
Pension Benefits Act (Ontario)
Supplemental Pension Plans Act (Québec)
Financial Institutions Act (British Columbia)
Pension Benefit Standards Act (British Columbia)

Subject to the assumptions, limitations and restrictions described under “Canadian Federal Income Tax Considerations” being met, and to the provisions of any particular plan, in the opinion of such Counsel, as at the date hereof, the Trust Units will also be qualified investments for trusts governed by RRSPs, RRIFs, DPSPs and RESPs and will not constitute foreign property for trusts governed by RRSPs, RRIFs, DPSPs or other entities subject to Part XI of the Tax Act. The Trust Units will not be prohibited investments for registered pension plans, so long as the Fund is not (i) an employer who participates in such a registered pension plan; (ii) a person connected with such an employer; (iii) a person that controls, directly or indirectly, in any manner whatever, such an employer or connected person; or (iv) a person that does not deal at arm’s length with a member of such a registered pension plan or with any persons or partnerships described in (i), (ii) or (iii) above, each for purposes of the Tax Act. See “Canadian Federal Income Tax Considerations” for additional comments. Trusts governed by RESPs are not subject to restrictions on their holdings of foreign property under the Tax Act.

MARKET FOR SECURITIES

The Trust Units have been listed and posted for trading on the Toronto Stock Exchange since December 23, 1997 under the symbol “APF.UN”.

TRUSTEES OF THE FUND

The following table sets forth certain information with respect to the Trustees of the Fund. The Fund has no officers.

Name and Municipality of Residence	Principal Occupation
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GEORGE L. STEEVES Aurora, Ontario	Energy Consultant.
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Name and Municipality of Residence Principal Occupation

KENNETH MOORE Managing Partner, Newpoint Capital Partners Inc., an investment
Toronto, Ontario banking firm.

CHRISTOPHER J. BALL Executive Vice President, Corpfinance International Limited
Toronto, Ontario

Mr. Steeves has served in his capacity as Trustee since September 8, 1997. Mr. Moore became a Trustee on December 18, 1998 and Mr. Ball became a Trustee on October 22, 2002. Each of the Trustees will serve as a Trustee of the Fund until the next annual meeting of Unitholders or until his successor is elected in accordance with the Declaration of Trust.

Each of the Trustees has held their principal occupations for more than five years, other than Mr. Steeves who was from January 2001 to April 2002 a division manager of Earthtech Canada Inc. (engineering firm) and prior to January 2001, the president of Cummings Cockburn Limited (engineering firm). Mr. Ball has been a senior officer of Corpfinance International Limited for more than five years.

The Fund does not have an executive committee of the Trustees. The Fund is required to have an audit committee. Messrs. Steeves, Moore and Ball are members of the audit committee.

None of the Trustees beneficially own any Units of the Fund, although Mr. Ball exercises control and direction over 2,000 Units beneficially owned by his spouse.

DIRECTORS AND EXECUTIVE OFFICERS OF THE MANAGER AND POWER SYSTEMS

The following sets out certain information with respect to the directors and executive officers of the Manager and Power Systems. Unless otherwise indicated, the directors and officers have been in their principal occupations for more than five years.

Name and Municipality of Residence	Office	Principal Occupation
CHRISTOPHER K. JARRATT Oakville, Ontario	Chief Executive Officer and Director of the Manager and Director of Powers Systems	Principal of Algonquin Power
IAN E. ROBERTSON Oakville, Ontario	Director of the Manager and of Power Systems	Principal of Algonquin Power
JOHN M.H. HUXLEY Toronto, Ontario	Director of the Manager and of Power Systems	Principal of Algonquin Power

Name and Municipality of Residence	Office	Principal Occupation
DAVID C. KERR Toronto, Ontario	Director of the Manager and Secretary and Director of Power Systems	Principal of Algonquin Power
PETER KAMPIAN Cambridge, Ontario	Chief Financial Officer of the Manager and of Power Systems	Chief Financial Officer of Algonquin Power Trust
ROBERT DODDS Mississauga, Ontario	President of Power Systems	Employee of Algonquin Power Trust

Approximately 86,255 of the Trust Units are beneficially owned, directly or indirectly, by the directors and senior officers of the Manager, as a group.

RISK FACTORS

The following are certain additional risk factors relating to the business of the Fund. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this annual information form and the documents incorporated by reference herein.

Investment Eligibility

The Fund will endeavour to ensure that the Trust Units continue to be qualified investments for trusts governed by RRSPs, RRIFs, DPSPs (collectively, the “Plans”) and RESPs, under the Tax Act and will not be “foreign property” to Plans. RESPs are not subject to restrictions on their holdings of foreign property. If the Fund ceases to qualify as a mutual fund trust and its registration as a registered investment under the Tax Act is revoked, the Trust Units will cease to be qualified investments for Plans and RESPs. Where, at the end of any month, a Plan or RESP holds Trust Units that are not qualified investments, the Plan or RESP may become liable to pay a penalty tax in respect of that month equal to 1% of the fair market value of the Trust Units at the time Trust Units were acquired by the Plan. Certain other adverse tax consequences could also arise for a Plan or RESP or an annuitant or subscriber thereunder if the Plan or RESP acquires or holds Trust Units and such units are not qualified investments. One of the ways in which the Fund could cease to qualify as a mutual fund trust would be if non-residents of Canada (“non-residents”) within the meaning of the Tax Act were to become the beneficial owners of a majority of the Trust Units. There can be no assurance that income tax laws and the treatment of mutual fund trusts will not be changed in a manner which adversely affects Unitholders (see also “Canadian Federal Income Tax Considerations”).

Dependence upon Fund Businesses

The Fund will be entirely dependent upon the operations and assets of the Fund Businesses. Accordingly, distributions to Unitholders will be dependent upon the ability of each of the Fund Businesses to pay principal and interest on the notes issued by it and to declare and pay dividends or distributions. The profitability of the Fund Businesses may be affected by expiry of the present long-term power purchase agreements to which certain of the Fund Businesses are a party.

Completion of Acquisitions

In any additional offerings, the Manager intends to utilize the net proceeds from the additional offering (the “Net Proceeds”) to complete the acquisitions detailed in the prospectus, promptly following the closing of an additional offering. While Fund Businesses generally enter into agreements governing the purchase and sale of potential facility interests to be acquired, there can be no assurances that the vendors of such facility interests will close the transactions of purchase and sale. In the event the Manager is unsuccessful in completing any particular acquisition within 30 days from closing of an additional offering, the Manager intends to utilize the portion of the Net Proceeds plus accrued interest thereon (i) firstly, to retire any indebtedness of the Fund or its Facilities then outstanding and (ii) secondly, the balance thereof shall be distributed pro-rata to Unitholders as a return of capital.

Regulatory Climate and Permits

Profitability of the Fund Businesses will be in part dependent upon the continuation of a favourable regulatory climate with respect to the continuing operations and the future growth and development of the independent power production industry as a whole and, in particular, with respect to the hydroelectric power segment of the industry. Should the regulatory regime be modified in a manner which adversely affects the treatment of such facilities, including increases in taxes and permit fees, Distributable Cash may be adversely affected.

The operation of infrastructure facilities is highly regulated. For example, in the case of hydroelectric generating facilities, water rights are generally owned by government and government agencies reserve the right to control water levels. The failure to obtain all necessary licences or permits, including renewals thereof or modifications thereto, may adversely affect Distributable Cash.

In the United States, FERC issues licences for the construction, operation and maintenance of generating facilities. Facilities are required to be licensed or have valid exemptions from FERC. Failure to maintain such licences, including amendments or modifications thereto, may result in the owner being unable to operate the licensed facility and could adversely affect Distributable Cash.

The US facilities obtain certain benefits and exemptions because of their Qualifying Facility status (“QF Status”) under PURPA. If any facility were to lose its QF Status, the facility would no longer be entitled to the exemptions and benefits thereof. Loss of QF Status may also require the facility to cease selling electricity at the rates set forth in the existing power purchase agreements to the extent they exceed current short run avoided costs. Under certain circumstances, loss of QF Status on a retroactive basis could lead to, among other things, claims by the utility customers for a refund of payments previously made.

The Fund's water and wastewater utilities are subject to rate setting by State regulatory authorities. Rates charged by the Fund's utilities may be reviewed and altered by the State regulatory authorities from time to time.

The Fund's water and wastewater utilities are subject to State and Federal permits, discharge parameters and other environmental requirements. Discharge and treatment requirements may change from time to time.

Growth Capital Requirements

The Fund's water and wastewater utilities may be located within areas of United States experiencing high growth. These utilities may have an obligation to service new residential, commercial and industrial customers. Accordingly, the Fund may have an obligation to expand its infrastructure and facilities to accommodate this growth. The Fund may have a requirement to access capital to undertake this construction obligation.

Environmental and Safety Considerations

The facilities encompass operations which require adherence to environmental and safety standards imposed by regulatory bodies. Failure to operate the facilities in strict compliance with these regulatory standards may expose the facilities to claims and clean-up costs.

Equipment Failure

There is a risk of equipment failure due to wear and tear, design error or operator error, among other things, which could adversely affect revenues and Distributable Cash. Regular maintenance programs, insurance and maintenance funds partially mitigate this risk.

Commodity Prices

Distributable Cash will, in part, depend upon prices to be paid for energy purchased by customers. Such commodity pricing will vary over time. Over the long term, unexpected fluctuations in such pricing may impact upon Distributable Cash.

Labour Relations

While labour relations have been stable to date and there have not been any disruptions in operations as a result of labour disputes with employees, the maintenance of a productive and efficient labour environment cannot be assured. With the exception of the Peel Facility, employees of the Fund Businesses and their material subcontractors are non-unionized. The Peel Facility is unionized and a new collective bargaining agreement is currently being negotiated. In the event of a strike or lock-out, the ability of Fund Businesses to generate Distributable Cash may be impaired.

Reliance on the Manager and Power Systems and Potential Conflicts of Interest

Unitholders will be dependent upon the Manager for the administration of the Fund and upon the Manager and Power Systems for the management and operation of the facilities.

There may be situations in which conflicts of interest may arise between the Manager, Power Systems and their respective officers and directors in relation to the interests of the Fund. The Manager and its affiliated entities may engage in activities similar to the activities of the Fund. The Manager or affiliated entities may acquire, own, manage and administer other facilities in the independent power production industry and, in particular, in the hydroelectric power segment of the industry. Provisions in business corporations act legislation provides certain procedures to be followed by directors and officers and remedies available against them where such procedures are not followed in the event of conflicts of interest. In addition, the Management Agreement provides that to the extent there is a conflict of interest which is not required to be dealt with by a board of directors or trustees, the resolution of the conflict by the Manager shall be fair and reasonable to the Fund Businesses.

Dependence Upon Key Customers

The customers that currently purchase power from the facilities are large utilities. If, for any reason, such customers were unable to fulfill their contractual obligations under the power purchase agreements, Distributable Cash would decline.

Delays in Distributions

Payments by Algonquin Canada and Algonquin Power Trust to the Fund may be delayed by restrictions imposed by lenders, disruptions in service, recovery by the Manager of its expenses or the establishment of reserves for expenses.

Nature of Trust Units

The Trust Units are dissimilar to conventional debt instruments in that there is no principal amount owing directly to Unitholders. The Trust Units do not represent a traditional investment and should not be viewed by investors as shares of Algonquin Canada or its subsidiaries or trust units of Algonquin Power Trust. Each Trust Unit represents an equal undivided beneficial interest in the Fund. The Fund's sole assets will be the Fund Assets and other permitted investments.

Unitholder Limited Liability

The Declaration of Trust provides that no Unitholder will be subject to any liability in connection with the Fund or its obligations and affairs. The Declaration of Trust also provides that the Trustees and the Fund will make all reasonable efforts to include as a specific term of any obligations or liabilities being incurred by the Fund or by the Trustees on behalf of the Fund a contractual provision to the effect that neither the Unitholders nor the Trustees have any personal liability or obligations in respect thereof. Personal liability may arise in respect of claims against the Fund that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The Manager believes that the possibility of any personal liability of this nature arising is unlikely.

The Fund notes that the Ontario government, as part of its 2003 budget, has proposed to enact legislation to provide unitholders of certain publicly traded income trusts resident in Ontario with limited liability similar to the limited liability of shareholders of corporations.

The operations of the Fund will be conducted, upon the advice of counsel, in such a way and in such jurisdictions so as to avoid as far as reasonably possible any material risk of liability on the Unitholders for claims against the Fund.

Uncertain Trust Unit Market

The Fund cannot predict at what price the Trust Units will continue to trade and there can be no assurance that an active trading market in the Trust Units will be sustained.

Units of a publicly traded income fund will not necessarily trade at values determined solely by reference to the underlying value of its assets.

One of the factors that may influence the market price of the Trust Units is the annual distribution on the Trust Units. An increase in market interest rates may lead purchasers of Trust Units to demand a higher annual distribution and this could adversely affect the market price of the Trust Units. In addition, the market price for the Trust Units may be affected by changes in general market conditions, fluctuations in the market for equity or debt securities and numerous other factors beyond the control of the Fund.

There can be no assurance that the Fund will be in a position to redeem Trust Units when requested to do so.

Climate

Based on the type of power purchase agreements in place at all of the facilities in which the Fund has an interest, the revenue generated by the facilities is proportional to the amount of electrical energy generated. In addition, the amount of energy generated at the hydroelectric generating facilities is dependent upon available water flows. Accordingly, revenues will be significantly affected by low and high water flows within the watercourses on which the facilities are located. Engineering studies have been undertaken to assess the amount of energy which can be expected to be generated from each facility on an average annual basis. Furthermore, the majority of the facilities have significant operating histories with which to compare the theoretical estimates determined in the engineering studies. However, there can be no assurance that the historical water availability will remain unchanged or that no material hydrologic event will impact the hydrologic conditions which exist within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

Severe flooding may damage the hydroelectric generating facilities. Insurance and geographical diversity may partially reduce this risk.

Exchange Rates

Currency fluctuations may affect the cash flow which the Fund will realize from its operations, as certain of the Fund Businesses sell electricity in the United States and receive proceeds from such sales in US dollars. Such Fund Businesses also incur costs in US dollars.

Loan Defaults

The cash flows from several of the facilities are subordinated to senior debt. There is a risk that any particular loan may go into default if there is a breach in complying with such covenants and obligations resulting in the lender realizing on its security and, indirectly, causing the Fund to lose its investment in such facility.

Revolving Credit Facility

The Fund has negotiated a \$100 million revolving credit facility with a major Canadian bank, which will mature April 26, 2004. Under the terms of the revolving credit facility, the Fund may acquire generating facilities and infrastructure assets that meet the Fund's acquisition guidelines. At December 31, 2002, no amounts were outstanding under the facility, with the exception of certain letters of guarantee totalling \$31.7 million, posted as security. The terms of the credit agreement require the Fund to pay a standby charge of 0.425% on the unused portion of the revolving credit facility and maintain certain financial covenants. The facility is secured by, among other things, a fixed and floating charge over all the entities owned by the Fund.

Tax Related Risks

There can be no assurance that income tax laws and the tax treatment of mutual fund trusts will not be changed in a manner which adversely affects Unitholders. In addition, adverse tax consequences may arise to Unitholders and to the Fund in the event that the Fund ceases to qualify as a "mutual fund trust" under the Tax Act, including potential liability for Part XII.2 taxes under the Tax Act. Although the Fund is of the view that all expenses being claimed by the Fund are reasonable and that the cost amount of the Fund's depreciable properties have been correctly determined, there can be no assurance that CCRA will agree. If CCRA successfully challenges the deductibility of such expenses or the correctness of such cost amounts, the return to Unitholders may be adversely affected.

ADDITIONAL INFORMATION

Additional information, including Trustees' remuneration and indebtedness, principal holders of Trust Units, options to purchase securities of the Fund and interests of insiders in material transactions, as applicable, is contained in the Fund's prospectus dated October 9, 2002 and the Fund's information circular dated May 12, 2003 for the annual and special meeting of Unitholders to be held on June 26, 2003. Additional financial information is provided in the Fund's financial statements for the year ended December 31, 2002. A copy of such documents may be obtained upon request from the Fund.

The Fund will also provide to any person upon request to the Fund:

- (a) when Trust Units are in the course of a distribution pursuant to a short form prospectus or when a preliminary short form prospectus has been filed in respect of a distribution of Trust Units,
 - (i) one copy of the Fund's Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

(ii) one copy of the comparative financial statements of the Fund for its most recently completed financial year together with the accompanying report of the auditors and one copy of any interim financial statements of the Fund subsequent to the financial statements for its most recently completed financial year;

(iii) one copy of the Fund's information circular in respect of its most recent annual meeting of Unitholders that involved the election of Trustees or one copy of any annual filing prepared in lieu of that information circular, as appropriate; and

(iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, one copy of any other documents referred to in (a)(i), (ii) and (iii) above, provided the Fund may require the payment of a reasonable charge if the request is made by a person who is not a Unitholder.

SCHEDULE A GLOSSARY

In this Annual Information Form, unless the context otherwise requires:

"Administration Agreement" means the agreement between the Manager and the Fund dated December 23, 1997, pursuant to which the Manager provides administrative services to the Fund;

"Advance Payment Account" means a provision in the power purchase agreements between Niagara Mohawk and Trafalgar in respect of the Kayuta Lake facility and the Adams facility which tracks the amounts paid to Trafalgar from these two facilities which is either above or below Niagara Mohawk's actual Avoided Costs. Payments to Trafalgar above the Avoided Costs results in a positive balance to the account and a payment below the Avoided Costs results in a negative balance to the account. At the end of the contract period, a positive balance results in Trafalgar owing Niagara Mohawk the balance and a negative balance results in Niagara Mohawk owing Trafalgar the balance;

"affiliate" means an affiliate within the meaning of the *Securities Act* (Ontario);

"Algonquin America" means Algonquin Power Fund (America) Inc., a Delaware corporation wholly-owned by Algonquin Canada;

"Algonquin America Holdco" means Algonquin Power Fund (America) Holdco Inc., a Delaware corporation wholly-owned by Algonquin America;

"Algonquin Canada" means Algonquin Power Fund (Canada) Inc., a Nova Scotia corporation wholly-owned by Algonquin Holdco;

"Algonquin Canada Shares" means common shares of Algonquin Canada;

"Algonquin Holdco" means Algonquin Holdco Inc., an Ontario corporation wholly-owned by the Fund;

"Algonquin LSR Companies" means Algonquin Power (Long Sault) Corporation Inc., an Ontario corporation, and Energy Acquisition (Long Sault) Ltd., an Ontario corporation;

"Algonquin Power" means Algonquin Power Corporation Inc., an Ontario corporation;

"Algonquin Power (Long Sault) Partnership" means the partnership formed between the Algonquin LSR Companies, which partnership owns a 50% undivided interest in the Long Sault Rapids Facility;

"Algonquin Power Trust" means the Algonquin Power Trust, an unincorporated open-ended trust established under the laws of Ontario and of which the Fund is the sole beneficiary;

"Ashuelot Facility" means the 900 kilowatt hydroelectric generating facility located on the Ashuelot River approximately 0.2 kilometres upstream of the highway bridge at Hinsdale, New Hampshire and which is owned by the HDI III Partnership;

"associate" means an associate within the meaning of the *Securities Act* (Ontario);

"**Avery Dam Facility**" means the 260 kilowatt hydroelectric generating facility located on the Winnepesaukee River near the City of Laconia, New Hampshire and which is owned by the Avery Dam Partnership;

"**Avery Dam Partnership**" means Avery Hydroelectric Associates, a New Hampshire limited partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Avery Dam Facility;

"**Avoided Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator;

"**AWRA**" means Algonquin Water Resources of America Inc., a Delaware corporation wholly-owned by Algonquin Canada;

"**Bella Vista Facility**" means the wastewater treatment facility located in the Town of Sierra Vista Arizona, and which is owned by Bella Vista Water Company, Inc., an Arizona corporation wholly-owned by AWRA;

"**Belleterre Facility**" means the 2,200 kilowatt hydroelectric generating facility located on the Winneway River, in the Municipality of Laforce, Québec and which is owned by Algonquin Canada;

"**Belleterre Facility Equipment**" means the equipment relating to the Belleterre Facility and related personal property, but does not include the real property on which the equipment is located or any other immovables;

"**Belleterre Facility Lease**" means the lease agreement dated February 3, 1998 pursuant to which the Fund leases the Belleterre Facility Equipment to Algonquin Canada;

"**Black Mountain Facility**" means the wastewater treatment facility located in the residential portion of the Boulders Resort, located 10 miles north of Scottsdale, Arizona, in the Town of Carefree, Arizona and which is owned by Black Mountain Sewer Corporation, an Arizona corporation wholly-owned by AWRA;

"**Brooklyn Facility**" means a 23.8 MW biomass-fired electric generating facility located in Queen's County, Nova Scotia;

"**Burt Dam Facility**" means the 600 kilowatt hydroelectric generating facility located on the Eighteen Mile Creek in the Town of Newfane, New York and which is owned by the Burt Dam Partnership;

"**Burt Dam Partnership**" means Burt Dam Power Company, a New York general partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Burt Dam Facility;

"**Business Corporations Act**" means the *Business Corporations Act* (Ontario);

"**Campbellford Facility**" means a 4,000 kilowatt hydroelectric generating facility located at Lock No. 14 on the Trent-Severn Waterway approximately four kilometers north of Campbellford, Ontario and which is owned by Algonquin Power (Campbellford) Limited Partnership, a limited partnership of which Algonquin Power Trust holds 50% of the limited partnership interests;

"Cardinal Facility" means a 150 MW combined cycle co-generation facility fuelled by natural gas located in Cardinal, Ontario;

"Chapais Facility" means an electricity generating facility which burns woodwaste and which is located in the Town of Chapais, Québec;

"Clement Dam Facility" means the 2,400 kilowatt hydroelectric generating facility located on the Winnepesaukee River near the Town of Tilton, New Hampshire and which is owned by Clement Dam Hydroelectric, LLC, a New Hampshire limited liability company of which Algonquin America and Algonquin America Holdco are the sole members;

"Cochrane Facility" means a 35.8 MW combined cycle co-generation facility located in Cochrane, Ontario;

"Co-Owners" means Algonquin Power (Long Sault) Partnership, an Ontario partnership, and N-R Power Partnership, an Ontario partnership, the co-owners of the Long Sault Rapids Facility;

"Côte Ste-Catherine Facility" means the 11,120 kilowatt hydroelectric generating facility located on the St. Lawrence River near Montreal, Québec, which facility was constructed in three separate phases commissioned in 1989, 1993 and 1996, respectively, and which is owned by MTL Partnership;

"Crossroads Facility" means the 10 MW cogeneration facility located in Mahwah, New Jersey and which is owned by KMS Crossroads Inc., a Delaware corporation, which is wholly-owned, indirectly, by KMS;

"Declaration of Trust" means the declaration of trust dated as of September 8, 1997, as amended, as the same may be further amended, supplemented or restated from time to time, pursuant to which the Fund was created;

"Dickson Dam Facility" means the 15 MW hydroelectric generating facility located on the Red Deer River at Dickson Dam, 20 kilometers west of the Town of Innisfail, Alberta and which is owned by Drayton Valley Power Income Fund;

"Distributable Cash" means all amounts received by the Fund in respect of dividends, distributions or return of capital on equity and interest or repayment of principal on the Fund Notes, lease payments pursuant to the Leases, payments pursuant to the LSR Royalty Interests, plus the income, if any, from other permitted investments, less amounts that may be paid by the Fund in connection with any cash redemptions of Trust Units, capitalized interest with respect to the Fund Notes and amounts reasonably required for the business and operations of the Fund;

"Donnacona Facility" means the 4,800 kilowatt hydroelectric generating facility located on the lower portion of the Jacques Cartier River, near the Town of Donnacona, Québec and which facility is owned by the Donnacona Partnership;

"Donnacona Facility Equipment" means certain equipment relating to the Donnacona Facility and related personal property, but does not include the real property on which the equipment is located or any other immovables;

"Donnacona Facility Lease" means the lease agreement dated November 30, 1997 pursuant to which the Fund leases the Donnacona Facility Equipment to the Donnacona Partnership;

"Donnacona Holdco" means Donnacona Holdings Inc., an Ontario corporation wholly-owned by Algonquin Canada, and which owns a 0.01% interest in the Donnacona Partnership;

"Donnacona Partnership" means Société Hydro-Donnacona S.E.N.C., a Québec general partnership comprised of Algonquin Canada holding a 99.99% interest and its wholly-owned subsidiary, Donnacona Holdco, holding a 0.01% interest;

"Drayton Valley Facility" means the 12 MW biomass-fired generating facility located in the Town of Drayton Valley, Alberta and which is owned by Valley Power LP, a limited partnership of which Drayton Valley Power Income Fund owns 49.9995% of the limited partnership interests and Algonquin Power Trust indirectly holds 50% of the general partnership interests;

"Drayton Valley Power Income Fund" means Drayton Valley Power Income Fund, an unincorporated open-ended trust established under the laws of the Province of Alberta, the sole unitholder of which is Algonquin Power Trust;

"Extraordinary Resolution" means a resolution passed by a majority of not less than 66²/₃% of the votes cast, either in person or by proxy, at a meeting of Unitholders called for the purpose of approving such resolution, or approved in writing by the holders of not less than 66²/₃% of the Trust Units entitled to be voted on such resolution;

"Facilities" means infrastructure facilities in which the Fund has an interest, directly or indirectly;

"FERC" means the Federal Energy Regulatory Commission;

"Franklin Facility" means the 1,820 kilowatt hydroelectric generating facility located on the Winnepesaukee River near the Town of Franklin, New Hampshire and which is owned by Franklin Power, LLC, a New Hampshire limited liability company wholly-owned by Algonquin America;

"Fund" means the Algonquin Power Income Fund, an unincorporated open-ended trust established under the laws of Ontario;

"Fund Assets" means the shares of Algonquin Holdco, units of the Algonquin Power Trust, the Fund Notes, the Lease Payment Rights, the LSR Royalty Interests and any other securities or assets held directly or indirectly by the Fund from time to time;

"Fund Businesses" means the businesses carried on by Algonquin Holdco, Algonquin Canada, Algonquin Power Trust, Algonquin America, Algonquin America Holdco, Donnacona Holdco, the Donnacona Partnership, the Nicholls LSR Companies, the Algonquin LSR Companies, the Co-Owners, the HDI Partnership, the Glenford Partnership, the Rattle Brook Partnership, the Avery Dam Partnership, the Burt Dam Partnership, the Hadley Falls Partnership, the HDI III Partnership, the Hollow Dam Partnership, the Lakeport Corporation, the Moretown Partnership, Clement Dam Hydroelectric LLC, MTL Partnership, Gregg Falls Hydroelectric Associates Limited Partnership, Pembroke Hydro Associates Limited Partnership, SFR Hydro Corporation, Mine Falls Limited Partnership, Great Falls Hydroelectric Company, Great Falls Energy, L.L.C., Tug Hill Energy, Inc., Worcester Hydro Company, Inc., Oswego Hydro

Partners, L.P., CSI Oswego Corp., Oswego Energy Corp., Court Street Investments, Inc., Oswego Power Company, Inc., Algonquin Water Resources of America, Inc., Black Mountain Sewer Corporation, Gold Canyon Sewer Company, Drayton Valley Power Income Fund, KMS, KMS Peel Inc., KMS America, Inc., KMS Crossroads, Inc., KMS Joliet Power Partners, L.P., Peel Resource Recovery Operations Inc., Bella Vista Water Company, Inc., Franklin Power LLC, Sanger Power, L.L.C., Algonquin Windsor Locks LLC, Litchfield Park Services Company, Tall Timbers Utility Company, Inc. and Woodmark Utility Company, Inc. and any other business a subsidiary of the Fund may acquire or any other business carried on by a corporation, partnership or other entity, the shares, partnership interests or other equity interest, as the case may be, of which the Fund acquires;

"Fund Notes" means any notes issued by Algonquin Power Trust, Algonquin Canada, Algonquin Holdco and Algonquin America to the Fund, the LSR Subordinate Note and the Trafalgar Class B Note;

"Glenford Facility" means the 4,950 kilowatt hydroelectric generating facility located on the Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec and which is owned by the Glenford Partnership;

"Glenford Minority Inc." means an Ontario corporation which is currently wholly-owned by Algonquin Power and which holds a 0.01% limited partnership interest in the cash distributions and income allocations from the Glenford Partnership;

"Glenford Note" means the 8.5% secured, subordinated note due July 1, 2023 of Algonquin Power in the principal amount of approximately \$5.0 million issued to Algonquin Canada on July 7, 1998;

"Glenford Partnership" means Société en Commandite Chute Ford, a limited partnership formed under the laws of Québec comprised of Algonquin Power and Glenford Minority Inc.;

"Glenford Senior Debt" means financing in the outstanding principal amount of approximately \$5.7 million provided by Corpfinance International Limited to the Glenford Partnership;

"Gold Canyon Facility" means the wastewater treatment facility located in an industrial area of the Town of Gold Canyon, Arizona and which is owned by Gold Canyon Sewer Company, an Arizona corporation wholly-owned by AWRA;

"Governance Agreement" means the agreement entered into on December 23, 1997, between the Fund, the Manager, Algonquin Canada and Algonquin America dealing with the composition of the board of directors of Algonquin Canada and other matters;

"Great Falls Facility" means a 10,950 kilowatt hydroelectric generating facility located on the Passaic River near the City of Paterson, New Jersey and which is owned by the Great Falls Partnership;

"Great Falls Partnership" means Great Falls Hydroelectric Company Limited Partnership, a Maryland limited partnership which owns the Great Falls Facility;

"Gregg Falls Facility" means the 3,500 kilowatt hydroelectric generating facility located at the Piscataquog River near the Town of Goffstown, New Hampshire and which is owned by Gregg Falls Hydroelectric Associates Limited Partnership, a limited partnership between Algonquin America and Algonquin Holdco;

"Hadley Falls Facility" means the 250 kilowatt hydroelectric generating facility located at the Hadley Falls Dam near the Town of Goffstown, New Hampshire and which is owned by the Hadley Falls Partnership;

"Hadley Falls Partnership" means Hadley Falls Associates, a New Hampshire limited partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Hadley Falls Facility;

"HDI Partnership" means HDI Associates I, an Indiana general partnership comprised of Algonquin America and Algonquin America Holdco, which owns the Lochmere Facility and the Hopkinton Facility;

"HDI III Partnership" means HDI Associates III, a New Hampshire limited partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Lower Robertson Facility and the Ashuelot Facility;

"Hollow Dam Facility" means the 900 kilowatt hydroelectric generating facility located on the West Branch of the Oswegatchie River in the Town of Fowler, New York and which is owned by the Hollow Dam Partnership;

"Hollow Dam Partnership" means Hollow Dam Power Company, a New York general partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Hollow Dam Facility;

"Hopkinton Facility" means the 250 kilowatt hydroelectric generating facility located on the Contoocook River in the Village of Contoocook, New Hampshire and which generating facility is owned by the HDI Partnership;

"Hydraska Facility" means the 2,250 kilowatt hydroelectric generating facility located on the Yamaska River near the Town of Ste-Hyacinthe, Québec and which is owned by Algonquin Power Trust;

"Joliet Facility" means the 3.2 MW landfill gas-fuel generating facility located in Joliet, Illinois and which is owned by KMS Joliet Power Partners, L.P., an Illinois limited partnership, of which KMS America is the sole limited partner and KMS America (GP) Inc. is the sole general partner;

"kilowatt hour" or **"kW-hr"** means an hour during which one kilowatt of electrical energy has been continuously produced;

"kilowatts" or **"kW"** means 1,000 watts of electrical power;

"Kings Falls Facility" means a 1,750 kilowatt hydroelectric generating facility located on the Deer River, near the Town of Copenhagen in Lewis County, New York;

"Kirkland Lake Facility" means a 102 MW combined cycle power co-generation facility located in Kirkland Lake, Ontario;

"KMS" means KMS Power Income Fund, an unincorporated open-ended trust established under the laws of Alberta;

"KMS America" means KMS America Inc., a Delaware corporation which is wholly-owned by KMS Peel;

"KMS Peel" means KMS Peel Inc., an Ontario corporation which is wholly-owned by KMS;

"Lakeport Corporation" means Lakeport Hydroelectric Corporation, an S Corporation under United States law whose sole shareholder is Algonquin America, and which owns the Lakeport Facility;

"Lakeport Facility" means the 600 kilowatt hydroelectric generating facility located on the Winnepesaukee River near the Town of Lakeport, New Hampshire and which is owned by the Lakeport Corporation;

"Leases" means the Donnacona Facility Lease, the Ste-Brigitte Facility Lease, the Belleterre Facility Lease and the Rawdon Facility Lease;

"Litchfield Facility" means the wastewater treatment facility located in Litchfield Park, Arizona and which is owned by Litchfield Park Service Company, an Arizona corporation which is wholly-owned by AWRA;

"Lochmere Facility" means the 1,200 kilowatt hydroelectric generating facility located on the Winnepesaukee River, in the Village of Lochmere, New Hampshire and which facility is owned by the HDI Partnership;

"Long Sault Rapids Facility" means the 18,000 kilowatt hydroelectric generating facility located on the Abitibi River, near the Town of Cochrane, Ontario and which facility is owned by the Co-Owners;

"Lower Robertson Facility" means the 960 kilowatt hydroelectric generating facility located on the Ashuelot River approximately one kilometre upstream of the Highway bridge at Hinsdale, New Hampshire and which is owned by the HDI III Partnership;

"LSR Algonquin Note" means the 9% secured, subordinated note due January 1, 2038 of Algonquin Power in the principal amount of approximately \$10.3 million issued to Algonquin Canada on April 17, 1998;

"LSR Brace Royalty Interest" means the cash flows generated by the Long Sault Rapids Facility paid pursuant to an agreement dated November 1, 1989, as amended November 2, 1989, between N-R Power, Nirabro Industries Ltd., Mr. Tim Richardson and Mr. John Brace respecting certain payments to be paid for ten years commencing April 1, 1998, which obligation was assigned by N-R Power to the Co-Owners and which was acquired by the Fund on April 17, 1998;

"LSR McKenzie Royalty Interest" means the cash flows generated by the Long Sault Rapids Facility paid pursuant to an agreement dated September 12, 1994 between N-R Power and Mr. Rodney S. McKenzie respecting payments of \$150,000 per year payable in arrears for a period of 20 years commencing April 1, 1998, which obligation was assigned by N-R Power to the Co-Owners and which was acquired by the Fund on April 17, 1998;

"LSR Nicholls Note" means the 9% secured, subordinated note due January 1, 2038 of N-R Power in the principal amount of approximately \$6.6 million issued to Algonquin Canada on April 17, 1998;

"LSR Richardson Royalty Interest" means the cash flows generated by the Long Sault Rapids Facility paid pursuant to an agreement dated December 11, 1992 between N-R Power and Mr. Tim Richardson respecting payments of \$83,333 per year payable in arrears for a period of six years commencing April 1, 1998, which obligation was assigned by N-R Power to the Co-Owners and which was acquired by the Fund on April 17, 1998;

"LSR Royalty Interests" means the LSR Brace Royalty Interest, the LSR McKenzie Royalty Interest and the LSR Richardson Royalty Interest, all acquired by the Fund on April 17, 1998;

"LSR Senior Debt" means financing in the principal amount of approximately \$45,000,000 provided jointly and severally to Algonquin Power (Long Sault) Partnership and N-R Power Partnership as co-owners of the Long Sault Rapids Facility by a syndicate of life insurance lenders, with The Clarica Life Insurance Company as one of the lenders and acting as agent for the other lenders;

"LSR Subordinate Note" means the 14.14% secured, subordinated note in the principal amount of \$2,000,000 issued jointly and severally by Algonquin Power (Long Sault) Corporation Inc., Energy Acquisition (Long Sault) Ltd., Nicholls Holdings Inc. and Radtke Holdings Inc. and acquired by the Fund on April 17, 1998;

"Management Agreement" means the agreement between the Manager and Algonquin Canada entered into on December 23, 1997, as amended, and pursuant to which the Manager or its delegate provides management services to the subsidiary entities of the Fund;

"Manager" means Algonquin Power Management Inc., an Ontario corporation wholly-owned by the shareholders of Algonquin Power;

"Manager Interest" means the voting but otherwise essentially non-participating shares held by the Manager in Algonquin Canada, Algonquin America and, subject to completion of the reorganization described in the management information circular of the Fund dated May 12, 2003, KMS Peel and KMS America;

"megawatt" or **"MW"** means 1,000,000 watts of electrical power;

"megawatt hour" or **"MW-hr"** means 1,000 kilowatt hours of electrical energy;

"Milton Facility" means the 1,335 kilowatt hydroelectric generating facility located on the Salmon River on the Maine-New Hampshire border, approximately 70 km from Manchester, New Hampshire and which is owned by SFR Hydro Corporation;

"Mine Falls Facility" means the 3,000 kilowatt hydroelectric generating facility located on the Nashua River near the City of Nashua, New Hampshire and which is owned by the Mine Falls Hydroelectric Limited Partnership;

"Mont Laurier Facility" means the 2,725 kilowatt hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec and which is owned by the MTL Partnership;

"Moretown Facility" means the 1,200 kilowatt hydroelectric generating facility located on the Mad River near the Town of Moretown, Vermont and which is owned by the Moretown Partnership;

"Moretown Partnership" means Moretown Hydro Energy Company, a Vermont partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Moretown Facility;

"MTL Partnership" means Algonquin Power (Mont-Laurier) Limited Partnership, a Quebec limited partnership between Algonquin Canada and Algonquin Power Trust;

"New England Development" means the Gregg Falls Facility, the Pembroke Facility, the Clement Dam Facility, the Franklin Facility, the Moretown Facility, the Lochmere Facility, the Lower Robertson Facility, the Ashuelot Facility, the Lakeport Facility, the Avery Dam Facility, the Hadley Falls Facility, the Hopkinton Facility, the Milton Facility, the Mine Falls Facility, the Great Falls Facility and the Worcester Facility;

"Newfoundland Development" means the Rattle Brook Facility;

"New York Development" means the following hydroelectric generating facilities: Ogdensburg, Forestport, Herkimer, Hollow Dam, Christine Falls, Burt Dam, Cranberry Lake, Kayuta Lake, Adams, Kings Falls, Otter Creek and Phoenix;

"Newspring" means Newspring Water LLC, a partnership formed between Algonquin Power and third parties to manage and operate water distributin wastewater treatment facilities in Arizona and Texas;

"NHPUC" means the New Hampshire Public Utilities Commission;

"Niagara Mohawk" means Niagara Mohawk Power Corporation;

"Nicholls LSR Companies" means Nicholls Holdings Inc., an Ontario corporation, and Radtke Holdings Inc., an Ontario corporation;

"N-R Power" means N-R Power & Energy Corp., an Ontario corporation;

"N-R Power Partnership" means the partnership formed between the Nicholls LSR Companies, which partnership owns a 50% undivided interest in the Long Sault Rapids Facility;

"OEFC" means Ontario Electricity Financial Corporation;

"Off-peak" means hours other than On-peak hours;

"On-peak" means hours between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays;

"Ontario Development" means the following hydroelectric generating facilities: Long Sault Rapids, Hurdman Dam, Drag Lake Dam, Burgess Dam and Campbellford;

"Operations Supervisory Agreement" means the agreement between Algonquin Canada and Power Systems entered into on December 23, 1997, as amended, and pursuant to which Power Systems provides operations and supervisory services to certain of the subsidiary entities of the Fund;

"Otter Creek Facility" means the 530 kilowatt hydroelectric generating facility located on the Otter Creek, near the Town of Craig, New York and which is owned by Tug Hill Energy, Inc., a New York corporation and an indirect, wholly-owned subsidiary of Algonquin America;

"Peel Facility" means the 10 MW energy from waste generating facility located in the Regional Municipality of Peel, Ontario and which is owned by KMS Peel Inc., a wholly-owned subsidiary of KMS;

"Pembroke Facility" means the 2,600 kilowatt hydroelectric generating facility located on the Suncook River near the Town of Pembroke, New Hampshire and which is owned by Pembroke Hydro Associates Limited Partnership, a New Hampshire limited partnership formed between Algonquin America and Algonquin America Holdco;

"Phoenix Facility" means the 3500 kilowatt hydroelectric generating facility located on the Oswego River, in the Town of Phoenix, Onondaga County, New York;

"Power Systems" means Algonquin Power Systems Inc., an Ontario corporation wholly-owned by Algonquin Power;

"PSNH" means Public Service Company of New Hampshire, a large, investor-owned utility;

"Québec Development" means the Côte Ste-Catherine Facility, the Ste-Raphaël Facility, the Mont Laurier Facility, the Rivière-du-Loup Facility, the Hydraska Facility, the Saint-Alban Facility, the Glenford Facility, the Donnacona Facility, the Ste-Brigitte Facility, the Rawdon Facility, the Belleterre Facility and the Arthurville Facility;

"Rattle Brook Facility" means the 4,000 kilowatt hydroelectric generating facility located on the Rattle Brook, near the Village of Jackson's Arm, Newfoundland and which is owned by the Rattle Brook Partnership;

"Rattle Brook Partnership" means the Algonquin Power (Rattle Brook) Partnership, a Newfoundland partnership currently comprised of Algonquin Power Corporation (Rattle Brook) Inc., wholly-owned by the shareholders of Algonquin Power and Algonquin Canada;

"Rawdon Facility" means the 2,500 kilowatt hydroelectric generating facility located on the Ouareau River approximately one kilometre from the Village of Rawdon, Québec and which is owned by Algonquin Canada;

"Rawdon Facility Equipment" means the equipment relating to the Rawdon Facility and related personal property, but does not include the real property on which the equipment is located or any other immovables;

"Rawdon Facility Lease" means the lease agreement pursuant to which the Fund leases the Rawdon Facility Equipment to Algonquin Canada;

"Rivière-du-Loup Facility" means the 2,600 kilowatt hydroelectric generating facility located on the Rivière-du-Loup near the Town of Rivière-du-Loup, Québec, formerly known as the Hydro Senmo Facility, and which is owned by Algonquin Canada;

"run-of-the-river" means a mode of operation of a hydroelectric generating facility where there is a continuous discharge of water from the facility with no storage and release of water;

"Saint-Alban Facility" means the 8,200 kilowatt hydroelectric generating facility located on the Ste-Anne River approximately one kilometre from the Village of Saint-Alban, Québec and which is owned by SLI;

"Saint-Alban Transfer Date" means the date upon which the title of the leasehold interest may be transferred to Algonquin Canada in accordance with the terms of the lease;

"Sanger Facility" means a 43.5 MW natural gas-fired generating facility located in the City of Sanger, California and which is owned by Sanger Power, L.L.C.;

"SLI" means SNC-Lavalin Inc., a Canadian corporation which owns the Saint-Alban Facility;

"SLI Saint-Alban Note" means the secured note due on the Saint-Alban Transfer Date of SLI in the principal amount of approximately \$15.0 million issued to a trust company acting on behalf of Algonquin Canada on July 7, 1998;

"St. Raphaël de Bellechasse Facility" means a 650 kilowatt hydroelectric generating facility located on the Du Sud River near Saint-Raphaël de Bellechasse, approximately 40 kilometers east of Québec City, also known as the Arthurville Facility, and which is owned by Algonquin Power Trust;

"Ste-Brigitte Facility" means the 4,200 kilowatt hydroelectric generating facility located on the Nicolet River, in the Municipality of Ste-Brigitte-des-Saults, Québec and which is owned by Algonquin Canada;

"Ste-Brigitte Facility Equipment" means the equipment relating to the Ste-Brigitte Facility and related personal property, but does not include the real property on which the equipment is located or any other immovables;

"Ste-Brigitte Facility Lease" means the lease agreement dated November 30, 1997 pursuant to which the Fund leases the Ste-Brigitte Facility Equipment to Algonquin Canada;

"Ste-Raphaël Facility" means the 3,500 kilowatt hydroelectric generating facility located on the Rivière de Sud near Québec City;

"Stranded Costs" means costs incurred by a utility during the normal course of business prior to deregulation that can no longer be paid by the rate base due to changes to various factors, including price, the economy, system requirements, government policies and technology;

"Tall Timbers Facility" means the wastewater treatment facility located in Tyler, Texas and which is owned by Tall Timbers Utility Company, Inc., a Texas corporation which is wholly-owned by AWRA;

"Tax Act" means the *Income Tax Act* (Canada);

"Thermal Development" means the Fund's indirect interests in the Peel Facility, the Joliet Facility, the Crossroads Facility, the Sanger Facility and the Windsor Locks Facility;

"Trafalgar" means Trafalgar Power, Inc., a Delaware corporation;

"**Trafalgar Class A Note**" means the 9.75% secured note due February 10, 2003 of the Trafalgar Companies jointly and severally;

"**Trafalgar Class B Note**" means the 6.10% secured, subordinated note due December 31, 2010 jointly and severally of the Trafalgar Companies;

"**Trafalgar Companies**" means Trafalgar and Christine Falls Corporation, a New York corporation;

"**Trafalgar Contingency Participation**" means the contingent management fee paid to the operator of the Trafalgar Facilities pursuant to the Trafalgar Operations Contract and the Trafalgar Indenture;

"**Trafalgar Facilities**" means the following hydroelectric generating facilities: Ogdensburg, Forestport, Herkimer, Christine Falls, Cranberry Lake, Kayuta Lake and Adams, which are owned by the Trafalgar Companies;

"**Trafalgar Indenture**" means the collateral trust indenture between the Trafalgar Companies and a security trustee dated July 1, 1988, as amended and restated on January 15, 1996, which governs the terms of the Trafalgar Class A Note and the Trafalgar Class B Note, among other things;

"**Trafalgar Operating Cashflow**" means the cash flows generated from the operation of the Trafalgar Facilities after payment of direct operating costs, including, without limitation, property taxes, supplies and consumables and amounts due to Algonquin Power under the Trafalgar Operations Contract, prior to deduction of amounts payable in respect of the Trafalgar Contingency Participation;

"**Trafalgar Operations Contract**" means the agreement dated January 15, 1996 between Algonquin Power and the Trafalgar Companies, pursuant to which Algonquin Power provides operations and management services for the Ogdensburg, Forestport, Herkimer, Christine Falls, Cranberry Lake, Kayuta Lake and Adams facilities;

"**Trafalgar Operations Subcontract**" means the agreement dated December 23, 1997 between Algonquin Power and Algonquin Canada, pursuant to which Algonquin Canada provides those services to be provided by Algonquin Power in connection with the operation of the Ogdensburg, Forestport, Herkimer, Christine Falls, Cranberry Lake, Kayuta Lake and Adams facilities under the Trafalgar Operations Contract;

"**Trust Units**" means units of the Fund, each unit representing an equal undivided beneficial interest in the Fund;

"**Trustee**" means a trustee of the Fund from time to time;

"**Unitholders**" means the holders of Trust Units from time to time;

"**Wastewater Treatment Development**" means the Black Mountain Facility and the Gold Canyon Facility, the Bella Vista Facility, the Tall Timbers Facility, the Woodmark Facility and the Litchfield Facility;

"**Western Canada Development**" means the Dickson Dam Facility and the Drayton Valley Facility;

"Windsor Locks Facility" means the 56 MW (gross) combined cycle, gas-fired co-generation facility located at Windsor Locks, Connecticut and which is owned by Algonquin Windsor Locks LLC, a Connecticut limited liability company, wholly-owned by Algonquin America;

"Woodmark Facility" means the wastewater treatment facility located in Tyler, Texas and which is owned by Woodmark Utility Company, Inc., a Texas corporation which is wholly-owned by AWRA; and

"Worcester Facility" means the 180 kilowatt hydroelectric generating facility located on the North Branch of Winnooskie River, in the Town of Worcester, Vermont and which is owned by Worcester Hydro Company, Inc., a Vermont corporation which is indirectly wholly-owned by Algonquin America.

Words importing the singular number only include the plural and vice versa and words importing any gender include all genders.

All dollar amounts are in Canadian dollars unless otherwise stated.

For the purposes of this annual information form, any reference to any direct or indirect subsidiary, associate or affiliate of the Fund or KMS or any entity in which the Fund or KMS holds, directly or indirectly, a majority of the equity interests, the word "control", the word "wholly-owned" and similar expressions, shall be construed without reference to any holdings by the Manager of special voting shares entitling the Manager to elect directors of Algonquin Canada, Algonquin America, KMS Peel or KMS America, as the case may be.