



FORM 10-K

SEMCO ENERGY INC – SEN

Filed: March 14, 2006 (period: December 31, 2005)

Annual report which provides a comprehensive overview of the company for the past year

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

Form 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2005

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

For the transition period from to

Commission File Number 001-15565

SEMCO Energy, Inc.

(Exact name of registrant as specified in its charter)

Michigan
*(State or other jurisdiction of
incorporation or organization)*

38-2144267
*(I.R.S. Employer
Identification No.)*

1411 Third Street, Suite A, Port Huron, Michigan
(Address of principal executive offices)

48060
(Zip Code)

(Registrant's telephone number, including area code) 810-987-2200

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

<u>Title of Each Class</u>	<u>Name of Each Exchange on Which Registered</u>
Common Stock, \$1 Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the Registrant's Common Stock held by non-affiliates as of June 30, 2005, was \$162,666,818 based on 27,156,397 shares held by non-affiliates and the closing price of \$5.99 on that day (New York Stock Exchange).

Number of outstanding shares of the Registrant's Common Stock as of February 28, 2006: 33,726,152

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of Registrant's definitive Proxy Statement (filed pursuant to Regulation 14A) with respect to Registrant's 2006 Annual Meeting of Common Shareholders are incorporated by reference in Part III of this Form 10-K.

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<u>CFO Certification Pursuant to Section 302</u>	
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Information About Forward-Looking Statements

This annual report on Form 10-K contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are based on current expectations, estimates and projections of the registrant, SEMCO Energy, Inc. (the “Company”). Statements that are not historical facts, including statements about the Company’s outlook, beliefs, plans, goals, and expectations, are forward-looking statements. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as “may,” “will,” “expect,” “intend,” “estimate,” “anticipate,” “believe,” or “continue” or the negatives of these terms or variations of them or similar terminology. These statements are subject to potential risks and uncertainties and, therefore, actual results may differ materially from the expectations described in these statements. Although the Company believes that the expectations reflected in these forward-looking statements are reasonable, the Company cannot provide any assurance that these expectations will prove to be correct. Important factors that could cause actual results to differ materially from the Company’s expectations are described in the Risk Factors section in Item 1A of this Form 10-K and include:

- the effects of weather and other natural phenomena (including the effects of these phenomena on customer consumption);
- the economic climate and growth in the geographical areas where the Company does business;
- the capital intensive nature of the Company’s business;
- the operational risks associated with operating businesses involved in the storage, transportation and distribution of natural gas and propane;
- competition within the energy industry as well as from alternative forms of energy;
- the timing and extent of changes in commodity prices for natural gas and propane and the resulting changes in, among other things, the Company’s working capital requirements, customer rates and customer gas consumption;
- the effects of changes in governmental and regulatory policies, including income taxes, environmental compliance and authorized rates;
- the adequacy of authorized rates to compensate the Company, on a timely basis, for the costs of doing business, including the cost of capital and cost of gas supply, and the amount of any cost disallowances;
- the Company’s ability to procure its gas supply on reasonable credit terms;
- the availability of long-term gas supplies in the Cook Inlet region of Alaska;
- the amounts and terms of the Company’s debt and its credit ratings;
- the Company’s ability to remain in compliance with its debt covenants and accomplish its financing objectives in a timely and cost-effective manner;
- the Company’s ability to maintain an effective system of internal controls;
- the Company’s ability to execute its strategic plan effectively, including the ability to make acquisitions and investments on reasonable terms and the reasonableness of any conditions imposed on those transactions by governmental and regulatory agencies;
- the Company’s ability to conclude litigation and other dispute resolution proceedings on reasonable terms;
- the Company’s ability to utilize its net operating loss carry-forwards for federal income tax purposes; and
- changes in the performance of certain assets, which could impact the carrying amount of the Company’s existing goodwill.

In this Form 10-K, “include”, “includes”, or “including” means include, includes or including without limitation.

PART I

Item 1. Business

SEMCO Energy, Inc.

The Company is a New York Stock Exchange (“NYSE”)–listed regulated public utility company headquartered in Port Huron, Michigan. It was founded in 1950 as Southeastern Michigan Gas Company (“SMGC”). In 1977, the Company initiated a reorganization, pursuant to which Southeastern Michigan Gas Enterprises, Inc. (“SMGE”) was formed and SMGC became a wholly-owned subsidiary of SMGE. On April 24, 1997, SMGE’s name was changed to SEMCO Energy, Inc. and SMGC’s name was changed to SEMCO Energy Gas Company. On January 1, 2000, SEMCO Energy Gas Company was merged into SEMCO Energy, Inc. References to the “Company” in this document mean SEMCO Energy, Inc., its subsidiaries, divisions or the business segments discussed below as appropriate in the context of the disclosure.

The Company operates one reportable business segment: Gas Distribution. The Gas Distribution business segment includes the Company’s natural gas distribution operations in Michigan and Alaska. The Company’s other business segments that do not meet the quantitative thresholds to be reportable business segments (“non-separately reportable business segments”) are combined and included with the Company’s corporate division in a category to which the Company refers to as “Corporate and Other.” The Company’s non-separately reportable business segments primarily include Company operations and investments in information technology services, propane distribution, intrastate natural gas pipelines, and a natural gas storage facility. For further information on the Company’s business segments, refer to Note 11 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K.

Gas Distribution Business Segment

The Company’s Gas Distribution business segment consists of natural gas distribution operations in Michigan and Alaska. The Michigan operation is sometimes referred to as “SEMCO Gas” and the Alaska operation is sometimes referred to as “ENSTAR.” These operations are referred to together as the “Gas Distribution Business.”

SEMCO Gas is a division of the Company. The ENSTAR operation includes ENSTAR Natural Gas Company, Alaska Pipeline Company (“APC”) and NORSTAR Pipeline Company (“NORSTAR”). ENSTAR Natural Gas Company is a division of the Company. APC is a subsidiary of the Company and NORSTAR is a subsidiary of APC. APC’s transmission system delivers natural gas from producing fields in South Central Alaska to ENSTAR’s Anchorage-area gas distribution system. APC’s only customer is ENSTAR. NORSTAR began operations in 2002 and provides pipeline management and pipeline construction management services to non-affiliated customers in Alaska.

The Gas Distribution Business purchases, transports, distributes, and sells natural gas to residential, commercial and industrial customers and is the Company’s largest business segment. The Company’s strategy for the existing Michigan and Alaska gas distribution operations is to expand its transmission and distribution system in an economical manner through appropriate system improvements and the attachment of new customers located on or near gas mains within the Company’s existing service territories. The Company will also seek to grow its Gas Distribution Business (including related pipeline and storage operations) by making appropriate acquisitions and investments in Michigan, Alaska and elsewhere.

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Set forth in the following table is financial and operating information for the Gas Distribution Business:

	Years Ended December 31,		
	2005	2004	2003
Gas sales revenues (in thousands)			
Residential	\$ 385,978	\$ 315,606	\$ 290,911
Commercial and industrial	183,158	147,750	137,025
Total gas sales revenue	<u>\$ 569,136</u>	<u>\$ 463,356</u>	<u>\$ 427,936</u>
Gas transportation revenue (in thousands)	\$ 29,142	\$ 29,071	\$ 27,737
Cost of gas sold (in thousands)			
Purchased	\$ 473,157	\$ 351,288	\$ 331,821
Withdrawn from (injected into) storage	(29,297)	(5,047)	(22,902)
Total cost of gas sold	<u>\$ 443,860</u>	<u>\$ 346,241</u>	<u>\$ 308,919</u>
Volumes of gas sold (MMcf)(a)			
Residential	44,235	44,880	45,324
Commercial and industrial	20,488	21,285	21,948
Total volumes of gas sold	64,723	66,165	67,272
Volumes of gas transported (MMcf)	55,709	56,619	51,358
Total volumes delivered	<u>120,432</u>	<u>122,784</u>	<u>118,630</u>
Temperature Statistics(b)			
Degree Days			
Alaska	9,572	9,573	9,384
Michigan	6,689	6,726	7,063
Percent colder (warmer) than normal			
Alaska	(5.7)%	(6.0)%	(8.0)%
Michigan	(0.1)%	(0.3)%	4.7%
Number of customers at year end	409,462	398,225	390,677
Number of customers, annual average			
Residential	363,678	354,261	346,819
Commercial and industrial	37,639	37,234	37,640
Transportation	1,638	1,540	1,481
	<u>402,955</u>	<u>393,035</u>	<u>385,940</u>

- (a) MMcf is a quantity of natural gas equal to one million standard cubic feet.
- (b) Degree days are a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular year are determined by adding the degree days incurred during each day of that year. The Company determines the percent (%) that weather is warmer or colder than normal for a particular year by computing the deviation of actual degree days for that year from the average of degree days during the prior fifteen years and dividing the deviation by such fifteen-year average. Degree days are an indicator of natural gas consumption, since natural gas supplied and delivered by the Company is used by many customers for space heating, and heating consumption is affected by how warm or cold it is.

All revenue generated by the Gas Distribution Business for the years ended December 31, 2005, 2004, and 2003, is from non-affiliated customers, except for an inconsequential amount, typically less than 0.05% per year. Refer to Note 11 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K, for

the operating revenues, operating income, assets and other financial information of the Gas Distribution Business for the past three years.

Rates and Regulation. The Gas Distribution Business is subject to regulation. The Michigan Public Service Commission (“MPSC”) has jurisdiction over the regulatory matters related to the Company’s Michigan customers, except for customers located in the City of Battle Creek and nearby communities. The regulatory matters related to customers located in the City of Battle Creek and nearby communities are currently subject to the jurisdiction of the City Commission of Battle Creek (“CCBC”). Regulatory matters related to customers in Alaska are subject to the jurisdiction of the Regulatory Commission of Alaska (“RCA”). These regulatory bodies have jurisdiction over, among other things, rates, accounting procedures, and standards of service. The approximate number of the Company’s customers located in service areas regulated by each of the three regulatory bodies is as follows: MPSC — 249,000; CCBC — 37,000; and RCA — 123,000. In October 2005, the Company and CCBC announced that they will petition the MPSC to assume jurisdiction over customers located in the City of Battle Creek and nearby communities (the regulatory jurisdiction currently exercised by the CCBC). The CCBC and the Company will jointly apply for MPSC acceptance of this jurisdictional change and propose that the MPSC accept the current rates charged to customers in the area regulated by the CCBC as the initial rates to be charged to these customers under MPSC jurisdiction until these rates are changed in accordance with the applicable MPSC procedures. The Company and the CCBC plan to file a joint application with the MPSC in 2006 asking for approval of this jurisdictional change.

For information on regulatory matters including recent regulatory orders, filings and rate cases, refer to Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K.

Gas Sales. Gas sales revenue is generated primarily through the sale and delivery of natural gas to residential and commercial customers. These customers use natural gas mainly for space heating. Consequently, weather has a significant impact on sales. As a result of the impact of weather on this business segment, most of the Company’s gas sales revenue is generated in the first and fourth quarters of the calendar year. Revenues from gas sales accounted for 93% of consolidated operating revenues in 2005, 91% of consolidated operating revenues in 2004, and 90% of consolidated operating revenues in 2003.

In Michigan, the MPSC has approved a program known as the Gas Customer Choice Program that allows gas sales customers to purchase natural gas from third-party suppliers, while allowing the Gas Distribution Business to continue charging existing distribution charges and customer fees plus a gas load balancing fee. As a result, the Company’s earnings are generally not materially affected by customers switching from gas sales service to the Gas Customer Choice Program. The program is available to all gas sales customers in the Company’s service area regulated by the MPSC. There were no customers taking service under the Gas Customer Choice Program at December 31, 2005. If customers elect to participate in the program, revenues associated with such customers would be recorded in transportation revenue rather than gas sales revenue.

In Alaska, commercial customers also may purchase natural gas from third-party suppliers. ENSTAR charges the same distribution charges and customer fees for gas transportation service to commercial customers as it does for gas sales service. As a result, the Company’s earnings are generally not materially affected by commercial customers switching from gas sales service to gas transportation service. If customers elect to purchase natural gas from a third-party supplier, revenues associated with such customers would be recorded in transportation revenue rather than gas sales revenue. There were approximately 1,300 commercial customers in Alaska receiving commercial transportation service at December 31, 2005.

Transportation. The Gas Distribution Business provides transportation services to its large-volume commercial and industrial customers. This service offers those customers the option of purchasing natural gas directly from third-party suppliers. The natural gas purchased by customers from third-party suppliers is then transported on the Company’s gas transmission and distribution network to the customers. Unlike gas sales service, the amount the Company charges its transportation service customers does not include the cost of gas because these customers are not purchasing natural gas from the Company. Transportation services are also available to smaller volume customers who participate in the Gas Customer Choice Program in Michigan or

commercial customers who elect transportation service in Alaska, as described under the caption “Gas Sales,” above.

Customer Base. At December 31, 2005, the Gas Distribution Business had approximately 409,000 customers, including 286,000 customers in Michigan and 123,000 customers in Alaska. The largest concentration of customers in Michigan, approximately 119,000, is located in southeastern Michigan, just northeast of the metro-Detroit area. The remaining Michigan customers are located in various areas throughout the state, including Albion, Battle Creek, Holland, Houghton, Marquette, Niles, Ontonagon, St. Ignace and Three Rivers. Customers in Alaska are located in and around the Anchorage and Cook Inlet area, including Big Lake, Bird Creek, Butte, Chugiak, Eagle River, Eklutna, Girdwood, Houston, Indian, Kasilof, Kenai, Knik, Nikiski, Palmer, Peters Creek, Portage, Sterling, Soldotna, Wasilla and Whittier. ENSTAR distributes natural gas to the greater Anchorage metropolitan area, and its service area encompasses over 56% of the population of Alaska.

The Gas Distribution Business’ customer base is diverse and includes residential, commercial and industrial customers. The largest customers in Michigan include food production facilities, paper processing plants, furniture manufacturers and others in a variety of industries. The largest customers in Alaska include power plants, a liquefied natural gas (“LNG”) plant, a refinery and a fertilizer plant. For further discussion on the potential loss of the fertilizer plant as a customer, refer to the caption “Natural Gas Supply” in Item 1 of this Form 10-K. The average number of customers at SEMCO Gas has increased by an average of approximately 1.4% annually during the past three years (1.3% in 2005), and the average number of customers at ENSTAR has increased by an average of approximately 3.3% annually during the past three years (3.4% in 2005). Average annual gas consumption per customer in both Michigan and Alaska generally has been decreasing because, among other things, new homes and appliances are typically more energy efficient than older homes and appliances. In addition, recent increases in natural gas prices appear to have prompted customers to reduce their gas consumption. For additional information on the impact of higher natural gas prices, refer to the caption “The Impact of Higher Natural Gas Prices” in Item 7 of this Form 10-K.

Competition. Competition in the gas sales market generally arises from alternative energy sources, such as electricity, propane and oil. However, this competition is generally inhibited because of the time, inconvenience and investment necessary for residential and commercial customers to convert to an alternative energy source even as the price of natural gas fluctuates. For residential and commercial gas sales customers, natural gas typically is the most economical energy source for heating.

Competition in the gas transportation market generally arises from alternative energy sources, such as coal, electricity, oil and steam. Certain large industrial customers may be able to use one or more alternative energy sources or may shift production to facilities outside the Company’s service territories if the price of natural gas and delivery services increases significantly. Natural gas has typically been less expensive than these alternative energy sources. However, over the past three years, natural gas prices have been higher and more volatile, making some of these alternative energy sources less expensive than natural gas. During the last half of 2005 in particular, the price of natural gas increased substantially. During this period, certain of the Company’s large Michigan industrial customers periodically switched to alternative energy sources. To lessen the possibility of such fuel switching by industrial customers, the Company offers flexible contract terms and additional services, such as gas storage and balancing. Partially offsetting the impact of this price sensitivity among certain large industrial customers has been the use of natural gas as an industrial fuel because of environmental regulations and other programs and activities and the resultant pressures on industrial customers to reduce emissions from their plants.

There is a risk that industrial customers located in close proximity to interstate natural gas pipelines will bypass the Company’s transmission and distribution system by connecting directly to those pipelines. The Company has addressed, and expects to continue to address, any such efforts by offering flexible contract terms and additional services intended to retain these customers on the Company’s system. Gas sales, power plant and commercial transportation customers in ENSTAR’s service territory are currently precluded from bypassing ENSTAR’s transportation and distribution system due to the limited availability of gas transmission systems and the large distances between producing fields and the locations of current customers.

Natural Gas Supply. SEMCO Gas has access to natural gas supplies throughout the United States and Canada via major interstate and intrastate pipelines in and near Michigan. SEMCO Gas has pipeline capacity contracts with ANR Pipeline Company, Great Lakes Gas Transmission Limited Partnership, Northern Natural Gas Company, Panhandle Eastern Pipe Line Company, Trunkline Gas Company, LLC, Michigan Consolidated Gas Company and Consumers Energy Company. The Company also owns underground storage facilities in Michigan with a working capacity of 5.1 billion cubic feet (“Bcf”). In addition, it leases 6.5 Bcf of storage from Eaton Rapids Gas Storage System (“ERGSS”) and 3.5 Bcf from non-affiliates in Michigan. The owned and leased storage capacity equals approximately 37% of the Company’s 2005 annual gas sales volumes in Michigan. SEMCO Gas Storage Company, a subsidiary of the Company, is a 50% owner of the ERGSS.

SEMCO Gas has negotiated standard terms and conditions for the purchase of natural gas under the North American Energy Standards Board (“NAESB”) form of agreement with a variety of suppliers, including BP Canada Energy Marketing Corp. (“BP”), Charlevoix Energy, Chevron U.S.A., Cinergy Marketing, Coral Energy, Cornerstone Energy, Husky Oil, Mid-American Energy, Nexen Marketing, OGE Energy, ONEOK Energy, ConocoPhillips, Cargill Inc., and Tenaska Marketing. SEMCO Gas purchases natural gas under one or more of these agreements for resale to customers in Michigan, typically in accordance with a gas supply procurement plan approved by the MPSC for customers in areas regulated by the MPSC.

SEMCO Gas has an asset management agreement with BP covering the period of April 1, 2005, through March 31, 2008. Under the agreement with BP, BP provides transportation and storage asset management services for the Company for customers in its service area regulated by the MPSC (“MPSC-regulated customers”) and customers in its service area regulated by the CCBC (“CCBC-regulated customers”).

The Company’s MPSC-regulated customers have paid for natural gas commodity costs through a gas cost recovery (“GCR”) pricing mechanism since April 1, 2002. The MPSC typically reviews and approves a gas supply procurement plan submitted annually by the Company, covering purchases from April 1 of one year to March 31 of the next year. These purchases include both gas supplies for use by customers, commitments to future gas deliveries, and storage injections and withdrawals. The Company’s MPSC-approved GCR gas purchase plans require the Company to solicit bids for all supplies with contract term lengths longer than three days, which, during 2005, constituted approximately 100% of the Company’s sales to MPSC customers. Supplies with contract term lengths of three days or less may be purchased without bidding.

The Company’s CCBC-regulated customers have paid for natural gas commodity costs through a GCR pricing mechanism since April 1, 2005. The CCBC periodically audits the Company’s gas supply procurement plan, which is substantially similar to the one used to procure gas supplies for MPSC-regulated customers.

For MPSC- and CCBC-regulated customers, all gas supplies purchased during each GCR period are based on a portfolio of short-term fixed priced and short-term index priced supply agreements. For information about how the GCR pricing mechanism and related MPSC reviews impact the cost of gas, refer to the “Cost of Gas, Gas Charges Recoverable from Customers, and Amounts Payable to Customers” section within Note 1 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K.

ENSTAR has access to natural gas supplies in close proximity to its Alaska service territory. ENSTAR’s system, including the APC pipeline system, is not linked to major interstate and intrastate pipelines and natural gas supplies in other states or Canada. As a result, ENSTAR procures natural gas supplies under long-term, RCA-approved contracts, from producers in and near the Cook Inlet area.

ENSTAR has a gas purchase contract with Marathon Oil Company (“Marathon”) that has been approved by the RCA (the “1988 Marathon Contract”). It is a requirements contract with no specified daily deliverability or annual take-or-pay quantities. Marathon is required to deliver up to 13 Bcf of gas in 2006. Each year thereafter, Marathon’s maximum delivery obligation decreases by 2 Bcf per year until 2010 when it will be 5 Bcf. The annual delivery obligation remains at 5 Bcf per year until the original commitment of 456 Bcf has been exhausted, which is expected to be in 2018. The contract has a base price and is subject to an annual adjustment based on changes in the price of certain traded oil futures contracts plus reimbursement for severance taxes and other charges.

ENSTAR has RCA-approved gas purchase contracts with Anchorage Municipal Light and Power, Chevron U.S.A., Inc. and ConocoPhillips Alaska, Inc. that provide for the delivery of gas through the year 2009 from the Beluga natural gas field (collectively, the “Beluga Contract”). ENSTAR’s obligation to take gas under the Beluga Contract is estimated to be approximately 1.1 Bcf in 2006, declining to approximately 0.6 Bcf in 2009. The pricing mechanism in the Beluga Contract is similar to the Marathon Contract.

ENSTAR has an RCA-approved gas supply contract with Aurora Gas for natural gas deliveries from the Moquawkie natural gas field (the “Moquawkie Contract”). The Moquawkie Contract provides that Aurora Gas will supply a portion of ENSTAR’s needs through 2014. Aurora is required to deliver up to 1.8 Bcf of natural gas in 2006. This requirement declines annually until the projected final year requirement of 0.2 Bcf in 2014. The total remaining commitment at the end of 2005 was approximately 10 Bcf. The contract has a base price, subject to annual adjustment based upon 50% of the change in certain inflation measures, plus reimbursement for any severance taxes and other charges.

ENSTAR also has an RCA-approved gas supply contract with Union Oil Company of California (“Unocal”) (the “Unocal Contract”). Natural gas deliveries under this contract began in 2004. The Unocal Contract provides that Unocal will supply all of ENSTAR’s natural gas requirements not met by the 1988 Marathon, Beluga and Moquawkie Contracts, through 2005, and supply all or a portion of ENSTAR’s requirements in years beyond 2005 based upon additional commitments that may be made by Unocal annually in October. In October 2005, Unocal made a commitment to supply all of ENSTAR’s requirements (not met by the 1988 Marathon, Beluga and Moquawkie Contracts) through 2008 and to supply 19 Bcf in 2009 and in 2010. In any year after 2010, Unocal cannot reduce its commitment by more than 3 Bcf per year. Under the terms of the Unocal Contract, Unocal must advise ENSTAR each October of Unocal’s commitments for the next five years. Each commitment of gas is subject to review by an independent petroleum engineer, but Unocal does not guarantee that it has reserves sufficient to meet its obligations. Under specified circumstances, Unocal may reduce or terminate its obligations to deliver gas. Gas supplied under the Unocal Contract is priced annually according to a 36-month daily average price of certain traded natural gas futures contracts, subject to a floor price. The Unocal Contract also provides for reimbursement for severance taxes and other charges.

ENSTAR has entered into an additional gas supply agreement for its Alaska service area with Marathon Oil Company (the “2005 Marathon Contract”). The 2005 Marathon Contract provides for natural gas deliveries to begin in 2009 and run through at least 2017, for a total of approximately 60 Bcf of natural gas. The 2005 Marathon Contract is a requirements-style contract, with annual delivery amounts dependent upon the Company’s annual natural gas demand in its Alaska service area and the deliveries under the Company’s other RCA-approved gas supply contracts. Gas supplied under the 2005 Marathon Contract is priced annually according to a 12-month daily average price of certain traded natural gas futures contracts, discounted if the average price exceeds \$6.00 per thousand cubic feet (“Mcf”), and subject to indexed floor and ceiling prices. The 2005 Marathon Contract also provides for a \$0.25 per Mcf transportation fee and reimbursement for severance taxes and other charges. The 2005 Marathon Contract is subject to the approval of the RCA and was submitted for approval in November 2005.

The Unocal, 1988 Marathon, Beluga and Moquawkie Contracts collectively provide for all of ENSTAR’s supply requirements through 2008. RCA approval of the 2005 Marathon Contract will extend that timeframe through 2010. If Unocal continues to commit 19 Bcf per year through 2016, then all of ENSTAR’s requirements will be provided for through 2016. After 2016, natural gas will still be available under the Unocal Contract, the 1988 Marathon Contract and the 2005 Marathon Contract in accordance with their terms, but at least a portion of ENSTAR’s requirements is expected to be met by amendments to those contracts or by new contracts.

Production from the Cook Inlet area natural gas fields is declining, and new discoveries have been modest. As of January 1, 2004, the Cook Inlet area had approximately 2.1 trillion cubic feet (“Tcf”) of total proven natural gas reserves according to the most recently available information contained in the Alaska Department of Natural Resources Division of Oil and Gas 2004 Annual Report. Based on the Department’s reported 2003 net production of 208 Bcf, there was a reserve life at January 1, 2004, of approximately 10 years

in the Cook Inlet area, although shortages of daily deliverability have occurred, resulting in curtailment of some industrial loads during cold weather periods. There is ongoing exploration for natural gas in the Cook Inlet area by several parties, including producers that have supply contracts with ENSTAR. This exploration is confined to areas in or near producing fields. The United States Geological Survey and Minerals Management Service has estimated that the Cook Inlet area contains approximately 2.3 Tcf of undiscovered natural gas, but there are no assurances that any of this natural gas will be discovered and, if discovered, can be produced economically and secured by ENSTAR on terms and conditions that would be acceptable to the RCA.

ENSTAR has been active in efforts to extend its supply of Cook Inlet area natural gas and to find other gas sources. Approximately 125 to 140 Bcf of natural gas are exported each year from Cook Inlet in the form of LNG and ammonia-urea fertilizer. The owner of the fertilizer plant has publicly announced that it has experienced difficulty in securing sufficient natural gas supplies at an appropriate price to continue operating in the future. The owner of the plant has said that it has secured sufficient natural gas supplies to operate at a reduced rate through October 2006, but currently does not have sufficient natural gas under contract at an appropriate price to operate after that date. The Company cannot predict whether the fertilizer plant will ultimately close or whether the export license for the LNG plant that expires on March 31, 2009, will be renewed. In the negotiations with potential gas suppliers, ENSTAR is encouraging development of storage to minimize potential deliverability problems and to enhance opportunities for independent producers to develop natural gas fields that might not be economical without storage. In addition, preliminary activity by other energy industry participants is underway to finance, permit and build a natural gas pipeline that would extend from Alaska's North Slope, through central Alaska and Canada, to the lower 48 states of the United States. Assuming this pipeline is built, the flow of natural gas through it could not be expected to begin before the middle of the next decade, at the earliest. ENSTAR is engaged in an effort to make customers and public officials aware of the importance of the North Slope natural gas pipeline and the need to make North Slope natural gas available in the Cook Inlet area. The Company can provide no assurances, however, with respect to the building of this pipeline, when it will be put in service, or whether natural gas supplies transported by the pipeline would be available to ENSTAR customers and secured by ENSTAR on terms and conditions that would be acceptable to the RCA.

Environmental Matters. Prior to the construction of major natural gas interstate pipelines, gas for heating and other uses was manufactured from processes involving coal, coke or oil. Residual byproducts of these processes may have caused environmental conditions that require investigation and remediation. The Company owns seven sites in Michigan where such manufactured gas plants were located. Even though the Company never operated manufactured gas facilities at four of the sites, and did so at one site for only a brief period of time, the Company is subject to local, state and federal laws and regulations that require, among other things, the investigation and, if necessary, the remediation of contamination associated with these sites, irrespective of fault, legality of initial activity, or ownership, and which may impose liability for damages to natural resources. The Company has complied with the applicable Michigan Department of Environmental Quality ("MDEQ") requirements, which require current landowners to mitigate unacceptable risks to human health from the byproducts of manufactured gas plant operations and to notify the MDEQ and adjacent property owners of potential contaminant migration. The Company is currently investigating these sites, and anticipates conducting any necessary additional investigatory and remedial activities as appropriate. The Company has already remediated and closed a site related to one of the manufactured gas plant sites, with the MDEQ's approval.

The Company is also attempting to identify other potentially responsible parties to bear some or all of the costs and liabilities associated with the investigatory and remedial activities at several of these sites and also is pursuing recovery of the costs of these activities from insurance carriers. The Company is unable to predict, however, whether and to what extent it will be successful in involving other potentially responsible parties in investigatory or remedial activities, or in bearing some or all of the costs thereof, or in securing insurance recoveries for some or all of the costs associated with these sites.

The Company also is unable to estimate, at present, the costs that may be incurred in connection with the investigation and remediation of these sites or other potential environmental liabilities relating to these sites.

In accordance with an MPSC accounting order, environmental investigation and remediation costs associated with certain manufactured gas plant sites are deferred and amortized over ten years. Rate recognition of the related amortization expense does not begin until a review of the related costs in a base rate case.

Corporate and Other

Corporate and Other includes the Company's corporate division and non-separately reportable business segments. These non-separately reportable businesses are organized as subsidiaries of SEMCO Energy, Inc. and generally complement the Company's Gas Distribution Business. Refer to Note 11 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K, for operating revenues, operating income, assets and other financial information for Corporate and Other for the past three years.

The Company has reorganized its information technology ("IT") business operation to focus primarily on the Company's IT needs, resulting in declining IT revenues from non-affiliated customers. The focus on the Company's IT needs includes the expected implementation, in 2006, of a new Customer Information System and related system changes and upgrades. The Company expects to continue to provide IT services to certain non-affiliated customers where it believes that it can do so profitably. As part of the restructuring of its IT business operation, the Company exited the residential internet service provider ("ISP") portion of its ISP business.

The Company owns a propane distribution business known as "Hotflame." Hotflame typically supplies approximately 4 million gallons of propane annually to retail customers in Michigan's Upper Peninsula and northeast Wisconsin. Because propane is used principally for heating, most of the operating income for the propane business is generated in the first and fourth quarters of the calendar year. Propane is transported easily in pressurized containers and is generally used in rural areas where natural gas pipelines and distribution systems do not exist or are not economical to build. The Company has access to a variety of propane suppliers, including NGL Supply, Inc., Mark West, and Amerigas. The propane operation competes with other energy sources, such as natural gas, fuel oil, electricity and other regional and national propane providers, generally based on price and service.

The Company's pipelines and storage business consist of three pipelines and a gas storage facility, all of which are located in Michigan. The Company has a partial ownership interest in one of the pipelines and an equity interest in the gas storage facility. Refer to Item 2 of this Form 10-K for additional information on each pipeline and the storage facility.

The Company's corporate division is a cost center rather than a business segment. The operating expenses of the corporate division that relate to the ongoing operations of the Company's business segments are allocated to those business segments using a formula that is accepted by the regulatory bodies that have jurisdiction over the Gas Distribution Business. Examples of functions performed by the corporate division on behalf of the Company's business segments include administration, human resources, legal, treasury, finance and accounting. Any corporate expenses that do not relate to the ongoing operations of the Company's business segments or are not allocable to them under various regulatory rules are not allocated to these segments but remain on the books of the corporate division.

Miscellaneous Information

The Company had approximately 566 full-time employees at December 31, 2005, compared to 576 full-time employees at December 31, 2004. Approximately 277 of the employees at December 31, 2005, were represented by unions for purposes of collective bargaining compared to 269 employees at December 31, 2004. The current collective bargaining agreements with various union-represented employees are identified below:

<u>Collective Bargaining Agreement With</u>	<u>Division/ Business Unit</u>	<u>No. of Employees Covered</u>	<u>Expiration Date</u>
Local 328 Teamsters	Hotflame	9	February 28, 2007
Local 3135 Steelworkers	MPSC	20	April 19, 2007
Local 16201 Steelworkers	MPSC	44	June 28, 2007
Local 473 Utility Workers	MPSC	39	December 7, 2007
Local 445 Utility Workers	Battle Creek	38	September 11, 2008
Local 367 Plumbers and Pipefitters Operating Unit	ENSTAR	88	April 1, 2009
Local 367 Plumbers and Pipefitters Clerical Unit	ENSTAR	39	April 1, 2009
Total		277	

The Company maintains a website on the Internet at address <http://www.semcoenergy.com>. The Company makes available free of charge, on or through its website, its proxy statements, annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission ("SEC"). This reference to the Company's Internet address shall not, under any circumstances, be deemed to incorporate the information available at such Internet address into this Form 10-K or other SEC filings. The information available at the Company's Internet address is not part of this Form 10-K or any other report filed by the Company with the SEC. The public may read and copy any documents the Company files at the SEC's Public Reference Room at 100 F Street, N.E. Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The Company's SEC filings can also be obtained on the SEC's website on the Internet at address <http://www.sec.gov>.

Item *Risk Factors*
1A.

Investing in the Company involves a number of risks. Investors should carefully consider all of the information contained in this annual report on Form 10-K, as well as the other filings of the Company with the SEC, including the risk factors set forth below, before making an investment in the Company. Described below are some of the risk factors currently known to the Company which make an investment in the Company speculative or risky. The Company may encounter risks in addition to those described below. Investors may lose all or part of their investment in the Company.

Risks Relating to the Company's Operations

The Company's natural gas distribution business is subject to rate regulation, and certain actions of these regulatory bodies may reduce the Company's revenues, earnings and cash flow.

The Company is currently regulated by the MPSC and the CCBC in Michigan and the RCA in Alaska. These regulatory bodies have jurisdiction over, among other things, rates, accounting procedures and standards of service. With regard to regulation by the MPSC and the CCBC, in March 2005 and February 2005, respectively, the Company entered into settlements which, upon approval, authorized rate increases for customers in these jurisdictions. With certain exceptions, the Company has agreed not to request a further base rate increase with the CCBC to be effective before April 1, 2008, but the Company is not restricted in requesting that the MPSC authorize further base rate increases. In addition, on October 5, 2005, the Company and the CCBC announced that they will ask the MPSC to assume jurisdiction over the CCBC

service area. The Company and the CCBC plan to file a joint application with the MPSC in 2006 asking for approval of this jurisdictional change. The Company cannot predict when the MPSC will assume jurisdiction, if at all. The Company believes that this proposed change will not have a material impact on the natural gas rates it charges in its CCBC service area, but the Company cannot assure that this change in jurisdiction will not affect the rates it charges or other aspects of the terms and conditions of service. With regard to regulation by the RCA, in June 2005, the RCA issued an order that, among other things, requires ENSTAR and APC to file a depreciation study of their Alaska utility plant by June 1, 2007 (as of December 31, 2006) and a revenue requirement and cost-of-service study (including rate design data) with the RCA by June 6, 2008 (using a test year ended December 31, 2007).

Approximately 99% of the Company's 2005 consolidated operating revenues were generated by its regulated Gas Distribution Business. While the Company currently has settlements with the MPSC and the CCBC setting rates in those jurisdictions, there is no guarantee that the Company would prevail in seeking rate increases in future rate cases. The Company also has no guarantee that it will be successful in its rate case to be filed with the RCA after December 31, 2007. The possibility of a rate decrease, the failure to grant any requested rate increase, cost disallowances, the precise timing of any rate increase, decrease or any other action by the Company's regulators, may reduce the Company's revenues, earnings and cash flow.

The increased cost of purchasing natural gas during periods in which natural gas prices are rising significantly could adversely impact the Company's liquidity and earnings.

One component of the regulation of the Company's rates is the ability to recover the cost of purchasing natural gas. In general, the costs of natural gas purchased for customers are recovered on a dollar-for-dollar basis (in the absence of disallowances), without a profit component. The recovery of these gas costs is accomplished through regulatory body-approved GCR pricing mechanisms whereby customer rates are periodically adjusted for increases and decreases in the cost of gas purchased by the Company for sale to its customers. Under the GCR pricing mechanisms, the gas commodity charge portion of customers' gas rates (which is also referred to as the "GCR rate") in Alaska and the Company's Michigan service area regulated by the MPSC is generally adjusted annually to reflect the estimated cost of gas purchased for the upcoming 12-month GCR period. The GCR rate may be adjusted more frequently than annually if it is determined that there are significant variances from the estimates used in the annual determination. The GCR rate for the Company's Battle Creek service territory can be adjusted monthly.

The price of natural gas has increased substantially since mid-2005 and natural gas purchases for customers in the Company's Michigan gas service areas since then have, and future purchases are expected to, cost significantly more than in the past. The price of natural gas purchased under long-term contracts for the Company's Alaska service area customers has also increased, and future purchases are expected to cost the Company more than in the past, as the indexes used to determine the prices the Company pays for natural gas under these contracts reflect market price increases.

These increases in natural gas prices and corresponding increases in GCR rates may contribute, in varying amounts, depending on the way in which these costs are recovered in customer rates in each jurisdiction in which the Company does business, to: (i) increased costs associated with lost and unaccounted-for gas; (ii) higher customer bad debt expense for uncollectible accounts; (iii) higher working capital requirements; and (iv) reduced sales volumes and related margins due to lower customer consumption.

Volatility in the price of natural gas could result in large industrial customers switching to alternative energy sources and reduced revenues, earnings and cash flow.

The market price of alternative energy sources such as coal, electricity, oil and steam is the primary competitive factor affecting the demand for the Company's gas transportation services. Certain large industrial customers have, or may acquire, the capacity to be able to use one or more alternative energy sources or shift production to facilities outside the Company's service area if the price of natural gas and delivery services increases significantly. Natural gas has typically been less expensive than these alternative energy sources. However, generally over the past three years and recently in a more significant way, natural gas prices have

been higher and more volatile, making some of these alternative energy sources more economical or, for other reasons, more attractive than natural gas. During this period, certain of the Company's large Michigan industrial customers have periodically switched to alternative energy sources.

To lessen the possibility of fuel switching by industrial customers, the Company offers flexible contract terms and additional services, such as gas storage and balancing. Partially offsetting the impact of this price sensitivity among certain large industrial customers has been the use of natural gas to reduce emissions from their plants. The Company cannot predict the future stability of natural gas prices; nor can the Company make any assurances that the impact of environmental legislation or any special services the Company offers will outweigh the negative effects of natural gas price increases and volatility. Should these customers convert their requirements to another form of energy, the Company's revenues, earnings and cash flow would be adversely affected.

The Company's liquidity and earnings could be adversely affected by the MPSC's disallowance of costs after retrospective reviews of the Company's gas procurement practices.

In the Company's gas distribution area regulated by the MPSC, the Company's gas procurement practices are subject to an annual retrospective MPSC review. If costs are disallowed in this review process, such costs would be expensed in the cost of gas but would not be recovered by the Company in rates. The ability of the MPSC to annually retrospectively review the Company's gas procurement practices creates the potential for the disallowance of the Company's recovery, through its GCR rates, of some of its costs of purchasing gas. Such disallowances could affect the Company's liquidity and earnings.

The Company's earnings and cash flow are sensitive to decreases in customer consumption resulting from warmer than normal temperatures and customer conservation.

The Company's gas sales revenue is generated primarily through the sale and delivery of natural gas to residential and commercial customers who use natural gas mainly for space heating. Consequently, weather has a significant impact on sales and revenues. Given the impact of weather on the Company's Gas Distribution Business, this segment is a seasonal business. Most of the Company's gas sales revenue is generated in the first and fourth quarters of the calendar year and the Company typically experiences losses in the non-heating season, which occurs in the second and third fiscal quarters of the year. In addition, conservation has continued to reduce demand for natural gas from the Company's customers.

Warmer than normal weather and conservation over the last several years have adversely affected the earnings and cash flow of the Company's Gas Distribution Business, which has accounted for more than 98% of consolidated operating revenues for the last three fiscal years. In the Michigan service area, the temperature was approximately 0.1% and 0.3% warmer than normal during 2005 and 2004, respectively, and approximately 4.7% colder than normal during 2003. The temperature was approximately 5.7%, 6.0% and 8.0% warmer than normal in the Alaska service area during 2005, 2004 and 2003, respectively. In addition, the average annual natural gas consumption of customers has been decreasing because, among other things, new homes and appliances are typically more energy efficient than older homes and appliances, and customers appear to be continuing a pattern of conserving energy by utilizing energy efficient heating systems, insulation, alternative energy sources, and other energy savings devices and techniques. A mild winter, as well as continued or increased conservation, in any of the Company's service areas can have a significant adverse impact on demand for natural gas and, consequently, earnings and cash flow.

The Company's earnings are substantially dependent on its current customers maintaining a certain level of consumption as well as customer growth.

As discussed above, many of the Company's customers appear to be continuing a pattern of conserving energy by utilizing energy efficient heating systems, insulation, alternative energy sources, and other energy savings devices and techniques. During the past several years, average annual gas consumption has been decreasing. In addition, increases in natural gas prices appear to have increased conservation efforts by customers. The Company expects this conservation trend to continue as an era of higher and more volatile

natural gas prices influences customer consumption. The Company's rates are currently based on certain levels of consumption by its customers. Continued and significant declines in consumption by the Company's current customers, without an adjustment to its rates or rate design, may negatively impact the Company's earnings.

In addition, the Company's earnings growth is substantially dependent on customer growth. The average number of gas sales customers in Michigan and Alaska combined (excluding customers acquired in the acquisition of Peninsular Gas Company ("Peninsular Gas")) has increased by an average of 2.0% annually during the past three years. If the Company is unable to achieve sufficient customer growth within its existing service territories or add additional customers by expanding service territories, the Company's earnings growth may be negatively impacted.

The Company's customers may be able to acquire natural gas without using the Company's distribution system, which would reduce revenues and earnings.

There is potential risk that industrial customers and electric generating plants located in close proximity to interstate natural gas pipelines will bypass the Company's distribution system and connect directly to such pipelines, which would reduce the Company's revenues and earnings. From time to time, customers raise the issue of bypass and the Company attempts to address their concerns. The Company can make no assurances that its customers will not bypass the Company's distribution system or that the Company could successfully retain such customers.

Declining production from the Cook Inlet gas fields may result in potential deliverability problems in ENSTAR's service area.

ENSTAR's gas distribution system, including the APC pipeline system, is not linked to major interstate and intrastate pipelines or natural gas supplies in the United States or Canada. As a result, ENSTAR procures natural gas supplies under long-term RCA-approved contracts from producers in and near the Cook Inlet area. Production from the Cook Inlet area gas fields is declining and new discoveries have been modest. As of January 1, 2004, the Cook Inlet area had approximately 2.1 Tcf of total proven natural gas reserves according to the most recently available information contained in the Alaska Department of Natural Resources Division of Oil and Gas 2004 Annual Report. Based on the Department's reported 2003 net production of 208 Bcf, there was a reserve life at January 1, 2004, of approximately 10 years in the Cook Inlet area, although shortages of daily deliverability have occurred resulting in curtailment of some industrial loads during cold weather periods. There is ongoing exploration for natural gas in the Cook Inlet area by several parties, including producers that have supply contracts with ENSTAR. The United States Geological Survey and Minerals Management Service has estimated that the Cook Inlet area contains another approximately 2.3 Tcf of undiscovered natural gas, but there are no assurances that any of this natural gas will be discovered and, if discovered, can be produced economically and secured by ENSTAR on terms and conditions that would be acceptable to the RCA.

ENSTAR has been active in efforts to extend its supply of Cook Inlet gas and to find other gas sources. In addition, preliminary activity by other energy industry participants is underway to finance, permit and build a natural gas pipeline that would extend from Alaska's North Slope, through Alaska and Canada, to the lower 48 states of the United States. Assuming this pipeline is built, the flow of natural gas through it could not be expected to begin before the middle of the next decade, at the earliest. ENSTAR is engaged in an effort to make customers and public officials aware of the importance of the North Slope natural gas pipeline and the need to make North Slope natural gas available in the Cook Inlet area. The Company can provide no assurances, however, with respect to the building of this pipeline, when it will be put in service, or whether natural gas supplies transported by the pipeline would be available to ENSTAR customers and secured by ENSTAR on terms and conditions that would be acceptable to the RCA.

Changes in the regulatory environment and events in the energy markets that are beyond the Company's control may reduce the Company's earnings and limit its access to capital markets.

The Company's Gas Distribution Business is subject to regulation by various federal, state and local regulators as well as the actions of federal, state and local legislators. As a result of the energy crisis in California during 2000 and 2001, the recent volatility of natural gas prices in North America, the bankruptcy filings by certain energy companies, investigations by governmental authorities into energy trading activities, the collapse in market values of energy companies and the downgrading by rating agencies of a large number of companies in the energy sector, companies in regulated and unregulated energy businesses have generally been under an increased amount of scrutiny by federal, state and local regulators, participants in the capital markets and debt rating agencies. In addition, the Financial Accounting Standards Board, or FASB, or the SEC could enact new accounting standards that could impact the way the Company is required to record revenues, expenses, assets and liabilities. The Company cannot predict or control what effect these types of events, or future actions of regulatory agencies in response to such events, may have on its earnings or access to the capital markets.

The Company may be required to recognize additional impairment charges which would reduce its earnings.

Pursuant to generally accepted accounting principles, the Company is required to perform impairment tests on its goodwill balance annually or at any time when events occur that could impact the value of its business segments.

The 2005 annual goodwill impairment test for the Company's propane business was performed during the third quarter of 2005 and showed that there was no impairment of goodwill. The 2005 annual impairment test for the Company's Gas Distribution Business was performed during the fourth quarter of 2005 and showed that there was no impairment of goodwill. There were no adverse changes in the carrying amount of goodwill for 2005.

During the fourth quarter of 2004, it was determined that all of the goodwill associated with the Company's IT services business (\$0.2 million) was impaired. The \$0.2 million before-tax charge for impairment of goodwill is reflected in the Company's Consolidated Statements of Operations for the year ended December 31, 2004, in operating expenses. During the third quarter of 2003, it was determined that all of the goodwill associated with the Company's construction services business (\$17.6 million) was impaired. The \$17.6 million before-tax charge for impairment of goodwill is reflected in the Company's Consolidated Statements of Operations for the year ended December 31, 2003, as part of the loss from the discontinued construction services business.

The Company's determination of whether an impairment has occurred is based on an estimate of discounted cash flows attributable to reporting units that have goodwill. The Company must make long-term forecasts of future revenues, expenses and capital expenditures related to the reporting unit in order to make the estimate of discounted cash flows. These forecasts require assumptions about future demand, future market conditions, regulatory developments and other factors. Significant and unanticipated changes to these assumptions could require a provision for impairment in a future period that could substantially reduce the Company's earnings in a period of such change, but not have any impact on its cash flow.

The Company's ability to use net operating loss carry-forwards may be impaired.

As of December 31, 2005, the Company had available approximately \$96 million of net operating losses, or NOLs, with which to offset federal income taxes with respect to the Company's future taxable income. In 2004, the Company underwent an "ownership change" for purposes of Section 382 of the Internal Revenue Code of 1986, as amended. In general, an ownership change occurs whenever there is a more than 50% change in the ownership of the stock of a corporation, taking into account all cumulative changes in ownership over the preceding three years. As a result of the ownership change, the Company's ability to use approximately \$86 million of its total NOLs in the future is limited. However, the Company believes that, based on the size

of the limitation and projections of future taxable income, the Company should be able to utilize all of the NOLs before they expire.

The issuance of additional shares in the Company's capital stock could ultimately trigger another ownership change that could further limit the Company's ability to use such NOLs. While the Company's March 2005 issuance of 5% Series B Convertible Cumulative Preferred Stock ("Preferred Stock") and the August 2005 Common Stock offering did not trigger such an ownership change, those offerings when coupled with future capital stock offerings and changes in the ownership of the Company's capital stock (some of which will be beyond the Company's control) will probably lead to a future ownership change. Any such future ownership change could result in the imposition of lower limits on the Company's utilization of the NOLs to offset future taxable income as well as the Company's ability to use certain losses and tax credits. The magnitude of such limitations and their effect on the Company is difficult to assess and will depend in part on the value of the Company at the time of any such ownership change and prevailing interest rates at that time.

The Company's operations and business are subject to environmental laws and regulations that may increase the Company's cost of operations, impact or limit the Company's business plans or expose the Company to environmental liabilities.

The Company's operations and business are subject to environmental laws and regulations that relate to the environment and health and safety, including those that impose liability for the costs of investigation and remediation, and for damage to natural resources from, past spills, waste disposal on- and off-site and other releases of hazardous materials or regulated substances. In particular, under applicable environmental requirements, the Company may be responsible for the investigation and remediation of environmental conditions at currently owned or leased sites, as well as formerly owned, leased, operated or used sites. The Company may be subject to associated liabilities, including liabilities resulting from lawsuits brought by private litigants, related to the operations of the Company's facilities or the land on which such facilities are located, regardless of whether the Company leases or owns the facility, and regardless of whether such environmental conditions were created by the Company or by a prior owner or tenant, or by a third-party or a neighboring facility whose operations may have affected the Company's facility or land.

Given the nature of the past operations conducted by the Company and others at the Company's properties, there can be no assurance that all potential instances of soil or groundwater contamination have been identified, even for those properties where environmental site assessments or other investigations have been conducted. Changes in existing laws or policies or their enforcement, future spills or accidents or the discovery of currently unknown contamination may give rise to environmental liabilities which may be material. Based upon the information presently available to the Company, the Company expects to incur costs associated with investigatory and remedial actions at seven of its Michigan sites that formerly housed manufactured gas plant operations. Because the extent of the soil and groundwater contamination at these sites has not been fully delineated and the scope of the Company's liability (along with other responsible parties, if any) has not been determined, it is difficult for the Company to estimate its liability at this time. However, it is possible that the Company's share of such liability could be material. To the extent not fully recoverable from customers through regulatory proceedings or from insurance, these costs would reduce the Company's earnings and results of operations.

Compliance with the requirements and terms and conditions of the environmental licenses, permits and other approvals that are required for the operation of the Company's business may cause the Company to incur substantial capital costs and operating expenses and may impose restrictions or limitations on the operation of the Company's business, all of which could be substantial. Environmental, health and safety regulations may also require the Company to install new or updated pollution control equipment, modify its operations or perform other corrective actions at its facilities. Existing environmental laws and regulations may be revised to become more stringent or new laws or regulations may be adopted or become applicable to the Company which may result in increased compliance costs or additional operating restrictions and could reduce the Company's earnings and harm the Company's business, particularly if those costs are not fully recoverable from its customers through regulatory proceedings.

Substantial operational risks are involved in operating a natural gas distribution, pipeline and storage system and such operational risks could adversely affect the Company's revenues, earnings, cash flow and financial condition.

There are substantial risks associated with the operation of a natural gas distribution, pipeline and storage system, such as operational hazards and unforeseen interruptions caused by events beyond the Company's control. These include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of pipeline facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, floods, landslides or other similar events beyond the Company's control. These risks could result in injury or loss of life, property damage, business interruption or environmental pollution, which in turn could lead to substantial financial losses to the Company. In accordance with customary industry practice, the Company maintains insurance against some, but not all, of these risks. Liabilities incurred that were not fully covered by insurance could adversely affect the Company's earnings, cash flow and financial condition. Additionally, interruptions to the operation of the Company's gas distribution, pipeline or storage system caused by such an event could reduce revenues generated by the Company and, consequently, earnings and cash flow.

The Company's ability to grow its businesses will be adversely affected if the Company is not successful in making acquisitions or in integrating the acquisitions it makes.

One of the Company's strategies is to grow through acquisitions. There is growing and significant competition for acquisitions in the U.S. natural gas industry, and the Company believes that there are numerous potential acquisition candidates, some of which represent opportunities that would be material to the Company. The Company cannot assure that it will find attractive acquisition candidates in the future, that it will be able to acquire such candidates on economically acceptable terms, that any acquisitions will not be dilutive to earnings or that any additional debt incurred to finance acquisitions will not impair its capitalization. The Company's amended and restated three-year unsecured revolving bank credit facility for \$120 million, which expires on September 15, 2008 (the "Bank Credit Agreement") also limits the consideration the Company may pay in connection with any one acquisition to \$50 million and in connection with all acquisitions occurring after September 15, 2005, to \$150 million. These limitations will not apply to acquisitions occurring after the Company reaches certain investment grade debt ratings.

In addition, the restructuring of the energy markets in the U.S. and internationally, including the privatization of government-owned utilities and the sale of utility-owned assets, is creating opportunities for, and competition from, well-capitalized existing competitors as well as new entrants to the markets, which may affect the Company's ability to achieve this aspect of its business strategy.

To the extent the Company is successful in making acquisitions, such acquisitions can involve a number of risks, including the assumption of material liabilities, the terms and conditions of any state or federal regulatory approvals required for the acquisitions, the diversion of management's attention from the management of daily operations to the integration of operations, difficulties in the assimilation and retention of employees and difficulties in the assimilation of different cultures and practices, as well as in the assimilation of broad and geographically dispersed personnel and operations. The failure to successfully make and integrate acquisitions could have an adverse effect on the Company's ability to grow its business.

Earnings and cash flow may be adversely affected by downturns in the economy.

The Company's operations are affected by the conditions and overall strength of the national, regional and local economies, which impact the amount of residential, industrial and commercial growth and actual gas consumption in the Company's service territories. Many of the Company's commercial and industrial customers use natural gas in the production of their products. During economic downturns, these customers may see a decrease in demand for their products, which in turn may lead to a decrease in the amount of natural gas they require for production. In addition, during periods of slow or little economic growth, energy conservation efforts often increase and the amount of uncollectible customer accounts often increases. These factors may reduce earnings and cash flow.

The Company's debt indentures and Bank Credit Agreement contain restrictive covenants that may reduce the Company's flexibility, and adversely affect its business, earnings, cash flow, liquidity and financial condition.

The terms of the indentures relating to certain of the Company's outstanding debt securities and of the Company's Bank Credit Agreement impose significant restrictions on the Company's ability and, in some cases, the ability of the Company's subsidiaries, to take a number of actions that the Company may otherwise desire to take, including:

- requiring the Company to dedicate a substantial portion of its cash flow from operations to the payment of principal and interest on the Company's indebtedness, thereby reducing the availability of cash flow for working capital, capital expenditures and other business activities;
- requiring the Company to meet certain financial tests, which may affect the Company's flexibility in planning for, or reacting to, changes in the Company's business and the industries in which the Company operates;
- limiting the Company's ability to sell assets, make investments or acquire assets of, or merge or consolidate with, other companies;
- limiting the Company's ability to repurchase or redeem its stock or enter into transactions with its stockholders or affiliates; and
- limiting the Company's ability to grant liens, incur additional indebtedness or contingent obligations or obtain additional financing for working capital, capital expenditures, acquisitions and general corporate and other activities.

These covenants place constraints on the Company's business and may adversely affect its growth, business, earnings, cash flow, liquidity and financial condition. The Company's failure to comply with any of the financial covenants in its Bank Credit Agreement may result in an event of default which, if not cured or waived, could result in the acceleration of the debt under the Company's Bank Credit Agreement or the indentures governing its outstanding debt issuances that contain cross-acceleration or cross-default provisions. In such a case, there can be no assurance that the Company would be able to refinance or otherwise repay such indebtedness, which could result in a material adverse effect on its business, earnings, cash flow, liquidity and financial condition.

Adverse changes in the Company's credit ratings may limit the Company's access to capital, increase the Company's cost of capital, increase the cost of maintaining certain contractual relationships or otherwise have a material adverse effect on the Company's business, earnings, cash flow, liquidity and financial condition.

In March 2003, Moody's Investors Service, Inc. reduced the credit rating on the Company's senior unsecured debt from Baa3 to Ba2. Since June 2003, Standard & Poor's Ratings Group has lowered the Company's corporate credit rating from BBB- to BB-. These downgrades have required the Company to pay higher interest rates for financing, increasing the Company's cost of capital. Any additional downgrades could further increase the Company's capital costs (including the rates for borrowing under the Company's Bank Credit Agreement) and limit its pool of potential investors and funding sources, possibly increasing the costs of operations or requiring the Company to use a higher percentage of its available borrowing capacity for ordinary course purposes.

Further credit downgrades could also negatively affect the terms on which the Company can purchase gas and pipeline capacity. As a result of the Company's non-investment grade credit rating noted above, the interstate pipelines the Company utilizes require prepayment for their services. In addition, certain of the Company's gas suppliers may require the Company to prepay or provide letters of credit for gas purchases over and above the levels of credit they may have extended to the Company. The Company can provide no assurance that suppliers will not impose additional requirements or restrictions on the conduct of the Company's business.

The Company can provide no assurance that any of its current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency. Any downgrade or other adverse action could adversely affect the Company's business, earnings, cash flow, liquidity and financial condition.

The Company's substantial indebtedness may limit its ability to borrow additional funds at all, or on reasonable terms, limit its growth and diminish its ability to respond to changing business and economic conditions and, thereby, may adversely affect its business, earnings, cash flow, liquidity and financial condition.

The Company's business is capital intensive and the Company has significant amounts of debt. At December 31, 2005, the Company had total short and long-term debt of \$520.6 million. The Company's substantial debt may adversely affect its business, earnings, cash flow, liquidity and financial condition. The Company's substantial debt may, among other things:

- limit the Company's ability to borrow additional funds;
- increase the cost of any future debt that the Company incurs;
- reduce cash flow from operations available for working capital, capital expenditures and other general corporate purposes;
- limit the Company's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates;
- place the Company at a competitive disadvantage as compared to the Company's competitors that are less highly leveraged;
- result in a downgrade in the Company's credit ratings; or
- diminish the Company's ability to successfully withstand a downturn in its business or the economy generally.

The Company's ability to meet its debt service obligations and to reduce its total indebtedness will depend upon its future performance, which will be subject to weather, general economic conditions, industry cycles and financial, business and other factors affecting the Company's operations, many of which are beyond the Company's control. No assurance can be provided that the Company's business will generate sufficient cash flow from operations or that future borrowings will be available to the Company in an amount sufficient to enable the Company to pay its indebtedness or to fund its other liquidity needs. The Company may need to refinance all or a portion of its indebtedness on or before maturity. No assurance can be provided that the Company will be able to refinance any of its indebtedness, including its Bank Credit Agreement and its existing debt and debt securities, on commercially reasonable terms or at all.

Despite the Company's substantial indebtedness, the Company may still be able to incur more debt, which could further exacerbate the risks associated with its substantial debt.

Although the Company is presently limited in incurring additional indebtedness, the Company may be able to incur additional debt in the future. Restrictions applicable to the Company on the incurrence of additional debt contained in the indentures and Bank Credit Agreement governing the Company's existing debt are subject to a number of qualifications and exceptions that allow the Company to incur additional debt. An increase in the amount of indebtedness may negatively affect the Company's capital structure and credit ratings. If new debt is added to the Company's current debt levels, the risks that the Company now faces could intensify.

The Company is vulnerable to interest rate risk with respect to its debt which could lead to an increase in interest expense and a corresponding decrease in earnings and cash flow.

The Company's ability to finance capital expenditures and to refinance our maturing debt will depend in part on conditions in the capital markets, including rising interest rates. The Company's cost of borrowing under its Bank Credit Agreement is also dependent on interest rates. In addition, in order to maintain the Company's desired mix of fixed-rate and variable-rate debt, the Company may use interest rate swap agreements and exchange fixed and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. No assurance can be provided that the Company will be successful in structuring such swap agreements to manage its risks effectively. If the Company is unable to do so, its earnings and cash flow may be reduced.

The Company's Shareholder Rights Plan and other defensive mechanisms could make it more difficult for an acquisition bid for the Company or a change of control transaction to succeed.

Certain provisions of the Company's organizational documents, as well as other statutory and regulatory factors, may discourage or prevent acquisition offers that are in the best interests of the Company and its stockholders:

- the Company's Shareholder Rights Plan grants holders of its Common Stock certain rights upon the occurrence of certain triggering events unless a majority of independent directors on the Board of Directors (the "Board") determines that the takeover offer is fair and otherwise in the best interests of the Company and its stockholders;
- the Company's articles of incorporation divide the Board into three classes that serve staggered terms, and directors may be elected by stockholders only at an annual meeting of stockholders or at a special meeting called for that purpose by the Board;
- a director may be removed by stockholders but only for cause and only at an annual meeting of stockholders and by the affirmative vote of a majority of the shares then entitled to vote for the election of directors;
- holders of the Preferred Stock have certain rights, including the right to receive a make-whole premium in connection with exercising their conversion rights in connection with a fundamental change, which would include certain acquisition offers;
- the Bank Credit Agreement and certain of the Company's debt indentures include provisions whereby the acquisition of a certain percentage of the Company's Common Stock would be an event of default and cause the outstanding loans to become due and payable, or would require the Company to make an offer to holders of notes to repurchase outstanding notes at a premium;
- unless the Board approves a business combination or the combination meets certain enumerated fairness standards, Michigan law requires the affirmative vote of 90% of the votes of each class of stock entitled to vote, and not less than two-thirds of the votes of each class of stock entitled to vote, voting as a separate class, to approve a business combination; and
- Michigan law provides that control shares of a public company acquired in a control share acquisition have no voting rights except as granted by resolution approved by the stockholders of the company, effectively conditioning the acquisition of voting control of a corporation on the approval of a majority of pre-existing, disinterested stockholders.

In addition, the acquisition or accumulation of large blocks of the Company's voting securities may require prior approval of the RCA and may result in the acquiring entity becoming subject to the jurisdiction of and regulation of the RCA and, notwithstanding the repeal of the Public Utility Holding Company Act of 1935, to other state or federal regulation as a public utility holding company. These consequences would result in substantial increases in that entity's administrative, legal and regulatory compliance costs and could have similar adverse consequences for the Company.

Item 1B. *Unresolved Staff Comments*

None.

Item 2. *Properties*

Gas Distribution Business Segment

The natural gas transmission and delivery system of SEMCO Gas included approximately 160 miles of gas transmission pipelines and 5,591 miles of gas distribution mains and service lines at December 31, 2005. The pipelines, mains and service lines are located throughout the southern half of Michigan's lower peninsula (centered in and around the cities of Albion, Battle Creek, Holland, Niles, Port Huron and Three Rivers) and also in the central and western areas of Michigan's Upper Peninsula. At December 31, 2005, ENSTAR's natural gas delivery system (including APC's natural gas transmission system) included approximately 393 miles of gas transmission pipelines and 2,650 miles of gas distribution mains and service lines. ENSTAR's pipelines, mains and service lines are located in Anchorage and the Cook Inlet area.

The distribution mains and service lines of the Gas Distribution Business are, for the most part, located on or under public streets, alleys, highways and other public places, or on private property not owned by the Company with permission or consent, except to an inconsequential extent, of the individual property owners. The distribution mains and service lines located on or under public streets, alleys, highways and other public places were installed under valid rights and consents granted by appropriate local authorities.

The Gas Distribution Business owns underground gas storage facilities in eight depleted salt caverns and three depleted gas fields, together with related measuring, compressor and transmission facilities. The storage facilities are all located in Michigan. The aggregate working capacity of the storage system is approximately 5.1 Bcf.

The Gas Distribution Business also owns meters and service lines, gas regulating and metering stations, garages, warehouses and other buildings necessary and useful in conducting its business. In addition, the Gas Distribution Business leases a significant portion of its transportation equipment and certain buildings.

Corporate and Other

The principal properties of this segment include interests and operations in IT services, propane distribution, natural gas transmission pipelines, an underground gas storage system and general corporate facilities supporting these operations.

The properties of the Company's IT services business consist of a building, office equipment, telecommunications equipment and computer equipment. The building is located in Marysville, Michigan, and houses this equipment.

The property of the propane distribution operation consists primarily of pressurized propane storage tanks used by customers to store propane purchased from the Company and trucks for transporting propane. The Company also owns large propane storage tanks that allow the Company to store up to 258,000 gallons of propane inventory. The propane distribution property is located in Michigan's Upper Peninsula and northeast Wisconsin.

The Company owns a 50% equity interest in the ERGSS. The Company's equity investment in the ERGSS totaled approximately \$6.9 million at December 31, 2005. This natural gas storage system, located near Eaton Rapids, Michigan, became operational in March 1990 and consists of approximately 12.8 Bcf of underground storage capacity. The Gas Distribution Business leases 6.5 Bcf of the capacity.

The following table sets forth the natural gas pipeline operations wholly or partially owned by the Company, the total net property of each system, and the Company's ownership percentage and net property in each system at December 31, 2005:

	<u>Total Net Property</u>	<u>The Company's Percent Ownership</u> (In thousands, except percents)	<u>The Company's Net Property</u>
Litchfield Lateral	\$ 7,230	33%	\$ 2,410
Greenwood Pipeline	4,553	100%	4,553
Eaton Rapids Pipeline	382	100%	382
	<u>\$ 12,165</u>		<u>\$ 7,345</u>

The Litchfield Lateral is a 31-mile pipeline located in southwest Michigan. The line, which is leased entirely to ANR Pipeline Company, links the ERGSS with interstate pipeline supplies. The Greenwood Pipeline, is an 17-mile pipeline that connects an interstate pipeline with the DTE Energy Greenwood Power Plant located near Port Huron, Michigan. The pipeline provides transportation services to the Greenwood Power Plant and also supplies the Gas Distribution Business' service area north of Port Huron, Michigan. The Eaton Rapids Pipeline is a 37-mile pipeline that delivers gas from the ERGSS to the Gas Distribution Business' systems in Battle Creek and Albion, Michigan.

The Company's corporate division is a cost center rather than a business segment. The properties of the corporate division primarily include leasehold improvements, office furniture, office equipment, computers and computer systems. These properties are located in a leased office building in Port Huron, Michigan (which houses the Company's headquarters), and leased satellite office space in Troy, Michigan.

Item 3. Legal Proceedings

In the normal course of business, the Company may be a party to lawsuits and administrative proceedings before various courts and government agencies. The Company also may be involved in private dispute resolution proceedings. These lawsuits and proceedings may involve personal injury, property damage, contractual issues and other matters (including alleged violations of federal, state and local laws, rules, regulations and orders). Management cannot predict the outcome or timing of any pending or threatened litigation or of actual or possible claims. Except as otherwise stated, management believes resulting liabilities, if any, will not have a material adverse impact upon the Company's financial position, results of operations, or cash flows.

In October 2004, two Company subsidiaries (SEMCO Energy Services, Inc. and SEMCO Pipeline Company) were added as defendants in a putative class action lawsuit brought in federal district court in West Virginia alleging that the approximately 30 defendants named in the lawsuit engaged in gas marketing activities that violated state and federal anti-trust laws and otherwise tortiously interfered with the business opportunities of the plaintiffs from 1996 to present. On October 4, 2005, the court granted a motion to dismiss filed by certain defendants, including the Company's subsidiaries, as to federal anti-trust claims arising prior to October 25, 2000. On January 30, 2006, the court declined a request that it amend its dismissal order to include any state anti-trust claims arising during the same period. The Company plans to file additional motions raising defenses with respect to all remaining claims. The Company sold its gas marketing business in 1999.

In connection with the issuance of its 6% Series B Convertible Preference Stock ("Convertible Preference Stock" or "CPS") and Common Stock warrants ("Warrants") to K-1 GHM, LLLP, an affiliate of a private equity firm, k-1 Ventures Limited ("K-1"), during 2004, the Company agreed to seek certain rulings from the RCA. As part of RCA proceedings instituted with respect to the rulings sought by the Company, the Alaska Attorney General asserted, among other things, that (i) the Company's issuance of the CPS and Warrants to K-1 resulted in a control change requiring prior approval by the RCA, (ii) such a control change did not adversely affect ENSTAR and therefore should be approved by the RCA, and (iii), in connection with approving this control change, the RCA should institute a rate proceeding to review the base rates of

ENSTAR, using a 2005 test year and a new depreciation study for ENSTAR's property. The Company believed that no control change occurred upon the issuance of the CPS and Warrants to K-1 and thus no RCA approval was required. The Company also opposed the proposal that the RCA institute a rate proceeding to review ENSTAR's base rates and, in connection with that review, order that a depreciation study of ENSTAR's property be done.

After repurchasing the CPS and Warrants from K-1 on March 15, 2005, the Company filed a motion to terminate proceedings with the RCA on the basis that the repurchase made such proceedings moot. The Company also continued to oppose the proposal that the RCA institute a rate proceeding to review ENSTAR's base rates and conduct a depreciation study. On June 20, 2005, the RCA terminated the proceeding. It also required ENSTAR to file a revenue requirement and cost of service study (including rate design data) with the RCA by June 6, 2008 (using a test year ended December 31, 2007). In addition, ENSTAR is required to file a depreciation study of utility plant (as of December 31, 2006) by June 1, 2007. These filings also will include the Company's APC subsidiary.

In September 2002, the Company agreed to relocate its headquarters to Port Huron, Michigan, and leased part of a new office building in Port Huron from Acheson Ventures LLC ("Acheson"). As part of the transaction, Acheson agreed to sublease office space occupied by the Company in Farmington Hills, Michigan, and, beginning in February 2005, began to pay the Company's Farmington Hills lease costs (approximately \$36,000 per month until March 31, 2011, when the Farmington Hills lease expires), as agreed. In June 2005, Acheson ceased making these payments, ostensibly because the Company had breached its obligations by maintaining a satellite office in Troy, Michigan, for certain executives who also have offices in the Company's Port Huron headquarters. The Company has filed an action in Michigan state court, seeking (i) damages for Acheson's failure to pay the Company's Farmington Hills lease costs, and (ii) a declaratory judgment that the Company has met its obligations to Acheson. To mitigate its damages, the Company is paying the Farmington Hills lease costs and is attempting to market the space to prospective subtenants. On January 16, 2006, Acheson answered the Company's complaint, filed counter-claims alleging breach of contract, fraud, and negligent misrepresentation, and sought a change of venue for these proceedings, to Port Huron, Michigan. The Company has made filings to answer Acheson's counter claims, denying any liability to Acheson, and opposing a change of venue.

Item 4. *Submission of Matters to a Vote of Security Holders*

No matter was submitted to a vote of security holders during the fourth quarter of 2005.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

The Company's Common Stock began trading on the NYSE on January 6, 2000, with the trading symbol "SEN." The table below shows the reported high and low sales prices of the Company's Common Stock during 2005 and 2004, as reported on the NYSE.

<u>Quarter</u>	<u>2005 Price Range</u>	
	<u>High</u>	<u>Low</u>
First Quarter	\$ 6.24	\$ 5.10
Second Quarter	\$ 6.19	\$ 5.00
Third Quarter	\$ 7.05	\$ 5.82
Fourth Quarter	\$ 6.85	\$ 5.16

Quarter	2004 Price Range	
	High	Low
First Quarter	\$ 6.38	\$ 4.80
Second Quarter	\$ 6.35	\$ 5.00
Third Quarter	\$ 5.88	\$ 4.86
Fourth Quarter	\$ 5.74	\$ 4.50

At February 28, 2006, the closing price of the Company's Common Stock was \$5.60 per share and the Company had 33,726,152 shares of Common Stock outstanding and had 7,909 registered holders of its Common Stock.

For information regarding dividends, see Item 6 of this Form 10-K and Notes 4 and 15 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K.

For information relating to compensation plans under which equity securities of the Company are authorized for issuance, see Item 12 of this Form 10-K.

During the fourth quarter of 2005, the Company issued an aggregate of 474 shares of unregistered Common Stock, valued at approximately \$3,081, to members of the Board pursuant to an equity compensation plan described in the Company's definitive Proxy Statement (filed pursuant to Regulation 14A), incorporated by reference in Item 12 of this Form 10-K. The transactions were exempt from registration under Section 4(2) of the Securities Act of 1933, as amended.

Item 6. Selected Financial Data

The following tables set forth selected financial and operating data. The selected financial data presented below as of December 31, 2001, and for the year then ended, have been derived from the Company's consolidated financial statements that were audited by Arthur Andersen LLP. The selected financial data presented below as of December 31, 2002, 2003, 2004 and 2005, and for each of the four years then ended, have been derived from the Company's consolidated financial statements that were audited by PricewaterhouseCoopers LLP. The selected financial data presented below should be read in conjunction with the Company's consolidated financial statements and the Notes to the Company's Consolidated Financial Statements in Item 8 of this Form 10-K and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this Form 10-K.

	Years Ended December 31,				
	2005	2004	2003	2002	2001
	(In thousands, except per share amounts)				
Statement of operations data					
Operating revenues	\$ 615,102	\$ 508,336	\$ 472,955	\$ 374,162	\$ 328,663
Operating expenses					
Cost of gas sold	\$ 443,860	\$ 346,241	\$ 308,919	\$ 220,422	\$ 184,973
Operations and maintenance(a)	71,913	75,883	65,152	54,373	55,493
Depreciation and amortization	28,224	27,578	27,448	27,127	28,887
Property and other taxes	11,601	13,149	10,739	10,816	10,554
	<u>\$ 555,598</u>	<u>\$ 462,851</u>	<u>\$ 412,258</u>	<u>\$ 312,738</u>	<u>\$ 279,907</u>
Operating Income	\$ 59,504	\$ 45,485	\$ 60,697	\$ 61,424	\$ 48,756
Other income (deductions)(b)	<u>(41,746)</u>	<u>(41,796)</u>	<u>(61,561)</u>	<u>(27,647)</u>	<u>(27,418)</u>
Income (loss) before income taxes and minority interest	\$ 17,758	\$ 3,689	\$ (864)	\$ 33,777	\$ 21,338
Income tax (expense) benefit	(6,021)	467	80	(13,005)	(7,100)
Minority interest, net of income tax benefit	—	—	(4,300)	(8,601)	(8,603)
Income (loss) from continuing operations	\$ 11,737	\$ 4,156	\$ (5,084)	\$ 12,171	\$ 5,635
Discontinued operations, net of income tax	<u>538</u>	<u>(9,339)</u>	<u>(24,871)</u>	<u>(3,222)</u>	<u>(11,996)</u>
Net income (loss)	\$ 12,275	\$ (5,183)	\$ (29,955)	\$ 8,949	\$ (6,361)
Dividends on convertible cumulative preferred stock	2,994	—	—	—	—
Dividends and repurchase premium on convertible preference stock	<u>9,112</u>	<u>3,203</u>	<u>—</u>	<u>—</u>	<u>—</u>
Net income (loss) available to common shareholders	\$ 169	\$ (8,386)	\$ (29,955)	\$ 8,949	\$ (6,361)

- (a) 2004 includes \$8,398 of expenses related to the terminated sale of a subsidiary and a \$152 goodwill impairment charge and 2001 includes \$3,005 for restructuring and asset impairment charges.
- (b) 2005 includes debt extinguishment expenses of \$1,456 and 2003 includes debt exchange and extinguishment expenses of \$24,030.

	Years Ended December 31,				
	2005	2004	2003	2002	2001
	(In thousands, except per share amounts)				
Common stock and per share data					
Average shares outstanding (in thousands)					
Basic	30,408	28,263	22,297	18,472	18,106
Diluted	30,408	28,296	22,297	18,493	18,106
Earnings per share on income (loss) from continuing operations					
Basic	\$ (0.01)	\$ 0.03	\$ (0.23)	\$ 0.66	\$ 0.31
Diluted	\$ (0.01)	\$ 0.03	\$ (0.23)	\$ 0.66	\$ 0.31
Earnings per share on net income (loss) available to common shareholders					
Basic	\$ 0.01	\$ (0.30)	\$ (1.34)	\$ 0.48	\$ (0.35)
Diluted	\$ 0.01	\$ (0.30)	\$ (1.34)	\$ 0.48	\$ (0.35)
Dividends declared per share	\$ —	\$ 0.08	\$ 0.35	\$ 0.50	\$ 0.84
Statement of financial position data at December 31					
Total assets	\$ 1,016,555	\$ 926,198	\$ 951,219	\$ 927,703	\$ 905,094
Capitalization					
Long-term debt, including current maturities(a)	\$ 441,659	\$ 498,427	\$ 529,007	\$ 505,462	\$ 508,360
Convertible cumulative preferred stock	66,526	—	—	—	—
Series B convertible preference stock	—	48,405	—	—	—
Common shareholders' equity	194,000	166,086	174,418	110,022	113,810
Total Capitalization	<u>\$ 702,185</u>	<u>\$ 712,918</u>	<u>\$ 703,425</u>	<u>\$ 615,484</u>	<u>\$ 622,170</u>

(a) Includes Company-obligated mandatorily redeemable trust preferred securities for 2002 and 2001.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

Business Strategy Summary

The Company is primarily a regulated natural gas distribution company with operations in Michigan and Alaska. The Company provides natural gas service to approximately 409,000 customers, with approximately 286,000 customers in Michigan and 123,000 customers in Alaska. Approximately 90% of the Company's market consists of residential customers. The Company's Gas Distribution Business sells a significant portion of gas to customers for heating purposes and, therefore, is a seasonal business. As a result, earnings are significantly influenced by the weather and concentrated in the first and fourth fiscal quarters of the year. The Company typically experiences net losses during the non-heating season, which takes place in the second and third fiscal quarters of the year. The Company's business is regulated by the MPSC, CCBC, and RCA.

The Company's current strategic focus remains two-fold. First, the Company continues to seek to improve its financial performance by enhancing financial flexibility through cost control and improving credit quality. In 2006, this effort is expected to include containing its controllable costs (including capital expenditures and operation and maintenance expenses). The Company is also considering (i) seeking MPSC and RCA approval of possible changes in the methods by which the Company charges customers for natural gas service (which is known in the industry as "rate design"), and (ii) depending on analyses of the Company's revenue needs, seeking approval of increases in the rates the Company's charges customers for natural gas service in jurisdictions where doing so is warranted and otherwise considered achievable. An analysis of possible rate design proposals is currently under way, including an assessment of the relative merits

of various alternative ways of collecting revenues from customers. A primary focus of this effort is to attempt to devise acceptable revenue collection methods that address the impact of higher and more volatile gas prices on the Company. Analyses of the Company's need for additional revenue, by jurisdiction, will be performed using 2005 year-end data, again with a view towards assessing that need (if any) and other aspects of any base rate increase proposals, including the expected receptivity of regulatory agencies where such requests would be filed, to such proposals and the relationships (if any) between possible rate increase proposals and the Company's rate design proposals, when finalized. Part of the analysis of the Company's need for additional revenue is expected to involve an assessment of ratemaking conventions that affect the calculation of revenues the Company is authorized to collect and the need for, and acceptability of, changes in such conventions.

Upon completion of the analyses of the Company's need for additional revenue, with respect to the Company's MPSC-regulated service area, it is anticipated that the Company will have a revenue deficiency in connection with its allowed rate of return, using a 2005 test year. Also, under current rate designs in Michigan, the Company believes it is disadvantaged in achieving its authorized return, given the current higher and more volatile natural gas price environment. Of particular concern are declining consumption per customer, higher bad debt expense, increased lost and unaccounted for ("LAUF") gas expense, higher working capital requirements, and conventions used to estimate the impact of weather on the Company's revenues. Depending on the results of the analyses of the Company's need for additional revenues and rate design alternatives, the Company would expect to file for base rate changes and/or rate design changes for its MPSC-regulated service area during the second quarter of 2006.

The second aspect of the Company's strategic focus is growing its Gas Distribution Business (including related pipeline and storage operations) by seeking to make appropriate acquisitions and investments in Michigan, Alaska, and elsewhere. The Company's ability to make such acquisitions and investments will be affected by efforts to improve the Company's financial condition described above and elsewhere in this Form 10-K as well as by the availability of appropriate acquisition and investment opportunities and the ability to consummate any such transactions on reasonable terms.

It is the Company's intent that any such acquisitions and investments, which typically would be subject to federal and state regulatory approvals, would be accretive to earnings. It is unlikely, however, that such acquisitions and investments, if made, would significantly change the profile of the Company's business, since any natural gas distribution, pipeline or storage operations the Company would acquire would likely share the characteristic of having earnings that are significantly influenced by the weather. Such acquisitions and investments also would likely involve companies that are subject to regulation with respect to services, rates, and other terms and conditions of service by federal, state, and local regulatory bodies.

Summary of Results of Operations

The discussions in this section are summarized and intended to provide an overview of the results of Company operations. In most instances, the items discussed here are covered in greater detail in later sections of Management's Discussion and Analysis. Any variances in results in this section are quantified on an after-tax basis. The Company uses an effective income tax rate of 36.8% to estimate these after-tax amounts. All references to earnings or losses per share ("EPS") in Management's Discussion and Analysis are on a fully diluted basis. For information related to the calculation of diluted EPS, refer to Note 10 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K. The following table summarizes the Company's operating results for the past three years:

	Years Ended December 31,		
	2005	2004	2003
	(In thousands, except per share amounts)		
Operating revenues	\$ 615,102	\$ 508,336	\$ 472,955
Operating expenses	<u>555,598</u>	<u>462,851</u>	<u>412,258</u>
Operating income	\$ 59,504	\$ 45,485	\$ 60,697
Other income (deductions)	(41,746)	(41,796)	(61,561)
Income tax (expense) benefit	(6,021)	467	80
Minority interest — dividends on trust preferred securities, net of income tax benefit	<u>—</u>	<u>—</u>	<u>(4,300)</u>
Income (loss) from continuing operations	\$ 11,737	\$ 4,156	\$ (5,084)
Income (loss) from discontinued operations, net of income tax	<u>538</u>	<u>(9,339)</u>	<u>(24,871)</u>
Net income (loss)	\$ 12,275	\$ (5,183)	\$ (29,955)
Dividends on convertible cumulative preferred stock	2,994	—	—
Dividends and repurchase premium on convertible preference stock	<u>9,112</u>	<u>3,203</u>	<u>—</u>
Net income (loss) available to common shareholders	\$ 169	\$ (8,386)	\$ (29,955)
Earnings per share — basic			
Income (loss) from continuing operations	\$ (0.01)	\$ 0.03	\$ (0.23)
Net income (loss) available to common shareholders	\$ 0.01	\$ (0.30)	\$ (1.34)
Earnings per share — diluted			
Income (loss) from continuing operations	\$ (0.01)	\$ 0.03	\$ (0.23)
Net income (loss) available to common shareholders	\$ 0.01	\$ (0.30)	\$ (1.34)
Average common shares outstanding — basic	30,408	28,263	22,297
Average common shares outstanding — diluted	30,408	28,296	22,297

Comparison of 2005 and 2004 results. The Company's \$0.2 million of net income available to common shareholders for 2005 is an \$8.6 million improvement over 2004 results. There were a number of offsetting factors that impacted net income available to common shareholders. The primary factors that improved 2005 results, when compared to 2004, were: an increase in gas sales margin and other gas distribution revenue; the absence from 2005 results of expenses associated with the terminated sale of the Company's APC subsidiary; changes in results from discontinued operations (\$0.5 million of income in 2005 compared to \$9.3 million of losses in 2004); and a decrease in property and other taxes. The increase in gas sales margin and other gas distribution revenue increased net income by approximately \$6.6 million and was attributed in large part to rate increases in Michigan and the addition of new customers, partially offset by a decrease in gas consumption by customers. The expenses included in 2004 results for the Company's APC subsidiary include costs associated with an arbitration proceeding over the termination of the Company's sale of the APC subsidiary and a payment by the Company to settle the matter. These APC-related expenses increased the 2004 net loss by approximately \$5.3 million. The decrease in property and other tax expense increased 2005 net income by approximately \$1.0 million.

The primary factors that negatively impacted earnings for 2005, when compared to 2004, were: a premium associated with the repurchase of the CPS; a non-cash debt extinguishment charge; increases in operations and maintenance expenses; increased depreciation expense; and the absence from 2005 results of state income tax benefits recorded in 2004. The premium associated with the repurchase of the CPS decreased net income by approximately \$8.2 million. The non-cash debt extinguishment charge, which represents the write-off of unamortized debt issuance costs associated with long-term debt retired in 2005, decreased net income by approximately \$0.9 million. The increase in operations and maintenance expenses, which decreased net income by approximately \$2.9 million, was due primarily to increases in employee benefit and incentive costs, compensation, facilities costs, uncollectible customer accounts and various other operating expenses, due to the increasing cost of doing business. The increase in depreciation expense reduced net income by approximately \$0.4 million. The state income tax benefits recorded in 2004 amounted to approximately \$2.2 million and related to a change in estimate of the Company's prior years state income taxes. Combined financing costs for 2005, which include interest expense and dividends on both the CPS and newly-issued Preferred Stock, were essentially unchanged from 2004.

Comparison of 2004 and 2003 results. The \$8.4 million net loss available to common shareholders for 2004 is a \$21.6 million improvement over 2003 results. There were a number of offsetting factors that impacted the net loss available to common shareholders. The primary factors that improved earnings for 2004, when compared to 2003, were: a \$15.5 million decrease in losses from the Company's discontinued construction services business; the non-recurrence in 2004 of \$15.2 million of debt exchange and extinguishment costs recorded in 2003; and a change in estimate of the Company's prior years state income taxes, which resulted in an additional income tax benefit of approximately \$2.2 million in 2004.

The primary factors that negatively impacted earnings for 2004, when compared to 2003, were: a decrease in gas sales margin; the previously discussed APC-related expenses incurred in 2004; and increases in operations and maintenance expenses and financing costs. The decrease in gas sales margin, which increased the net loss for 2004 by approximately \$1.2 million, was largely caused by a decrease in gas consumption by customers and an increase in LAUF gas expense partially offset by gas sales margins from new customers. The increase in operations and maintenance expenses increased the 2004 net loss by approximately \$1.4 million and the increase in financing costs increased the net loss by approximately \$1.8 million.

The business segment analysis and other discussions on the next several pages provide additional information regarding the differences in operating results when comparing 2005, 2004 and 2003.

The Impact of Higher Natural Gas Prices

The market price of natural gas increased substantially during the second half of 2005. The Company believes that such price increases were caused, in large part, by the impact of Hurricanes Katrina and Rita on drilling, production, pipelines and processing facilities in and around the Gulf of Mexico, along with the supporting infrastructure and resources for those facilities. The Company also believes that higher natural gas prices may persist or remain volatile even after hurricane-related damage to production and other facilities is repaired, due to an apparent imbalance between natural gas supplies and demand resulting from, among other factors, the use of substantial amounts of natural gas to generate electricity and environmental and other restrictions on natural gas exploration and production.

For customers in its Michigan service areas, the Company purchases natural gas supplies throughout the year, in order to (i) meet current customer needs, (ii) inject gas into storage for use by customers during the winter heating season, and (iii) have sufficient supplies under contract for the winter heating season. Recent natural gas purchases for customers in the Company's Michigan gas service areas have, and future purchases are expected to, cost significantly more than purchases during prior years due to the increase in natural gas prices. Since mid-December 2005, natural gas prices have receded from their peak levels established earlier in December 2005. The recent decline in prices may be attributable, among other factors, to reduced customer gas consumption in reaction to high prices, relatively warm weather in January 2006 throughout the midwestern and eastern portions of the United States and relatively high levels of working gas in storage in comparison to average levels over the last five years. Despite the recent pullback in natural gas prices, future

prices still remain relatively high for the upcoming 2006–2007 winter heating season. Additionally, since the majority of the Company’s Michigan gas procurement for the 2005–2006 winter heating season occurred throughout 2005, the recent reduction in natural gas prices is not expected to impact the gas commodity portion of customer rates substantially until after the 2005–2006 winter heating season has passed. Approximately 45% to 48% of annual Michigan sales volumes typically occur in the first quarter of each year, so nearly half of the Company’s 2006 gas sales in Michigan will have occurred before there would be any significant decrease in the gas commodity portion of customer rates.

For customers in Alaska, the Company’s facilities are located near natural gas supplies, and the Company has RCA–approved gas purchase contracts with various Cook Inlet area producers. The price of gas purchased under these contracts is adjusted annually in January. Much of the natural gas purchased by the Company for its Alaska customers is priced on trailing average prices for oil and natural gas, so recent price increases are not yet fully reflected in the price the Company is currently paying for gas sold to customers in its Alaska service area. However, gas prices under these contracts have increased over the past few years and, based on these trailing average prices, are expected to increase in the future.

In general, the costs of natural gas purchased for customers are recovered on a dollar–for–dollar basis (in the absence of regulatory disallowances), without a profit. The recovery of these gas costs is accomplished through the Company’s GCR pricing mechanisms, through which customer rates are periodically adjusted for increases and decreases in the cost of gas purchased by the Company for sale to customers. Refer to the caption “Cost of Gas, Gas Charges Recoverable from Customers, and Amounts Payable to Customers” in Note 1 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10–K for additional information on the GCR pricing mechanisms.

When gas costs increase substantially (such as has been the case recently), the Company may require regulatory approval in certain of its regulatory jurisdictions to increase the commodity, or GCR, component of rates, to ensure the timely recovery of the cost of gas purchased for sale to customers. In addition, higher gas costs may increase delinquent or uncollectible accounts, increase the value of LAUF gas and decrease customer consumption. These and other factors could result in an increase in working capital requirements and the need for the Company to borrow additional amounts under its Bank Credit Agreement.

The Company has been addressing, and continues to address, the likely impact of higher natural gas prices by (i) seeking GCR rate increases in Michigan to recover the cost of gas on a timely basis, (ii) closely monitoring customer payment patterns in Michigan and Alaska, encouraging the use of budget–type leveled payment plans and referring customers to sources of charitable and public assistance, (iii) attempting to secure MPSC approval to recover the commodity costs associated with LAUF gas and uncollectibles in the GCR component of rates or in another way that would reflect actual costs incurred by the Company, and (iv) monitoring the impact of higher gas costs on customer consumption and the Company’s working capital. In addition, the Company is assessing the need for changes in rate design, changes in ratemaking conventions, and increases in revenues to be collected from customers, with a view towards addressing, among other things, the impact of higher and more volatile natural gas prices.

The MPSC–approved GCR rate affects approximately 249,000 customers in the Company’s service territory regulated by the MPSC. In October 2005, the MPSC approved a settlement under which the Company increased its GCR rate to recover the increases in the cost of natural gas purchased by the Company for sale to customers. The GCR rate for the approximately 37,000 customers in the service territory regulated by the CCBC is revised monthly, to track and recover changes in the cost of natural gas purchased by the Company for use by Battle Creek area customers. The GCR rate for the approximately 120,000 customers in Alaska is established annually in January by the RCA to reflect the pricing mechanisms in certain long–term gas supply contracts approved by the RCA and, recovers the cost of natural gas purchased by the Company under those contracts.

Higher gas costs, to the extent they are reflected in revised rates, may affect the ability of some customers to pay their bills for gas service on time or in full. The Company plans to monitor customer payment patterns closely and has been and is encouraging customers to elect budget–type leveled payment plans, to spread winter heating season bills over a twelve–month period. In addition to cutting off service to delinquent

customers, as necessary and permitted, the Company will refer customers to sources of charitable and public assistance. The Company participates in efforts to secure charitable donations that will provide such assistance.

The Company's uncollectibles expense for gas sales customers as a percent of gas sales revenue was 0.50% in 2003, 0.43% in 2004 and 0.42% for 2005. Assuming that future uncollectibles expense as a percent of gas sales revenue is similar to the experience in 2005, for each 10% increase in gas sales revenue (principally driven by the change in natural gas prices), there would be an expected increase in uncollectibles of approximately \$0.2 million. The Company cannot provide any assurance that its future uncollectibles expense will be consistent with its prior experience, in view of the increased cost of natural gas and related rate increases and other factors affecting customer payment patterns.

The Company also expects that higher gas costs will increase the expense associated with LAUF gas in its Michigan service areas, assuming that LAUF volumes are consistent with LAUF volumes in prior periods. Annual LAUF volumes in Michigan have ranged from 0.5% to 1.4% of volumes sold and transported in the Company's Michigan service area over the last 10 years. The Company's Michigan gas distribution operation typically accounts for 48% to 57% of total volumes sold and transported by the Company.

The Company also believes that higher gas costs, to the extent they are reflected in rates, have affected, and may continue to affect, gas consumption by customers, who are induced by higher prices to conserve. The Company is unable to estimate the amount of conservation (if any) that is likely to occur. However, the Company estimates that every one percent decrease in customer consumption in Michigan may cause a decrease in gas sales margin of \$0.2 million to \$0.3 million for the first quarter of 2006. The Company estimates that every one percent decrease in customer consumption in Alaska may cause a decrease in gas sales margin of \$0.1 million to \$0.2 million for the first quarter of 2006.

The Company expects that higher gas costs will increase its need for working capital to finance gas purchases at higher market prices, finance storage inventory, carry accounts receivables, and carry any under-recovery of gas costs not recouped in current rates. The Company uses its Bank Credit Agreement to fund its working capital requirements, which normally peak around year-end or in early-January due to the seasonal nature of the Company's business. The Company expects that its Bank Credit Agreement will provide sufficient borrowing capacity to fund working capital requirements through the 2005-06 winter heating season.

The Impact of Weather and Energy Conservation

Temperature fluctuations and energy conservation have a significant impact on operating results of the Company. Accordingly, the Company believes that information about normal temperatures and consumption is useful for understanding its business and operating results. Consumption of natural gas for heating is largely determined by weather, and a portion of the Company's revenues are collected through consumption-based charges. The Company's budgets, forecasts and business plans are prepared using expected gas consumption under normal weather conditions and historical consumption patterns. The regulatory bodies that have jurisdiction over the rates charged by the Gas Distribution Business use weather-normalized consumption data to set customer rates and to establish authorized rates of return.

Many of the Company's customers appear to be continuing a pattern of conserving energy by utilizing energy efficient heating systems, insulation, alternative energy sources, and other energy saving devices and techniques. During the past several years, average annual gas consumption has been decreasing. In addition, increases in natural gas prices appear to have increased conservation efforts by customers. The Company expects this conservation trend to continue as an era of higher and more volatile natural gas prices influences customer consumption.

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The following table provides temperature and customer consumption data for the years 2003 through 2005:

	Years Ended December 31,		
	2005	2004	2003
Michigan			
Degree days (DD)(a)			
Actual	6,689	6,726	7,063
Normal(b)	6,694	6,747	6,746
Actual DD as a percent of normal DD	99.9%	99.7%	104.7%
Percent by which actual DD differ from:			
Normal DD(c)	(0.1)%	(0.3)%	4.7%
Prior year actual DD(d)	(0.6)%	(4.8)%	5.9%
Average annual gas consumption per customer (Mcf)			
Residential gas sales customers	103.7	107.8	116.7
Residential gas sales customers normalized(e)	103.8	108.1	111.5
Percent by which residential gas sales customers normalized differs from prior year residential gas sales customers normalized(f)	(4.0)%	(3.0)%	(0.7)%
All gas sales customers	146.1	152.7	163.2
All gas sales customers normalized(e)	146.2	153.2	155.9
Percent by which all gas sales customers normalized differs from prior year all gas sales customers normalized(f)	(4.5)%	(1.7)%	(3.8)%
Alaska			
Degree days (DD)(a)			
Actual	9,572	9,573	9,384
Normal(b)	10,151	10,187	10,204
Actual DD as a percent of normal DD	94.3%	94.0%	92.0%
Percent by which actual DD differ from:			
Normal DD(c)	(5.7)%	(6.0)%	(8.0)%
Prior year actual DD(d)	(0.0)%	2.0%	(0.1)%
Average annual gas consumption per customer (Mcf)			
Residential gas sales customers	165.2	173.4	166.7
Residential gas sales customers normalized(e)	175.2	184.5	181.3
Percent by which residential gas sales customers normalized differs from prior year residential gas sales customers normalized(f)	(5.1)%	1.8%	0.9%
All gas sales customers	197.3	208.1	203.8
All gas sales customers normalized(e)	209.2	221.4	221.6
Percent by which all gas sales customers normalized differs from prior year all gas sales customers normalized(f)	(5.5)%	(0.1)%	(0.0)%

- (a) Degree days are a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular year are determined by adding the degree days incurred during each day of the year.
- (b) Normal degree days for a particular year is the average of degree days during the prior fifteen years. Beginning in 2006, the Company plans to determine normal degree days for its Alaska operations using a ten-year average of degree days rather than a fifteen-year average.
- (c) The percent by which actual degree days differ from normal degree days is often referred to as the percent by which temperatures were colder (warmer) than normal.
- (d) The percent by which actual degree days differ from prior year actual degree days is often referred to as the percent by which temperatures were colder (warmer) than the prior year.
- (e) Normalized average annual gas consumption is determined by dividing the actual average annual gas consumption by actual degree days as a percent of normal degree days. The normalized average annual gas consumption represents an estimate of what average annual gas consumption would have been if during the period in question, actual degree days had equaled normal degree days.
- (f) The percent by which normalized average annual gas consumption differs from prior year normalized average annual gas consumption represents an estimate of the percentage change in gas consumption from one year to the next caused by factors other than temperature variations. This change can relate to various factors but is most likely due to changes in energy conservation by customers.

The Company has estimated that in its Michigan service area, temperatures were approximately 0.1% and 0.3% warmer than normal during 2005 and 2004, respectively, and approximately 4.7% colder than normal during 2003. In the Company's Alaska service area, temperatures were estimated to be approximately 5.7%, 6.0% and 8.0% warmer than normal during 2005, 2004 and 2003, respectively.

Normalized average annual gas consumption for all gas sales customers in the Company's Michigan and Alaska service areas decreased in 2005 by a larger percentage than in previous years. The Company has estimated that in its Michigan service area, normalized average annual gas consumption during 2005 for all gas sales customers decreased by approximately 4.5%, when compared to 2004. In the Company's Alaska service area, normalized average annual gas consumption during 2005 for all gas sales customers decreased by an estimated 5.5%, when compared to 2004.

The Company estimates that the combined variations from normal temperatures and normalized gas consumption decreased net income by approximately \$3.3 million in 2005 and approximately \$2.0 million during 2004. These estimates reflect the adoption of new methodologies that are designed to more accurately estimate the impact of combined variations from normal temperatures and normalized gas consumption. The Company estimates the impact on its operating results of combined variations from normal temperatures and normalized gas consumption by comparing average annual gas consumption per customer during a year to the normalized average annual gas consumption per customer for the prior year. The difference is multiplied by the average number of customers during the year to arrive at the total estimated increase or decrease in consumption associated with the combined variations from normal temperatures and normalized gas consumption. The total increase or decrease in consumption is multiplied by the actual gas sales margin per unit of gas consumption during the year to arrive at the estimated impact on operating results of combined variations from normal temperatures and normalized gas consumption.

Reportable Business Segments

The Company is required to disclose information regarding its reportable business segments. Business segments that do not exceed the quantitative thresholds required to be reportable business segments are combined and included with the Company's corporate division in a category the Company refers to as "Corporate and Other." The Company reports one reportable business segment: Gas Distribution. The operating results of this business segment are discussed on the following pages. There is also a discussion of the results for Corporate and Other. The Company evaluates the performance of its business segments based on operating income. Operating income does not include income taxes, interest expense, discontinued operations, or other non-operating income and expense items. A review of the non-operating items follows the Gas Distribution and Corporate and Other discussions. The business segment discussions should be read in conjunction with Item 1 of this Form 10-K, which provides information regarding competition and other business matters. Refer to Note 11 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K for further information regarding business segments and a summary of business segment financial information.

Gas Distribution Business Segment

Gas Sales Revenue. The Company's gas sales revenue was \$569.1 million, \$463.4 million and \$427.9 million for 2005, 2004 and 2003, respectively. The most significant factor causing the change in gas sales revenue from year-to-year is the change in the cost of gas sold. A significant portion of the Company's cost of gas sold is accounted for by the Company's GCR pricing mechanisms, which allow for the adjustment of rates charged to customers to reflect increases and decreases in the cost of gas purchased by the Company. Under these mechanisms, customers are charged rates that allow the Company to recoup its cost of gas purchased for sale to customers, subject, in the Company's Michigan service territory regulated by the MPSC, to a review by the MPSC of the Company's GCR gas purchase plan and the reasonableness of actual purchases and procurement practices. In Alaska, gas supply contracts are reviewed by the RCA at the time the Company enters into those contracts. As a result of the use of these mechanisms, in the absence of regulatory disallowances, for any increase or decrease in cost of gas sold, there is a corresponding increase or decrease in gas sales revenue. Refer to the caption "Cost of Gas, Gas Charges Recoverable from Customers,

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and Amounts Payable to Customers” in Note 1 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K for further information on cost of gas and the GCR mechanisms. Management generally evaluates changes in gas sales margin rather than gas sales revenue, due to the fluctuations caused by market-driven changes in cost of gas sold. Please refer to the gas sales margin section below for a detailed variance analysis.

	Years Ended December 31,		
	2005	2004	2003
		(\$ in thousands)	
Gas sales revenues	\$ 569,136	\$ 463,356	\$ 427,936
Cost of gas sold	443,860	346,241	308,919
Gas sales margin	\$ 125,276	\$ 117,115	\$ 119,017
Gas transportation revenue	29,142	29,071	27,737
Other operating revenue	8,037	5,822	7,216
	\$ 162,455	\$ 152,008	\$ 153,970
Operations and maintenance	66,626	60,779	58,935
Depreciation and amortization	26,825	25,925	25,528
Property and other taxes	11,040	12,544	10,285
Operating income	\$ 57,964	\$ 52,760	\$ 59,222
Volumes of gas sold (MMcf)	64,723	66,165	67,272
Volumes of gas transported (MMcf)	55,709	56,619	51,358
Number of customers at year end	409,462	398,225	390,677
Average number of customers			
Gas sales customers	401,317	391,495	384,459
Transportation customers	1,638	1,540	1,481
	402,955	393,035	385,940
Degree Days			
Alaska	9,572	9,573	9,384
Michigan	6,689	6,726	7,063
Percent colder (warmer) than normal			
Alaska	(5.7)%	(6.0)%	(8.0)%
Michigan	(0.1)%	(0.3)%	4.7%

The amounts in the above table include intercompany transactions.

Gas Sales Margin. The Company’s gas sales margin is derived primarily from customer service fees and consumption-based distribution fees. The customer service fees are fixed amounts charged to customers each month. Distribution fees vary each month because they are based on the volume of gas consumed by customers. There are four primary factors that have historically impacted gas sales margin and may impact future gas sales margin. These factors are changes in: (i) customer gas consumption; (ii) the number of gas sales customers; (iii) LAUF gas; and (iv) customer rates, including gas cost savings. In addition to these recurring factors, the Company sold excess gas to a third-party gas supplier in 2005, which also increased gas sales margin for 2005 by approximately \$1.4 million.

Changes in customer gas consumption from one year to another have historically been attributable primarily to the impact of changes in temperatures between periods. However, in recent years, other factors (including conservation by customers, the increasing use of more energy efficient gas furnaces and appliances, the addition of new energy efficient homes to the Company’s gas distribution system and the price of natural gas) have contributed more significantly than in the past to changes in customer gas consumption. A decrease in customer gas consumption reduced gas sales margin for 2005 by approximately \$3.6 million, when

compared to 2004. During 2005, customer gas consumption was lower than expected, given that temperatures during 2005 were similar to temperatures during 2004. The Company believes the decrease in gas consumption was due in large part to conservation prompted by the increased cost of natural gas. Refer to the discussion in Management's Discussion and Analysis under the caption "The Impact of Higher Natural Gas Prices." A decrease in customer gas consumption reduced gas sales margin for 2004 by approximately \$2.3 million, when compared to 2003.

The average number of gas sales customers in Michigan and Alaska combined (excluding customers acquired in the acquisition of Peninsular Gas) has increased by an average of 2.0% annually during the past three years. During 2005, Company's average number of gas sales customers in Michigan and Alaska combined (excluding Peninsular Gas customers) increased by 7,653 or 1.9% when compared to 2004. During 2004, the Company's average number of gas sales customers increased by 7,095 or 1.8% when compared to 2003. Customer additions increased gas sales margin for 2005 by approximately \$2.5 million, when compared to 2004. Customer additions increased gas sales margin for 2004 by approximately \$2.1 million, when compared to 2003. Customers added to the Company's Michigan operation as a result of the acquisition of Peninsular Gas contributed \$0.5 million to gas sales margin for 2005.

LAUF gas is a term used in the natural gas distribution industry to refer to the difference between the gas that is measured and injected into the Company's gas distribution system and the amount of gas measured at customer meters. Typically, there is more gas injected into a gas utility's distribution system than is actually measured as sold or transported at customer meters. There are a number of reasons for this LAUF gas, including measurement errors and leaks. The annual LAUF gas volumes in Michigan have ranged from 0.5% to 1.4% of total gas volumes sold and transported in Michigan over the last ten years. An increase in LAUF gas expense decreased gas sales margin for 2005 by approximately \$0.1 million, when compared to 2004. An increase in LAUF gas expense decreased gas sales margin for 2004 by approximately \$1.0 million, when compared to 2003. The cost of LAUF gas is affected by the underlying commodity cost and rate mechanisms employed to price LAUF gas volumes and recover this cost from customers. Refer to the discussion in Management's Discussion and Analysis under the caption "The Impact of Higher Natural Gas Prices," for more information.

The remainder of the change in gas sales margin from 2004 to 2005, an increase of \$7.5 million, was due primarily to changes in rates and gas cost savings, as well as other miscellaneous factors. These same items also contributed to the remainder of the change in gas sales margin from 2003 to 2004, a decrease of \$0.7 million. There was an increase in customer rates effective in March 2005, for MPSC-regulated customers. The rate increase for MPSC-regulated customers was the result of a settlement agreement reached with the MPSC. The CCBC approved new rates for CCBC-regulated customers, effective in April 2005, and the use of a GCR pricing mechanism, effective in April 2005. During 2003, 2004 and the first three months of 2005, the Company's service area regulated by the CCBC was not operating under a GCR pricing mechanism and certain gas cost savings allowed under the terms of a gas supply and management agreement (which expired March 31, 2005) were retained by the Company. The gas cost savings realized under the agreement varied from year to year. For information on new rates and rate cases filed by the Company, refer to Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K. For further information regarding the Company's natural gas supply and management agreements, GCR pricing mechanisms and gas cost savings, refer to the caption "Cost of Gas, Gas Charges Recoverable from Customers, and Amounts Payable to Customers" in Note 1 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K.

Gas Transportation Revenue. The Company provides gas transportation services to customers who typically consume large volumes of natural gas. These customers purchase their natural gas directly from third-party suppliers. The natural gas purchased by customers from third-party suppliers is then transported on the Company's gas distribution system to the customers. There was a \$0.1 million increase in gas transportation revenue in 2005, when compared to 2004. The increase was primarily due to higher rates and volumes to industrial customers and an increase in transportation volumes to commercial customers, partially offset by a decrease in transportation volumes to power plants. There was a \$1.3 million increase in gas transportation revenue in 2004, when compared to 2003. The primary reasons for the increase were increases

in transportation volumes and rates for commercial transport customers, as well as an increase in transportation volumes for industrial and power plant transport customers.

One of the Company's Alaska service area industrial transportation customers, a fertilizer manufacturer, has publicly announced that it has experienced difficulty in securing sufficient natural gas supplies at an appropriate price to continue operating in the future. The customer has indicated that it has secured sufficient natural gas supplies to operate at a reduced rate through October 2006, but currently does not have sufficient natural gas under contract at an appropriate price to operate after that date. Transportation revenues to this customer totaled \$2.0 million in 2004 and \$2.0 million in 2005. Based upon volumes transported during 2005 and estimates provided by the customer, transportation revenues to this facility are expected to total \$1.4 million in 2006. The Company cannot predict the likely pattern of future operations at this plant, including whether the plant will ultimately close.

Other Operating Revenue. Increases in miscellaneous customer revenues and pipeline management revenues are the primary reasons for changes in other operating revenue during the past three years. In addition, a scheduled fee increase and a one-time settlement related to one of the Company's large pipeline capacity contracts also contributed to the increase in other operating revenue in 2005. The miscellaneous customer revenues include various service fees and late payment fees charged to customers. An increase in these fees from 2004 to 2005 increased other operating revenue for 2005 by approximately \$1.0 million. An increase in miscellaneous customer fees from 2003 to 2004 increased other operating revenue for 2004 by approximately \$1.2 million.

The pipeline management revenue is earned by NORSTAR. These revenues increased approximately \$0.4 million in 2005, when compared to 2004, because of revenues earned from NORSTAR's management of a pipeline construction project performed during 2005. Pipeline management revenue for 2004 decreased approximately \$2.6 million from 2003 because NORSTAR was only performing routine pipeline management work and did not have a large management project similar to a project NORSTAR managed in 2003.

Operations and Maintenance Expenses. For the year 2005, operations and maintenance ("O&M") expenses increased by \$5.8 million when compared to 2004. During 2004, O&M expenses increased by \$1.8 million when compared to 2003. The changes in operating expenses over the past three years resulted from four primary factors: (i) employee benefit costs; (ii) professional fees; (iii) commercial insurance and claims costs; and (iv) uncollectible customer accounts.

Employee benefit costs primarily include pension expense, medical coverage expense (including retiree medical coverage), and incentive compensation. For 2005, employee benefit costs increased by approximately \$2.6 million. Approximately 66% of this increase was due to increased pension expense while much of the remainder of the increase was due to an increase in incentive compensation. For 2004, employee benefit costs decreased by approximately \$0.9 million. The decrease for 2004 was a result of a \$1.6 million decrease in medical coverage costs partially offset by increases in other employee benefits. The decrease in medical coverage costs in 2004 was primarily due to plan modifications that required employees and retirees to pay for a larger portion of their medical coverage costs and a decrease in retiree medical expense due to the provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("Medicare Act"). For more information on the Medicare Act, refer to Note 8 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K.

Professional fees (consisting primarily of accounting and legal fees) for 2005 were essentially unchanged from 2004 levels, but professional fees for 2004 increased by approximately \$2.3 million, when compared to 2003. The increase in the amount of professional fees in 2004 and continued level in 2005 were due in large part to the increased level of costs to comply with the Sarbanes-Oxley Act of 2002.

Commercial insurance and claims costs decreased by approximately \$0.4 million for 2005, when compared to 2004. For 2004, commercial insurance and claims costs increased by approximately \$0.7 million, when compared to 2003. Commercial insurance costs have increased significantly over the past few years as a result of the September 11, 2001 attack on the U.S., which has caused increases in liability insurance costs, and recent corporate financial wrongdoing by other large companies, which has increased director and officer

liability insurance costs. The Company had previously been shielded from these increases due to a three-year fixed premium general liability policy, which expired in 2003, and a fixed-premium excess liability policy, which expired in 2004.

Uncollectible customer accounts increased by approximately \$0.4 million in 2005, when compared to 2004. By comparison, during 2004, uncollectible customer accounts decreased by approximately \$0.7 million, when compared to 2003. The increase in 2005 was due in large part to a higher cost of gas in 2005, offset partially by increased collection efforts and collection programs initiated by the Company. The decrease in uncollectible customer accounts in 2004 was primarily due to a reduction in large customer bankruptcy write-offs.

The remaining increase in O&M expenses from 2003 to 2004, and from 2004 to 2005, was caused by increases in compensation expense, facilities expense (including building and office lease expense), customer collection expense and various other expenses due primarily to inflationary pressures on expenses and the increased cost of doing business.

When expenses continue to increase as a result of inflation or other factors, the Company typically files base rate cases to recover the increased cost of doing business. Refer to Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K for information regarding recent rate case filings.

Depreciation and Amortization. The addition of new customers to the Company's gas distribution system typically requires expansion of the system. In addition, the Company has a replacement program to ensure that older sections of its distribution system are being upgraded and replaced, and the Company also typically upgrades and relocates parts of its system in connection with public works projects to improve roads and other public facilities. The increase in depreciation and amortization expense from year to year is due to depreciation on net additional property, plant and equipment placed in service as a result of expanding and upgrading the system.

Property and Other Taxes. The Company's property and other taxes have increased over the past three years. The increases are primarily attributed to property taxes. Each year the Company's property taxes generally increase as a result of taxes on net additional property, plant and equipment placed in service as part of the expansion and upgrading of the Company's gas distribution system. During 2004, the Company also incurred \$1.4 million in additional property tax expense as a result of adjusting the amount it estimated it would recover from certain prior years property tax appeals. During 2005, the Company initiated settlement offers to all taxing jurisdictions involved with the property tax appeals. Numerous taxing jurisdictions have accepted the Company's settlement offer and, as a result, the Company reduced its 2005 property tax expense by approximately \$0.5 million. The Company intends to pursue further refunds in 2006, which is expected to reduce 2006 property tax expense. Refer to Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K for information about the property tax appeals.

Regulatory, Environmental and Other Matters. For further information regarding regulatory matters and the application of the FASB's Statement of Financial Accounting Standards ("SFAS") 71, "Accounting for the Effects of Certain Types of Regulation," refer to Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K, the "Critical Accounting Policies" section of Management's Discussion and Analysis and the Rates and Regulation section in Item 1 of this Form 10-K. For information regarding environmental matters and property tax litigation, refer to Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K. Refer to the section titled "Gas Distribution Business Segment" in Item 1 of this Form 10-K for information on competition in this business segment.