AMERICAN TRANSMISSION COMPANY LLC

Financial Statements for the Years Ended December 31, 2003, 2002 and 2001 and Independent Auditors' Report

American Transmission Company LLC

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Deloitte

Deloitte & Touche LLP
411 E. Wisconsin Avenue
Milwaukee, WI 53202-4496
USA

Tel: +1 414 271 3000
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of ATC Management Inc.,
Corporate Manager of American Transmission Company LLC:

We have audited the accompanying balance sheets of American Transmission Company LLC (a Wisconsin limited liability company) as of December 31, 2003 and 2002 and the related statements of operations, changes in members' equity and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002 and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

January 29, 2004

Member of
Deloitte Touche Tohmatsu

American Transmission Company LLC

Statements of Operations
For the Years Ended December 31, 2003, 2002 and 2001

(In Thousands)

	2003	2002	2001
Operating Revenues			
Transmission Service Revenue	$224,453	$202,856	$171,377
Other Operating Revenue	1,155	2,442	3,155
Total Operating Revenues	225,608	205,298	174,532
Operating Expenses			
Operations and Maintenance	93,681	86,556	72,890
Depreciation and Amortization	40,694	38,407	34,178
Taxes Other than Income	5,174	6,096	5,568
Deferral of Start-up Costs	-	-	(2,501)
Total Operating Expenses	139,549	131,059	110,135
Operating Income	86,059	74,239	64,397
Other Income (Expense)			
Other Income (Expense), net	81	(269)	2,412
Allowance for Equity Funds Used During Construction	2,474	1,675	1,531
Total Other Income (Expense)	2,555	1,406	3,943
Earnings Before Interest and Tax	88,614	75,645	68,340
Interest Expense			
Interest Expense	27,730	22,655	16,510
Allowance for Borrowed Funds Used During Construction	(1,822)	(1,067)	(1,371)
Net Interest Expense	25,908	21,588	15,139
Earnings Before Tax	$62,706	$54,057	$53,201

The accompanying notes are an integral part of these financial statements.

American Transmission Company LLC

Statements of Cash Flows
For the Years Ended December 31, 2003, 2002 and 2001

(In Thousands)

	2003	2002	2001
Cash Flows from Operating Activities			
Earnings Before Tax	$62,706	$54,057	$53,201
Adjustments to Reconcile Earnings Before Tax to Net Cash Provided by Operating Activities-			
Depreciation and Amortization	40,694	38,407	34,178
Bond Discount and Debt Issuance Cost Amortization	457	418	293
Allowance for Equity Funds Used During Construction	(2,474)	(1,675)	(1,531)
Change in-			
Accounts Receivable	2,212	(6,709)	(18,028)
Other Current Assets	(299)	(429)	(531)
Accounts Payable	(4,230)	6,140	1,474
Accrued Liabilities	5,370	1,787	20,650
Other	(7,025)	4,332	(6,104)
Total Adjustments	34,705	42,271	30,401
Net Cash Provided by Operating Activities	97,411	96,328	83,602
Cash Flows from Investing Activities			
Capital Expenditures for Property, Plant and Equipment	(193,574)	(123,447)	(70,162)
Allowance for Borrowed Funds Used During Construction	(1,822)	(1,067)	(1,371)
Net Cash Used in Investing Activities	(195,396)	(124,514)	(71,533)
Cash Flows from Financing Activities			
Distribution of Earnings to Members	(47,850)	(48,189)	(27,212)
Issuance of Membership Units for Cash	17,194	578	8,411
Redemption of Membership Units	(1,078)	(523)	(258,002)
Repayment of Short-term Debt, Net	-	-	(9,800)
Issuance of Long-term Debt, Net of Issuance Costs	99,198	49,377	294,405
Advances under Interconnection Agreements	26,217	3,776	-
Payments under Interconnection Agreements	(1,361)	-	-
Net Cash Provided by Financing Activities	92,320	5,019	7,802
Net Change in Cash and Cash Equivalents	(5,665)	(23,167)	19,871
Cash and Cash Equivalents, Beginning of Period	14,830	37,997	18,126
Cash and Cash Equivalents, End of Period	$9,165	$14,830	$37,997
Supplemental Disclosures of Cash Flows Information			
Cash Paid for-			
Interest	$25,091	$21,479	$10,021
Significant Non-cash Transactions-			
Issuance of Membership Units for Transmission Assets	$8,219	$1,928	$592,252
Issuance of Membership Units to Repay Member Advances	$ -	$ -	$ 17,002

The accompanying notes are an integral part of these financial statements.

American Transmission Company LLC

Balance Sheets
As of December 31, 2003 and 2002

(In Thousands)

ASSETS	2003	2002
Transmission and General Plant		
Property, Plant and Equipment	$1,354,377	$1,211,859
Less- Accumulated Depreciation	(558,267)	(527,538)
	796,110	684,321
Construction Work in Progress	113,057	49,209
Net Transmission and General Plant	909,167	733,530
Current Assets		
Cash and Cash Equivalents	9,165	14,830
Accounts Receivable	22,525	24,737
Other Current Assets	1,387	1,088
Total Current Assets	33,077	40,655
Regulatory and Other Assets		
Regulatory Assets	8,512	9,903
Other Assets	9,595	10,949
Total Regulatory and Other Assets	18,107	20,852
Total Assets	$960,351	$795,037

MEMBERS' EQUITY AND LIABILITIES		
Capitalization		
Members' Equity	$432,693	$393,502
Long-term Debt	448,215	348,033
Total Capitalization	880,908	741,535
Current Liabilities		
Accounts Payable	21,821	23,289
Accrued Liabilities	28,974	23,604
Current Portion of Advances Under Interconnection Agreements	15,797	-
Total Current Liabilities	66,592	46,893
Long-term Liabilities	12,851	6,609
Commitments and Contingencies (see Notes)	-	-
Total Members' Equity and Liabilities	$960,351	$795,037

The accompanying notes are an integral part of these financial statements.

American Transmission Company LLC

Statements of Changes in Members' Equity
For the Years Ended December 31, 2003, 2002 and 2001

(In Thousands)

Members' Equity as of December 31, 2000	$ -
Issuance of Membership Units	617,665
Redemption of Membership Units	(258,002)
Earnings Before Tax	53,201
Distribution of Earnings to Members	(27,212)
Members' Equity as of December 31, 2001	$385,652
Membership Units Outstanding at December 31, 2001	27,974
Issuance of Membership Units	2,505
Redemption of Membership Units	(523)
Earnings Before Tax	54,057
Distribution of Earnings to Members	(48,189)
Members' Equity as of December 31, 2002	$393,502
Membership Units Outstanding at December 31, 2002	28,127
Issuance of Membership Units	25,413
Redemption of Membership Units	(1,078)
Earnings Before Tax	62,706
Distribution of Earnings to Members	(47,850)
Members' Equity as of December 31, 2003	$432,693
Membership Units Outstanding at December 31, 2003	30,319

The accompanying notes are an integral part of these financial statements.

(1) Nature of Operations and Summary of Significant Accounting Policies

(a) General

American Transmission Company LLC (the Company) was organized on June 12, 2000 as a limited liability company under the Wisconsin Limited Liability Company Act as a single purpose, for-profit electric transmission company. The Company's purpose is to plan, construct, operate, own and maintain electric transmission facilities to provide for an adequate and reliable transmission system that meets the needs of all users on the system and supports equal access to a competitive, wholesale electric energy market. The Company owns and operates the electric transmission system, under the direction of the Midwest Independent Transmission System Operator, Inc. ("MISO"), in parts of Wisconsin, Illinois and the Upper Peninsula of Michigan. The Company is subject to regulation by the Federal Energy Regulatory Commission ("FERC") as to rates, terms of service and financing and by state regulatory commissions as to other aspects of business, including the construction of electric transmission assets.

(b) Corporate Manager

The Company is managed by a corporate manager, ATC Management Inc. ("Management Inc."). The Company and Management Inc. have common ownership and operate as a single functional unit. Under the Company's operating agreement, Management Inc. has complete discretion over the business of the Company and provides all management services to the Company at cost. The Company itself has no employees. The Company's operating agreement establishes that all expenses of Management Inc. are the responsibility of the Company. These expenses consist primarily of payroll, benefits, payroll-related taxes and other employee related expenses. All such expenses are recorded in the Company's accounts as if they were direct expenses of the Company. As of December 31, the following net (receivables from)/payables to Management Inc. were included in the Company's balance sheets:

	2003	2002
Accrued Liabilities	$9,142	$4,678
Long-term Liabilities, net	-	2,818
Other Assets, net	(1,233)	-
Total Amount Payable to Management Inc.	$7,909	$7,496

Amounts included in accrued liabilities are primarily payroll and benefit related accruals. Amounts included in long-term liabilities or other assets relate primarily to certain long-term compensation arrangements covering Management Inc. employees, as described in Note (2), offset by a $6.3 million and $4.8 million receivable as of December 31, 2003 and 2002, respectively, for income taxes paid on Management Inc.'s behalf by the Company. The income taxes are due to timing differences relating to the tax deductibility of certain employee-related costs. As these timing differences reverse in future years, Management Inc. will recover the income taxes paid and repay the advances from the Company.

(c) Revenue Recognition

Wholesale electric transmission service for utilities, municipalities, municipal electric companies, electric cooperatives and other eligible entities is provided through the Company's facilities under the MISO open-access transmission tariff regulated by FERC. The Company charges for these services under FERC approved rates. The tariff specifies the general terms and conditions of service on the transmission system and the approved rates set forth the calculation of the amounts to be paid for those services. The Company's revenues are derived from agreements for the receipt and delivery of electricity at points along the transmission system. The Company does not take ownership of the electricity that it transmits.

The true-up provision in the formula rate tariff meets the requirements of an alternative revenue program set forth in the FASB's Emerging Issues Task Force Issue No. 92-7. Accordingly, revenue is recognized for services provided during the reporting period based on the revenue requirement formula in the tariff. The Company accrues or defers revenues to the extent that the actual revenue requirement for the reporting period is higher or lower, respectively, than the amounts billed during the reporting period. The true-up amount will automatically be reflected in customer bills within two years (see Note 7).

(d) Transmission and General Plant and Related Depreciation

Transmission Plant is recorded at the original cost of construction. Assets transferred to the Company by its members, which include investor-owned utilities, municipalities, municipal electric companies and electric cooperatives, have been recorded at their original cost in property, plant and equipment with the related reserves for accumulated depreciation also recorded.

The original cost of construction includes materials, labor, construction overhead, outside contractor costs and an allowance for funds used during construction. Additions to and significant replacements of transmission assets are charged to property, plant and equipment at cost; replacement of minor items is charged to maintenance expense. The cost of transmission plant, together with removal cost less salvage value, is charged to accumulated depreciation when assets are retired.

The provision for depreciation of transmission assets is an integral part of the Company's cost of service under FERC-approved rates. Depreciation rates include estimates for future removal costs and salvage value. Depreciation expense as a percentage of average transmission plant was 2.64% in 2003, 2.65% in 2002 and 2.62% in 2001. The reserves for accumulated depreciation as of December 31, 2003 and 2002 included approximately $78 million and $74 million, respectively, of accrued removal costs.

General plant, which includes buildings, office furniture and equipment, computer hardware and software, is recorded at cost. Depreciation is recorded at straight-line rates over the estimated useful lives of the assets, which range from three to forty years.

(e) Allowance for Funds Used During Construction

Allowance for funds used during construction ("AFUDC") represents the approximate cost of debt used to fund the construction of transmission assets and a return on members' capital devoted to construction. The portion of the allowance that applies to borrowed funds is presented in the statements of operations as a reduction of interest expense; the return on members' capital is presented as other income. Although the allowance does not represent current cash income, it is recovered under the ratemaking process over the service lives of the related assets. In accordance with FERC Order 561, the Company capitalized AFUDC at the following average rates in 2003, 2002 and 2001:

	2003	2002	2001
Debt Rate	3.1%	3.3%	4.6%
Equity Rate	4.3%	5.1%	5.0%
Total Rate	7.4%	8.4%	9.6%

(f) Interconnection Agreements

The Company has entered into a number of interconnection agreements with entities planning to build generation plants within the Company's service territory ("generators"). During construction, the generators will construct the interconnection facilities or finance and bear all financial risk of constructing the interconnection facilities under these agreements. The Company will own and operate the interconnection facilities when the generation plants become operational and will reimburse the generator for construction costs plus interest. If the generation plants do not become operational, the Company has no obligation to reimburse the generator for costs incurred during construction.

Certain of the agreements require the Company to construct the related transmission facilities. In such cases, the Company receives cash advances for construction costs from the generators. During construction, these costs are included in construction work in progress ("CWIP"). Cash advances from the generators, along with accruals for interest, are recorded as liabilities. Accruals for interest are also capitalized, in lieu of AFUDC, and included in CWIP. At December 31, 2003 and 2002, advances and accrued interest totaled \$28.6 million and \$3.8 million, respectively. Of these amounts, \$12.8 million and \$3.8 million were included in long-term liabilities at December 31, 2003 and 2002, respectively.

(g) Cash and Cash Equivalents

Cash and cash equivalents include highly liquid investments with original maturities of three months or less.

(h) Regulatory Assets

The Company's accounting policies conform to Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation". Accordingly, assets and liabilities that result from the regulated ratemaking process are recorded that would otherwise not be recorded under accounting principles generally accepted in the United States of America for non-regulated companies. Certain costs and credits are recorded as regulatory assets and liabilities as incurred and are recognized in the statements of operations at the time they are reflected in rates.

As of December 31, the following amounts were recorded as regulatory assets (in thousands):

	2003	2002
Deferred Start-up Costs, Net of Amortization	$6,028	$9,042
True-up of 2001 Revenue, Including Interest	-	5,699
True-up of 2002 Revenue, Including Interest	-	(4,838)
True-up of 2003 Revenue, Including Interest	2,484	-
	$8,512	$9,903

Under the rate settlement agreement (see Note 7) approved by FERC in November 2001, the Company anticipates recovering in rates, over a five-year period, certain start-up and development costs incurred in 2000 and 2001. The Company also earns its allowed rate of return on the unamortized portion of the start-up costs during each year. Accordingly, deferred start-up costs of $15.1 million are being amortized to expense over a five-year period beginning in 2001. Amortization expense of $3.0 million is included in 2003, 2002 and 2001 depreciation and amortization.

As discussed further in Notes 1(c) and 7, the November 2001 rate settlement approved by FERC provides for a true-up mechanism. Under the true-up mechanism, the Company was authorized to include an under-collection of approximately $5.4 million from 2001, plus interest, in its billings in 2003. During 2002, the Company over-collected approximately $4.6 million. Under the terms of the tariff, this amount would ordinarily be refunded, with interest, to customers in 2004; however, the Company filed an application with FERC on December 31, 2002, for a one-time amendment to the rates which would allow the Company to accelerate this refund by one year and net it against the 2001 under-collection. FERC approved this amendment on March 6, 2003, and the Company collected the net true-up of $0.8 million in its monthly billings in 2003.

Under the true-up mechanism, the Company under-collected approximately $2.5 million during 2003. This amount, plus interest, will be recovered during 2005 through the Company's monthly billings.

The Company continually assesses whether regulatory assets continue to meet the criteria for probability of future recovery. This assessment includes consideration of factors such as changes in the regulatory environment, recent rate orders to other regulated entities under the same jurisdiction and the status of any pending or potential deregulation legislation. If future recovery of regulatory assets becomes improbable, the affected assets would be written off in the period in which such determination is made.

(i) Other Assets

As of December 31, other assets were comprised of the following (in thousands):

	2003	2002
Preliminary Survey and Investigation Costs	$4,297	$7,410
Unamortized Debt Issuance Costs	4,065	3,539
Net Receivable from Management Inc. (see Note 1(b))	1,233	-
	$9,595	$10,949

Preliminary survey and investigation costs relate to study and planning costs in the early stages of construction projects. Costs directly attributable to the construction of transmission assets are capitalized as other assets until all required regulatory approvals are obtained and construction begins, at which time the costs are transferred to construction work in progress.

(j) Impairment of Long-lived Assets

The Company reviews the carrying values of long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying values may not be recoverable. Impairment would be determined based upon a comparison of the undiscounted future operating cash flows to be generated during the remaining life of the assets to their carrying values. An impairment loss would be measured by the amount that an asset's carrying amount exceeds its fair value. As long as its assets continue to be recovered through the rate-making process, the Company believes that such impairment is unlikely.

(k) Income Taxes

The Company is a limited liability company that has elected to be treated as a partnership under the Internal Revenue Code and applicable state statutes. As such, it is not liable for federal or state income taxes. The Company's members (except certain tax exempt members) report their share of the Company's earnings, gains, losses, deductions and tax credits on their respective federal and state income tax returns. Accordingly, these financial statements do not include a provision for federal and state income tax expense. Earnings before tax reported on the statements of operations is the Company's net income. See Note (6) for further discussion of income taxes.

(l) Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to apply policies and make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as depreciable lives of property, removal costs and salvage associated with asset retirements, tax provisions included in rates, actuarially determined benefit costs and accruals for construction costs and operations and maintenance expenses. As additional information becomes available, or actual amounts are determined, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

(m) New Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations", that applies to all companies. SFAS No. 143 provides accounting requirements for retirement obligations associated with tangible, long-lived assets. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract, or by legal construction under the doctrine of promissory estoppel. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Company has concluded that it does not have significant asset retirement obligations and therefore did not record any obligation when the statement was adopted on January 1, 2003. However, through the rate-making process, the Company collects removal costs through its depreciation rates for certain assets that do not have legal asset retirement obligations (see Note 1(d)).

In January 2003, the FASB issued Financial Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities". This interpretation of Accounting Research Bulletin No. 51, "Consolidated Financial Statements", addresses consolidation by business enterprises of variable interest entities. The Company has no association with any variable interest entities that would require the Company to consolidate another entity.

In December 2003, the FASB issued SFAS No. 132," Employers' Disclosures about Pensions and Other Postretirement Benefits". This statement revises employers' disclosures about pension plans and other postretirement benefit plans to present more information about the economic resources and obligations of such plans. The statement is effective for non-public companies for fiscal years ending after June 15, 2004. The Company will adopt this statement as of the effective date. The Company does not anticipate the statement will have a material affect on the Company's financial position or results of operations.

(2) Benefits

Management Inc. provides certain postretirement health care benefits to employees. The weighted average assumptions as of the measurement date of October 1 are as follows:

	2003	2002	2001
Discount Rate	6.25%	6.75%	7.00%
Medical Cost Trend:			
Initial Range	11.00%	18.00%	9.00%
Ultimate Range	5.00%	5.50%	5.50%

The components of Management Inc.'s postretirement benefits expense for 2003, 2002 and 2001 are as follows (in thousands):

	2003	2002	2001
Service Cost	$934	$658	$553
Interest Cost	413	292	225
Amortization of Prior Service Cost	250	250	250
Net Actuarial Loss	60	-	-
Net Periodic Postretirement Cost	$1,657	$1,200	$1,028

The assumed medical trend rates are critical assumptions in determining the service and interest cost and accumulated postretirement benefit obligation related to postretirement benefit costs. A one percent change in the medical trend rates for 2003, holding all other assumptions constant, would have the following effects (in thousands):

	One Percent Increase	One Percent Decrease
Effect on Total of Service and Interest Cost Components	$362,238	$(275,471)
Effect on Postretirement Benefit Obligation at the End of Year	1,372,919	(1,077,200)

A reconciliation of the change in the benefit obligation during 2003, 2002 and 2001 is as follows (in thousands):

	2003	2002	2001
Accumulated Postretirement Benefit Obligation at the Beginning of Year	$7,940	$4,168	$3,003
Service Cost	934	658	553
Interest Cost	413	292	225
Actuarial (Gains)/Losses	(3,029)	2,822	387
Benefit Obligation at End of Year	$6,258	$7,940	$4,168

Claims paid during 2003, 2002 and 2001 were not significant.

In December 2003, Management Inc. established a Voluntary Employee Benefit Association ("VEBA") trust and a 401(h) trust that will be funded as the Company recognizes post-retirement health obligations. On December 30, 2003, the Company transferred $3.9 million in cash as an initial funding of the VEBA. No amounts were contributed to the 401(h) trust in 2003. The long-term investment objectives of the trusts are to preserve and, if possible, enhance the post-inflation value of the trust's assets, subject to cash flow requirements, while maintaining an acceptable level of volatility.

A reconciliation of the funded status of the plan to the amounts recognized by the Company as long-term liabilities (payable to Management Inc.) in the December 31, 2003, 2002 and 2001 balance sheet is as follows (in thousands):

	2003	2002	2001
Funded Status as of December 31	$(2,385)	$(7,940)	$(4,168)
Unrecognized Prior Service Cost	2,252	2,502	2,752
Unrecognized Net Actuarial Loss	120	3,209	388
Net Amount Recognized as of December 31	$(13)	$(2,229)	$(1,028)

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. The Act introduced a prescription drug benefit program under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

The FASB issued FASB Staff Position (FSP) No. 106-1 that allows sponsors to elect to defer recognition of the effects of the Act. In accordance with FSP 106-1, the Company has elected to defer recognition of the effects of the Act. Accordingly, any measures of the net periodic postretirement benefit cost in the financial statements or the accompanying notes do not reflect the effects of the Act on the plan, as the Company has not determined the effect on the Plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require the Company to change previously reported information.

Management Inc. sponsors a defined contribution money-purchase pension plan, in which substantially all employees participate, and makes contributions to the plan for each participant based on several factors. Contributions made by Management Inc. to the plan totaled $1.6 million in 2003, $1.4 million in 2002 and $1.1 million in 2001.

Certain management employees who agreed to leave their prior employers and become employees of Management Inc. receive pension benefits from Management Inc. which are at least equal to the benefits the employees would have received under the pension plans of their prior employers. The Company accounts for the benefits as deferred compensation arrangements under APB 12 "Omnibus Opinion". As of December 31, 2003 and 2002, $1.3 million and $.9 million, respectively, was included in long-term liabilities related to this plan.

Management Inc. also provides a deferred compensation plan for certain employees. The plan allows for the elective deferral of a portion of an employee's base salary and incentive compensation and also contains a supplemental retirement and 401(k) component. As of December 31, 2003 and 2002, $3.1 million and $2.2 million, respectively, was included in long-term liabilities related to this deferred compensation plan. Amounts charged to expense, including interest accruals, in 2003, 2002 and 2001 were $.9 million, $.9 million and $1.3 million, respectively.

(3) Members' Equity

The Company's members include investor-owned utilities, municipalities, municipal electric companies and electric cooperatives. Each member was issued membership interests in proportion to the value of transmission assets and/or cash it contributed to the Company.

Distribution of earnings to members is at the discretion of the corporate manager. The operating agreement of the Company established a target for distribution of 80% of annual earnings. During 2003, 2002 and 2001, the Company distributed $47.9 million, $48.2 million and $27.2 million, respectively, of its earnings to its members in proportion to each member's ownership interest in the Company. A distribution of earnings for the fourth quarter of 2003, in the amount of $12.7 million, was approved by the board of directors on January 29, 2004, bringing the total distributions for 2003 to 80% of earnings.

(4) Debt

(a) Credit Facilities

On June 28, 2002, the Company entered into a syndicated, 364 day, revolving credit facility that allows the Company to borrow up to an aggregate $75 million from certain financial institutions. The Company may request that the aggregate commitment be increased to up to $100 million either by increasing the commitment of an existing lender or by adding additional lenders. The credit facility provides backup liquidity to the Company's $100 million commercial paper program. Interest rates on any outstanding borrowings under the facility are based on either a LIBOR rate plus a margin or an Alternate Base Rate plus a margin. The applicable margin is based on the Company's debt rating from Moody's and S&P and ranges from 0.35% to 1.25%.

On June 27, 2003, the Company renewed its 364-day, revolving credit facility on similar terms.

The credit facility contains restrictive covenants, including restrictions on liens, certain mergers, sales of assets, acquisitions, investments, transactions with affiliates, conduct of business, certain financial ratios and requires certain financial reporting. The credit facility also provides for certain customary events of default.

The Company had no borrowing outstanding under the credit facility as of December 31, 2003 and 2002.

(b) Commercial Paper

The Company and certain dealers closed on a $100 million unsecured, private placement, commercial paper program on August 29, 2001. Investors are limited to qualified institutional buyers and institutional accredited investors. Maturities may be up to 364 days from date of issue, with proceeds to be used for working capital and other capital expenditures. Pricing is par less a discount or, if interest bearing, at par. The Company did not have any borrowing under the commercial paper program as of December 31, 2003 and 2002.

(c) Long-term Debt

The following table summarizes the Company's commitments relating to debt as of December 31, (in thousands)

	2003	2002
Senior Notes at stated rate of 7.125%, due March 15, 2011	$ 300,000	$ 300,000
Discount	(1,785)	(1,967)
	298,215	298,033
Senior Notes at stated rate of 7.02%, due August 31, 2032	50,000	50,000
Senior Notes at stated rate of 6.79%, due on dates ranging from August 31, 2024 to August 31, 2043	100,000	-
Net Long-term Debt	$ 448,215	$ 348,033

The notes rank equivalent in right of payment with all of the Company's existing and future unsubordinated, unsecured indebtedness and senior in right of payment to all subordinated indebtedness of the Company.

The senior notes contain restrictive covenants, which include restrictions on liens, certain mergers and sales of assets and require certain financial reporting. The notes also provide for certain customary events of default. No principal amounts of the senior notes become due in the next five years.

The notes contain an optional redemption provision whereby the Company is required to make the note holders whole on any redemption prior to maturity. The notes may be redeemed at any time, at a redemption price equal to the greater of one hundred percent of the principal amount of the notes plus any accrued interest or the present value of the remaining scheduled payments of principal and interest from the redemption date to the maturity date discounted to the redemption date on a semi-annual basis at the then existing treasury rate plus 30 basis points, plus any accrued interest.

(5) Fair Value of Financial Instruments

The carrying amount and estimated fair value of the Company's long-term debt at December 31 are as follows (in millions):

	2003	2002
Carrying amount	$448.2	$ 348.0
Estimated fair value	$500.2	$ 395.6

The carrying amount of the Company's financial instruments included in current assets and current liabilities approximates fair value due to the short maturity of such financial instruments. The fair value of the Company's long-term debt is estimated based upon quoted market value for the same or similar issues or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the Company's bond rating.

(6) Income Taxes

Income tax liabilities are the responsibility of the Company's members (except certain tax exempt members) and are not reflected in these financial statements. However, the Company is allowed to recover in rates, as a component of its cost of service, the amount of income taxes that are the responsibility of its members. Accordingly, the Company includes a provision for its members' federal and state current and deferred income tax expenses and amortization of the excess deferred tax reserves and deferred investment tax credits associated with assets transferred to the Company by its members in its regulatory financial reports and rate filings. For purposes of determining the Company's revenue requirement under FERC-approved rates, rate base is reduced by an amount equivalent to net accumulated deferred taxes, including excess deferred tax reserves. Such amounts were approximately $72.2 million, $67.7 million and $65.8 million in 2003, 2002 and 2001, respectively, and are primarily related to accelerated depreciation and other plant-related differences. 2003, 2002 and 2001 revenues include recovery of $20.9 million, $17.4 million and $16.2 million, respectively, of income tax expense.

The Internal Revenue Service contacted the Company in January 2004 to schedule an examination of its 2001 federal income tax return. This will be the Company's first tax examination since it commenced operations. Any adjustments that might result from the examination would affect the tax liabilities of the Company's members. Because members' income taxes are recovered in rates, any such adjustments could also impact the Company's future revenues and earnings before tax.

(7) Regulatory Proceedings

In December of 2000, the Company filed a rate proceeding with FERC to supersede the original formula rates included as part of the open-access transmission tariff filed in July of 2000. On December 29, 2000, FERC accepted the Company's proposed rates, subject to refund and future hearings. As of January 1, 2001, the Company began collecting revenues under the proposed rates. In March 2001, the Company filed revised rates with FERC. The proposed rates were accepted and consolidated with the previous rate filing, subject to refund and future hearings. The Company began collecting revenues under the new rates on June 1, 2001. The proposed revisions modified the rate from a formula based on historical costs to a formula based on projected costs, subject to an annual true-up for the billing period.

In August 2001, the Company filed comprehensive settlement proposals with FERC that resolved all outstanding rate issues. The proposed settlements were certified by the presiding Administrative Law Judge of FERC in October 2001 and an order approving the settlements was issued by FERC in November 2001. Due to the transfer of tariff administration to MISO, described in Note 8(c), the Company's approved rates have been incorporated in Attachment O of the MISO tariff. The settlement rates included an annual true-up mechanism, whereby the Company must adjust its revenue requirement in the second year following the reporting year by the difference between the Company's actual cost of service plus allowed return for the reporting year and the amounts actually billed in the reporting year. As a result of applying the true-up mechanism for 2001, the Company determined that amounts billed to customers in 2001 were approximately $5.4 million less than its actual cost of service plus allowed return. Accordingly, the Company recorded this amount as a regulatory asset as of December 31, 2001. In 2002, the Company had determined that amounts billed to customers were approximately $4.6 million more than its actual cost of service plus allowed return. Under the terms of the tariff, this amount would ordinarily be refunded, with interest, to customers in 2004; however, the Company filed an application with FERC on December 31, 2002, for a one-time amendment to its rates which would allow the Company to accelerate this refund by one year and net it against the 2001 under-collection. FERC approved this amendment on March 6, 2003, and the Company collected the net true-up of $0.8 million in its monthly billing in 2003. Under the true-up provision, the Company under-collected approximately $2.5 million during 2003. This under-collection will be recovered through monthly billings in 2005.

On October 30, 2003, the Company filed an application with FERC for approval to modify its rate formula in Attachment O of the MISO Open Access Transmission Tariff. The Company is seeking authorization to make the following modifications to the rate formula:

a) Include Construction Work in Progress for new transmission investment in rate base to earn a current return in lieu of capitalizing an Allowance for Funds Used During Construction.

b) Allow current year expensing of preliminary survey and investigation costs for new transmission investment. Such costs are currently capitalized as a component of the associated transmission assets' cost and recovered, with a return on investment, over the life of the asset.

c) Increase the allowed return on equity from the current 12.20% to 12.38% to correspond to the rate FERC has allowed for other MISO transmission owners and return to a 50% debt, 50% equity capital structure.

On December 29, 2003, FERC issued an order that conditionally accepted for filing and nominally suspended the Company's proposed modifications, to become effective January 1, 2004, subject to refund. The order also established hearing and settlement judge procedures. Based on concerns raised by intervenors in the case, several issues were set for hearing, including the proposed capital structure and the rate impact of expensing preliminary survey and investigation costs for certain transmission projects. A hearing on these issues is being held in abeyance to give the Company and the intervenors an opportunity to reach a settlement. The Company anticipates, based on the current state of settlement discussions, that it will be able to reach a settlement on the issues set for hearing.

(8) <u>Commitments and Contingencies</u>

(a) <u>Operating Leases</u>

The Company leases office space under non-cancelable operating leases. Amounts incurred during 2003, 2002 and 2001 totaled approximately $1.3 million, $1.0 million and $0.7 million, respectively.

Future minimum lease payments, which will be expensed as incurred, under non-cancelable operating leases are as follows for the years ending December 31 (in thousands):

2004	$1,417
2005	1,411
2006	1,340
2007	1,284
2008	356
Thereafter	-
	$5,808

(b) Transfer of Operational Control of Transmission System

In compliance with Wisconsin statutes and FERC requirements, operational control of the Company's transmission system was transferred to MISO, a FERC-approved regional transmission organization (RTO), effective February 1, 2002.

MISO has operational control over the Company's system and has the authority to direct the manner in which the Company performs operations. The Company is also required to seek direction from MISO for certain operational actions the Company seeks to perform within its system. MISO is responsible for monitoring congestion, directing the associated operations to overcome congestion, approving transmission maintenance outages, as well as negotiating with generators on the timing of generator maintenance outages within the entire MISO system, including that portion representing the Company's system. The Company may be required to coordinate planning activities for new projects or system upgrades with MISO. Certain projects might require review by MISO before implementation.

(c) Transfer of Tariff Administration Responsibilities

In accordance with FERC Order 2000, MISO has become the tariff administrator for all of its transmission-owning members. MISO and the Company made a joint Section 205 filing with FERC that created an ATC pricing zone within MISO's tariff. This filing, which was accepted by FERC on February 11, 2002, reflected the terms and conditions of the Company's settlement agreement approved by FERC on November 7, 2001. As of February 1, 2002, the Company's rates for service are now administered under MISO's tariff. The Company will continue to file with FERC for approval of future changes to the formula that determines its revenue requirements.

(d) Regulatory Changes that may Affect the Company's Future Responsibilities and Relationship with MISO

On July 31, 2002, FERC issued a Notice of Proposed Rulemaking ("NOPR") entitled "Remedying Undue Discrimination Through Open-Access Transmission Service and Standard Electricity Market Design" that may ultimately lead to a final rule and future orders that will likely make changes to the Company's current tariff and rates for service. Future orders may also modify the Company's functional responsibilities in areas such as expansion planning, performing facilities and system impact studies, building new facilities, reliability management, congestion management and regional coordination. Comments on the NOPR were due to FERC in mid-November 2002 and in mid-January 2003. FERC issued a white paper and appendix on April 28, 2003 that reflected extensive comments received from utilities, state regulatory agencies and other interested parties. The timing of the final rule is uncertain at this time. Additionally, there are components of proposed energy legislation before the U.S. Congress that would prevent FERC from issuing any further orders related to Standard Market Design until 2005 or later.

The white paper and appendix contain provisions related to the allocation and characteristics of financial transmission rights ("FTRs"). The impact of these provisions on the Company is uncertain. The current tariff does not specify if revenue shortfalls associated with FTRs are subject to the true-up mechanism or if earnings are at risk due to the volatility of FTR revenues. On July 25, 2003, MISO filed a draft Transmission and Energy Markets Tariff ("TEMT") for implementation of its market design, which included provisions that would protect transmission owners from shortfalls in revenue related to FTRs. MISO subsequently announced in October that it would withdraw its original proposal and place primary focus on improving the reliability of the transmission grid. MISO's revised proposal would delay implementation of its market design until December 2004. Due to the uncertainty of how the current true-up mechanism will be applied, if the TEMT is not approved at such time as it is re-filed by MISO, the effort by FERC on standard market design could affect earnings and cash flows if adopted as proposed. At this time, the Company cannot predict whether the white paper and appendix will be promulgated as proposed. Future actions taken by Congress could affect the timing and substantive content of Standard Market Design.

In July 2003, the Wisconsin legislature enacted new legislation that modified the Company's statutory requirement to remain a member of MISO. Upon action by the Public Service Commission of Wisconsin ("PSCW"), the Company may be allowed to exit MISO. Should the Company be allowed to leave MISO, it may have liability for a portion of the deferred costs MISO has incurred for start-up and operations. The Company has no current plans to exit MISO. However, there is ongoing uncertainty about other transmission owners continuing their membership in MISO; this uncertainty raises the risk that MISO could become nonviable at some point in the future. The impact on the Company if this would occur is uncertain at this time.

On July 23, 2003, FERC issued an order eliminating the Regional Through and Out Rates ("RTOR") for point-to-point transmission services between MISO and the PJM Interconnection, effective October 31, 2003. On November 13, 2003, FERC delayed the effective date until April 1, 2004. RTOR revenues are collected by MISO and distributed to its member transmission owners. The Company currently receives approximately $3.2 million per year in RTOR revenues from MISO, which serves as a reduction in the amount of the Company's revenue requirement that is borne by its network transmission customers. A transitional revenue replacement mechanism, called the Seams Elimination Cost Assignment ("SECA"), is expected to be in place from April 1, 2004 through March 31, 2006. The purpose of the SECA is to protect the financial position of the transmission owners by preserving their revenue stream during the transition period, after which this revenue source will be permanently eliminated. Due to the nature of the Company's revenue requirement formula, including the true-up mechanism described above, management does not expect the elimination of RTOR revenues to have a significant impact on the Company's results of operations. The Company expects that any revenue shortfall associated with the SECA will be made up by the true-up mechanism during the transition period. Similarly, after the transition period, the elimination of RTOR revenues will result in an increase in the revenues collected from the Company's network transmission customers.

(e) MISO Point-to-Point Revenue Dispute

In December 2003, MISO notified the Company of a dispute filed by another transmission owner regarding the distribution of revenues for certain point-to-point transactions during 2002 and 2003. MISO had originally distributed 100% of the revenue, in the amount of $8.7 million, related to these transactions to the Company, but now asserts that the Company should only have received a portion of the revenue, in the amount of $2.3 million. MISO is seeking return of the remaining $6.4 million. The Company disagrees with MISO's determination and plans to formally dispute the matter. The Company cannot predict how much, if any, of the disputed amount it will ultimately have to refund to MISO; accordingly, no reserve has been recorded in the Company's financial statements at this time. Any amount that the Company would refund to MISO would reduce the revenue credits for point-to-point receipts in the Company's revenue requirement calculation and should be recovered as part of the revenue true-up for the year in which such refund is made. As such, the Company does not expect this matter to materially impact its results of operations.

(f) Arrowhead to Weston Line Project

The Arrowhead to Weston Line Project ("Project") is a transmission line construction project originally sponsored by Wisconsin Public Service Corporation ("WPSC") and Minnesota Power, Inc. ("Minnesota Power") under which a new high voltage 345kv electric transmission line would be built from the vicinity of Duluth, Minnesota to the vicinity of Wausau, Wisconsin. The Project was originally approved, at an estimated total cost of $165 million, by the PSCW on August 17, 2001. The original approval required that the PSCW be notified of any change greater than 10% of the approved cost estimate of $165 million. Management, along with WPSC and Minnesota Power, reviewed the Project's original cost estimate and notified the PSCW in November 2002 that there would be a cost increase. In May 2003, the Company provided the PSCW with a new project estimate of $420 million. The PSCW approved the revised cost estimate on December 19, 2003.

In addition to the PSCW approval, the Project requires permits from the Wisconsin Department of Natural Resources, the National Park Service and the Army Corps of Engineers. Permission is also required from several county governments for the line to cross their property. The Company expects to obtain the necessary permits during 2004 and begin construction on the Wisconsin portion of the line in early 2005. No additional approvals for the Minnesota portion of the line are required and construction will begin in 2004.

The Company acquired the current Project assets from WPSC at WPSC's cost of $20 million on June 13, 2003. WPSC will continue its role as the construction contractor on the Wisconsin portion of the Project; however, the Company has assumed primary project management responsibility and will acquire the Project facilities from WPSC, at WPSC's cost, on an as-constructed basis.

The Company has reached agreement in principle with Minnesota Power to acquire its interest in the Minnesota portion of the Project. It is the Company's intent to finalize the agreement under which the Company will assume approximately $2.6 million of project costs from Minnesota Power, assume primary project management responsibility and acquire the Project facilities, at Minnesota Power's cost, on an as-constructed basis. Minnesota Power would continue its role as construction contractor. The proposed agreement may require regulatory approvals.

As of December 31, 2003, the Company has accumulated approximately $29.4 million of costs associated with the Project, including the $20 million acquired from WPSC. To the extent the appropriate regulatory approvals related to the Project are obtained and the transmission line is constructed and placed in service, these costs, as well as the $2.6 million from Minnesota Power, will be included in the Company's rate base or otherwise recovered in rates. In the event the line is not approved or not constructed, the Company would seek recovery of all costs it has incurred related to the Project, including costs assumed from WPSC and Minnesota Power. If recovery is not permitted, such costs will be charged to expense.

(g) Interconnection Agreements

The Company has entered into a number of interconnection agreements with entities planning to build generation plants within the Company's service territory. During construction, the generators will construct the interconnection facilities or finance and bear all financial risk of constructing the interconnection facilities under these agreements. The Company will own and operate the interconnection facilities when the generation plants become operational and will reimburse the generator for construction costs plus interest. If the generation plants do not become operational, the Company has no obligation to reimburse the generator for costs incurred during construction.

The current estimate of the Company's commitment, if the generation plants become operational, under these agreements is approximately $326 million with the expected completion dates ranging from 2004 to 2012. In addition, there may be transmission service requests that require the Company to construct additional, or modify existing, transmission facilities to accommodate such requests. Whether such additions or upgrades to the Company's transmission system are required depends on the state of the transmission system at the time the transmission service is required.

On July 23, 2003, FERC issued Order 2003, which adopted new rules relating to generator interconnections. While the rules incorporate a number of changes to interconnection procedures and standardize the interconnection agreements, with some regional transmission organization flexibility, the rules preserve the responsibility of generators to pay the costs associated with interconnecting any generator to the Company's system, with the right to be reimbursed either in cash or through transmission service credits. Under certain circumstances, the rules increase the generators' responsibility to fund a greater range of transmission improvement costs, depending on the type of interconnection service the generators request. The Company believes that any such costs borne by the Company to upgrade or add to the transmission system to fulfill transmission service requests will be recovered in future rates.

(h) Arpin Agreement Dispute

The Arpin Substation Benefit Area Joint Operating, Planning and Cost Sharing Agreement ("the Agreement"), was entered into by Northern States Power Company ("NSP"), Marshfield Electric & Water Department ("MEWD"), Wisconsin Public Service Corporation ("WPSC"), Wisconsin Power & Light Company ("WPL") and Wisconsin Electric Power Company ("WE") in 1988. The Agreement provided for an annual payment of $295,000 from WPL to NSP for use of a 345kv transmission line owned by NSP. This annual payment was shared by WPL, WPSC and MEWD based on distribution load of the entities in the Arpin area. At the time the Company was formed, WPL transferred the Arpin substation to the Company and attempted to assign the Agreement to the Company. Accordingly, WPL has taken the position that the Company should now be responsible for the $295,000 annual payment. Total charges, including interest, for the period 2001 to 2003 would be approximately $1 million to $1.5 million. However, the Company disputes the validity of the assignment of the Agreement, as the Agreement requires the written consent of all parties for any assignment, and such consent was never obtained. In addition, the agreement requires the parties to renegotiate the $295,000 annual payment after ten years (1997). If the parties cannot agree on a new amount, the matter goes to arbitration, with the arbitrator expressly given authority to reestablish the payment back to the ten-year point. The arbitrator is required to take current FERC policy into account in its decision. Current FERC policy likely would not allow the $295,000 fee. Certain of the parties to the Agreement have indicated they are considering initiating price renegotiation. The Company does not believe that it will ultimately be responsible for the annual payments under the Agreement and has not recorded a liability in its financial statements for any amounts related to the Agreement.

(i) Potential Adverse Legal Proceedings

The Company may, in the future, become party to lawsuits, including certain suits that may involve claims for which it may not have sufficient insurance coverage. Such litigation could include suppliers and purchasers of energy transmitted by the Company and others with whom the Company conducts business. Effective August 5, 2002, FERC authorized a revision to the MISO tariff that may limit the Company's liability for interruptions in service to only direct charges.

(9) Related Party Transactions

(a) Asset Transfers and Membership Interests

On January 1, 2001, Wisconsin Electric Power Company, Edison Sault Electric Company, Wisconsin Power & Light Company, South Beloit Water, Gas & Electric Company, Wisconsin Public Service Corporation and Madison Gas and Electric Company (together "the contributing utilities") transferred transmission assets with a net book value of $554.5 million to the Company in exchange for equity interests in the Company. In addition, Wisconsin Public Power, Inc. and Management Inc. contributed cash of $16.9 million and $95,000, respectively, in exchange for equity interests in the Company. On April 2, 2001, $186.1 million of the initial membership interests of the Company were redeemed for cash.

On June 25, 2001, thirteen municipalities transferred transmission assets with net book values of $10.2 million and cash in the amount of $5.3 million to the Company in exchange for equity interests in the Company. On June 29, 2001, four electric cooperatives and Upper Peninsula Power Company ("UPPCo") transferred transmission assets with a net book value of $27.5 million and cash in the amount of $2.1 million to the Company in exchange for equity interests in the Company. Also on June 29, 2001, an additional $73.8 million of the initial ownership interests of the contributing utilities, municipalities, and cooperatives were redeemed for cash.

The original asset contribution agreement contained a provision under which WPSC would retain and complete certain construction projects. Upon completion, the assets would be contributed to the Company for additional equity interests. WPSC transferred such projects to the Company in the amount of $1.0 million in October 2002, $0.4 million in January 2003 and $5.8 million in December 2003.

On June 13, 2003, the Company acquired the Arrowhead to Weston Project assets from WPSC, at WPSC's cost of $20 million, in exchange for cash. As part of the agreement to transfer the Project, WPSC agreed to provide equity financing of 50% of the costs of the Project. During 2003, WPSC has contributed $13.5 million in cash, in exchange for additional equity interests in the Company, related to its financing of the Project.

During June 2003, Badger Power Marketing Authority transferred approximately $.9 million of transmission assets to the Company in exchange for an additional equity interest in the Company.

On December 31, 2003, Upper Peninsula Public Power Agency transferred $.8 million of transmission assets and $1.5 million of cash to the Company in exchange for an equity interest in the Company.

(b) Operations & Maintenance and Transitional Services Agreements

During 2003, 2002 and 2001, the Company operated under transitional services and operations and maintenance agreements whereby the contributing utilities, municipalities and cooperatives are required to provide certain administrative, operational, maintenance and construction services to the Company at a fully allocated cost, including direct cost, overheads, depreciation and return on assets employed in the services provided to the Company.

Additionally, the Company is obligated to pay each utility a minimum of 85% of the expenses previously incurred by the utility for such activities in a representative year. The amount paid exceeded the minimum in 2003, 2002 and 2001. One of the contributing utilities signed a new operations and maintenance agreement during the fourth quarter of 2003 extending these services through 2008. The new agreement does not contain the 85% clause. All other operations and maintenance agreements were automatically extended through 2004. The Company plans to renegotiate its operations and maintenance agreements. In the event that the Company is not able to renew these agreements at the end of their current terms, the Company cannot guarantee that it will be able to procure similar services at similar costs. The Company believes that the costs the Company must incur to provide transmission service will be recoverable in future rates. The terms of these agreements, including pricing, are subject to oversight by the PSCW and the Illinois Commerce Commission.

Beginning June 25, 2001 and June 29, 2001, respectively, some of the contributing municipalities and contributing cooperatives and UPPCO were also obligated to provide to the Company, at cost, for a period of three years, operation and maintenance services on the transmission facilities they had transferred to the Company. The terms of the agreements with UPPCO are identical to those with the contributing utilities. Those with the contributing municipalities and cooperatives are similar, but do not contain the 85% minimum payment clause.

The Company was billed approximately $75.2 million in 2003, $91.4 million in 2002 and $89.8 million in 2001 under these agreements. Accounts payable and accrued liabilities at December 31, 2003 and 2002 include amounts payable to these companies of $10.3 million and $18.1 million, respectively.

(c) Transmission Service

The contributing utilities, municipalities, cooperatives and UPPCo are the primary parties receiving service utilizing the Company's facilities under the MISO tariff. As such, the Company has entered into distribution-transmission interconnection agreements with each of the contributing members interconnected to it. In fewer instances, the Company has also entered into generation-transmission interconnection agreements with certain of these parties. Neither type of interconnection agreement contains a provision for the payment of rates or charges, except to provide that the Company shall offer transmission services pursuant to the applicable FERC-approved tariff.

The Company entered into a network integration transmission services agreement and a network operating agreement with each of the contributing utilities. The network integration transmission services agreement specifies the terms of service and the network load which shall be served to each of the contributing members. The obligation to render service under these agreements was transferred to MISO effective February 1, 2002. The network operating agreement specifies the procedures and safeguards each of the contributing members must follow to allow for integration of its load and resources on the Company's system.

Revenues from Wisconsin Electric Power Company, Wisconsin Power and Light Company, Wisconsin Public Service Corporation, Madison Gas and Electric Company and Wisconsin Public Power, Inc. ranged from 85-90% of the Company's transmission service revenue for the years ended December 31, 2003, 2002 and 2001.

(d) Lease Agreement with Alliant Energy

Beginning January 1, 2001, the Company entered into a lease agreement with Alliant Energy Corporate Services, Inc., an affiliate of the Company, for a portion of the Company's system operating center in Stoughton, WI and agreed to provide control and operational services at such center to Alliant. Both the lease and the services are being provided to Alliant at cost. Amounts billed under these agreements totaled \$2.7 million in 2003, \$4.2 million in 2002 and \$5.5 million in 2001.

(e) Management Inc.

As discussed in Note 1(b), the Company is managed by Management Inc. Management Inc. charged the Company approximately \$50.1 million, \$39.9 million and \$29.5 million for 2003, 2002 and 2001, respectively, primarily for employee related expenses. These amounts were charged to the applicable operating expense accounts, or capitalized as construction work in progress or other assets, as appropriate. The amounts are recorded in the Company's accounts in the same categories the amounts would have been recorded had the Company incurred the costs directly, except for income tax expense of Management Inc. that is recorded as other expense.

(f) Interconnection Agreements

As discussed in Notes 1(f) and 8(g), the Company has interconnection agreements related to the capital improvements required to connect new generation equipment to the grid. Some of these agreements are with members or affiliates of members of the Company. At December 31, 2003 and 2002, liabilities included $4.7 million and $1.0 million respectively, of amounts received related to these agreements from entities that are also members of the Company. $3.1 million was included in current liabilities as of December 31, 2003.

(10) Quarterly Financial Information (unaudited)

	Three Months Ended 2003				
	March 31	June 30	September 30	December 31	Total
Operating Revenues	$51,439	$55,142	$56,717	$62,310	$225,608
Operating Expenses	31,240	33,777	35,015	39,517	139,549
Operating Income	20,199	21,365	21,702	22,793	86,059
Other Income (Expense)	603	204	567	1,181	2,555
Interest Expense, net	6,092	6,339	6,397	7,080	25,908
Earnings Before Tax	$14,710	$15,230	$15,872	$16,894	$62,706

	2002				
	March 31	June 30	September 30	December 31	Total
Operating Revenues	$46,640	$49,221	$51,349	$58,088	$205,298
Operating Expenses	28,618	30,983	33,396	38,062	131,059
Operating Income	18,022	18,238	17,953	20,026	74,239
Other Income (Expense)	582	538	(121)	407	1,406
Interest Expense, net	5,234	5,190	5,238	5,926	21,588
Earnings Before Tax	$13,370	$13,586	$12,594	$14,507	$54,057

Because of seasonal factors impacting the Company's business, particularly the maintenance and construction programs, quarterly results are not necessarily comparable. In general, due to the Company's rate formula, revenues and operating income will increase throughout the year as newly constructed assets are placed into service and the Company begins to earn a return on those assets.

American Transmission Company LLC

Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following discussion provides information that management believes is relevant to an assessment and understanding of American Transmission Company LLC's ("the Company") results of operations and financial condition. This discussion should be read in conjunction with the financial statements and notes to financial statements.

The Company was organized as a Wisconsin limited liability company on June 12, 2000 and began operations on January 1, 2001. The Company's purpose is to plan, construct, operate, own and maintain electric transmission facilities to provide for an adequate and reliable transmission system that meets the needs of all users on the system and supports equal access to a competitive, wholesale, electric energy market. The Company owns and operates the electric transmission system, under the direction of the Midwest Independent Transmission System Operator, Inc. ("MISO"), in parts of Wisconsin, Illinois and the Upper Peninsula of Michigan.

The Company is managed by a corporate manager, ATC Management Inc. ("Management Inc."). The Company and Management Inc. have common ownership and operate as a single functional unit. All employees who serve the Company are employees of Management Inc. The expenses of Management Inc. are paid by the Company.

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to apply policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. Because of the inherent uncertainty in the nature of the matters where estimates are used, actual amounts could differ from estimated amounts. The following accounting policies represent those that management believes are particularly important to the financial statements and require the use of judgment in estimating matters that are inherently uncertain.

Revenues

Wholesale electric transmission service for utilities, municipalities, municipal electric companies, electric cooperatives and other eligible entities is provided through the Company's facilities under the MISO open-access transmission tariff regulated by the Federal Energy Regulatory Commission ("FERC"). The Company charges for these services under FERC-approved rates. The tariff specifies the general terms and conditions of service on the transmission system and the approved rates set forth the calculation of the amounts to be paid for those services. The Company's revenues are derived from agreements for the receipt and delivery of electricity at points along the transmission system. The Company does not take ownership of the electricity that it transmits. Revenue is recognized based on the amounts billable under the tariff for services provided during the reporting period (see "Rate Determination and Revenue Recognition" below). Based on a true-up provision in the approved rates, the Company accrues or defers revenues to the extent that the actual revenue requirement, as calculated under the rate formula, for the reporting period is higher or lower, respectively, than the amounts billed during the reporting period.

The revenue requirement for each year represents the total amount that the Company is entitled to collect from all revenue sources. The Company's revenues are divided into the following categories:

Network Service Revenue is charges paid by the Company's network customers to reserve transmission capacity on the Company's system. The annual network revenue requirement is divided among all of the Company's network customers based on their historic usage of the system, known as load ratio share. The charges for an individual customer are billed in even monthly installments during the year and are not dependent upon actual usage. Thus, the Company's network service revenue during a given year, which covers approximately 90% of the Company's total revenue requirement, will not vary once the revenue requirement and rates are determined for each year. In the event new customers join the Company's network during the year, the load ratio share and monthly charges of each customer are adjusted prospectively.

Point-to-Point Revenue relates to charges for delivering energy from specific points on the Company's transmission system to other specific points on the Company's transmission system. All point-to-point transactions are administered and billed by MISO; the Company receives a portion of the revenue from each transaction based on the MISO revenue allocation methodology. The point-to-point service revenue that the Company will realize each year depends on the length, duration and other terms of the firm contracts MISO has for point-to-point service and the volumes of electricity transmitted as non-firm service. Variations in point-to-point service revenues do not affect the Company's results of operations, however, because under the true-up mechanism described above, any over- or under-collection as measured against the Company's point-to-point service revenue projected in the current revenue requirement would be a component of any true-up adjustment recorded for network service revenue.

Other Transmission Service Revenue consists of: a) control area service revenue such as scheduling and re-dispatch services; b) recovery of start-up expenses; and c) recovery of annual FERC assessments.

Other Operating Revenue is derived from other transmission-related services provided to third parties, that are not provided under regulated tariffs, and rental of certain transmission and administrative property and equipment by third parties.

The Company's operating revenues for 2003, 2002 and 2001 consisted of:

(In Thousands)	2003	2002	2001
Network Service Revenue	$191,785	$ 168,454	$ 149,733
Point-to-Point Revenue	8,629	8,611	7,528
Other Transmission Service Revenue			
Scheduling, System Control and Dispatch	6,805	7,656	6,427
Reliability Redispatch	12,073	11,507	2,798
FERC Administrative Assessment	388	1,430	1,030
Recovery of Start-up Costs	4,730	5,198	3,827
Other	43	-	34
Transmission Service Revenue	224,453	202,856	171,377
Other Operating Revenue	1,155	2,442	3,155
Total Operating Revenues	$ 225,608	$ 205,298	$ 174,532

Regulatory Assets

Regulatory assets represent costs that have been deferred to future periods when it is certain or probable that the regulator will allow future recovery of those costs through rates. The accounting for these regulatory assets is in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation".

The Company continually assesses whether regulatory assets continue to meet the criteria for probability of future recovery. This assessment includes consideration of factors such as changes in the regulatory environment, recent rate orders to other regulated entities under the same jurisdiction, and the status of any pending or potential deregulation legislation. Regulatory assets related to the formula rate true-up are only recorded to the extent such amounts will be billed to customers within the next two years. If future recovery of regulatory assets becomes improbable, the affected assets would be written off in the period in which such determination is made.

Impairment of Long-lived Assets

The Company reviews the carrying values of long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying values may not be recoverable. Impairment would be determined based upon a comparison of the undiscounted future operating cash flows to be generated during the remaining life of the assets to their carrying values. An impairment loss would be measured by the amount that an asset's carrying amount exceeds its fair value. As long as its assets continue to be recovered through the rate-making process, the Company believes that such impairment is unlikely.

Rate Determination and Revenue Recognition

The Company's transmission service revenue requirement is determined by a formula agreed to in the comprehensive settlement approved by FERC on November 7, 2001, and transferred to the MISO tariff effective February 1, 2002. The formula is designed to reimburse the Company for all reasonable operating, maintenance and general and administrative expenses, taxes other than income taxes and depreciation, and to provide a return on assets employed in the provision of transmission services. The Company's rate base consists of the original cost of assets in service reduced by accumulated depreciation and deferred taxes associated with these assets, a working capital allowance and any prepayments. The weighted average cost of capital, or return rate, applied to rate base is intended to cover the cost of any long-term debt financing and provide equity holders a return that is commensurate with the risk involved in their investment. For 2003, 2002 and 2001, the allowed rate of return on common equity has been 12.2%. A provision for taxes on the equity component of the return is also included in the rate formula. Although the Company, as a non-taxable limited liability company, does not pay income taxes itself, it is allowed to include in its revenue requirement an estimate of income taxes that are the responsibility of the Company's taxable members.

The settlement, as approved by FERC, established both the rate formula described above and the methodology to be used to calculate rates each year. This methodology uses a three-year cycle to project and true-up rates. Prior to the beginning of each calendar year, the Company prepares a forecast of operating, maintenance, depreciation and tax expenses, as well as the projected rate base resulting from planned construction and other capital expenditures for the upcoming year. From this forecast, the Company computes a projected revenue requirement and projected rates for the year. These rates are billed and collected from network and point-to-point transmission customers throughout the first year. During the second year, after filing annual financial reports with FERC, the Company recalculates the revenue requirement for the first year based on actual results. Any difference from the projected revenue requirement, including any differences in point-to-point revenues collected, is added to, or subtracted from, the revenue requirement and rates computed in the third year.

The true-up calculation for 2003 resulted in $2.5 million of billings being recorded as accrued revenue. These amounts will be included in monthly billings in 2005. The true-up calculation for the year 2002 resulted in a refund of approximately $4.6 million due to customers. Per the original terms of the rate settlement, this refund would be repaid, with interest, in 2004; however, to promote greater rate stability, the Company filed an application with FERC on December 31, 2002 for a one-time amendment to the true-up mechanism which would allow the Company to accelerate repayment of the 2002 refund and offset it against the 2001 true-up billing of $5.4 million in 2003. FERC approved this amendment on March 6, 2003 and the Company collected the net true-up of $0.8 million in its monthly billings during 2003.

On October 30, 2003, the Company filed an application with FERC for approval to modify its rate formula in Attachment O of the MISO Open Access Transmission Tariff. The Company is seeking authorization to make the following modifications to the rate formula:

a) Include Construction Work in Progress for new transmission investment in rate base to earn a current return in lieu of capitalizing an Allowance for Funds Used During Construction.

b) Allow current year expensing of preliminary survey and investigation costs for new transmission investment. Such costs are currently capitalized as a component of the associated transmission assets' cost and recovered, with a return on investment, over the life of the asset.

c) Increase the allowed return on equity from the current 12.20% to 12.38% to correspond to the rate FERC has allowed for other MISO transmission owners and return to a 50% debt, 50% equity capital structure.

On December 29, 2003, FERC issued an order that conditionally accepted for filing and nominally suspended the Company's proposed modifications, to become effective January 1, 2004, subject to refund. The order also established hearing and settlement judge procedures. Based on concerns raised by intervenors in the case, several issues were set for hearing, including the proposed capital structure and the rate impact of expensing preliminary survey and investigation costs for certain transmission projects. A hearing on these issues is being held in abeyance to give the Company and the intervenors an opportunity to reach a settlement. The Company anticipates, based on the current state of the settlement discussions, that it will be able to reach a settlement on the issues set for hearing.

The revenue requirement calculations for the years ended December 31, 2003, 2002 and 2001 are below:

(In Thousands)	2003	2002	2001
Return on Rate Base			
Average Rate Base, including Unamortized Start-up Costs	$684,487	$594,704	$503,385
Weighted Rate of Return	9.52%	9.56%	9.57%
Return on Rate Base	65,175	56,824	48,149
Provision for Members' Income Taxes	20,884	17,415	16,248
Total Return and Income Taxes	86,059	74,239	64,397
Expenses			
Operations and Maintenance	93,681	86,556	72,890
Depreciation and Amortization	40,694	38,407	34,178
Taxes Other than Income	5,174	6,096	5,568
Deferral of Start-up Costs	-	-	(2,501)
Total Operating Expenses	139,549	131,059	110,135
Total Revenue Requirement	225,608	205,298	174,532
Less: Total Revenue Billed	223,134	209,909	169,152
True-up Collection / (Refund)	$2,474	$(4,611)	$5,380

Results of Operations

Earnings Overview

The Company's earnings for 2003 were $62.7 million, an increase of 16% from earnings of $54.1 million in 2002. Operating income increased by $11.8 million in 2003 as compared to 2002 due to the return earned on additional rate base (see previous table). Offsetting the $11.8 million increase in operating income is a $4.3 million increase in net interest expense resulting from additional long-term debt issued in the second half of 2002 and 2003 and short-term debt issued during 2003 to finance construction of transmission assets.

The Company's earnings for 2002 were $54.1 million, an increase of 2% from earnings of $53.2 million in 2001. Operating income increased by $9.8 million in 2002 as compared to 2001 due to the return earned on additional rate base (see previous table). Offsetting the increase in operating income is a $2.5 million decrease in other income and a $6.4 million increase in net interest expense, both described below.

Revenues

Total operating revenues increased $20.3 million, or 10%, during 2003, as compared to 2002. Approximately $8.5 million of the revenue increase was due to the recovery of additional operating expenses in 2003, including additional depreciation expense due to increased assets in service. The remainder of the increase in revenue was due to the Company's return on a higher rate base. The rate base continues to grow as additional assets are placed in service. Members' income taxes recovered through the revenue requirement increased by $3.5 million due to the higher return on rate base.

Total operating revenues increased $30.8 million, or 18%, during 2002, as compared to 2001. Approximately $20.9 million of the revenue increase was due to the recovery of additional operating expenses in 2002 as well as depreciation expense for additional assets in service. The remainder of the increase in revenue was due to the Company's return on a higher rate base. Members' income taxes recovered through the revenue requirement increased by $1.2 million due to the higher return on rate base, partially offset by an increase in the amortization of both excess deferred income taxes and investment tax credits.

Operating Expenses

Total operating expenses were $8.5 million, or 6%, higher during 2003 than 2002. Operations and maintenance expenses were $7.1 million higher in 2003, due to an increase in maintenance work related to construction projects, the addition of new facilities and information technology infrastructure and the development of supply chain capabilities to support the construction program. Depreciation also increased by $2.3 million, due to additional assets placed in service throughout 2002 and 2003.

Total operating expenses were $20.9 million, or 19%, higher during 2002 than 2001. Operations expenses were $7.2 million higher in 2002, primarily due to higher costs for re-dispatch of generation on the transmission grid related to construction outages on several transmission lines in the fourth quarter. General and administrative expenses increased $5.6 million as the Company added staff in 2002 and experienced the first full year of costs for employees hired in 2001. Depreciation also increased by $4.2 million, due to the contribution of assets in June 2001 and additional assets being placed in service by the Company throughout 2002 and 2001.

Other Income

Other income increased approximately $1.1 million during 2003, as compared to 2002. The increase was primarily due to a $.8 million increase in the allowance for equity funds during construction caused by a higher average CWIP balance during 2003 than 2002. During 2002, there was a $0.6 million one-time, below the line charge related to income tax expense incurred by Management Inc. that was charged to the Company under the operating agreement. Management decided not to seek rate recovery of this amount.

Other income decreased approximately $2.5 million during 2002, as compared to 2001. $0.6 million of the decrease was due to the income tax charge described above. The remainder of the decrease was due to lower cash balances available for investment during 2002, as surplus funds from the senior note issuance in 2001 were utilized for the Company's operations and construction program.

Net Interest Expense

Net interest expense was $4.3 million higher in 2003, as compared with 2002. This increase relates to interest on additional long-term debt issued during the second half of 2002 and 2003 and interest on commercial paper outstanding during 2003 prior to the issuance of long-term debt.

Net interest expense was $6.4 million higher in 2002 than in 2001, primarily because 2001 results include less than a full year's interest on the Company's $300 million senior notes, as the notes were not issued until the second quarter of 2001.

Liquidity and Capital Resources

During 2003, the Company used net cash of $5.7 million as compared to net cash used of $23.2 million in 2002. Net cash provided by operations increased $1.1 million, due to an increase in earnings before tax and depreciation and amortization, offset slightly by changes in working capital related to the timing of receipts from customers and payments to vendors. Net cash used in investing activities increased by $70.9 million, primarily due to a general increase in the Company's construction program, as well as work performed during 2003 in support of several generation interconnection projects. Cash provided by financing activities increased $87.3 million during 2003. The increase is due to the Company's net proceeds from long-term debt issuances of $99.2 million during 2003, as compared to net proceeds of $49.4 million during 2002. The Company also received $26.2 million in cash advances under generation interconnection agreements during 2003, compared to $3.8 million received during 2002. The Company received $17.2 million from the issuance of membership units during 2003, compared with $.6 million during 2002.

During 2002, the Company used net cash of $23.2 million as compared to net cash generated of $19.9 million in 2001. This change is primarily due to the Company's investing activities, particularly its construction program. Capital expenditures for property, plant and equipment increased by $53.3 million in 2002, as compared to 2001. Net cash provided by operations increased $12.7 million in 2002, due to higher return on rate base, depreciation and changes in working capital and other assets and liabilities, partially offset by higher interest expense. Cash provided by financing activities decreased $2.8 million in 2002, as compared to 2001. Distributions of earnings to members were $48.2 million in 2002, compared with $27.2 million during 2001, due to the payment of an additional quarterly distribution in 2002. In addition, in 2001 there was approximately $36 million in bond proceeds remaining after the redemption of $258 million in membership units. The remaining bond proceeds were invested as of December 31, 2002. These changes were partially offset by $49.4 million in net proceeds of additional debt issued during 2002 and $3.8 million of advances from generators under interconnection agreements.

Capital Requirements and Liquidity

Management believes that to provide adequate and reliable transmission service and to support access to competitive, wholesale energy markets without favoring any participant, it will be necessary to strengthen and expand the Company's transmission system to deliver electricity to customers in Wisconsin, Michigan and Illinois. Expansion will relieve transmission constraints, allow additional generation capacity to be connected to the system, enhance wholesale competition and permit entry by new competitors in electricity generation.

The Company has plans for approximately $260 million in new transmission construction projects and other capital spending in 2004, and expects that it could incur approximately $2.8 billion in capital expenditures over the next ten years. These estimates are based on the Company's 2004 capital budget and ten year transmission planning and needs assessment, much of which remains subject to regulatory approval and continuing analysis of system needs. This estimate does not include additional acquisitions of transmission assets the Company might make. Approximately $27 million of the anticipated capital spending in 2004 is related to generation interconnection agreements and will be funded by the generators, as described in the notes to financial statements.

Based on the capital expenditure forecast of $2.8 billion over the period 2004 through 2012, management anticipates, under its new tariff, as conditionally approved by FERC on December 29, 2003, its credit ratings to remain investment grade with a substantial margin of safety. The rate formula modification that the Company has conditionally received from FERC would generate increased cash flows through the accelerated recovery of preliminary survey and investigation costs in the current period and through allowing the Company to earn a current return on its investment in Construction Work in Progress for new transmission projects. In the event the Company does not reach a settlement on the approved rate formula modifications, the Company may need to reduce or defer capital expenditure levels during the period 2004 through 2012 to levels which should sustain the Company's current credit rating. If the Company cannot maintain its current credit rating, future financing costs could increase, future financing flexibility could be reduced, future access to capital could be difficult and future ability to finance capital expenditures demanded by the market could be impaired.

The ability to construct transmission assets is subject to the Company obtaining extensive regulatory approvals, including siting, from the Public Service Commission of Wisconsin ("PSCW") and other regulatory bodies. Management believes regulatory and siting issues pose the key risks to completing and placing transmission assets in service. Once approved, constructed and placed in service, the costs of transmission projects are expected to be included in the rate formula that determines the Company's revenue requirement; however, it is possible that some of the Company's capital projects will not be completed and placed in service. In such situations there is an additional risk, because while state regulatory bodies have jurisdiction over construction, FERC has jurisdiction over the Company's rates. While costs incurred by the Company for projects that are not completed are generally not significant, there is potential for higher costs to be incurred related to large projects, such as the Arrowhead to Weston project. MISO's tariff contains provisions under which such costs may potentially be recovered if the related project was included in MISO's Transmission Expansion Plan, required by MISO or otherwise approved by MISO. The Arrowhead to Weston Project is included in MISO's Transmission Expansion Plan. If recovery is not realized through the MISO tariff, the Company will seek recovery of such costs through its FERC regulated rate formula; however, there is no guarantee that such recovery will be allowed by FERC. If recovery is not realized through the MISO tariff, or recovered through rates, these costs would be charged to expense.

As part of the agreement to transfer the Arrowhead to Weston project to the Company, WPSC committed to provide equity funding for 50% of the total cost of the project. WPSC's contributions under this arrangement are made monthly based on project expenditures. In addition, certain of the Company's other members have the right, under the operating agreement, to contribute additional equity to maintain their ownership percentages as WPSC funds the Arrowhead to Weston project.

In the short run, management intends to finance construction with a combination of commercial paper offerings and private placement debt offerings having cash draw-down features that align with construction cash outflows. To the extent that the private placement debt market remains accessible to the Company at attractive rates and on attractive terms, management intends to finance the majority of its construction programs in this manner. Should access to this market become limited or inaccessible, the Company would exercise its option to expand back up lines of credit from its current $75 million to $100 million and issue commercial paper. As the commercial paper borrowing capacity is utilized, management would refinance outstanding commercial paper through long-term debt and/or equity issuances.

The timing and amount of the Company's construction requirements have a significant impact on the Company's liquidity and its cash requirements. To meet these requirements over the long-term, the Company plans to finance its capital expenditure program through the issuance of long-term debt, reinvested equity and, as necessary, additional equity infusions from current members, private equity investments and/or public equity offerings. In connection with these financing alternatives, management intends to maintain a debt to total capitalization ratio of 50% to 53% consistent with the maintenance of an "A" credit rating and tier-one commercial paper ratings.

The Company has funded its construction program from the proceeds of its senior debt offerings over the past three years. During interim periods, when such funds have been depleted, the Company has accessed the commercial paper market to finance construction on a short-term basis until its next debt offering. While the $30 million senior note issuance in October 2003 will fund the majority of near-term construction, continual access to the commercial paper and long-term debt markets will be necessary to fund the Company's construction plans.

The Company issued a voluntary capital call for $68 million to its members in December 2003 which will be payable in $17 million installments in January, April, July and October of 2004. The participating members will pay cash in exchange for additional membership units at the current book value per unit at the time of each installment. The majority of members have committed to provide equity via the capital call in 2004. These members have also given a non-binding indication that they expect to continue to provide equity funding for planned capital calls during 2005 and 2006.

Management cannot provide assurance that the Company will be able to secure the additional sources of financing needed to fund the significant capital requirements associated with the Company's transmission system expansions discussed above. In addition, some expenditures may not result in assets on which the Company will earn a return, as discussed above. The Company is required to finance the lag between when costs are incurred for planning and construction and when the assets are placed in service, although a portion of such financing costs are capitalized as allowance for funds used during construction and recovered through rates as part of the total cost of the associated assets. The Company also must finance any timing differences between when revenues are collected under the current tariff and the Company's related expenditures.

The Company's operating agreement provides that the board of directors of its corporate manager, Management Inc., will determine the timing and amount of distributions to be made to the Company's members. In this agreement, the corporate manager also declared its intent, subject to certain restrictions, to distribute an amount equal to 80% of the Company's earnings before taxes. The Company's operating agreement also provides that it may not pay, and no member is entitled to receive, any distribution that would generally cause the Company to be unable to pay its debts as they become due. Cash available for distribution for any period consists of cash from operations after provision for capital expenditures, debt service and reserves established by Management Inc.

Long-term Contractual Obligations and Commercial Commitments

The Company's contractual obligations as of December 31, 2003, representing cash obligations that are considered to be firm commitments, are as follows (in thousands):

		Payment Due Within			Due After
	Total	1 Year	2 – 3 Years	4 – 5 Years	5 Years
Long-term Debt	$450,000	$ -	$ -	$ -	$450,000
Interconnection Agreements	$325,622	17,293	44,993	-	263,336
Operating Leases	$5,808	1,417	2,751	1,640	-
Total Contractual Obligations	$781,430	$18,710	$47,744	$1,640	$713,336

The Company currently contracts with several utility providers for certain operation and maintenance services (as further discussed below). The Company is obligated to pay each utility a minimum of 85% of the expenses previously incurred by the utility for such activities in a representative year. The Company met this obligation in 2003, 2002 and 2001 and management believes it will continue to meet this obligation in the future.

Related Party Transactions

The Company is operating under transitional services and operations and maintenance services agreements whereby the contributing utilities, municipalities and cooperatives are required to provide certain administrative, operational, maintenance and construction services to the Company at a fully allocated cost, including direct cost, overheads, depreciation and a return on assets employed in the services provided to the Company. The operations and maintenance agreements were in effect until December 31, 2003 whereas the transitional services agreements are open-ended. One of the contributing utilities signed a new operations and maintenance agreement during the fourth quarter of 2003 extending those services through 2008. The new agreement does not contain the 85% clause. All other operations and maintenance agreements were automatically extended for an additional year. The Company plans to renegotiate these operations and maintenance agreements. In the event that the Company is not able to renew the agreements at the end of their current terms, the Company cannot guarantee that it will be able procure similar services at similar costs. The Company believes that the costs the Company must incur to provide transmission service will be recoverable in future rates. The terms of these agreements, including pricing, are subject to oversight by the PSCW and the Illinois Commerce Commission.

The Company is managed by a corporate manager, Management Inc. The Company and Management Inc. have common ownership and operate as a single functional unit. Under the Company's operating agreement, Management Inc. has complete discretion over the business of the Company. Accordingly, Management Inc. provides all management services to the Company at cost. The Company itself has no employees. The Company's operating agreement also establishes that all expenses of Management Inc. are the responsibility of the Company. These expenses consist primarily of payroll, benefits, payroll-related taxes and other employee expenses. All such expenses are recorded in the Company's accounts as if they were direct expenses of the Company.

Business and Operating Environment

In accordance with Wisconsin statutes and FERC requirements, operational control of the Company's transmission system was transferred to MISO, a FERC-approved regional transmission organization (RTO), effective February 1, 2002.

As a requirement of the transfer of functional control to MISO, the obligation to provide transmission service to customers over the Company's system is provided under the MISO open-access transmission tariff. The Company will continue to file with FERC for approval of future changes to the formula and determination of cost of service elements that determines its revenue requirements.

MISO has operational control over the Company's system and has the authority to direct the manner in which the Company performs operations. The Company is also required to seek direction from MISO for certain operational actions the Company seeks to perform within its system. MISO is responsible for monitoring congestion, directing the associated operations to overcome congestion, approving transmission maintenance outages, as well as negotiating with generators on the timing of generator maintenance outages within the entire MISO system, including that portion representing the Company's system. The Company may be required to coordinate planning activities for new projects or system upgrades with MISO. Certain projects might require review by MISO before implementation.

The Company remains responsible for monitoring and physically operating its transmission system. The Company also remains responsible for the planning, design, construction and maintenance of its assets.

In July 2003, the Wisconsin legislature enacted new legislation that modified the Company's statutory requirement to remain a member of MISO. Upon action by the PSCW, the Company may be allowed to exit MISO. Should the Company be allowed to leave MISO, it may have liability for a portion of the deferred costs

MISO has incurred for start-up and operations. The Company has no current plans to exit MISO. However, there is ongoing uncertainty about other transmission owners continuing their membership in MISO; this uncertainty raises the risk that MISO could become nonviable at some point in the future. The impact on the Company if this would occur is uncertain at this time.

On July 31, 2002, FERC issued a Notice of Proposed Rulemaking ("NOPR") entitled "Remedying Undue Discrimination Through Open-Access Transmission Service and Standard Electricity Market Design" that may ultimately lead to a final rule and future orders that will likely make changes to the Company's current tariff and rates for service. Future orders may also modify the Company's functional responsibilities in areas such as expansion planning, performing facilities and system impact studies, building new facilities, reliability management, congestion management and regional coordination. Comments on the NOPR were due to FERC in mid-November 2002 and in mid-January 2003. FERC issued a white paper and appendix on April 28, 2003, that reflected extensive comments received from utilities, state regulatory agencies and other interested parties. The timing of the final rule is uncertain at this time. Additionally, there are components of proposed energy legislation before the U.S. Congress which would prevent FERC from issuing any further orders related to Standard Market Design until 2005 or later.

The white paper and appendix contain provisions related to the allocation and characteristics of financial transmission rights ("FTRs"). The impact of these provisions on the Company is uncertain. The current tariff does not specify if revenue shortfalls associated with FTRs are subject to the true-up mechanism or if earnings are at risk due to the volatility of FTR revenues. On July 25, 2003, MISO filed a draft Transmission and Energy Markets Tariff ("TEMT") for implementation of its market design, which included provisions that would protect transmission owners from shortfalls in revenue related to FTRs. MISO subsequently announced in October that it would withdraw its original proposal and place primary focus on improving the reliability of the transmission grid. MISO's revised proposal would delay implementation of its market design until December 2004. Due to the uncertainty of how the current true-up mechanism will be applied, if the TEMT is not approved at such time as it is re-filed by MISO, the effort by FERC on standard market design could affect earnings and cash flows if adopted as proposed. At this time, the Company cannot predict whether the white paper and appendix will be promulgated as proposed. Future actions taken by Congress may also affect the timing and substantive content of Standard Market Design.

On February 15, 2003, FERC issued a notice of proposed pricing policy for efficient operation and expansion of the transmission grid. The proposed policy would provide certain financial incentives related to divestiture of transmission assets from vertically integrated utilities, placement of assets under the control of a regional transmission organization and investment in new transmission facilities. The Company has evaluated the potential impact this policy could have on its operations, and has determined that the modifications to the rate formula contained in its recent filing with FERC would be more beneficial to the Company and has, therefore, proposed such changes as an alternative incentive mechanism to the incentives contained in FERC's proposed pricing policy.

On July 23, 2003, FERC issued an order eliminating the Regional Through and Out Rates ("RTOR") for point-to-point transmission services between MISO and the PJM Interconnection, effective October 31, 2003. On November 13, 2003, FERC delayed the effective date until April 1, 2004. RTOR revenues are collected by MISO and distributed to its member transmission owners. The Company currently receives approximately $3.2 million per year in RTOR revenues from MISO, which serves as a reduction in the amount of the Company's revenue requirement that is borne by its network transmission customers. A transitional revenue replacement mechanism, called the Seams Elimination Cost Assignment ("SECA"), is expected to be in place from April 1, 2004 through March 31, 2006. The purpose of the SECA is to protect the financial position of the transmission owners by preserving their revenue stream during the transition period, after which this revenue source will be permanently eliminated. Due to the nature of the Company's revenue requirement formula, including the true-up mechanism described above, management does not expect the elimination of RTOR revenues to have a significant impact on the Company's results of operations. The Company expects that any revenue shortfall associated with the SECA will be made up by the true-up mechanism during the transition period. Similarly, after the transition period, the elimination of RTOR revenues will result in an increase in the revenues collected from the Company's network transmission customers.

Qualitative Disclosures about Market Risks

The Company manages its interest rate risk by limiting its variable rate exposure and continually monitoring the effects of market changes on interest rates. The Company's interest rate risk related to its long-term debt is mitigated by the fact that its long-term debt rate is included as a component of its revenue requirement calculation.

The Company has a significant concentration of major customers; its five largest customers generate approximately 85% - 90% of its revenue on an ongoing basis. The Company closely monitors the business and credit risk associated with its major customers. These major customers are all investor-owned utilities that currently have investment grade debt ratings.