OTTER TAIL CORPORATION

PRINCIPLED

FAIR, HONEST AND ETHICAL

RESPECTFUL OF OTHERS

SAFE WORK ENVIRONMENTS

FISCALLY RESPONSIBLE

BUILD RELATIONSHIPS

CELEBRATE SUCCESS

2003 ANNUAL REPORT

LEARN FROM MISTAKES

ATTRACT AND RETAIN TAL[illegible]D PEO

DECENTRALIZED DECISION[illegible]G

RESOURCEFUL AND ENTREPRENEURIAL

Contents

	2003	2002	Percent change
CONSOLIDATED OPERATIONS:			
Total operating revenues	$ 753,239,000	$ 646,337,000*	16.5
Net income	39,656,000	46,128,000	(14.0)
Basic earnings per share	1.52	1.80	(15.6)
Diluted earnings per share	1.51	1.79	(15.6)
Dividends per common share	1.08	1.06	1.9
Return on average common equity	12.2%	15.3%	(20.3)
Book value per common share	12.98	12.25	6.0
Cash flow from operations	76,955,000	76,797,000	0.2
Number of common shares outstanding	25,723,814	25,592,160	0.5
Number of common shareholders	14,723	14,503	1.5
Closing stock price	26.73	26.90	(0.6)
Total return (share price appreciation plus dividends)	3.4%	(4.0)%	–
Total market value of common stock	687,598,000	688,429,000	(0.1)
ELECTRIC OPERATIONS:			
Operating revenues:			
Retail	$ 217,611,000	$ 207,039,000	5.1
Wholesale	29,530,000	18,295,000*	61.4
Other	20,353,000	18,671,000	9.0
Total electric operating revenues	$ 267,494,000	$ 244,005,000	9.6
Total retail electric sales (kwh)	3,716,342,000	3,690,587,000	0.7
Operating income	57,537,000	53,879,000	6.8
Customers	127,534	127,157	0.3
Gross plant investment	889,302,000	874,505,000	1.7
Total assets	609,190,000	586,231,000**	3.9
Capital expenditures	28,177,000	45,842,000	(38.5)
Employees (includes temporary and part-time)	699	728	(4.0)
NONELECTRIC OPERATIONS:			
Operating revenues	$ 485,745,000	$ 402,332,000	20.7
Operating income	13,623,000	28,438,000	(52.1)
Total assets	377,233,000	327,881,000	15.1
Capital expenditures	22,557,000	29,691,000	(24.0)
Employees (includes temporary and part-time)	2,438	2,383	2.3

** Restated to reflect implementation of EITF Issue 03-11. See note 1 to consolidated financial statements.*
***Restated to reflect reclassification of reserve for estimated removal costs from accumulated depreciation to a regulatory liability.*

Cover artwork created at BTD Manufacturing, an operating company of Otter Tail Corporation

COMMITTED VISION

Our vision provides a clear and continuous path to performance: Otter Tail Corporation creates value and growth through the acquisition, long-term ownership and decentralized operation of diverse businesses.

FOCUSED GROWTH

We are a growing organization with more than 3,000 people *working in many industries, including electric utility, health services,* manufacturing, plastics and other businesses.

PRINCIPLED PERFORMANCE

We have a long-standing reputation for principled performance, as solid today as when our organization was created in 1907. Over the years as business goals and strategies evolved, we have stayed true to this heritage.

TO OUR SHAREHOLDERS

JOHN ERICKSON, PRESIDENT AND CEO

PRINCIPLED.

OTTER TAIL

VALUE.

INTEGRITY AND PERFORMANCE

Our values set the standards for our actions. They define how we relate to others and how we guide our business operations. In short, we require integrity. Integrity of character from all individuals across our organization. Integrity of products and services within our diverse businesses. Integrity in how we achieve revenue and profit.

Principled behavior is essential in business, especially when challenges arise. The year 2003 presented challenges and Otter Tail Corporation experienced a decline in earnings. This was not typical for us, but neither was it a major setback. In fact, many positive results occurred. Revenues were higher. Net income and returns on capital, while not at the levels we initially targeted, were still solid. Our capital structure remained strong. Dividends increased. We identified exciting opportunities and addressed challenges.

As we expected with our diversified strategy, certain companies fared better than others. While the consolidated results did not meet our expectations, our electric utility performed exceptionally well and some of our manufacturing companies also had an excellent year.

OUR VISION / / / / / / TO CREATE VALUE AND GROWTH THROUGH THE ACQUISITION,

OUR MISSION

To create value for our customers, shareholders and employees: for customers by focusing on their needs and providing quality products and services; for shareholders by providing returns on their investments that consistently are above average; and for employees by providing economic and career-development opportunities in a challenging, rewarding environment.

Here is an overview of Otter Tail Corporation performance in 2003:

- Operating revenues reached $753 million.
- Net income was $39.7 million.
- Earnings per share were $1.51.
- The common dividend paid in 2003 was raised to $1.08 per share, representing a dividend yield of 4%.
- OTTR stock provided a total return of 3.4%.

While the stocks of many companies experienced significant declines during the past several years and are now increasing, our stock has remained relatively steady. As a long-term investment, our performance remains strong. Over the past five years, an investment in Otter Tail Corporation stock provided a total return of 65%.

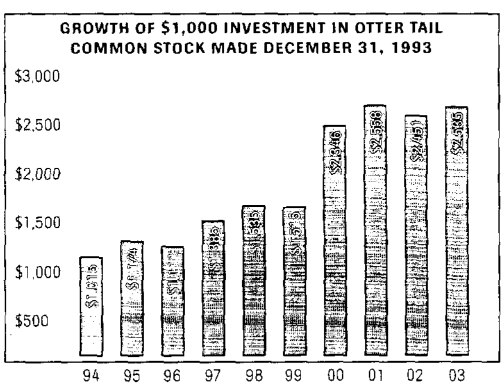
A LONG-TERM COMMITMENT

In February 2004, our Board of Directors raised the dividend to an indicated annual rate of $1.10 per share. This represents the 29th consecutive year of dividend growth.

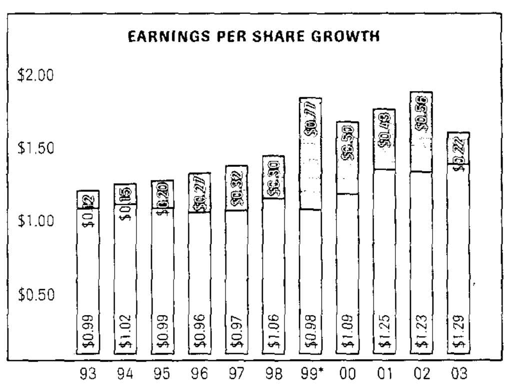
Otter Tail Corporation has provided dividends for 65 consecutive years with no reductions, extending back to 1938. This ongoing record of stability exemplifies our organization's long-held commitment to deliver value to shareholders.

As the economy begins to shake off an extended slump, we recognize the recovery will not be uniform across all industries and geographic regions. Economic challenges likely will continue to constrict performance in some of our businesses. We believe those companies that have experienced slowdowns are positioned to perform well when industry conditions improve and the economic upturn becomes more widespread.

We remain confident of our course for the long term. And we are definitely not complacent in the meantime. Smart, dedicated people lead our companies. These leaders are taking appropriate actions to strengthen earnings while keeping the companies sound and responsive.



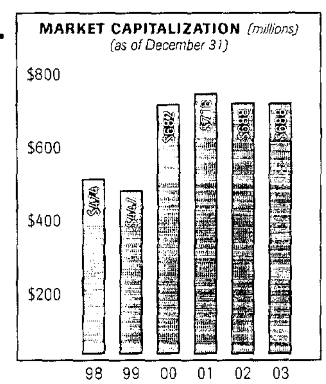
Shareholder value compounded at an average annual rate of 9.75% over the past ten years.



☐ *Nonelectric*
☐ *Electric*

Earnings per share have grown at a compounded rate of 3% over the past ten years.

**Nonelectric for 1999 includes $0.34 per share related to sale of radio station assets.*



Our market capitalization has increased 45% over the past five years. Over that same period of time, we've paid out $128 million in common dividends.

AN ONGOING, PROVEN STRATEGY

Our focus remains firm on long-term ownership of a diversified set of businesses with a solid utility base. This strategy has been in place for nearly 15 years. Over time, the prospect for consistent growth in earnings and dividends is higher when derived from participation in diverse industries rather than from a single source.

This is and will remain the right course for Otter Tail Corporation. We carefully manage our exposure to risk. We will not weaken our established success with short-term fixes, overly aggressive targets or risky acquisitions. Steady long-term results demand farsighted, principled action. And we will not lose this conviction.

Otter Tail Corporation continues to grow both organically and through acquisition. Organic, or internal, growth will come from new products, market expansion and increased efficiencies. Through our acquisition process, we seek companies with growth potential, solid market share and top-notch management teams. This is an intensive process and, as such, we are highly selective in choosing acquisition candidates.

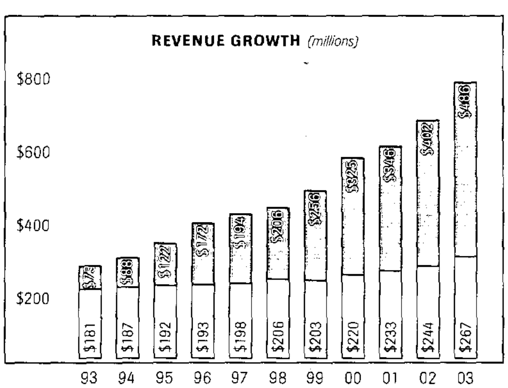
In 2003, our health services segment added two cardiac monitoring equipment companies to its health technologies division that will broaden sales opportunities. We also added Foley Company, a well-respected mechanical and prime contracting firm based in Kansas City, Missouri, to our other business operations. Foley Company celebrated its 90th year of business in 2003 and is prepared to continue to grow as the newest member of our organization.

LEADING WITH HIGH STANDARDS

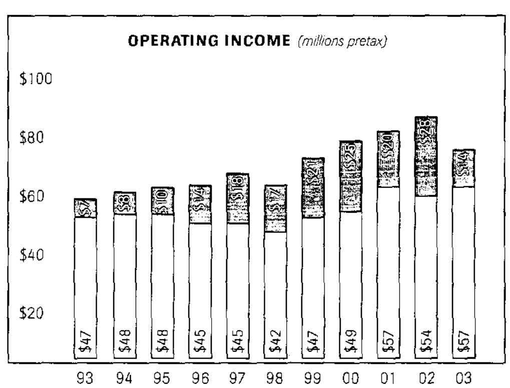
Fiscal accountability. Maintaining a strong balance sheet. Straightforward financial reporting. All are examples of how our principles guide our accounting and reporting practices. Our history of good corporate governance has prepared us well to adopt the more exacting compliance standards now required of all public companies by the Securities and Exchange Commission. Under the guidance of our internal audit department, an implementation team is developing consistent approaches for documenting internal financial controls within each of our operating companies.

OUR VALUES

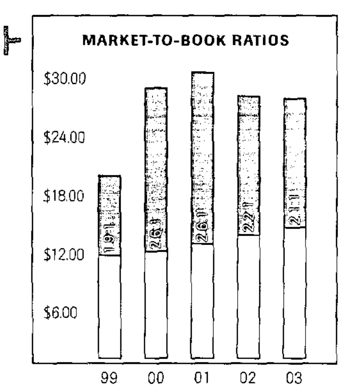
- We will be fair, honest and ethical.
- We will attract and retain talented people.
- We will expect decentralized decision-making.
- We will be respectful of others.
- We will be resourceful and entrepreneurial.
- We will build relationships.
- We will be fiscally responsible.
- We will celebrate success and learn from mistakes.
- We will have safe work environments.



☐ Nonelectric
☐ Electric
Total company revenue has grown at a compounded annual rate of 11.5% over the past ten years.



☐ Nonelectric
☐ Electric
Operating income has grown at a compounded annual rate of 2.8% over the past ten years.



☐ *Year-end market price per share*
☐ *Year-end book value per share*

Our 2:1 market-to-book ratio over the past five years puts us among the top ten investor-owned electric utilities in the nation.

Our Board of Directors governs Otter Tail Corporation in an open, honest and ethical manner. The board strives to ensure that the best interests of our shareholders are always met. At the end of 2003, Maynard Helgaas retired from the Otter Tail Corporation board. We are deeply grateful for his dedication and service to the board over the past 18 years. As a new year begins, it is a pleasure to welcome Karen Bohn as a new director. She is the president and chief executive officer of the Galeo Group, a management consulting firm specializing in the areas of governance, philanthropy, strategy and management effectiveness. Her depth of business knowledge, which includes more than 20 years in executive roles at Piper Jaffray, and her expertise in governance will provide an excellent resource to Otter Tail Corporation's Board of Directors in the coming years.

To learn more about the people who guide our organization, the structure of the board and our approach to corporate governance, visit our web site, www.ottertail.com.

COMPETITIVE ADVANTAGES

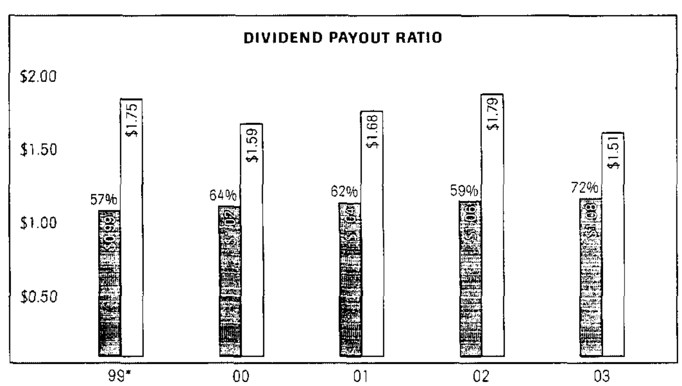
- Otter Tail Corporation maintains a strong balance sheet.
- Our financial health does not rely on any one segment of the economy.
- Talented and resourceful people work together to make our organization successful.

A PRINCIPLED PERSPECTIVE

Our mission is to create value for our shareholders, customers and employees. Fulfilling this mission allows our companies to flourish on a regional and, for some, a national scale. Yet their respective successes also have an impact on local and personal levels—through stable employment, economic development and social responsibility.

The theme of this report, *Principled*, underscores our commitment to ensure Otter Tail Corporation remains positioned for long-term growth and success. We are ever mindful of the tremendous responsibility that comes with delivering on this mission. On behalf of all Otter Tail Corporation companies, I want to thank you for your support as we work to deliver value to our many stakeholders.

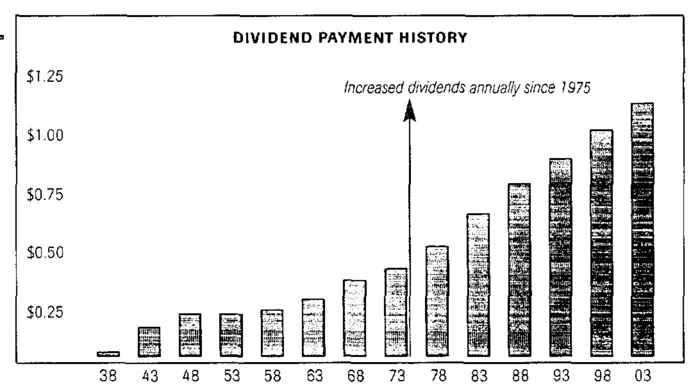
John Erickson
President and CEO



Dividend per share
Earnings per share

Over the past five years, dividends have increased while the average payout rate has been 63%.

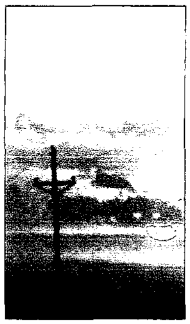
**1999 earnings per share includes $0.34 related to sale of radio station assets.*



Otter Tail has paid common dividends every year since 1938 and increased those dividends each year since 1975.

STRONG BALANCE SHEET / / / / STRAIGHTFORWARD FINANCIAL REPORTING / / /

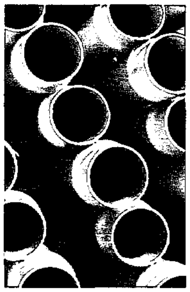
BUSINESS SEGMENTS	OPERATING COMPANY DESCRIPTIONS



ELECTRIC

OTTER TAIL POWER COMPANY provides reliable, low-cost electricity to more than 127,000 customers in 50,000 square miles of Minnesota, North Dakota and South Dakota. Peak demand in 2003 was 668,703 kilowatts and total net generating capacity was 696,380 kilowatts. Owned generation includes three coal-fired steam plants, six hydroelectric plants and four combustion turbine generators.
Coal-fired steam plant ownership and locations:

- Co-owns/operates Big Stone Plant, Milbank, SD; net capability 468 megawatts, Otter Tail share 252 megawatts.
- Co-owns/operates Coyote Station, Beulah, ND; net capability 426 megawatts, Otter Tail share 149 megawatts.
- Owns/operates Hoot Lake Plant, Fergus Falls, MN; net capability 153 megawatts.



PLASTICS

NORTHERN PIPE PRODUCTS, INC., manufactures and sells PVC and polyethylene pipe used in municipal water, rural water, wastewater and water reclamation systems in the northern, midwestern and western regions of the United States as well as in Canada.
VINYLTECH CORPORATION manufactures and sells PVC pipe used in municipal water, rural water, wastewater and water reclamation systems in the south-central, southwestern and western regions of the United States.

MANUFACTURING

BTD MANUFACTURING, INC., provides metal fabrication services for custom machine parts and metal components through metal stamping, tool and die, machining, tube bending, welding and assembly.
CHASSIS LINER CORPORATION produces and markets auto and truck frame-straightening equipment and other automotive repair products.
DMI INDUSTRIES, INC., engineers and manufactures wind towers and other heavy metal fabricated products.
SHOREMASTER, INC., produces and markets residential and commercial waterfront equipment, ranging from boatlifts and docks to full marina systems.
ST. GEORGE STEEL FABRICATION, INC., fabricates structural steel for buildings and bridges, as well as ductwork, conveyors, hoppers and plate steel products.
T.O. PLASTICS, INC., manufactures and sells plastic thermoformed products for the horticulture industry and packing products for other industries.

HEALTH SERVICES

DMS HEALTH GROUP is composed of two primary business units that deliver innovative, high-quality diagnostic imaging and healthcare solutions across the nation.

- DMS Health Technologies sells and installs diagnostic medical imaging systems, patient monitoring equipment and medical supplies and provides ongoing service maintenance. Major distributor for Philips Medical Systems.
- DMS Imaging provides shared diagnostic medical imaging services for MRI, CT, nuclear medicine, PET, ultrasound, mammography and bone density testing. Delivery of services is primarily through DMS Imaging mobile units with options available for interim and fixed-site delivery. Also provides portable X-ray, ultrasound and EKG services.

OTHER BUSINESSES

E.W. WYLIE CORPORATION operates a fleet of approximately 170 trucks as a flatbed contract and common carrier across the lower 48 United States and Canada.
FOLEY COMPANY provides mechanical and prime contracting for water and wastewater treatment plants, power generation plants, hospital and pharmaceutical facilities, and other industrial and manufacturing projects.
MIDWEST CONSTRUCTION SERVICES, INC., provides a full spectrum of electrical design and construction services for the industrial, commercial and municipal business markets, including government, institutional, communications, utility and renewable energy projects.
MIDWEST INFORMATION SYSTEMS, INC., provides telephone, cable TV and Internet services.

OTTERTAIL CORPORATION

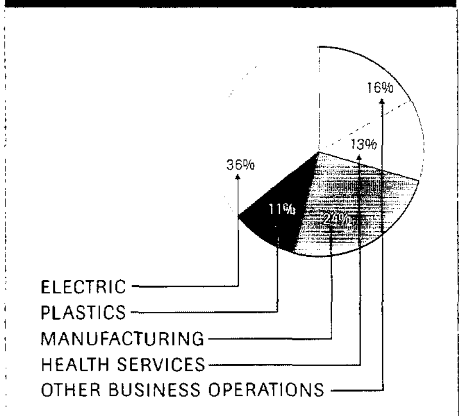
ELECTRIC	PLASTICS	MANUFACTURING	HEALTH SERVICES	OTHER BUSINESSES
Otter Tail Power Company Fergus Falls, MN/1907 Chuck MacFarlane 699 employees *www.otpco.com*	**Northern Pipe Products, Inc.** Fargo, ND/1995 Wayne Voorhees 114 employees *www.northernpipe.com*	**BTD Manufacturing, Inc.** Detroit Lakes, MN/1995 Earl Rasmussen 345 employees *www.btdmfg.com*	**DMS Health Group** Fargo, ND/1993 Wayne Sanders 431 employees *www.dmshg.com*	**E.W. Wylie Corporation** Fargo, ND/1999 Marv Skar 150 employees *www.wylietrucking.com*
	Vinyltech Corporation Phoenix, AZ/2000 Steve Laskey 64 employees *www.vtpipe.com*	**Chassis Liner Corporation** Alexandria, MN/1997 Kent Johnson 48 employees *www.chassisliner.com*		**Foley Company** Kansas City, MO/2003 Mike Palmer 131 employees *www.foleycompany.com*
		DMI Industries, Inc. West Fargo, ND/1990 Lars Moller 130 employees *www.dmiindustries.com*		**Midwest Construction Services, Inc.** Moorhead, MN/1992 Paul Bruhn 338 employees *www.mwcsi.com*
		ShoreMaster, Inc. Fergus Falls, MN/2002 Erik Ahlgren 277 employees *www.shoremaster.com*		**Midwest Information Systems, Inc.** Parkers Prairie, MN/1992 Mark Roach 24 employees *www.midwestinfo.com*
		St. George Steel Fabrication, Inc. St. George, UT/2001 John Campos 144 employees *www.stgeorgesteel.com*		
		T.O. Plastics, Inc. Minneapolis, MN/2001 Chuck Goers 204 employees *www.toplastics.com*		

Chart Legend

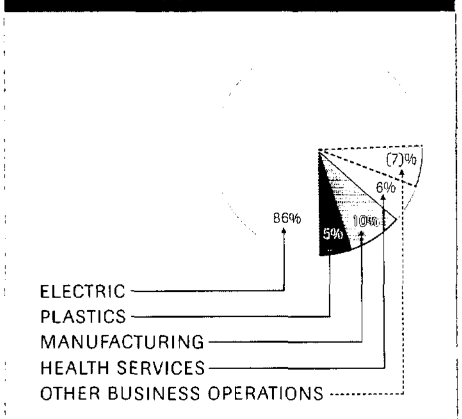
- Location of headquarters and year acquired
- Operating company leader
- Employees (includes part-time and temporary)
- *Web site address*

For the year ended December 31, 2003

REVENUES BY SEGMENT



NET INCOME BY SEGMENT



"WE ARE NOW A TRULY NATIONAL COMPANY

because of Otter Tail Corporation. With their support, ShoreMaster acquired another waterfront equipment company and significantly expanded our business coast to coast."

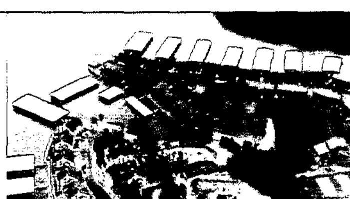
An established manufacturing company offering residential docks, waterfront equipment and commercial marina systems, ShoreMaster weighed many options for supporting ongoing growth, including a change in ownership. In 2002, Erik Ahlgren and his team looked at potential suitors and, attracted by the solid reputation and resources, approached Otter Tail Corporation. Within six months of transferring ownership to Otter Tail, Minnesota-based ShoreMaster in turn acquired Galva Foam Marine Industries, a Missouri company with complementing product lines. For Otter Tail Corporation, ShoreMaster represents an ideal acquisition: a proven track record, entrepreneurial leadership, good returns and excellent growth potential.

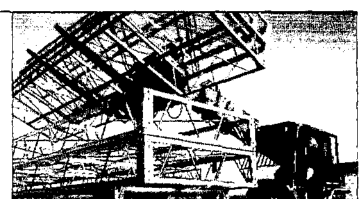
ERIK AHLGREN SHOREMASTER PRESIDENT

Strategy for Growth

Visionary leadership has kept Otter Tail Corporation successful throughout our long history. In 1989, we determined that diversification was the best strategy to address the prospect of limited growth in revenues and earnings from the electric utility operations. We embarked on our diversification path with the goal of acquiring and growing well-managed, profitable businesses.

A principled approach continues to guide our strategy. We do not acquire companies in pursuit of short-term gains. Our aim is for long-term ownership with predictable and steady growth. By investing in different industries, we believe our strategy of diversification also lessens the impact of a downturn in a specific industry or company. We did not expect our diversification strategy to be a defense to a broad-based economic downturn. Our experience in 2003 confirmed this. In the long run, however, we remain firmly convinced that our strategy of long-term ownership of diverse companies will generate above-average returns to our shareholders.


SHOREMASTER DOCK SYSTEMS ENHANCE SHORELINES NATIONWIDE.


WATERFRONT PRODUCTS ARE MADE FOR RESIDENTIAL AND COMMERCIAL NEEDS.

Operating Model

Decentralized with discipline. Overseeing diverse businesses requires a decentralized model, where operating company leadership is responsible for development and implementation of strategies that result in profits and growth. The benefit of this model is an environment where innovation, energy, customer focus, commitment and integrity flourish.

We respect the knowledge and entrepreneurial vision of our operating company leaders and their teams. They know how to move their businesses forward. They act when challenges or opportunities arise. With access to the capital and other resources of Otter Tail Corporation, they have the tools to be successful. Although we operate in a decentralized environment, we have developed disciplined processes that appropriately define and guide achievement of our expectations, including consistency with our values. We believe we have found the right balance for long-term, principle-driven performance.

2003 Overview

Diversification with a stable utility base is the established guidepost to viable growth opportunities for Otter Tail Corporation. Our electric utility had an outstanding year, again providing the foundation of our consolidated financial performance. Nonelectric operations provided 64% of consolidated revenues and 14% of net income in 2003, reflecting disappointing results at some companies. The following sections in this report provide a look at 2003 challenges and accomplishments, including actions that will lead to improved prospects for 2004 and beyond.

2003 Segment Results

(in millions)	Revenues	Net Income
Electric	$ 267.5	$ 34.1
Plastics	86.0	2.0
Manufacturing	177.8	3.9
Health services	100.9	2.5
Other business operations	121.0	(2.8)
Total	$ 753.2	$ 39.7

WE WILL EXPECT DECENTRALIZED DECISION MAKING

Electric

Providing high-quality, low-cost electricity for customers in Minnesota, North Dakota and South Dakota. Creating a safe and rewarding workplace for employees. Producing dependable earnings. Otter Tail Power Company again met its top goals in 2003. The company achieved customer satisfaction, rate, reliability and safety targets for North Dakota performance-based regulation and served customers in other states with similar attention. Safety rates were impressive. OSHA recordable injuries, lost workdays and preventable vehicle accidents were lower than half the industry average. Far exceeding initial expectations for the year, Otter Tail Power Company delivered 86% of consolidated net income.

Managing costs, capitalizing on wholesale electricity sales opportunities and performing contract work for other utilities were major factors contributing to this achievement. Centralized cash remittance processing, call center technologies, workforce planning, load control equipment upgrades and supply chain process improvements will contribute to even more efficient customer service and shareholder value in 2004.

Meeting challenging goals consistently requires dedication and cooperation. Achievements such as 2003's average total outage of only 76 minutes per customer result from coordinated employee effort. Excellent performance is second nature to the nearly 700 men and women of Otter Tail Power Company, who provide exceptional levels of experience, customer service and teamwork.

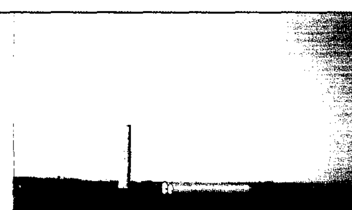
Successfully constructing the wind collector system, overhead lines and substations for three wind farms under extremely tight timelines was a source of pride for the company in 2003. These large-scale projects tallied up 40,000 labor hours in five months. Despite OSHA statistics indicating that at least one major accident is likely during projects of this size, not a single lost-time injury occurred.

Otter Tail Power Company's three coal-fired plants continue to provide the low-cost, around-the-clock energy for retail and wholesale sales. In 2003, these plants achieved a near record 91.01% plant equivalent availability. In addition, Otter Tail Power Company brought a new 45-megawatt, natural gas-fired combustion turbine online in June 2003.

Chuck MacFarlane was named Otter Tail Power Company president in May 2003, having served as interim president since August 2002. In September 2003, he participated as the only utility representative on a 12-member advisory group that met with President Bush at the White House to discuss the proposed Clear Skies legislation. The invitation to provide input to the President is recognition of Otter Tail Power Company's ongoing environmental efforts and respected reputation in the utility industry.


AREA CHILDREN HELP GOV. JOHN HOEVEN DEDICATE NORTH DAKOTA'S NEW WIND FARM.


LINEMAN MARK TOSO STRINGS OVERHEAD CONDUCTOR TO THE SITE.


A WELL-TIMED RAINBOW APPEARS DURING TOWER CONSTRUCTION.

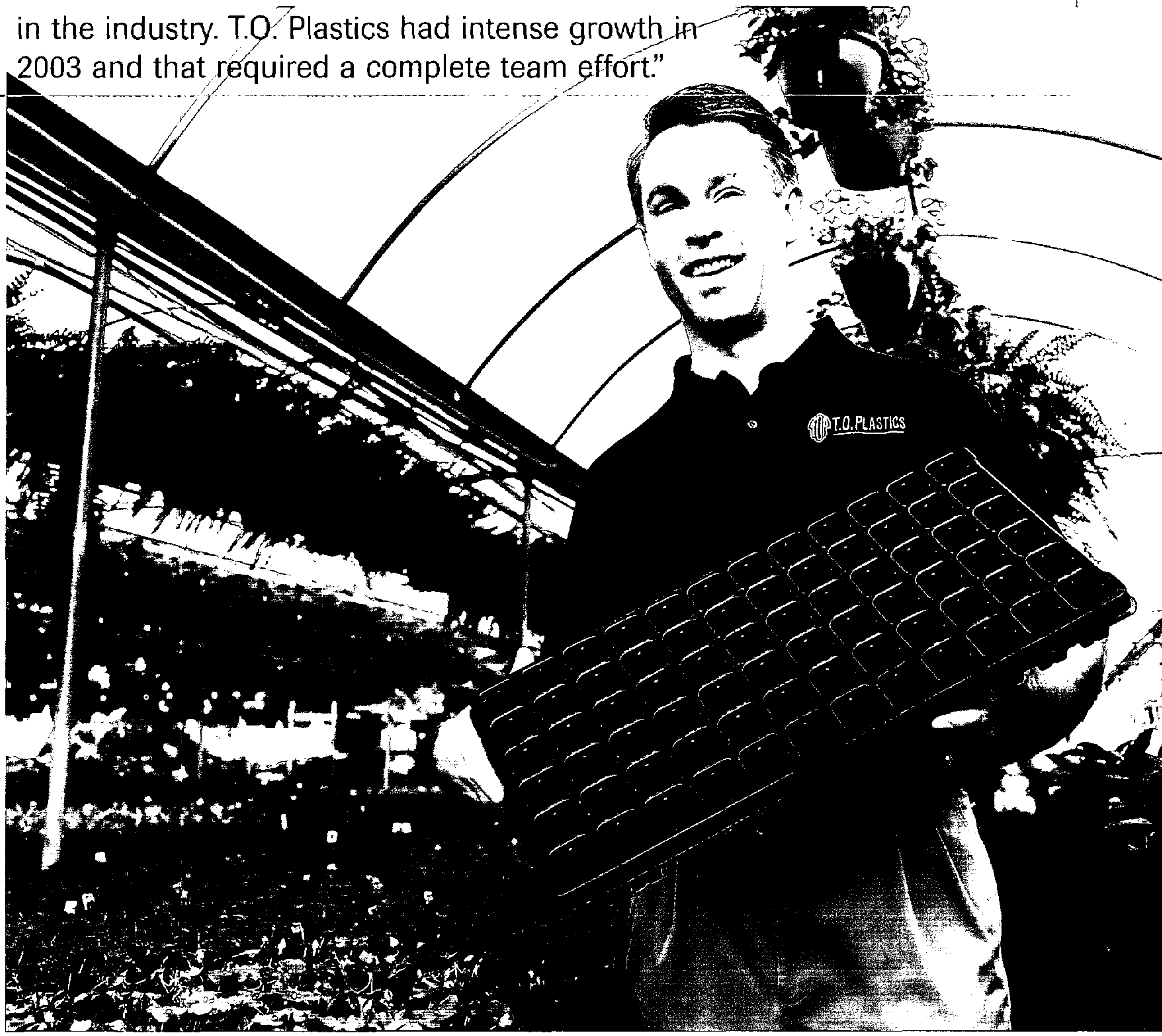
"AS AN EMPLOYEE OF A GREAT COMPANY

and the mayor of Edgeley, I want to express appreciation to all the people who spent the summer working on the wind farm near our community. Together, we wrote a new chapter in the history of North Dakota."

The three states Otter Tail Power Company serves are among the top ten in the nation for wind resources. That is one reason Steve Powers is keen on building wind farms in his backyard. And as mayor of Edgeley, North Dakota, he recognizes the economic boost these projects bring to rural communities. During 2003, he worked on Otter Tail Power Company's crew that helped construct the infrastructure connecting a new wind farm near Edgeley to the power grid. Owned by Florida-based FPL Energy, this is North Dakota's second utility-scale wind farm. Otter Tail Power Company has purchased the farm's entire 21-megawatt output, increasing renewable resources to 10% of the utility's energy mix.

STEVE POWERS OTTER TAIL POWER COMPANY SERVICE REPRESENTATIVE

"I JOINED THIS COMPANY BECAUSE IT IS A LEADER in the industry. T.O. Plastics had intense growth in 2003 and that required a complete team effort."



At T.O. Plastics, the best designs are cultivated by listening to customer needs and expectations. Mike Vallafskey knows this for a fact. In 2003, the company began to assess the best ways to expand its horticultural product mix and he set out to discover which container ideas would take root. That meant visiting distributors, gathering input at greenhouses and discussing the fine points of automated greenhouse machinery with equipment manufacturers. Countless hours of research and development resulted in some of the most technical yet versatile growing containers in the industry. More than 50 new products were introduced in the horticulture line and the number of T.O. Plastics distributors across the country increased significantly.

MIKE VALLAFSKEY T.O. PLASTICS SALES AND MARKETING DIRECTOR

VALUES WE WILL BUILD RELATIONSHIPS

Plastics

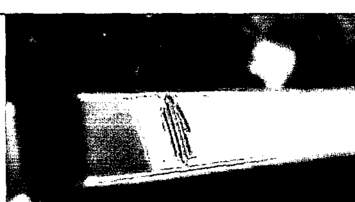
While revenues increased in this segment, net income was lower as a result of competitive factors that reduced margins for the PVC pipe companies.

Extending its operations base into a new state and new products, North Dakota-based Northern Pipe Products opened a 45,000-square-foot plant in Hampton, Iowa in 2003. The plant is the production site for corrugated polyethylene (PE) pipe used in drainage and sewer systems.

Located in the fastest growing region of the United States, Arizona-based Vinyltech Corporation achieved record sales and production levels in 2003. Both Vinyltech and Northern Pipe continue to focus on manufacturing efficiencies through innovative processes and upgrades to equipment and facilities.

Manufacturing

Many of the companies in this segment suffered through the effects of a significant economic downturn in the manufacturing sector. Challenges included overcapacity in the industry, international competition and higher costs in 2003 due to U.S. steel tariffs. Although there were difficulties, there were also noteworthy accomplishments.



THE T.O.P. LOGO GRACES MORE THAN 200 STYLES OF PLANT CONTAINERS.

THERMOFORMED PROJECTS OF ALL SIZES REQUIRE LARGE SCALE TECHNOLOGY

Starting the year with ambitious plans for product line growth and equipment investment, T.O. Plastics' strategic focus and execution led to excellent results. Multiple new products were developed in the horticulture line, requiring tremendous dedication from the engineering and tooling department as well as from all involved in the production process. Sales of other custom thermoformed products were also strong. As a result of the impressive growth, T.O. Plastics is expanding its main manufacturing plant in Clearwater, Minnesota.

ShoreMaster staff from Fergus Falls, Minnesota, assisted co-workers in Camdenton, Missouri, on training and start-up of rotomolding operations in a new facility adjacent to the Camdenton production plant. The addition of rotomolding in Camdenton will extend market reach in the south-central United States for floating dock supports and other ShoreMaster plastic resin products. ShoreMaster also put plans in motion to address future space needs at its Fergus Falls operations.

"Better Through Design" is the credo of BTD Manufacturing, which makes custom metal parts for major manufacturing partners. Recognizing the need for a more effective pallet, BTD created its own version using lightweight, durable aluminum. Launched in 2003 under the name RHINO, this represents BTD's first venture in marketing its own product.

Lars Moller was appointed president of wind tower manufacturer DMI Industries in September 2003. Previously DMI's vice president of sales, he has an extensive wind industry background with firms in the United States and abroad. While long-term prospects look promising in this industry, the prolonged delay in extending federal production tax credits for renewable energy has caused significant challenges for DMI and for St. George Steel, which also manufactures wind towers and large structural steel products.

Health Services

The DMS Health Group operates through two primary business units, DMS Health Technologies and DMS Imaging. DMS Health Technologies sells and services diagnostic imaging and patient monitoring equipment. DMS Imaging provides mobile, portable, interim and fixed-site diagnostic imaging services to more than 450 healthcare facilities across 42 states.

Although DMS Health Technologies had an excellent year financially, the results at DMS Imaging were disappointing primarily due to aggressive growth plans combined with subsequent integration challenges. DMS Imaging worked hard to address operational issues and keep a dynamic momentum. Mark Casner joined the DMS Health Group as president and chief operating officer of DMS Imaging in October 2003. His senior-level operations expertise is already providing sound insights and direction.

The acquisition of two companies, North Star Medical Systems and Topline Medical, resulted in the creation of a new Cardiac Monitoring Systems division under DMS Health Technologies. North Star Medical sells patient monitors and other products across a four-state region. Topline Medical specializes in the refurbishing and nationwide resale of patient monitoring equipment.

In its quest to improve quality of care, DMS Imaging's portable X-ray operations introduced computed radiography in 2003. This new technology captures images digitally, allowing for quick electronic transmission to off-site radiologists and faster diagnostic results.

In December 2003, the DMS Health Group renewed its Philips Medical Systems dealership agreement. This event sustains the DMS Health Group's long-standing relationship with one of the world's premier manufacturers of medical equipment.

Other Business Operations

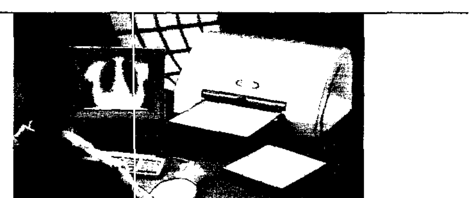
Otter Tail Corporation acquired Foley Company, a mechanical and prime contracting firm, in November 2003. Based in Kansas City, Missouri, Foley provides a range of specialty contracting services for large-scale construction projects, including water treatment plants, power plants and hospitals. Under the capable leadership of company president Mike Palmer and his management team, Foley Company consistently ranks in the top 100 of all specialty contractors nationwide.

Moorhead Electric, Aerial Contractors and related businesses were aligned under Midwest Construction Services, Inc. Integration efforts throughout 2003 focused on establishing the combined structure. Midwest Construction Services managed several successful large-scale electrical construction projects, including wind farm sites in Minnesota, North Dakota, Iowa and Pennsylvania.

In 2003, the American Trucking Association recognized E.W. Wylie Corporation as one of the top 10 truckload carriers in a national ranking by divisions. The company opened a terminal near Chicago, raising its trucking terminals to four locations. Its brokerage division, which contracts freight jobs with other trucking companies, experienced solid increases in volume and profits.

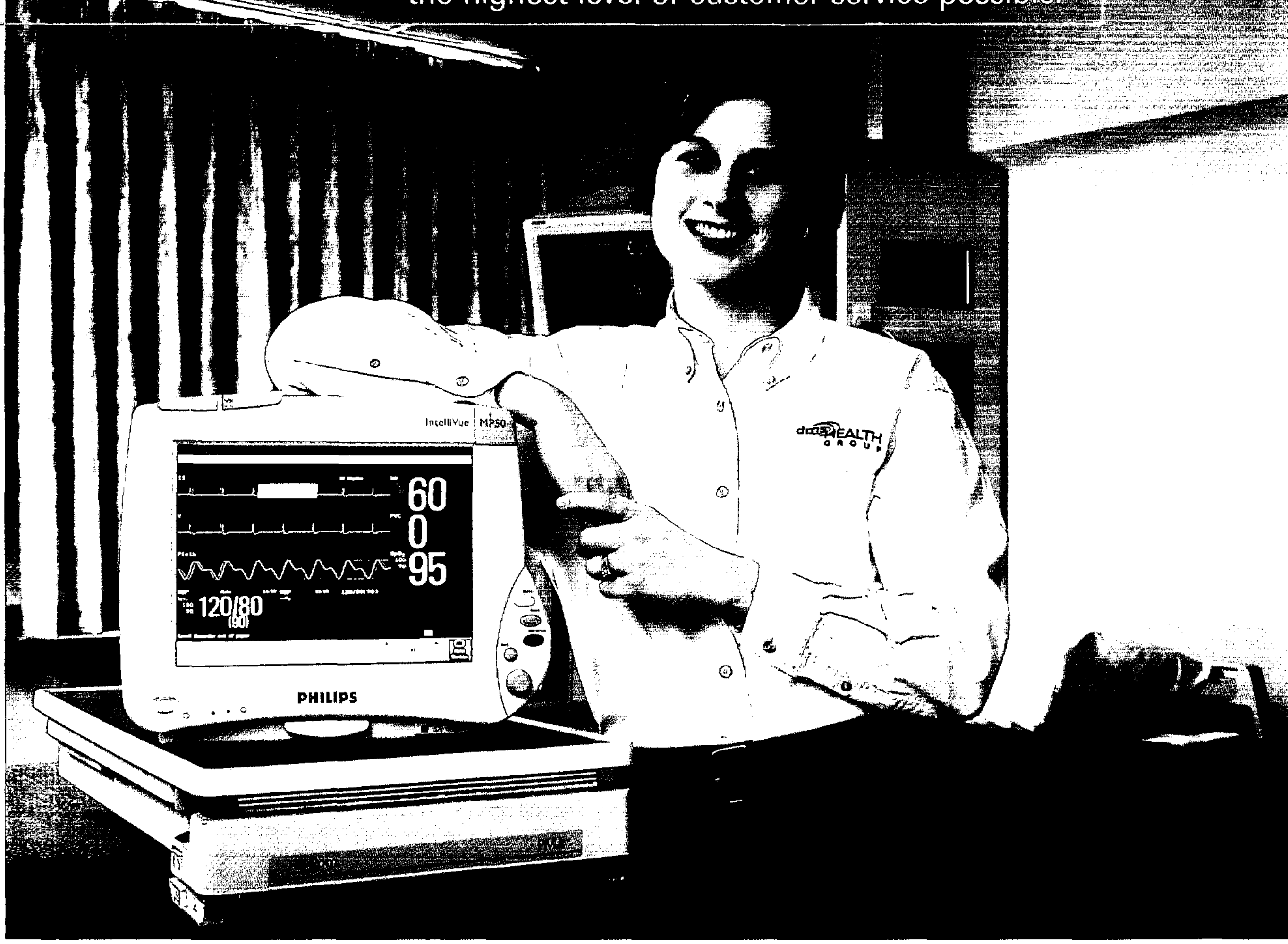

MORE THAN 100 MOBILE UNITS BRING MRI AND OTHER SERVICES TO PATIENTS.


NEW COMPUTED RADIOGRAPHY SERVICES ARE ENTIRELY PORTABLE...


...AND ALLOW OFF-SITE RADIOLOGISTS TO RECEIVE INSTANT IMAGES.

"OUR COMPANY DELIVERS ON OUR COMMITMENT

to healthcare providers. My personal commitment is to offer the highest level of customer service possible."



An ever-increasing demand for sophisticated healthcare tools keeps the DMS Health Group on the move. Motivated by a mission of providing innovative healthcare solutions wherever needed, DMS acquired two patient monitoring equipment companies in 2003. This allowed the organization to create a new division and also gain additional capable employees such as Katy Krinke. An account manager for the company's Cardiac Monitoring Services division, she ensures that more than 100 hospitals and healthcare providers across a four-state region receive state-of-the-art patient monitoring equipment and superior support services.

KATY KRINKE DMS HEALTH TECHNOLOGIES ACCOUNT MANAGER, CMS DIVISION

WE WILL HAVE SAFE WORK ENVIRONMENTS

FINANCIAL REVIEW

Earnings Per Share By Segment

	2003	2002	2001
Electric	$ 1.29	$ 1.23	$ 1.25
Plastics	0.08	0.22	(0.06)
Manufacturing	0.15	0.18	0.25
Health services	0.10	0.18	0.17
Other business operations	(0.11)	(0.02)	0.07
Reported diluted earnings per share	$ 1.51	$ 1.79	$ 1.68
Add back goodwill amortization, net of tax	–	–	.09
Adjusted diluted earnings per share	$ 1.51	$ 1.79	$ 1.77

VALUES WE WILL BE FISCALLY RESPONSIBLE

Selected Consolidated Financial Data

(thousands except number of shareholders and per-share data)	**2003**	2002	2001	2000 (1)	1999 (1)(2)	1998 (3)	1993
Revenues							
Electric (7)	$ 267,494	$ 244,005	$ 232,720	$ 219,718	$ 203,393	$ 206,895	$ 180,912
Plastics	86,009	82,931	63,216	82,667	31,504	24,946	–
Manufacturing	177,805	142,390	123,436	97,506	87,086	62,488	8,473
Health services	100,912	93,420	79,129	66,319	68,805	69,412	32,068
Other business operations	123,475	84,627	80,667	78,159	68,322	48,829	32,396
Intersegment eliminations	(2,456)	(1,036)	–	–	–	–	–
Total operating revenues	$ 753,239	$ 646,337	$ 579,168	$ 544,369	$ 459,110	$ 412,570	$ 253,849
Special charges	–	–	–	–	–	9,522	–
Income from continuing operations	39,656	46,128	43,603	41,042	45,295	30,701	27,369
Cumulative change in accounting principle	–	–	–	–	–	3,819	–
Cash flow from operations	76,955	76,797	77,529	61,761	81,850	63,959	53,255
Capital expenditures	50,734	75,533	53,596	46,273	35,245	29,289	30,894
Total assets (6)	986,423	914,112	817,778	772,562	729,118	690,189	597,482
Long-term debt	265,193	258,229	227,360	195,128	180,159	181,046	166,563
Redeemable preferred	–	–	–	18,000	18,000	18,000	18,000
Basic earnings per share from continuing operations (4)	1.52	1.80	1.69	1.59	1.75	1.20	1.11
Diluted earnings per share from continuing operations (4)	1.51	1.79	1.68	1.59	1.75	1.20	1.11
Return on average common equity	12.2%	15.3%	15.5%	15.4%	18.4%	15.0%	14.9%
Dividends per common share	1.08	1.06	1.04	1.02	0.99	0.96	0.84
Dividend payout ratio	72%	59%	62%	64%	57%	71%	76%
Common shares outstanding–year end	25,724	25,592	24,653	24,574	24,571	23,759	22,360
Number of common shareholders (5)	14,723	14,503	14,358	14,103	13,438	13,699	13,634

Notes: (1) Restated to reflect the effects of two 2001 acquisitions accounted for under the pooling-of-interests method. The impact of the poolings on years prior to 1999 is not material.
(2) 1999 results include the sale of radio station assets for a net gain of $8.1 million or 34 cents per share.
(3) In the first quarter of 1998 the Company changed its method of electric revenue recognition in the states of Minnesota and South Dakota from meter-reading dates to energy-delivery dates. Basic and diluted earnings per share from continuing operations does not include 16 cents per share related to the cumulative effect of the change in accounting principle.
(4) Based on average number of shares outstanding.
(5) Holders of record at year end.
(6) Prior years are restated to reflect reclassification of reserve for estimated removal costs from accumulated depreciation to a regulatory liability.

Selected Electric Operating Data

	2003	2002	2001	2000	1999	1998	1993
Revenues (thousands)							
Residential	$ 75,689	$ 72,180	$ 69,882	$ 66,168	$ 63,864	$ 64,430	$ 62,167
Commercial and farms	88,550	84,143	79,227	76,875	72,784	74,215	66,286
Industrial	48,315	45,803	45,813	41,269	40,494	43,426	36,442
Sales for resale (7)	29,530	18,295	23,255	22,366	15,025	8,460	6,729
Other electric	25,410	23,584	14,543	13,040	11,226	16,364	9,288
Total electric	$ 267,494	$ 244,005	$ 232,720	$ 219,718	$ 203,393	$ 206,895	$ 180,912
Kilowatt-hours sold (thousands)							
Residential	1,141,612	1,130,770	1,098,149	1,058,999	1,026,631	1,020,471	998,680
Commercial and farms	1,396,638	1,383,129	1,318,569	1,298,271	1,254,553	1,241,529	1,101,673
Industrial	1,108,021	1,106,241	1,117,482	1,074,724	1,029,798	1,144,025	888,418
Other	70,071	70,447	71,450	70,482	72,343	66,393	93,341
Total retail	3,716,342	3,690,587	3,605,650	3,502,476	3,383,325	3,472,418	3,082,112
Sales for resale	3,786,397	3,049,786	2,830,079	2,172,928	1,700,083	1,183,552	1,143,240
Total	7,502,739	6,740,373	6,435,729	5,675,404	5,083,408	4,655,970	4,225,352
Annual retail kilowatt-hour sales growth	0.7%	2.4%	2.9%	3.5%	(2.6)%	(0.3)%	5.3%
Heating degree days	9,071	9,033	8,575	8,993	8,046	7,913	9,444
Cooling degree days	81	129	186	55	71	57	31
Average revenue per kilowatt-hour							
Residential	6.63¢	6.38¢	6.36¢	6.25¢	6.22¢	6.31¢	6.22¢
Commercial and farms	6.34¢	6.08¢	6.01¢	5.92¢	5.80¢	5.98¢	6.02¢
Industrial	4.36¢	4.14¢	4.10¢	3.84¢	3.93¢	3.80¢	4.10¢
All retail	5.85¢	5.61¢	5.52¢	5.39¢	5.37¢	5.39¢	5.53¢
Customers							
Residential	100,515	100,092	99,667	99,724	99,323	98,849	96,112
Commercial and farms	25,900	25,950	25,825	25,917	25,861	25,777	25,221
Industrial	40	41	42	41	39	37	35
Other	1,079	1,074	1,084	1,068	1,069	1,049	1,049
Total electric customers	127,534	127,157	126,618	126,750	126,292	125,712	122,417
Residential sales							
Average kilowatt-hours per customer (8)	11,525	11,504	11,306	10,714	10,549	10,492	10,578
Average revenue per residential customer	$ 756.83	$ 732.64	$ 716.93	$ 670.25	$ 658.89	$ 662.44	$ 658.45

Notes: (7) Prior years are restated to reflect implementation of a new accounting standard, EITF Issue 03-11. See note 1 to consolidated financial statements for more information.
(8) Based on average number of customers during the year.

The primary financial goals of Otter Tail Corporation (the Company) are to maximize its earnings and cash flows and to allocate capital profitably toward growth opportunities that will increase shareholder value. Management meets these objectives by earning the returns regulators allow in electric operations combined with growing nonelectric operations. Meeting these objectives enables the Company to preserve and enhance its financial capability by maintaining optimal capitalization ratios and a strong interest coverage position, and preserving strong credit ratings on outstanding securities, which in the form of lower interest rates benefits both the Company's customers and shareholders.

Liquidity

The Company believes its financial condition is strong and that its cash, other liquid assets, operating cash flows, access to capital markets and borrowing ability because of strong credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. However, the Company's operating cash flow and access to capital markets can be impacted by macroeconomic factors outside its control. In addition, the Company's borrowing costs can be impacted by its short-term and long-term debt ratings assigned by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

The Company has achieved a high degree of long-term liquidity by maintaining desired capitalization ratios and strong credit ratings, implementing cost-containment programs, and investing in projects that provide returns in excess of the Company's weighted average cost of capital.

Cash provided by operating activities of $77.0 million for the year ended December 31, 2003 combined with cash on hand of $9.9 million at December 31, 2002 allowed the Company to pay dividends and finance all of its capital expenditures in 2003.

Cash provided by operating activities in 2003 was $77.0 million compared with $76.8 million in 2002. The slight increase in cash from operations includes a $7.0 million increase in noncurrent liabilities and deferred credits and a $3.3 million increase in noncash depreciation and amortization expense offset by a $6.5 million decrease in net income and a $4.5 million increase in cash used for working capital items.

The $19.2 million decrease in net cash used in investing activities between 2003 and 2002 reflects a decrease in capital expenditures of $24.8 million and $1.6 million in cash from redemption of other investments offset by a $6.3 million increase in cash used to complete acquisitions and a $0.8 million decrease in cash from disposal of assets. The decrease in consolidated capital expenditures reflects a high level of capital expenditures in 2002, a year that saw major plant additions and equipment purchases in all segments including the electric utility's expenditures for a new transmission line completed in 2002 and a new gas-fired combustion turbine that came online in June 2003.

In 2003, the Company completed three acquisitions: Two medical equipment companies were purchased for an aggregate of $1.9 million in cash. In November 2003, the Company acquired the assets and operations of Foley Company, a mechanical and prime contracting firm based in Kansas City, Missouri, for $12.3 million in cash.

Net cash used in financing activities was $19.2 million in 2003 compared with $1.4 million provided by financing activities in 2002. The $20.6 million decrease between the years is due to the following:

- Net short-term borrowings were $25.5 million less in 2003 than in 2002.
- Net proceeds from the issuance and retirement of long-term debt, including debt issuance expenses, were $8.4 million higher in 2003 than in 2002.
- Proceeds from employee stock plans decreased by $2.0 million in 2003 compared to 2002 due to a 64% reduction in the number of stock options exercised in 2003.
- Dividends paid and other distributions increased by $1.5 million in 2003.

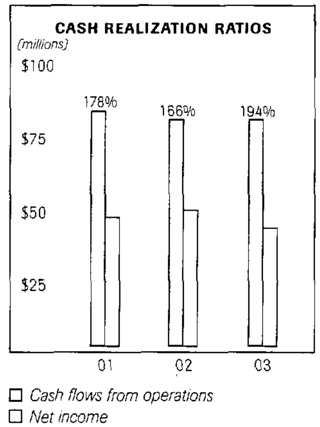
On September 24, 2003 the Company borrowed $16.3 million under a loan agreement with Lombard US Equipment Finance Corporation in the form of an unsecured note. The note bears interest at a variable rate of 3-month LIBOR plus 1.43% on the unpaid principal balance. The Company used proceeds from the note to pay down borrowings under the Company's line of credit that were used to finance acquisitions and capital expenditures of its nonelectric subsidiaries. The covenants associated with the note are consistent with existing credit facilities. There are no rating triggers associated with this note.

During 2003, 47,552 shares of common stock were issued for stock options exercised under the 1999 Stock Incentive Plan generating proceeds of $1.0 million. Also in 2003, in noncash transactions, the Company granted 90,900 shares of restricted stock to certain key executives and directors and issued 2,169 common shares for director compensation under the 1999 Stock Incentive Plan.

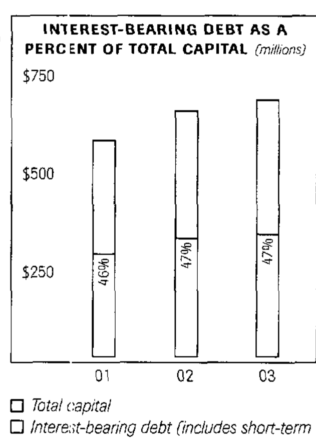
Capital Requirements

The Company has a capital expenditure program for the expansion, upgrade and improvement of its plants and operating equipment. Typical uses of cash for capital improvements are investments in electric generation facilities, transmission and distribution lines, equipment used in the manufacturing process, acquisitions of diagnostic medical equipment, transportation equipment and computer hardware and information systems. The capital expenditure program is subject to review and is revised annually in light of changes in demands for energy, technology, environmental laws, regulatory changes, the costs of labor, materials and equipment, and the Company's consolidated financial condition.

Consolidated capital expenditures for the years 2003, 2002 and 2001 were $50.7 million, $75.5 million and $53.6 million, respectively. The estimated capital expenditures for 2004 are $40.8 million and the total capital expenditures for the five-year period 2004 through 2008 are estimated to be approximately $208 million.



The cash realization ratio represents cash flows from operations expressed as a percent of net income.



The breakdown of 2001, 2002 and 2003 actual and 2004 through 2008 estimated capital expenditures by segment is as follows:

(in millions)	2001	2002	2003	2004	2004-2008
Electric	$ 35	$ 46	$ 28	$ 27	$ 132
Plastics	2	6	4	2	12
Manufacturing	11	15	10	5	43
Health services	3	4	6	3	5
Other business operations	3	5	3	4	16
Total	$ 54	$ 76	$ 51	$ 41	$ 208

The following table summarizes the Company's contractual obligations at December 31, 2003 and the effect these obligations are expected to have on its liquidity and cash flow in future periods.

(in millions)	**Total**	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term debt	$ 275	$ 10	$ 22	$ 51	$ 192
Coal contracts (required minimums)	86	29	11	11	35
Capacity and energy requirements	147	17	30	30	70
Other purchase obligations	3	3	–	–	–
Operating leases	65	21	30	10	4
Total contractual cash obligations	$ 576	$ 80	$ 93	$102	$ 301

Capital Resources

Financial flexibility is provided by unused lines of credit, strong financial coverages and credit ratings, and alternative financing arrangements such as leasing.

For the period 2004 through 2008, the Company estimates that funds internally generated net of forecasted dividend payments, combined with funds on hand, will be sufficient to meet scheduled debt retirements, provide for its estimated consolidated capital expenditures and pay off its currently outstanding short-term debt. Reduced demand for electricity, reductions in wholesale sales of electricity or margins on wholesale sales, or declines in the number of products manufactured and sold by the Company could have an effect on funds internally generated. Additional short-term or long-term financing will be required in the period 2004 through 2008 in the event the Company decides to refund or retire early any of its presently outstanding debt or cumulative preferred shares, to complete acquisitions or for other corporate purposes. There can be no assurance that any additional required financing will be available through bank borrowings, debt or equity financing or otherwise, or that if such financing is available, it will be available on terms acceptable to the Company. If adequate funds are not available on acceptable terms, the Company's business, results of operations, and financial condition could be adversely affected.

In order to maintain a balanced capital structure consistent with the risk profile of the Company's diversified mix of businesses, the Company began issuing new shares of common stock in January 2004 to meet the requirements of its dividend reinvestment program and share purchase plan rather than purchasing shares on the open market. The Company estimates this change will generate approximately $9 million in equity funding in 2004.

The Company has the ability to issue up to an additional $135 million of unsecured debt securities from time to time under its shelf registration statement on file with the SEC.

On August 25, 2003 the Company's line of credit was increased from $50 million to $70 million. This line is available to support borrowings of the Company's nonelectric operations. The Company anticipates the electric utility's cash requirements will be provided for by cash flows from electric utility operations. This line bears interest at the rate of LIBOR plus 0.5% and expires on April 28, 2004. The Company does not anticipate any difficulties in renewing this line of credit. The Company's bank line of credit is a key source of operating capital and can provide interim financing of working capital and other capital requirements, if needed. The Company's obligations under this line of credit are guaranteed by a 100%-owned subsidiary of the Company that owns substantially all of the Company's nonelectric companies. As of December 31, 2003, $30 million of the $70 million line was in use and the Company had $7.3 million in cash and cash equivalents.

The Company's line of credit, its $90 million 6.63% senior notes and Lombard US Equipment Finance note contain the following covenants: a debt-to-total capitalization ratio not in excess of 60% and an interest and dividend coverage ratio of at least 1.5 to 1. The 6.63% senior notes also require that priority debt not be in excess of 20% of total capitalization. As of December 31, 2003 the Company was in compliance with all of the covenants under its financing agreements.

The interest rate under the line of credit is subject to adjustment in the event of a change in ratings on the Company's senior unsecured debt, up to LIBOR plus 0.8% if the ratings on the Company's senior unsecured debt fall to BBB+ or below (Standard & Poor's) or Baa1 or below (Moody's). The line of credit also provides for accelerated repayment in the event the Company's long-term senior unsecured debt is rated below BBB- (Standard & Poor's) or Baa3 (Moody's).

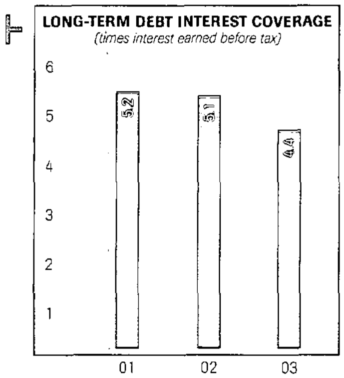
On September 18, 2003 Standard & Poor's Ratings Services lowered its rating on the Company's senior unsecured debt from A to A-, lowered its rating on the Company's preferred stock from A- to BBB and changed its outlook on the Company from stable to negative. According to Standard & Poor's, the rating action reflects the Company's increased business risk profile due to the increasing size of its nonelectric businesses and concerns associated with the future financial performance of the Company's manufacturing and health services segments. The ratings changes did not require any action under rating triggers and did not increase interest rates on current outstanding debt.

The Company's securities ratings at December 31, 2003 are:

	Moody's Investors Service	Standard & Poor's
Senior unsecured debt	A2	A-
Preferred stock	Baa1	BBB
Outlook	Negative	Negative

The Company's disclosure of these securities ratings is not a recommendation to buy, sell or hold its securities. Downgrades in these securities ratings could adversely affect the Company. Further downgrades could increase borrowing costs resulting in possible reductions to net income in future periods and increase the risk of default on the Company's debt obligations.

The Company's 6.63% senior notes contain an investment grade put that could require the Company to prepay this series with a make-whole premium if the Company's senior unsecured debt is rated below Baa3 (Moody's) or BBB- (Standard & Poor's). The Company's obligations under the 6.63% senior notes are guaranteed by a 100%-owned subsidiary of the Company that owns substantially all of the Company's nonelectric companies. The Company's Grant County and Mercer County pollution control refunding revenue bonds require that the Company grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds, a security interest in the assets of the electric utility if the rating on the Company's senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's). The Company believes the risk of the downgrade events described in this paragraph occurring is remote based on the current debt ratings of the Company combined with its strong debt-to-equity ratio and ability to generate cash from operations.



The Company's ratio of earnings to fixed charges was 3.5x for 2003 compared to 3.9x for 2002 and its long-term debt interest coverage ratio before taxes was 4.4x for 2003 compared to 5.1x for 2002. The main reason for the reduction in these coverage ratios is an $11.6 million reduction in income before interest and income taxes in 2003 compared to 2002. During 2004, the Company expects these coverage ratios to increase over 2003 levels if net income reaches management expectations.

Off-Balance-Sheet Arrangements

The Company does not have any off-balance-sheet arrangements or any relationships with unconsolidated entities or financial partnerships. These entities are often referred to as structured finance special purpose entities or variable interest entities, which are established for the purpose of facilitating off-balance-sheet arrangements or for other contractually narrow or limited purposes. The Company is not exposed to any financing, liquidity, market or credit risk that could arise if it had such relationships.

Results of Operations

CONSOLIDATED RESULTS OF OPERATIONS

The Company recorded diluted earnings per share of $1.51 for the year ended December 31, 2003 compared to $1.79 for the year ended December 31, 2002. Total operating revenues for 2003 were $753.2 million compared with $646.3 million for 2002. Operating income was $71.2 million for 2003 compared with $82.3 million for 2002.

Amounts presented in the following tables for 2003 and 2002 operating revenues, electric operation and maintenance expenses, cost of goods sold and nonelectric segment operating expenses will not agree with amounts presented in the Consolidated Statements of Income due to the elimination of intersegment transactions. The total intersegment eliminations include: $2,456,000 in operating revenues, $202,000 in electric operation and maintenance expenses, $495,000 in cost of goods sold and $1,759,000 in other nonelectric expenses in 2003; and $1,036,000 in operating revenues, $222,000 in electric operation and maintenance expenses, $446,000 in cost of goods sold and $368,000 in other nonelectric expenses in 2002. In 2001, intersegment eliminations were included in segment reporting due to immateriality.

ELECTRIC

Otter Tail Power Company, a division of Otter Tail Corporation, provides electrical service to more than 127,000 customers in a service territory exceeding 50,000 square miles.

In the third quarter of 2003, the electric utility began applying mark-to-market accounting to its forward contracts for the purchase or sale of energy that did not meet the definition of a capacity contract as a result of the issuance of Statement of Financial Accounting Standards (SFAS) No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. With the issuance of SFAS No. 149, any forward contracts for the purchase or sale of energy entered into after June 30, 2003 that do not meet the definition of a capacity contract and are subject to unplanned netting, referred to as a book out in the utility industry, are not eligible for the normal purchases and sales exception provided for under SFAS No. 133 and modified by SFAS No. 149.

In 2003, a consensus was reached on Emerging Issues Task Force (EITF) Issue 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, and Not "Held for Trading Purposes" as Defined in Issue No. 02-3. The reporting requirements of EITF Issue 03-11 are applicable to financial statement presentation in the fourth quarter of 2003. The Company determined that the net method of reporting was appropriate for the electric utility's forward energy contracts. Revenue from the electric utility's wholesale sales of energy purchased from other suppliers is now reflected net of the related purchase power costs in electric revenues on the Company's consolidated statements of income for the years 2003, 2002 and 2001. The effects of the application of EITF Issue 03-11 and reclassification of prior years' reported revenues are reflected in the table below. See note 1 to consolidated financial statements.

(in thousands)	**2003**	2002	2001
Retail sales revenues	$ 217,611	$ 207,039	$ 199,262
Wholesale revenues:			
Sales off company-owned generation	18,428	11,941	13,760
Net margins on purchased power resold	9,045	6,354	9,495
Net unrealized marked-to-market gains	2,057	—	—
Other revenues	20,353	18,671	10,203
Total operating revenue	$ 267,494	$ 244,005	$ 232,720
Production fuel	51,163	44,122	41,776
Purchased power—retail use	36,002	30,915	24,527
Other operation and maintenance expenses	87,186	80,756	75,531
Depreciation and amortization	26,008	24,910	24,272
Property taxes	9,598	9,423	9,464
Operating income	$ 57,537	$ 53,879	$ 57,150

The increase of $10.6 million in retail revenue from 2002 to 2003 is mainly due to a $9.4 million increase in cost-of-energy (COE) revenue. The remaining increase in retail revenue was due to a 0.7% increase in retail kilowatt-hour (kwh) sales. The increase in retail sales reflects minor increases (less than 1%) in residential, commercial and industrial kwh sales. Heating-degree-days totaled 9,071 in 2003 compared with 9,033 in 2002 and were not a discernable factor contributing to 2003 sales variances. The increase in COE revenues reflects a 13.2% increase in fuel and purchased power costs per kwh for retail use in 2003 compared with 2002.

Wholesale revenue from sales of company-owned generation increased 54.3% in 2003 compared with 2002 due to a 19.6% increase in kwh sales combined with a 29.0% increase in revenue per kwh of generation sold. Gross margins on resales of purchased power increased 42.4% between 2003 and 2002 as a result of a 25.1% increase in kwh sales combined with a 14.1% increase in the margin per kwh resold. The 36.1% increase in overall wholesale electric prices reflects increased demand for electricity in the Mid-Continent Area Power Pool (MAPP) region. Higher prices in the wholesale power markets also reflect generally increasing generation costs, reduced generation from regional hydro facilities due to lower spring runoff and the lack of summer rainfall and high-cost generation from natural gas-fired peaking units. The higher prices combined with increased availability of electric utility-owned generation and well-timed energy purchases in 2003 compared to 2002 put the electric utility in a favorable position to respond to the increased demand for electricity resulting in the increase in wholesale electric sales. Wholesale revenue reflects $2.1 million in unrealized marked-to-market gains on forward energy contracts at year-end 2003.

Other electric operating revenues increased $1.7 million or 9.0% between 2003 and 2002. The increase reflects $2.5 million in increased transmission related revenues from control area services, transmission tariffs and shared use deficiency payments, and a $1.3 million increase in revenue from the sale of steam to an ethanol plant that began operations in the third quarter of 2002, offset by a $2.1 million reduction in revenue from contract work. Revenue from major projects included $7.6 million from regional wind generation projects in 2003 compared to $9.9 million from work on a North Dakota transmission line for another area utility that was completed in the fourth quarter of 2002.

The 16.0% increase in production fuel expense in 2003 compared with 2002 is due to an increase in fuel costs and generation at the electric utility's coal-fired generating stations, and an increase in fuel costs from combustion turbine generation. A 12.0% increase in the fuel cost per kwh generated reflects increases in fuel cost per kwh at all of the electric utility's generating units including fuel costs for the Company's new combustion turbine brought online in June 2003. The 16.5% increase in purchased power costs for retail use in 2003 compared with 2002 was the result of a 21.3% increase in the cost per kwh purchased offset by a 4.0% decrease in kwh purchases for retail use.

The 8.0% increase in other operation and maintenance expenses in 2003 compared with 2002 includes increased labor related expenses of $2.7 million as a result of annual wage increases of about 3.5% and increases in employee benefit costs. Pole maintenance and tree-trimming costs increased $1.0 million and transportation and travel-related expenses increased $1.0 million between the years. Insurance costs including provisions for damages were up $0.8 million. Fuel procurement costs increased $0.5 million, mainly related to litigation before the Surface Transportation Board. Uncollectible accounts expense increased $0.4 million.

The 4.4% increase in depreciation and amortization expense for 2003 compared to 2002 is due to an increase in depreciable plant base as a result of recent capital expenditures.

The Company expects the electric segment to have a solid year financially, but does not expect electric segment results in 2004 to equal those of 2003.

The $7.8 million increase in retail sales from 2001 to 2002 reflects increased usage by residential and commercial customers partially offset by a decrease in usage by industrial customers. Heating-degree-days totaled 9,033 in 2002 compared with 8,575 in 2001, an increase of 5.3%. The increase in COE revenues reflects an 11.5% increase in fuel and purchased power costs per kwh for system use in 2002 compared with 2001. Wholesale revenue from sales of company-owned generation decreased $1.8 million or 13.2% on a 3.0% decrease in kwhs sold and a 10.5% decrease in revenue per kwh of generation sold. Net margins on purchased power resold declined $3.1 million or 33.1% between 2002 and 2001 despite a 10.2% increase in kwh sales mainly as a result of a 39.2% decrease in the margin per kwh resold. The 23% decrease in overall wholesale electric prices may be partially attributable to peaking generation added in the MAPP region since September 2001, as well as lower regional demand for electricity. The increase in other electric operating revenues of $8.5 million is primarily due to revenue earned on a large transmission line construction project completed for another regional utility in 2002.

The 5.6% increase in production fuel expense in 2002 compared with 2001 is primarily due to a 13.7% increase in fuel costs per kwh produced at the electric utility's coal-fired generating stations. The increase in fuel costs per kwh produced is due to higher costs reflected in new coal contracts that went into effect at the beginning of 2002 and increased freight rates for the shipping of coal to Big Stone and Hoot Lake Plants. In 2001, coal was being shipped to Big Stone Plant under a negotiated agreement that expired at the end of 2001. Currently, coal is being shipped to Big Stone Plant under a tariff rate.

The 26.0% increase in purchased power costs for retail use in 2002 over 2001 was the result of a 52.6% increase in kwh purchases for retail use offset by a 17.4% decrease in the cost per kwh purchased. The volume of power purchased in 2002 increased for both system use and resale purposes. Purchased power for retail use increased to meet system demand and to replace the loss of generation at Big Stone Plant during six weeks of scheduled maintenance in the fall of 2002.

The 6.6% increase in other operation and maintenance expenses in 2002 compared with 2001 includes $3.8 million in material costs incurred in the construction of a transmission line for another regional utility and $2.0 million in increased employee benefit expenses offset by a $1.0 million decrease in external services expenses. The 2.6% increase in depreciation and amortization expense for 2002 compared to 2001 is due to an increase in the electric utility's composite depreciation rate from 3.06% in 2001 to 3.08% in 2002 and an increase in depreciable plant base as a result of recent capital expenditures.

PLASTICS

Plastics consists of businesses involved in the production of polyvinyl chloride (PVC) and polyethylene (PE) pipe in the Upper Midwest and Southwest regions of the United States.

(in thousands)	**2003**	2002	2001
Operating revenues	$ 86,009	$ 82,931	$ 63,216
Cost of goods sold	76,046	65,628	57,932
Operating expenses	3,824	4,702	3,446
Depreciation and amortization	2,126	1,760	1,726
Amortization of goodwill	–	–	1,503
Operating income (loss)	$ 4,013	$ 10,841	$ (1,391)

Plastics operating revenues increased 3.7% in 2003 compared with 2002 due to an 8.2% increase in the average sales price per pound of pipe sold. The increase was partially offset by a 4.2% decrease in pounds sold between the years. The increased revenue was more than offset by a 15.9% increase in cost of goods sold reflecting a 20.9% increase in the average cost per pound of pipe sold. The average cost per pound of resin, the raw material used to produce PVC pipe, increased 26.3% between the periods. Operating expenses decreased 18.7% between the periods primarily due to decreased compensation directly related to the decrease in gross margins. The 20.8% increase in depreciation and amortization expense is related to a $4.4 million increase in depreciable plant in 2002 and a $3.5 million increase in depreciable plant in 2003.

The Company cannot predict if the tight operating margins experienced in the plastics segment in 2003 will continue into 2004. Gross margins generally decline when the supply of PVC pipe increases faster than demand. The gross margin percentage is sensitive to PVC raw material resin prices and the demand for PVC pipe. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or assume that historical trends will continue.

The 31.2% increase in plastics operating revenues for 2002 compared with 2001 reflects a 23.0% increase in pounds of PVC pipe sold combined with a 6.6% increase in the average sales price per pound. The 13.3% increase in cost of goods sold reflects $14.6 million in costs related to the increase in PVC pipe sold offset by a $7.0 million reduction in costs due to a 7.0% decrease in the price per pound of PVC resin. Operating expenses increased 36.4% primarily due to increases in sales commissions and incentive compensation related to increased profitability in this segment. In 2002, the amortization of goodwill was discontinued in accordance with a new accounting standard.

In 2003, 96.4% of raw material was purchased from two vendors. In 2002, 58.3% of raw material was purchased from two vendors and in 2001, 74.9% of raw material was purchased from two vendors. The Company believes relationships with their key raw material vendors are good. However, the loss of a key supplier or any interruption or delay in the supply of PVC resin could have a significant impact on the plastics segment.

MANUFACTURING

Manufacturing consists of businesses involved in the production of waterfront equipment, wind towers, frame-straightening equipment and accessories for the auto body shop industry, custom plastic pallets, material and handling trays and horticultural containers, fabrication of steel products, contract machining and metal parts stamping and fabricating. During 2002 and 2001 the following acquisitions were completed. See note 2 to consolidated financial statements.

Acquisition	Year Acquired	Business Combination
ShoreMaster, Inc.	May-02	Purchase
Galva Foam Marine Industries, Inc.	Oct-02	Purchase
T.O. Plastics, Inc.	Feb-01	Pooling of interests
St. George Steel Fabrication, Inc.	Sept-01	Pooling of interests
Titan Steel Corporation	Nov-01	Purchase

(in thousands)	**2003**	2002	2001
Operating revenues	$ 177,805	$ 142,390	$ 123,436
Cost of goods sold	139,720	107,977	91,360
Operating expenses	22,244	18,411	14,762
Depreciation and amortization	7,708	6,525	4,858
Amortization of goodwill	—	—	281
Operating income	$ 8,133	$ 9,477	$ 12,175

The 24.9% increase in manufacturing operating revenues for 2003 compared with 2002 includes a $25.7 million increase in revenue from the waterfront equipment companies acquired in 2002. Revenues from the Company's manufacturer of thermoformed plastic and horticultural products increased $8.0 million on an increase in the volume of products sold. Revenue at the metal parts stamping and fabrication company increased $3.0 million and the Company's manufacturer of wind towers recorded $1.5 million in increased revenue. These increases were offset by decreases in revenue of $2.5 million from the manufacturer of structural steel products and $0.3 million from the manufacturer of automobile frame-straightening equipment.

The 29.4% increase in cost of goods sold in 2003 compared with 2002 primarily reflects a $19.1 million increase in costs of goods sold at the waterfront equipment companies combined with increased costs of $6.0 million at the Company's manufacturer of wind towers mostly in material costs, $5.3 million from the Company's manufacturer of thermoformed plastic and horticultural products related to increased sales, and $2.5 million from the metal parts stamping and fabrication company primarily related to material costs. These increases were offset by a reduction in cost of goods sold of $0.4 million at the manufacturer of structural steel products, mainly related to reduced labor expenses, and $0.1 million from the manufacturer of automobile frame-straightening equipment. The 18.1% increase in depreciation and amortization expense in 2003 compared with 2002 is due to 2002 and 2003 plant expansions and equipment purchases at all the manufacturing companies.

While the Company does not expect the business conditions that contributed to decreased earnings from the manufacturing segment in 2003 to continue in 2004, the uncertainty of the economy and the Production Tax Credit in the wind energy business, and the impact of steel pricing could adversely impact this segment's performance in 2004.

The 15.4% increase in manufacturing operating revenues for 2002 compared with 2001 reflects the 2002 acquisitions of ShoreMaster and Galva Foam and increased production and sales of wind towers offset by decreased sales volumes of metal parts stamping and steel fabrication. Cost of goods sold increased 18.2% due to the ShoreMaster and Galva Foam acquisitions and increases of $9.3 million in material and subcontractor costs at the wind tower manufacturing business offset by a $4.8 million reduction in material costs at the metal parts stamping companies. The ShoreMaster and Galva Foam acquisitions accounted for $3.4 million of the $3.6 million increase in operating expenses between the periods and $0.4 million of the increase in depreciation and amortization expense. The remaining $1.3 million increase in depreciation and amortization expense in 2002 compared with 2001 is due to 2001 and 2002 plant expansions and equipment purchases at all the manufacturing companies. In 2002, the amortization of goodwill was discontinued in accordance with a new accounting standard.

HEALTH SERVICES

Health services include businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment, and related supplies and accessories. In addition, these businesses also provide service maintenance, mobile diagnostic imaging, mobile PET and nuclear medicine imaging, portable x-ray imaging and rental of diagnostic medical imaging equipment. During 2003, 2002 and 2001 the following acquisitions were completed. See note 2 to consolidated financial statements.

Acquisition	Year Acquired	Business Combination
Topline Medical/North Star Medical Systems	May/July 2003	Purchase
Computed Imaging Service, Inc.	May-02	Purchase
Mobile Diagnostic Services, Inc.	Nov-02	Purchase
Interim Solutions/Midwest Medical Diagnostics	Sept-01	Purchase
Nuclear Imaging, Ltd.	Sept-01	Purchase

(in thousands)	**2003**	2002	2001
Operating revenues	$ 100,912	$ 93,420	$ 79,129
Cost of goods sold	75,085	66,680	59,388
Operating expenses	15,442	13,676	9,362
Depreciation and amortization	5,137	4,410	2,912
Amortization of goodwill	—	—	605
Operating income	$ 5,248	$ 8,654	$ 6,862

The 8.0% increase in health services operating revenues for 2003 compared with 2002 reflects $6.7 million in additional scan and other services revenue, mostly from the acquisitions that occurred in 2002. Revenues from the sale of diagnostic imaging equipment increased $0.8 million between the periods in part due to recent acquisitions in 2003. The number of scans performed increased 12.6% mainly due to the 2002 acquisitions, while the average fee per scan decreased 1.8%.

Although revenues from imaging services increased by $6.7 million, the increase was more than offset by increases in equipment and infrastructure costs incurred to support expected revenue growth. While operating income for 2003 was significantly less than operating income in 2002, the segment's 2003 results have improved significantly from early 2003 in part due to steps taken by management to address increases in operating expenses of the diagnostic imaging operations. The company that sells and services medical diagnostic and monitoring equipment had a good year financially, but the results from imaging services were disappointing, primarily due to aggressive growth combined with subsequent integration challenges. Management continues to address the cost structure of the diagnostic imaging operations and hired a new president/chief operating officer in the fourth quarter of 2003 to lead the imaging part of the health services segment. In December 2003, the DMS Health Group renewed its dealership agreement with Philips Medical Systems.

The 18.1% increase in health services operating revenues, 12.3% increase in cost of goods sold, 46.1% increase in operating expenses and 51.4% increase in depreciation and amortization for 2002 compared with 2001 are primarily due to the acquisitions completed during September 2001 and May 2002. The number of scans performed increased 19.8% due to the acquisitions while the average fee per scan increased 7.6% primarily as a result of the addition of new modalities provided by the companies acquired in September 2001. Revenues from equipment sales decreased 3.4%. Operating margins improved slightly between the periods due to increases in margins on service sales in the diagnostic equipment imaging business and in the mobile imaging business offset by expenses incurred in the segment's continued investment in and promotion of fixed-based imaging systems. In 2002, the amortization of goodwill was discontinued in accordance with a new accounting standard.

OTHER BUSINESS OPERATIONS

The Company's other business operations include businesses involved in electrical and telephone construction contracting, specialty contracting including design and build services for new construction, transportation, telecommunications, entertainment, energy services, and natural gas marketing as well as the portion of corporate general and administrative expenses that are not allocated to the other segments. On November 1, 2003 the Company acquired the assets and operations of Foley Company (Foley), a mechanical and prime contracting firm based in Kansas City, Missouri. See note 2 to consolidated financial statements.

(in thousands)	2003	2002	2001
Operating revenues	$ 123,475	$ 84,627	$ 80,667
Cost of goods sold	82,378	46,414	41,109
Operating expenses	39,885	33,739	30,927
Depreciation and amortization	4,983	5,008	5,093
Amortization of goodwill	—	—	850
Operating (loss) income	$ (3,771)	$ (534)	$ 2,688

The 45.9% increase in operating revenues in 2003 compared with 2002 was mostly due to a $13.8 million increase in revenues from natural gas sales at the Company's energy services company related to an increase in natural gas prices. In addition, construction revenues increased by $21.4 million, of which $7.9 million came from Foley, acquired in November 2003. Transportation revenues increased by $2.3 million between the periods as a result of an 85.6% increase in brokered miles. The 77.5% increase in cost of goods sold reflects a $14.4 million increase in the cost of natural gas sold by the energy services company and a $21.6 million increase in construction costs at the construction companies, of which $6.5 million is attributable to Foley.

The 18.2% increase in operating expenses between the periods reflects a $2.4 million increase in transportation operating expenses mainly related to increased brokerage activity. The construction companies reported $1.0 million in increased operating expenses with $0.5 million of the increase related to Foley. Operating expenses also reflect $3.3 million in increased operating expenses related to unallocated corporate overhead costs mainly due to increased employee benefit costs and increases in self-insurance costs. Operating expense at the energy services company decreased $1.9 million from 2002 to 2003 as a result of decreased activity. The Company had recorded $250,000 in goodwill related to the acquisition of an energy management firm in 2002. Based on an offer to purchase this entity in the fourth quarter of 2003, the Company determined that the goodwill related to this entity was impaired and, accordingly, recorded a $250,000 charge to operating income in the fourth quarter of 2003.

Construction margins have declined due to the sluggish economy and increased competition for available work. A decrease of $1.2 million in construction operating income was offset by a $1.3 million decrease in operating losses from the energy services company. The telecommunications company reported a 4.7% decrease in operating income in 2003. The transportation company's operating income increased by 6.1% in 2003 but it is still faced with continuing pressure on operating margins because of increased fuel and insurance costs and highly competitive pricing.

The 4.9% increase in operating revenues in the other business operations segment for 2002 compared with 2001 includes increases of $3.1 million at the energy services company, $1.6 million at the construction subsidiaries and $0.5 million in corporate services revenue, partially offset by a decrease in revenue of $1.2 million at the transportation subsidiary. The increase in operating revenue at the energy services company reflects increased revenue from natural gas sales and increased revenue from the installation of energy efficient lighting equipment on customer premises in 2002 compared with 2001. The increase in operating revenues at the construction subsidiaries reflects an increase in the volume of work performed in 2002 compared with 2001. A decrease of 6.1% in miles driven combined with a 2.4% decrease in revenue per mile led to the decrease in operating revenues at the transportation subsidiary.

The 12.9% increase in cost of goods sold in the other business operations segment for 2002 compared with 2001 includes increases in cost of goods sold of $3.8 million at the energy services company and $1.8 million at the construction subsidiaries that are directly related to increased revenues at those companies. Increased costs in excess of increased operating revenues due to smaller margins on natural gas sales and competition for fewer jobs in the construction segment related to the economic slowdown resulted in a $0.9 million decrease in operating margins at those companies from 2001 to 2002. Operating expenses increased 8.5% primarily due to a $1.5 million increase in unallocated corporate costs, a $1.1 million increase in operating expenses at the energy services company and a $337,000 increase in operating expenses at the telecommunications subsidiary mainly due to increases in their provisions for doubtful accounts related to the WorldCom and Global Crossings bankruptcies. A 5.0% decrease in the average cost of diesel fuel per gallon at the transportation subsidiary partially offset the increase in operating expenses at the other companies. In 2002, the amortization of goodwill was discontinued in accordance with a new accounting standard.

The Company currently has $1.0 million of goodwill recorded on its balance sheet related to its energy services subsidiary that markets natural gas to approximately 150 retail customers. A recent evaluation of projected cash flows from this operation indicated that the related goodwill was not impaired. However, actual and projected cash flows from this operation are subject to fluctuations due to low profit margins on natural gas sales combined with high volatility of natural gas prices. Reductions in profit margins or the volume of natural gas sales could result in an impairment of all or a portion of its related goodwill. The Company will continue to evaluate this reporting unit for impairment on an annual basis and as conditions warrant.

The Company currently has $6.7 million of goodwill recorded on its balance sheet relating to the acquisition of E.W. Wylie Corporation (Wylie) its flatbed trucking company. Highly competitive pricing in the trucking industry in recent years has resulted in decreased operating margins and lower returns on invested capital for Wylie. The Company's current projections are for operating margins to increase from current levels over the next three to five years as demand for shipping increases relative to available shipping capacity and additional revenues are generated from added terminal locations. If current conditions persist and operating margins do not increase according to Company projections, the reductions in anticipated cash flows from transportation operations may indicate that the fair value of Wylie is less than its book value resulting in an impairment of goodwill and a corresponding charge against earnings. At December 31, 2003, assessment of Wylie indicated that its goodwill was not impaired. The Company will continue to evaluate this reporting unit for impairment on an annual basis and as conditions warrant.

CONSOLIDATED INTEREST CHARGES

As a result of lower variable interest rates, interest expense increased only $21,000 in 2003 compared to 2002. The average interest rate paid on short-term debt decreased from 2.2% in 2002 to 1.7% in 2003.

The $1.9 million (11.6%) increase in interest charges in 2002 over 2001 is due to higher long-term debt balances outstanding offset by lower interest rates on less short-term debt outstanding between the years. In late December 2001, the Company sold $90 million of 6.63% senior notes due 2011 and used part of the proceeds to retire $18 million of $6.35 cumulative preferred shares, $18 million of 8.75% first mortgage bonds due 2021, $17.3 million of subsidiary term debt and $20 million in short-term debt. The net impact of this refinancing resulted in additional interest expense from the additional long-term debt outstanding and the shift of $1.2 million from preferred dividend payments in 2001 to interest expense in 2002. Interest expense on short-term debt decreased from $1.0 million in 2001 to $0.3 million in 2002. The average daily short-term debt balance decreased from $16.7 million in 2001 to $13.2 million in 2002 and the average interest rate paid on short-term debt decreased from 5.2% in 2001 to 2.2% in 2002.

CONSOLIDATED INCOME TAXES

The Company's effective tax rate was 27.4% for 2003 compared with 30.3% for 2002. The reduction reflects the impact of R&D tax credits claimed in 2003. Without these credits, the 2003 effective tax rate would have been 28.5%. The remaining 1.8% difference in the effective tax rate for 2003 compared to 2002 is a function of the level of fixed deductions and credits in proportion to lower net income before tax in 2003 compared to 2002. See note 13 to consolidated financial statements.

The Company's effective tax rate was 30.3% for 2002 compared with 31.5% for 2001. Although net income before taxes was $2.5 million higher in 2002 than in 2001, income taxes remained essentially the same in both years. This reflects the discontinuance of goodwill amortization in 2002. The nontaxable portion of goodwill was $1.3 million in 2001. The tax reduction on the remaining $1.2 million in pre-tax income of approximately $0.5 million reflects a reduction of tax provisions related to the settlement of IRS audits of the Company's 1997 and 1998 tax returns.

IMPACT OF INFLATION

The electric utility operates under regulatory provisions that allow price changes in the cost of fuel and purchased power to be passed to most customers through automatic adjustments to its rate schedules under the cost-of-energy adjustment clause. Other increases in the cost of electric service must be recovered through timely filings for electric rate increases with the appropriate regulatory agency.

The Company's plastics, manufacturing, health services, and other business operations consist almost entirely of unregulated businesses. Increased operating costs are reflected in product or services pricing with any limitations on price increases determined by the marketplace. The impact of inflation on these segments has not been significant during the past few years because of the relatively low rates of inflation experienced in the United States. Raw material costs, labor costs and interest rates are important components of costs for companies in these segments. Any or all of these components could be impacted by inflation, with a possible adverse effect on the Company's profitability, especially in high inflation periods where raw material and energy cost increases would lead finished product prices.

Factors Affecting Future Earnings

The results of operations discussed above are not necessarily indicative of future earnings. Factors affecting future earnings include, but are not limited to, the Company's diversification efforts, growth of electric revenues, the timing and scope of deregulation and open competition, Federal Energy Regulatory Commission (FERC) mandated operational changes to the electricity transmission grid, impact of the investment performance of the Company's pension plan, changes in the economy, weather conditions, realization of recognized but unrealized market valuation gains on forward energy contracts, market valuation of forward energy contracts, availability of resin suppliers, resin prices, governmental and regulatory action, fuel and purchased power costs and environmental issues. Anticipated higher operating costs and carrying charges on increased capital investment in plant, if not offset by proportionate increases in operating revenues and other income (either by appropriate rate increases, increases in unit sales, or increases in nonelectric operations), will affect future earnings.

ELECTRIC OPERATIONS

Growth of Electric Revenue

Growth in electric sales will be subject to a number of factors, including the volume of sales of electricity to other utilities, the effectiveness of demand-side management programs, weather, competition, the price of alternative fuels, the rate of economic growth or decline in the electric utility's service area and potential acquisitions of other systems. The electric utility's business depends primarily on the use of electricity by customers in its service area and the demands of its wholesale customers. Electric kwh sales to retail customers increased 0.7% in 2003, 2.4% in 2002 and 2.9% in 2001.

Otter Tail Power Company has indicated interest in the South Dakota-based electric and gas operations of NorthWestern Corporation, which filed for bankruptcy in the fall of 2003 and is currently restructuring. Merrill Lynch has been retained as the financial advisor to negotiate with NorthWestern's unsecured creditors in the event of a sale of assets. Otter Tail Power Company co-owns two plants with NorthWestern and also has proximity to and a degree of overlap with NorthWestern service areas. Otter Tail Power Company's interest does not include NorthWestern's Montana properties or operations. The acquisition of the South Dakota assets would increase the number of utility customers by roughly 45%. Because the process has just begun, it is not possible to determine the likelihood of the acquisition being completed.

Factors beyond the electric utility's control, such as mergers and acquisitions, geographical location, transmission reservation costs, unplanned interruptions at the electric utility's generating plants, fluctuations in market prices of open forward energy contracts subject to mark-to-market accounting and the effects of deregulation, could lead to greater volatility in the volume and price of sales of electricity to other utilities. Activity in the short-term energy market is subject to change based on a number of factors and it is difficult to predict the quantity of wholesale power sales or prices for wholesale power, although it appears that market conditions for wholesale power transactions will not be as robust in the future because of generating unit additions in the power pool and the advent of transmission system operators mandated by the FERC.

Regulation

Electric utility operations remain regulated in all jurisdictions in which Otter Tail Power Company operates. Rates of return earned on utility operations are subject to review by the various state commissions that have jurisdiction over the electric rates charged by the Company. These reviews could result in future revenue and income reductions when actual rates of return are deemed by regulators to be in excess of allowed rates of return.

On December 29, 2000 the North Dakota Public Service Commission (NDPSC) approved a performance-based ratemaking plan that links allowed earnings in North Dakota to seven defined performance standards in the areas of price, electric service reliability, customer satisfaction and employee safety. The plan is in place for 2001 through 2005, unless suspended or terminated by the NDPSC or the Company. The electric utility's 2003 rate of return is expected to be within the allowable range defined in the plan.

Fuel Costs

The electric utility has an agreement for Big Stone Plant's coal supply through December 31, 2004. The Company is in negotiations with a new coal supplier for a long-term contract beginning in 2005. The electric utility has been unable to negotiate a competitive delivery rate for coal to Big Stone Plant with rail carriers. Coal is being shipped to Big Stone Plant under a tariff rate. The electric utility has commenced a proceeding before the Surface Transportation Board requesting the Board set a competitive rate, with a decision expected early in 2005. The electric utility expects the outcome to have a favorable impact on its fuel costs for Big Stone Plant.

The MAPP region has experienced a very slight increase in availability of surplus generation capacity due to the addition of peaking capacity. However, energy availability has declined due to a regional drought that has significantly reduced hydro generation in Manitoba and on the Missouri River Basin. The region is also experiencing increasing transmission system congestion, impacting the wholesale power market. While the availability of the electric utility's plants has been excellent, the loss of a major plant could expose the electric utility to higher purchased power costs. Two factors mitigate this financial risk. First, wholesale sales contracts include provisions to release the electric utility from its obligations in the event of a plant outage; and second, the electric utility has COE adjustment clauses that allow pass through of most of the increased energy costs to retail customers. However, increases in fuel costs or regional generating capacity could have a negative impact on wholesale electric sales and profit margins.

Environmental

Current regulations under the Federal Clean Air Act (the Act) are not expected to have a significant impact on future capital requirements or operating costs. However, proposed or future regulations under the Act, changes in the future coal supply market, and/or other laws and regulations could impact such requirements or costs. The electric utility anticipates that, under current regulatory principles, any such costs could be recovered through rates. All of the electric utility's electric generating plants operated within the Act's phase two standards for sulfur-dioxide and nitrogen-oxide emissions in 2003. Ongoing compliance with the phase two requirements is not expected to significantly impact operations at any of the electric utility's plants.

The Act called for Environmental Protection Agency (EPA) studies of the effects of emissions of listed pollutants by electric steam generating plants. The EPA has completed the studies and sent reports to Congress. The Act required that the EPA make a finding as to whether regulation of emissions of hazardous air pollutants from fossil fuel-fired electric utility generating units is appropriate and necessary. On December 14, 2000 the EPA announced that it would regulate mercury emissions from electric generating units. The EPA Administrator signed the proposed mercury rule on December 15, 2003. The proposal included two options for regulating mercury emission from coal-fired electric generating units. One option would set technology-based maximum achievable control technology standards under paragraph 112(d) of the Act. The other option embodies a market-based cap and trade approach to emissions reduction. The electric utility is currently evaluating the proposal. Because promulgation of rules by the EPA has not been completed, it is not possible to assess to what extent this regulation will impact the electric utility.

The EPA has targeted electric steam generating units as part of an enforcement initiative relative to compliance with the Act. The EPA is attempting to determine if utilities violated certain provisions of the Act by making major modifications to their facilities without installing state-of-the-art pollution controls. On January 2, 2001 the electric utility received a request from the EPA pursuant to Section 114(a) of the Act requiring the electric utility to provide certain information relative to past operation and capital construction projects at the Big Stone Plant. The electric utility has responded to that request. In March 2003, the EPA conducted a review of the plant's outage records as a follow-up to their January 2001 data request. Copies of the designated documents were provided to the EPA on March 21, 2003. At this time, the electric utility cannot determine what, if any, actions will be taken by the EPA.

At the request of the Minnesota Pollution Control Agency (MPCA), the electric utility has an ongoing investigation at the Hoot Lake Plant closed ash disposal sites. The MPCA continues to monitor site activities under their Voluntary Investigation and Cleanup Program. In April 2001, the electric utility submitted a Remedial Investigation Work Plan to the MPCA describing its plans to further investigate the environmental impact of the closed portion of the Hoot Lake Plant ash disposal site. The MPCA approved the plan, with some suggested modifications and these tasks have been completed. The MPCA also asked that the electric utility eliminate a ground water seepage that was originating from one of the disposal areas. Site work was completed in early November 2001; however, seepage reappeared in a new location in the spring of 2002. The electric utility initiated additional studies to further characterize the site and its report was submitted to the MPCA in March 2003 for their review and comment. The MPCA approved portions of the remediation measures that the electric utility proposed and those were implemented in 2003. Although the electric utility is still evaluating various options, its preliminary estimate of remediation costs to address the ash disposal site issues over the next three years is not expected to have a material impact on the Company's consolidated net income, financial position or cash flows.

Deregulation and Legislation

In the aftermath of the August 14, 2003 blackout, the FERC is contemplating how to enforce reliability standards, with or without energy legislation giving them explicit authority to do so. On the electricity market front, FERC's 2002 Notice of Proposed Rulemaking (NOPR) on Standard Market Design (SMD) met significant political resistance, especially from the Southeast and Western regions of the United States. As a direct result, FERC published a Wholesale Market Platform (WMP) white paper that provides for regional flexibility and state regulator involvement through Regional State Committees (RSCs).

The state regulators in the Midwest Independent Transmission System Operator (MISO) region initiated the startup of an RSC called the Organization of MISO States (OMS). The OMS has no regulatory authority. The purpose of the OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, the FERC, other relevant government entities and state commissions as appropriate.

MISO has delayed startup of its electricity markets until December 1, 2004. The integration of the electric utility's electric facilities with its region's nonjurisdictional utilities presents a challenge for a MISO market startup. MISO plans to implement a Locational Marginal Pricing (LMP) market on December 1, 2004. The Company is making preparations in advance of market implementation. Those preparations include participation in MISO working groups and committees, evaluation of software to assist in market operations, purchase of LMP forecasting software, and staff additions to meet the needs of a new market. LMP intends to manage transmission congestion more effectively than current processes, improve reliability of the grid, increase market efficiency, and provide greater price transparency to regulators. However, a recent Department of Energy study shows that wholesale market prices in the MAPP region will increase 10% from 2005-2010, remain unchanged from 2011-2015, and fall by 1% from 2016-2020. The study raises doubts about benefits of LMP in the MAPP region. Increased market efficiency and price transparency may reduce wholesale electric sales margins from current levels.

Electric retail deregulation was not a subject debated in any of the state legislatures in the electric utility's service territory (Minnesota, North Dakota, and South Dakota) in 2003. Further, none of these state legislatures passed significant new requirements negatively affecting the ownership or operation of investor-owned utility assets in 2003.

NONELECTRIC OPERATIONS

In 2003, approximately 14% of the Company's net income was contributed by nonelectric operations. The Company plans to make additional acquisitions. The following guidelines are used when considering acquisitions: emerging or middle market company; proven entrepreneurial management team that will remain after the acquisition; products and services intended for commercial rather than retail consumer use; the ability to provide immediate earnings and future growth potential. The Company intends to grow earnings as a long-term owner of its operating companies. The Company also assesses the performance of its operating companies' return on capital and will consider divesting under-performing operating companies. Continuing growth from nonelectric operations could result in earnings, cash flow and stock price volatility.

While the Company cannot predict the success of its current nonelectric businesses, the Company believes opportunities exist for growth in these business segments. Factors that could affect the results of its nonelectric businesses include, but are not limited to, the following: fluctuations in the cost and availability of raw materials and the ability to maintain favorable supplier arrangements and relationships; competitive products and pricing pressures and the ability to gain or maintain market share in trade areas; general economic conditions; interest rates and their impact on housing starts; the impact of government regulation; effectiveness of advertising, marketing, and promotional programs; impairment of goodwill recorded in connection with the acquisition of nonelectric businesses; adverse weather conditions; and competition in the transportation industry. The failure of Congress to pass a broad energy bill in 2004 could have an unfavorable impact on the Company's operations that manufacture towers for the wind energy industry.

Critical Accounting Policies Involving Significant Estimates

The Company's significant accounting policies are described in note 1 to consolidated financial statements. The discussion and analysis of the *financial statements* and results of operations are based on the Company's consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these consolidated financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosure of contingent assets and liabilities.

The Company uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, environmental liabilities, valuation of forward energy contracts, unbilled electric revenues, unscheduled power exchanges, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs. As better information becomes available or actual amounts are known, estimates are revised. Operating results can be affected by revised estimates. Actual results may differ from these estimates under different assumptions or conditions. Management has discussed the application of these critical accounting policies and the development of these estimates with the Audit Committee of the Board of Directors. The following critical accounting policies affect the Company's more significant judgments and estimates used in the preparation of the consolidated financial statements.

PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

Pension and postretirement benefit liabilities and expenses for the Company's electric utility and corporate employees are determined by actuaries using assumptions about the discount rate, expected return on plan assets, rate of compensation increase and healthcare cost-trend rates. Further discussion of the Company's pension and postretirement benefit plans and related assumptions is included in note 10 to consolidated financial statements.

These benefits, for any individual employee, can be earned and related expenses can be recognized and a liability accrued over periods of up to 40 or more years. These benefits can be paid out for up to 40 or more years after an employee retires. Estimates of liabilities and expenses related to these benefits are among the Company's most critical accounting estimates. Although deferral and amortization of fluctuations in actuarially determined benefit obligations and expenses are provided for when actual results on a year-to-year basis deviate from long-range assumptions, compensation increases and healthcare cost increases or a reduction in the discount rate applied from one year to the next can significantly increase the Company's benefit expenses in the year of the change. Also, a reduction in the expected rate of return on pension plan assets in the Company's funded pension plan or realized rates of return on plan assets that are well below assumed rates of return could result in significant increases in recognized pension benefit expenses in the year of the change or for many years thereafter because actuarial losses can be amortized over the average remaining service lives of active employees.

For the Company's pension fund, the average rate of return on assets over the past five years of 7.6% compared to an average assumed rate of 9.3% combined with a reduction in the discount rate from 7.5% at year-end 2001 to 6.25% at year-end 2003 contributed to a shift from a $14 million unrecognized actuarial gain as of December 31, 2001 to a $23 million unrecognized actuarial loss as of December 31, 2003. A 22.9% return on plan assets in 2003 was a major factor contributing to a shift from a $5.4 million net pension liability and an accumulated other comprehensive loss of $7 million as of December 31, 2002 to a prepaid pension asset of $8 million and elimination of the $7 million accumulated other comprehensive loss as of December 31, 2003. Pension benefit costs for 2004 are expected to be $2.1 million compared to $1.5 million in 2003. The impact on 2004 pension benefit costs of the change in the estimated discount rate from 6.75% at year-end 2002 to 6.25% at year-end 2003 will be more than offset by the reduction in the assumed rate of increase in future compensation levels from 4.25% at year-end 2002 to 3.75% at year-end 2003.

Subsequent increases or decreases in actual rates of return on plan assets over assumed rates or increases or decreases in the discount rate or rate of increase in future compensation levels could significantly change projected costs. For 2003, all other factors being held constant: a 0.25 increase (or decrease) in the discount rate would have decreased (or increased) the 2003 pension benefit cost by $277,000; a 0.25 increase (or decrease) in the assumed rate of increase in future compensation levels would have increased (or decreased) the 2003 pension benefit cost by $355,000; a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) the 2003 pension benefit cost by $380,000.

In 2003, the Company's Executive Survivor and Supplemental Retirement Plan (ES&SRP) accrued benefit liability increased by $1.9 million as a result of an increase in accumulated benefits earned and a reduction in the discount rate from 6.75% at year-end 2002 to 6.25% at year-end 2003. Shareholders' equity increased by $0.6 million in the form of a reduction to "other comprehensive loss" due to plan amendments that resulted in an increase in unrecognized prior service costs. The 0.50 decrease in the assumed discount rate and the 0.25 increase in the assumed rate of increase in future compensation levels as of December 31, 2003 will contribute to increases in the Company's ES&SRP periodic benefit costs which are currently projected to be $3.1 million in 2004, $3.2 million in 2005, $3.4 million in 2006, $3.5 million in 2007 and $3.7 million in 2008.

A decrease in the discount rate from 6.75% at December 31, 2002 to 6.25% at December 31, 2003 contributed to a $2.7 million increase in the postretirement medical benefit plan's projected benefit obligation and a $0.3 million increase in the plan's unrecognized actuarial loss from year-end 2002 to year-end 2003. The changes in these factors will be offset by updates to actuarial tables resulting in a minor increase in postretirement healthcare benefit costs from $4.78 million in 2003 to a projected $4.83 million in 2004. Subsequent increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change these projected costs. A 0.25 increase (or decrease) in the discount rate would have decreased (or increased) the 2003 postretirement medical benefit cost by $132,000. See note 10 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

REVENUE RECOGNITION

The construction companies and three manufacturing companies record operating revenues on a percentage-of-completion basis for fixed-price construction contracts. The method used to determine the progress of completion is based on the ratio of costs incurred to total estimated costs. The duration of the majority of these contracts is less than a year. Revenues recognized, including revenues recognized by Foley prior to acquisition, on jobs in progress as of December 31, 2003 were $138 million. There are no losses expected on jobs in progress at year-end 2003. The Company believes that the accounting estimate related to the percentage-of-completion accounting on uncompleted contracts is critical to the extent that any underestimate of total expected costs on fixed-price construction contracts could result in reduced profit margins being recognized on these contracts at the time of completion.

FORWARD ENERGY CONTRACTS CLASSIFIED AS DERIVATIVES

The electric utility's forward contracts for the purchase and sale of energy are considered derivatives subject to mark-to-market accounting under generally accepted accounting principles. The market prices used to value the electric utility's forward contracts for the purchases and sales of electricity are determined by survey of counterparties by the electric utility's power services personnel responsible for contract pricing and, as such, are estimates. Over 69% of the forward purchase and sales contracts that are marked to market as of December 31, 2003 are offsetting in terms of volumes and delivery periods. Over 93% of these forward energy transactions by volume are scheduled for settlement prior to May 1, 2004.

Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can result in transmission constraints and the cancellation of scheduled transactions by the independent transmission system operator. In these situations, which are relatively infrequent in occurrence, the counterparties to the cancelled transaction are generally not made whole for the difference in the contract price and the market price of the electricity at the time of cancellation. In some instances the electric utility may deliver on a sale where its offsetting purchase has been cancelled or take delivery on a purchase where its offsetting sale has been cancelled. All forward energy transactions are subject to a small, and likely unquantifiable, risk of cancellation by the independent transmission system operator due to unanticipated physical constraints on the transmission system. At the time of cancellation, the electric utility could be in a gain or loss position depending on the market price of electricity relative to the contract price and the electric utility's position in the transaction.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

The Company encounters risks associated with sales and the collection of the associated accounts receivable. As such, the Company records a monthly provision for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, the Company primarily utilizes a historical rate of accounts receivables written off as a percentage of total revenue. This historical rate is applied to the current revenues on a monthly basis. The historical rate is updated periodically based on events that may change the rate such as a significant increase or decrease in collection performance and timing of payments as well as the calculated total exposure in relation to the allowance. Periodically, the Company compares the identified credit risks with the allowance that has been established using historical experience and adjusts the allowance accordingly. In circumstances where the Company is aware of a specific customer's inability to meet its financial obligations, the Company records a specific allowance for bad debts to reduce the net recognized receivable to the amount the Company reasonably believes will be collected.

The Company believes the accounting estimate related to the allowance for doubtful accounts is critical because the underlying assumptions used for the allowance can change from period to period and could potentially cause a material impact to the income statement and working capital.

During 2003, $1.0 million of bad debt expense was recorded and the allowance for doubtful accounts was $2.5 million (2.3% of trade accounts receivable) as of December 31, 2003. General economic conditions and specific geographic concerns are major factors that may affect the adequacy of the allowance and may result in a change in the annual bad debt expense. An increase or decrease of one percentage point in the Company's allowance for doubtful accounts based on outstanding receivables at December 31, 2003 would result in a $1.1 million increase or decrease in bad debt expense.

Although an estimated allowance for doubtful accounts on the Company's accounts receivable is provided for, the allowance for doubtful accounts on the electric segment's wholesale electric sales is insignificant in proportion to annual revenues from these sales. The electric segment has not experienced a bad debt related to wholesale electric sales due largely to stringent risk management criteria related to these sales. However, nonpayment on a single wholesale electric sale could result in a significant bad debt expense.

DEPRECIATION EXPENSE AND DEPRECIABLE LIVES

The provisions for depreciation of electric utility property for financial reporting purposes are made on the straight-line method based on the estimated service lives (5 to 65 years) of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 3.07% in 2003, 3.08% in 2002 and 3.06% in 2001. Depreciation rates on electric utility property are subject to annual regulatory review and approval and depreciation expense is recovered through rates set by ratemaking authorities. Although the useful lives of electric utility properties are estimated, the recovery of their cost is dependent on the ratemaking process. Deregulation of the electric industry could result in changes to the estimated useful lives of electric utility property that could impact depreciation expense.

Property and equipment of nonelectric operations are carried at historical cost or at the current appraised value if acquired in a business combination accounted for under the purchase method of accounting and are depreciated on a straight-line basis over useful lives (3 to 40 years) of the related assets. The Company believes that the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries in which its companies operate or innovations in technology could result in a reduction of the estimated useful lives of the Company's property, plant and equipment or in an impairment write-down of the carrying value of these properties.

ASSET IMPAIRMENT

The Company is required to test for asset impairment relating to property and equipment whenever events or changes in circumstances indicate that the carrying value of an asset might not be recoverable. The Company applies SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in order to determine whether or not an asset is impaired. This standard requires an impairment analysis when indicators of impairment are present. If such indicators are present, the standard requires that if the sum of the future expected cash flows from a company's asset, undiscounted and without interest charges, is less than the carrying value, an asset impairment must be recognized in the financial statements. The amount of the impairment is the difference between the fair value of the asset and the carrying value of the asset.

The Company believes that the accounting estimates related to an asset impairment are critical because they are highly susceptible to change from period to period reflecting changing business cycles and require management to make assumptions about future cash flows over future years and the impact of recognizing an impairment could have a significant effect on operations. Management's assumptions about future cash flows require significant judgment because actual operating levels have fluctuated in the past and are expected to continue to do so in the future.

As of December 31, 2003 an assessment of the carrying values of the Company's long-lived assets and other intangibles indicated that these assets were not impaired.

GOODWILL IMPAIRMENT

Beginning in 2002, goodwill is required to be evaluated annually for impairment, according to SFAS No. 142, Goodwill and Other Intangible Assets. The standard requires a two-step process be performed to analyze whether or not goodwill has been impaired. Step one is to test for potential impairment, and requires that the fair value of the reporting unit be compared to its book value including goodwill. If the fair value is higher than the book value, no impairment is recognized. If the fair value is lower than the book value, a second step must be performed. The second step is to measure the amount of impairment loss, if any, and requires that a hypothetical purchase price allocation be done to determine the implied fair value of goodwill. This fair value is then compared to the carrying value of goodwill. If the implied fair value is lower than the carrying value, an impairment must be recorded.

The Company believes that accounting estimates related to goodwill impairment are critical because the underlying assumptions used for the discounted cash flow can change from period to period and could potentially cause a material impact to the income statement. Management's assumptions about inflation rates and other internal and external economic conditions, such as earnings growth rate, require significant judgment based on fluctuating rates and expected revenues. Additionally, SFAS No. 142 requires that the goodwill be analyzed for impairment on an annual basis using the assumptions that apply at the time the analysis is updated.

As of December 31, 2003 an assessment of the carrying values of the Company's goodwill indicated no impairment.

Key Accounting Pronouncements

SFAS No. 143: The Financial Accounting Standards Board (FASB) has issued SFAS No. 143, Accounting for Asset Retirement Obligations (ARO), which provides accounting requirements for retirement obligations associated with tangible long-lived assets. The Company adopted SFAS No. 143 on January 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal constructions under the doctrine of promissory estoppel. Adoption of SFAS No. 143 changed the accounting for ARO costs of the utility's generating plants. SFAS No. 143 requires the present value of the future decommissioning cost to be recognized as a liability on the balance sheet with an offsetting amount being added to the capitalized cost of the related long-lived asset. The liability will be accreted to its present value each month and the capitalized cost will be depreciated over the useful life of the related asset.

The Company's asset retirement obligations include site restoration, the closure of ash pits and the removal of storage tanks and asbestos at certain electric utility generating plants. The Company has legal obligations associated with retirement of other long-lived assets used in its electric operations that cannot be reasonably estimated because the useful lives of those assets are not determinable. There are no assets legally restricted for the settlement of any of the Company's asset retirement obligations. The Company reclassified $35.4 million in accumulated reserves related to estimated removal costs from accumulated depreciation and amortization to a regulatory liability on the face of its Consolidated Balance Sheet as of December 31, 2002. Disclosure requirements under SFAS No.143 are included in note 1 to consolidated financial statements.

SFAS No. 149: The FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, in April 2003. The statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. This statement is effective for contracts entered into or modified after June 30, 2003. With the issuance of SFAS No.149, any forward contracts for the purchase or sale of energy entered into after June 30, 2003 that do not meet the definition of a capacity contract and are subject to unplanned netting, referred to as a book out in the utility industry, are not eligible for the normal purchases and sales exception provided for under SFAS No. 133 and modified by SFAS No. 149. These contracts are considered derivatives and are now subject to mark-to-market accounting. This classification applies to virtually all of the electric utility's forward wholesale purchases and sales of energy, which, prior to the issuance of SFAS No. 149, qualified for the normal purchases and sales exception from mark-to-market accounting treatment on the basis that it was probable that these contracts would not settle net and would result in physical delivery. As a result of the issuance of SFAS No. 149, unrealized gains and losses on forward purchases and sales of energy are now recorded by the electric utility. All provisions of this statement have been applied prospectively.

The electric utility recorded $4.1 million in net marked-to-market gains on derivative energy contracts in 2003, which reflects the difference between the contracted prices for forward purchases and sales of energy and the fair market values of contracts with matching terms and characteristics from the time the contracts are entered into until they are settled. As of December 31, 2003, $2.1 million in recognized marked-to-market net gains was unrealized. The electric utility expects these gains to be realized within the first six months of 2004. A portion of the marked-to-market value of derivative assets and liabilities is not reflected in current income but has been deferred under regulatory accounting treatment until realized at the time of physical delivery.

EITF Issue 03-11: At the July 31, 2003 EITF meeting, EITF Issue 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, and Not "Held for Trading Purposes" as Defined in Issue No. 02-3, was discussed. The EITF reached a consensus by agreeing that determining whether realized gains and losses on derivative contracts not "held for trading purposes" should be reported on a net or gross basis is a matter of judgment that depends on the relevant facts and circumstances. The FASB ratified the EITF consensus at its August 13, 2003 meeting. The reporting requirements of EITF Issue 03-11 are applicable to financial statement presentation in the fourth quarter of 2003. The electric utility determined that the net method of reporting was appropriate for its forward energy contracts. Revenue from the electric utility's wholesale sales of energy purchased from other suppliers are now reflected net of the related purchase power costs in electric revenues on the Company's consolidated statements of income for the years 2003, 2002 and 2001. The effects of the application of EITF Issue 03-11 and reclassification of prior year's reported revenues are shown in the table under Revenue Recognition in note 1 to the consolidated financial statements. The application of the reporting requirements of EITF Issue 03-11 had no effect on the Company's consolidated net income, financial position or cash flows.

FASB Interpretation (FIN) No. 46 (revised December 2003), Consolidation of Variable Interest Entities, is an interpretation of Accounting Research Bulletin No. 51, that addresses consolidation by business enterprises of variable interest entities which have certain characteristics related to equity at risk and rights and obligations to profits and losses. The effective date for application of certain provisions of FIN 46 has been deferred until the first quarter of 2004 for interests in variable interest entities created before February 1, 2003 and held by a public entity that has not previously applied the provisions of FIN 46. Implementation of FIN 46 will have no impact on the Company's consolidated net income, financial position or cash flows.

SFAS No. 132 (revised 2003), Employers' Disclosures about Pensions and Other Postretirement Benefits, was revised in 2003 to require additional footnote disclosures about the assets, obligations, cash flows and net periodic benefit cost to defined benefit pension plans and other defined benefit postretirement plans. The additional disclosures include information describing the types of plan assets, investment strategy, measurement dates, plan obligations, cash flows, and components of net periodic benefit cost recognized during interim periods. This statement is effective for financial statements with fiscal years ending after December 15, 2003. See note 10 to consolidated financial statements.

Quantitative and Qualitative Disclosures About Market Risk

At December 31, 2003 the Company had limited exposure to market risk associated with interest rates and commodity prices and no exposure to market risk associated with changes in foreign currency exchange rates.

The majority of the Company's long-term debt has fixed interest rates. The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. The Company manages its interest rate risk through the issuance of fixed-rate debt with varying maturities, through economic refunding of debt through optional refundings, limiting the amount of variable interest rate debt, and the utilization of short-term borrowings to allow flexibility in the timing and placement of long-term debt. As of December 31, 2003 the Company had $30.6 million of long-term debt subject to variable interest rates. Assuming no change in the Company's financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on December 31, 2003 interest expense and pretax earnings would change by approximately $306,000.

The Company has not used interest rate swaps to manage net exposure to interest rate changes related to the Company's portfolio of borrowings. The Company maintains a ratio of fixed-rate debt to total debt within a certain range. It is the Company's policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet its stated objectives. The Company does not enter into transactions for speculative or trading purposes.

The electric utility's retail portion of fuel and purchased power costs are subject to cost-of-energy adjustment clauses that mitigate the commodity price risk by allowing a pass through of most of the increase or decrease in energy costs to retail customers. In addition, the electric utility participates in an active wholesale power market providing access to energy resources that may serve to mitigate price risk.

The Company's energy services subsidiary markets natural gas to approximately 150 retail customers. Some of these customers are served under fixed-price contracts. There is price risk associated with these limited number of fixed-price contracts since the corresponding cost of natural gas is not immediately locked in. This price risk is not considered material to the Company. These contracts call for the physical delivery of natural gas and are considered executory contracts for accounting purposes. Current accounting guidance requires losses on firmly committed executory contracts to be recognized when realized.

The plastics companies are exposed to market risk related to changes in commodity prices for PVC resins, the raw material used to manufacture PVC pipe. The PVC pipe industry is highly sensitive to commodity raw material pricing volatility. Historically, when resin prices are rising or stable, margins and sales volume have been higher and when resin prices are falling, sales volumes and margins have been lower. Gross margins also decline when the supply of PVC pipe increases faster than demand. Due to the commodity nature of PVC resin and the dynamic supply and demand factors worldwide, it is very difficult to predict gross margin percentages or to assume that historical trends will continue.

The electric utility has market, price and credit risk associated with forward contracts for the purchase and sale of energy. As of December 31, 2003 the electric utility had recognized, on a pretax basis, $2.1 million in net unrealized gains on open forward contracts for the purchase and sale of energy. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can result in transmission constraints and the cancellation of scheduled transactions by the independent transmission system operator. In these situations, the counterparties to the cancelled transaction are generally not made whole for the difference in the contract price and the market price of the electricity at the time of cancellation. In some instances the electric utility may deliver on a sale where its offsetting purchase has been cancelled or is undeliverable, or take delivery on a purchase where its offsetting sale has been cancelled or is undeliverable. All forward energy transactions are subject to a small, and likely unquantifiable, risk of cancellation by the independent transmission system operator due to unanticipated physical constraints on the transmission system. At the time of cancellation, the electric utility could be in a gain or loss position depending on the market price of electricity relative to the contract price and the electric utility's position in the transaction.

The market prices used to value the electric utility's forward contracts for the purchases and sales of electricity are determined by survey of counterparties by the electric utility's power services' personnel responsible for contract pricing with adjustment for transmission costs required to move energy from its purchase point to its delivery point. Over 69% of the forward purchase and sales contracts that are marked to market as of December 31, 2003 are offsetting in terms of volumes and delivery periods.

The Company has in place an energy risk management policy with a goal to manage, through the use of defined risk management practices, price risk and credit risk associated with wholesale power purchases and sales. These policies require that most forward sales of electricity in wholesale markets be covered by offsetting forward purchases of electricity with matching terms and delivery dates or by the portion of company-owned generation projected to be in excess of retail load requirements. Currently, a portion of marked-to-market gains or losses on a sales contract will be offset by a marked-to-market loss or gain on the offsetting purchase contract.

The Company's energy risk management policy allows for long open positions with limitations on the aggregate marked-to-market value of open positions. These positions are closely monitored and covered with offsetting sales when the risk of loss exceeds predefined limits. The exposure to price risk of these open positions as of December 31, 2003 was not material.

The following table shows the effect of marking-to-market forward contracts for the purchase and sale of energy on the Company's Consolidated Balance Sheet as of December 31, 2003 and the change in its Consolidated Balance Sheet position from December 31, 2002 to December 31, 2003:

(in thousands)	December 31, 2003
Current asset–marked-to-market gain	$ 5,443
Regulatory asset–deferred marked-to-market loss	1,802
Total assets	7,245
Current liability–marked-to-market loss	(3,504)
Regulatory liability–deferred marked-to-market gain	(1,684)
Total liabilities	(5,188)
Net fair value of marked-to-market energy contracts	$ 2,057

(in thousands)	Year Ended December 31, 2003
Fair value at beginning of year	$ –
Amount realized on contracts delivered in 2003	(2,001)
Changes in fair value	4,058
Net fair value at end of period	2,057
Net change recorded as marked-to-market	$ 2,057

The $2.1 million in recognized but unrealized net gains on the forward energy purchases and sales marked-to-market on December 31, 2003 is expected to be realized on physical settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2004	2nd Quarter 2004	4th Quarter 2004	Total
Net gain	$ 2,026	$ 11	$ 20	$ 2,057

The electric utility has credit risk associated with the nonperformance or nonpayment by counterparties to its forward energy purchases and sales agreements. The Company has established guidelines and limits to manage credit risk associated with wholesale power purchases and sales. Specific limits are determined by a counterparty's financial strength. The Company's credit risk with its largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2003 was $9.3 million. As of December 31, 2003 the Company had a net credit risk exposure of $1.6 million from 32 counterparties with investment grade credit ratings.

The $1.6 million credit risk exposure includes net amounts due to the electric utility on receivables/payables from completed transactions billed and unbilled plus marked-to-market gains/losses on forward contracts for the purchase and sale of energy scheduled for delivery after December 31, 2003. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

Cautionary Statements

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, the Company makes the following statements.

The information in this annual report includes forward-looking statements. Important risks and uncertainties that could cause actual results to differ materially from those discussed in such forward-looking statements are set forth above under "Critical Accounting Policies Involving Significant Estimates" and "Factors Affecting Future Earnings." Other risks and uncertainties may be presented from time to time in the Company's future Securities and Exchange Commission filings.

REPORT OF MANAGEMENT

Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this annual report. The consolidated financial statements have been prepared in conformity with generally accepted accounting principles as applied to regulated and nonregulated businesses and necessarily include some amounts that are based on informed judgments and best estimates and assumptions of management.

To meet its responsibilities with respect to consolidated financial information, management maintains and enforces an internal control system designed to provide assurance, on a cost-effective basis, that transactions are carried out in accordance with management's authorizations and assets are safeguarded against loss from unauthorized use or disposition. Management believes the Company's accounting policies and controls prevent material errors and irregularities, and they allow employees in the normal course of their duties to detect inaccuracies within a timely period. In addition, the Company has a code of conduct that sets high standards of ethical conduct for all employees to maintain. The Company's internal staff is charged with the responsibility for determining compliance with Company procedures.

Directors, who are not officers or employees, make up the Audit Committee of the Board of Directors. This committee meets with management, internal auditors, and independent auditors to evaluate the Company's internal control and financial reports. The independent auditors and internal auditors have free access to the Audit Committee, without management's presence, to discuss the results of their audits.

John Erickson
President and Chief Executive Officer

Kevin Moug

Kevin Moug
Chief Financial Officer and Treasurer

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Otter Tail Corporation

We have audited the accompanying consolidated balance sheets and statements of capitalization of Otter Tail Corporation and its subsidiaries (the Company) as of December 31, 2003 and 2002, and the related consolidated statements of income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2003. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

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

As discussed in Note 1 to the consolidated financial statements, effective in 2003 the Company adopted Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations and SFAS No. 149, Amendment of Financial Accounting Standards Board Statement No. 133 on Derivative and Hedging Activities, and in 2002 the Company changed its method of accounting for goodwill and other intangible assets.

DELOITTE & TOUCHE LLP

Deloitte & Touche LLP

Minneapolis, Minnesota
February 23, 2004

Consolidated Statements of Income—For the Years Ended December 31

(in thousands, except per-share amounts)	**2003**	2002	2001
Operating revenues	$ 753,239	$ 646,337	$ 579,168
Operating expenses			
Production fuel	51,163	44,122	41,776
Purchased power	36,002	30,915	24,527
Electric operation and maintenance expenses	86,984	80,534	75,531
Cost of goods sold	372,734	286,253	249,789
Other nonelectric expenses	79,636	70,160	58,497
Depreciation and amortization	45,962	42,613	42,100
Property taxes	9,598	9,423	9,464
Total operating expenses	682,079	564,020	501,684
Operating income	71,160	82,317	77,484
Other income and deductions—net	1,292	1,717	2,193
Interest charges	17,866	17,845	15,991
Income before income taxes	54,586	66,189	63,686
Income taxes	14,930	20,061	20,083
Net income	39,656	46,128	43,603
Preferred dividend requirements	735	736	1,993
Earnings available for common shares	$ 38,921	$ 45,392	$ 41,610
Average number of common shares outstanding—basic	25,673	25,176	24,600
Average number of common shares outstanding—diluted	25,826	25,397	24,832
Basic earnings per share	$ 1.52	$ 1.80	$ 1.69
Diluted earnings per share	$ 1.51	$ 1.79	$ 1.68
Dividends per common share	$ 1.08	$ 1.06	$ 1.04

See accompanying notes to consolidated financial statements.

Consolidated Balance Sheets, December 31

(in thousands)	2003	2002
ASSETS		
Current assets		
Cash and cash equivalents	$ 7,305	$ 9,937
Accounts receivable:		
Trade (less allowance for doubtful accounts of $2,510,000 for 2003 and $3,833,000 for 2002)	107,634	81,670
Other	7,830	1,466
Inventories	56,966	44,154
Deferred income taxes	3,532	4,487
Accrued utility revenues	14,866	11,633
Costs and estimated earnings in excess of billings	4,591	5,529
Other	10,385	5,337
Total current assets	213,109	164,213
Investments and other assets	35,987	36,135
Goodwill—net	72,556	64,557
Other intangibles—net	7,096	5,592
Deferred debits		
Unamortized debt expense and reacquisition premiums	8,081	8,895
Regulatory assets	14,669	10,238
Other	1,600	1,220
Total deferred debits	24,350	20,353
Plant		
Electric plant in service	875,364	835,382
Nonelectric operations	193,858	178,656
Total	1,069,222	1,014,038
Less accumulated depreciation and amortization	453,791	432,383
Plant—net of accumulated depreciation and amortization	615,431	581,655
Construction work in progress	17,894	41,607
Net plant	633,325	623,262
Total	$ 986,423	$ 914,112

See accompanying notes to consolidated financial statements.

Consolidated Balance Sheets, December 31

(in thousands)	**2003**	2002
LIABILITIES AND EQUITY		
Current liabilities		
Short-term debt	$ 30,000	$ 30,000
Current maturities of long-term debt	9,718	7,690
Accounts payable	83,338	52,430
Accrued salaries and wages	14,677	18,194
Accrued federal and state income taxes	4,152	–
Other accrued taxes	10,491	10,150
Other accrued liabilities	10,003	5,760
Total current liabilities	162,379	124,224
Pensions benefit liability	16,919	20,484
Other postretirement benefits liability	23,230	20,382
Other noncurrent liabilities	11,102	7,840
Commitments (note 8)		
Deferred credits		
Deferred income taxes	101,596	94,147
Deferred investment tax credit	11,630	12,782
Regulatory liabilities	42,926	44,509
Other	2,061	2,550
Total deferred credits	158,213	153,988
Capitalization (page 36)		
Long-term debt, net of current maturities	265,193	258,229
Cumulative preferred shares	15,500	15,500
Common shares, par value $5 per share—authorized, 50,000,000 shares; outstanding, 2003—25,723,814 shares; 2002—25,592,160 shares	128,619	127,961
Premium on common shares	26,515	24,135
Unearned compensation	(3,313)	(1,946)
Retained earnings	186,495	175,304
Accumulated other comprehensive loss	(4,429)	(11,989)
Total common equity	333,887	313,465
Total capitalization	614,580	587,194
Total	$ 986,423	$ 914,112

See accompanying notes to consolidated financial statements.

Consolidated Statements of Common Shareholders' Equity

(in thousands, except common shares outstanding)	Common shares outstanding	Par value, common shares	Premium on common shares	Unearned compensation	Retained earnings	Accumulated other comprehensive income/(loss)	Total equity
Balance, December 31, 2000	24,574,288	$ 122,871	$ 50	$ (226)	$ 140,796	$ (220)	$ 263,271
Common stock issuances	79,202	396	1,187				1,583
Amortization of unearned compensation—stock awards				75			75
Comprehensive income:							
Net income					43,603		43,603
Minimum liability adjustment						(1,755)	(1,755)
Total comprehensive income							41,848
Tax benefit for exercise of stock options			302				302
Remove capital stock expense $6.35 preferred shares			246		(246)		—
Purchase stock for employee purchase plan			(259)		(168)		(427)
Cumulative preferred dividends					(2,088)		(2,088)
Common dividends					(25,256)		(25,256)
Balance, December 31, 2001	24,653,490	123,267	1,526	(151)	156,641	(1,975)	279,308
Common stock issuances	938,670	4,694	22,094	(2,674)			24,114
Amortization of unearned compensation—stock awards				879			879
Comprehensive income:							
Net income					46,128		46,128
Minimum liability adjustment						(10,014)	(10,014)
Total comprehensive income							36,114
Tax benefit for exercise of stock options			720				720
Purchase stock for employee purchase plan			(205)				(205)
Cumulative preferred dividends					(736)		(736)
Common dividends					(26,729)		(26,729)
Balance, December 31, 2002	25,592,160	127,961	24,135	(1,946)	175,304	(11,989)	313,465
Common stock issuances	140,621	703	2,793	(2,477)			1,019
Common stock retirements	(8,967)	(45)	(225)				(270)
Amortization of unearned compensation—stock awards				1,110			1,110
Comprehensive income:							
Net income					39,656		39,656
Minimum liability adjustment						7,560	7,560
Total comprehensive income							47,216
Tax benefit for exercise of stock options			111				111
Purchase stock for employee purchase plan			(299)				(299)
Cumulative preferred dividends					(735)		(735)
Common dividends					(27,730)		(27,730)
Balance, December 31, 2003	25,723,814	$ 128,619	$ 26,515	$ (3,313)	$ 186,495	$ (4,429)	$ 333,887

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows—For the Years Ended December 31

(in thousands)	**2003**	2002	2001
Cash flows from operating activities			
Net income	$ 39,656	$ 46,128	$ 43,603
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	45,962	42,613	42,100
Deferred investment tax credit—net	(1,152)	(1,153)	(1,177)
Deferred income taxes	3,078	2,669	(1,441)
Change in deferred debits and other assets	(3,324)	(5,178)	(8,434)
Change in noncurrent liabilities and deferred credits	8,026	1,049	2,484
Allowance for equity (other) funds used during construction	(1,355)	(1,742)	(963)
Unrealized (gains)/losses on derivatives net of regulatory deferral	(2,057)	–	–
Other—net	1,629	1,399	(81)
Cash provided by (used for) current assets and current liabilities:			
Change in receivables and inventories	(35,451)	(4,192)	4,880
Change in other current assets	(2,499)	(2,512)	(432)
Change in payables and other current liabilities	19,260	2,288	(581)
Change in interest and income taxes payable	5,182	(4,572)	(2,429)
Net cash provided by operating activities	76,955	76,797	77,529
Cash flows from investing activities			
Capital expenditures	(50,734)	(75,533)	(53,596)
Proceeds from disposal of noncurrent assets	1,621	2,462	3,298
Acquisitions—net of cash acquired	(12,896)	(6,591)	(8,948)
Decreases/(increases) in other investments	1,601	5	(1,884)
Net cash used in investing activities	(60,408)	(79,657)	(61,130)
Cash flows from financing activities			
Net borrowings under line of credit	–	25,507	–
Proceeds from employee stock plans	1,072	3,091	1,347
Proceeds from issuance of long-term debt	18,690	65,124	121,146
Payments for retirement of long-term debt	(9,906)	(62,161)	(81,549)
Payments for debt issuance expenses	(98)	(2,677)	(1,880)
Redemption of preferred stock	–	–	(18,000)
Dividends paid and other distributions	(28,937)	(27,465)	(27,344)
Net cash (used in) provided by financing activities	(19,179)	1,419	(6,280)
Net change in cash and cash equivalents	(2,632)	(1,441)	10,119
Cash and cash equivalents at beginning of year	9,937	11,378	1,259
Cash and cash equivalents at end of year	$ 7,305	$ 9,937	$ 11,378
Supplemental disclosures of cash flow information			
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 16,781	$ 16,831	$ 16,313
Income taxes	$ 8,437	$ 22,835	$ 23,575

See accompanying notes to consolidated financial statements.

Consolidated Statements of Capitalization, December 31

(in thousands)	**2003**	2002
Long-term debt		
Lombard US Equipment Finance note, variable, 2.59% at December 31, 2003, due October 2, 2006	$ 16,300	$ —
Senior debentures 6.375%, due December 1, 2007	50,000	50,000
Senior notes 6.63%, due December 1, 2011	90,000	90,000
Insured senior notes 5.625%, due October 1, 2017	40,000	40,000
Senior notes 6.80%, due October 1, 2032	25,000	25,000
Pollution control refunding revenue bonds, variable, 1.35% at December 31, 2003, due December 1, 2012	10,400	10,400
Grant County, South Dakota pollution control refunding revenue bonds 4.65%, due September 1, 2017	5,185	5,185
Mercer County, North Dakota pollution control refunding revenue bonds 4.85%, due September 1, 2022	20,765	20,790
Obligations of Varistar Corporation:		
8.15% five-year term note, due October 31, 2005	1,957	3,531
7.80% ten-year term note, due October 31, 2007	3,960	6,712
Variable 2.87% at December 31, 2003, due July 3, 2007	2,789	3,634
Various up to 12.67% at December 31, 2003	8,839	11,022
Total	275,195	266,274
Less:		
Current maturities	9,718	7,690
Unamortized debt discount	284	355
Total long-term debt	265,193	258,229
Cumulative preferred shares—without par value (stated and liquidating value $100 a share)—authorized 1,500,000 shares;		
Series outstanding:		
$3.60, 60,000 shares	6,000	6,000
$4.40, 25,000 shares	2,500	2,500
$4.65, 30,000 shares	3,000	3,000
$6.75, 40,000 shares	4,000	4,000
Total preferred	15,500	15,500
Cumulative preference shares—without par value, authorized 1,000,000 shares; outstanding: none		
Total common shareholders' equity	333,887	313,465
Total capitalization	$ 614,580	$ 587,194

See accompanying notes to consolidated financial statements.

1. Summary of Significant Accounting Policies

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements of Otter Tail Corporation and its wholly owned subsidiaries (the Company) include the accounts of the following segments: electric, plastics, manufacturing, health services and other business operations. The electric segment is regulated while the other segments are not regulated. See note 2 to the consolidated financial statements for further descriptions of the Company's business segments. All significant intercompany balances and transactions have been eliminated in consolidation except profits on sales to the regulated electric utility company from nonregulated affiliates, which is in accordance with the requirements of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. These amounts are not material.

REGULATION AND STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 71

As a regulated entity, the Company and the electric utility account for the financial effects of regulation in accordance with SFAS No. 71. This statement allows for the recording of a regulatory asset or liability for costs that will be collected or refunded through the ratemaking process in the future. In accordance with regulatory treatment, the Company defers utility debt redemption premiums and amortizes such costs over the original life of the reacquired bonds. See note 4 for further discussion.

The Company's regulated business is subject to various state and federal agency regulations. The accounting policies followed by this business are subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's nonelectric businesses.

PLANT, RETIREMENTS AND DEPRECIATION

Utility plant is stated at original cost. The cost of additions includes contracted work, direct labor and materials, allocable overheads and allowance for funds used during construction (AFC). AFC, a noncash item, is included in utility construction work in progress. The amount of AFC capitalized was $1,970,000 for 2003, $2,636,000 for 2002 and $1,342,000 for 2001. The cost of depreciable units of property retired less salvage is charged to accumulated depreciation. Removal costs, when incurred, are charged against the accumulated reserve for estimated removal costs, a regulatory liability. Maintenance, repairs and replacement of minor items of property are charged to operating expenses. The provisions for utility depreciation for financial reporting purposes are made on the straight-line method based on the estimated service lives of the properties. Such provisions as a percent of the average balance of depreciable electric utility property were 3.07% in 2003, 3.08% in 2002 and 3.06% in 2001. Gains or losses on asset dispositions are taken to the accumulated provision for depreciation reserve and impact current and future depreciation rates.

Property and equipment of nonelectric operations are carried at historical cost or at the then-current appraised value if acquired in a business combination accounted for under the purchase method of accounting, and are depreciated on a straight-line basis over useful lives (3 to 40 years) of the related assets. Replacement and major improvements are capitalized; maintenance and repairs are expensed as incurred. Gains or losses on asset dispositions are included in the determination of operating income.

JOINTLY OWNED PLANTS

The consolidated financial statements include the Company's 53.9% (Big Stone Plant) and 35% (Coyote Station) ownership interests in the assets, liabilities, revenue and expenses of Big Stone Plant and Coyote Station. Amounts at December 31, 2003 and 2002 included in the consolidated balance sheet are as follows:

(in thousands)	Big Stone Plant	Coyote Station
December 31, 2003		
Electric plant in service	$ 116,240	$ 146,431
Accumulated depreciation	(68,387)	(72,946)
Net plant	$ 47,853	$ 73,485
December 31, 2002		
Electric plant in service	$ 113,731	$ 146,739
Accumulated depreciation	(67,993)	(74,610)
Net plant	$ 45,738	$ 72,129

The Company's share of direct revenue and expenses of the jointly owned plants is included in operating revenue and expenses in the Consolidated Statements of Income.

RECOVERABILITY OF LONG-LIVED ASSETS

The Company reviews its long-lived assets whenever events or changes in circumstances indicate the carrying amount of the assets may not be recoverable. The Company determines potential impairment by comparing the carrying value of the assets with net cash flows expected to be provided by operating activities of the business or related assets. Should the sum of the expected future net cash flows be less than the carrying values, the Company would determine whether an impairment loss should be recognized. An impairment loss would be quantified by comparing the amount by which the carrying value exceeds the fair value of the asset where fair value is based on the discounted cash flows expected to be generated by the asset.

INCOME TAXES

Comprehensive interperiod income tax allocation is used for substantially all book and tax temporary differences. Deferred income taxes arise for all temporary differences between the book and tax basis of assets and liabilities. Deferred taxes are recorded using the tax rates scheduled by tax law to be in effect when the temporary differences reverse. The Company amortizes the investment tax credit over the estimated lives of the related property.

REVENUE RECOGNITION

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold. The Company recognizes revenue when the earnings process is complete, evidenced by an agreement with the customer, there has been delivery and acceptance, and the price is fixed or determinable. In cases where significant obligations remain after delivery, revenue is deferred until such obligations are fulfilled. Provisions for sale returns and warranty costs are recorded at the time of the sale based on historical information and current trends. In the case of derivative instruments, such as the electric utility's forward energy contracts, the Company recognizes gains and losses on changes in the fair market value of derivative instruments over the period held on a net basis, in revenue, in accordance with the requirements of SFAS No. 133 as amended by SFAS No. 149 and, when realized, on a net basis in a manner prescribed by Emerging Issues Task Force (EITF) Issue 03-11. Gains and losses on forward energy contracts subject to regulatory treatment are deferred and recognized on a net basis in revenue in the period realized.

For those operating businesses recognizing revenue when shipped, the operating businesses have no further obligation to provide services related to such product. The shipping terms used in these instances are FOB shipping point.

Electric customers' meters are read and bills are rendered monthly. Revenue is accrued for electricity consumed but not yet billed. Rate schedules applicable to substantially all customers include a cost-of-energy adjustment clause—under which the rates are adjusted to reflect changes in average cost of fuels and purchased power—and a surcharge for recovery of conservation-related expenses. Revenue is accrued for fuel and purchased power costs incurred in excess of amounts recovered in base rates but not yet billed through the cost-of-energy adjustment clause.

Revenues on wholesale electricity sales from Company-owned generating units are recognized when energy is delivered.

As of July 1, 2003 the Company's unrealized gains and losses on forward energy contracts, not meeting the definition of capacity contracts, are marked-to-market and reflected on a net basis in electric revenue on the Company's consolidated statement of income. Prior to the issuance of SFAS No. 149 in 2003, these forward energy contracts qualified for the normal purchases and sales exception in SFAS No. 133 as amended by SFAS No. 138; revenues on forward energy sales were recognized on delivery and costs related to forward energy purchases were recognized as purchased power expenses when the energy was received. With the issuance of SFAS No. 149, the Company's forward energy contracts not meeting the definition of a capacity contract and subject to unplanned netting no longer qualify for the normal purchase and sales exception. The Company is required to mark-to-market these forward energy contracts and recognize changes in the fair value of these contracts as components of income over the life of the contracts.

In the fourth quarter of 2003, the FASB reached a consensus on EITF Issue 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, and Not "Held for Trading Purposes." The Company determined that the net basis prescribed in EITF Issue 03-11 is the appropriate treatment for reporting its realized gains and losses on forward energy contracts. Accordingly, the Company has reclassified prior period purchased power expenses related to forward energy contracts as components of electric operating revenue. The effects of the reclassification on prior period income statements are shown in the following table.

(in thousands)	2002	2001
Operating revenue previously reported	$ 710,116	$ 654,132
Less: Cost of forward energy purchases for resale	(63,779)	(74,964)
Operating revenue under net reporting method	$ 646,337	$ 579,168
Purchased power expense previously reported	$ 94,694	$ 99,491
Less: Cost of forward energy purchases for resale	(63,779)	(74,964)
Purchased power expense under net reporting method	$ 30,915	$ 24,527

Plastics operating revenues are recorded when the product is shipped.

Health services operating revenues on major equipment and installation contracts are recorded when the equipment is delivered or when installation is completed and accepted. Amounts received in advance under customer service contracts are deferred and recognized on a straight-line basis over the contract period. Revenues generated in the mobile imaging operations are recorded on a fee-per-scan basis when the scan is performed.

Manufacturing operating revenues are recorded when products are shipped and on a percentage-of-completion basis for construction type contracts.

Other business operations operating revenues are recorded when services are rendered or products are shipped. In the case of construction contracts, the percentage-of-completion method is used.

Some of the operating businesses enter into fixed-price construction contracts. Revenues under these contracts are recognized on a percentage-of-completion basis. The method used to determine the progress of completion is based on the ratio of costs incurred to total estimated costs. If a loss is indicated at a point in time during a contract, a projected loss for the entire contract is estimated and recognized. The following summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	**December 31, 2003**	December 31, 2002
Costs incurred on uncompleted contracts	$ 124,839	$ 42,768
Less billings to date	(137,881)	(44,572)
Plus estimated earnings recognized	13,611	6,340
	$ 569	$ 4,536

The following costs and estimated earnings in excess of billings are included in the Company's Consolidated Balance Sheet. Billings in excess of costs and estimated earnings on uncompleted contracts are included in accounts payable.

(in thousands)	**December 31, 2003**	December 31, 2002
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 4,591	$ 5,529
Billings in excess of costs and estimated earnings on uncompleted contracts	(4,022)	(993)
	$ 569	$ 4,536

PRE-PRODUCTION COSTS

The Company incurs costs related to the design and development of molds, dies and tools as part of the manufacturing process. The Company accounts for these costs under EITF Issue 99-5, Accounting for Pre-production Costs Related to Long-Term Supply Arrangements. The Company capitalizes the costs related to the design and development of molds, dies and tools used to produce products under a long-term supply arrangement, some of which are owned by the Company. The balance of pre-production costs deferred on the balance sheet was $1,439,000 as of December 31, 2003 and $1,621,000 as of December 31, 2002. These costs are amortized over a three-year period and evaluated annually for impairment.

SHIPPING AND HANDLING COSTS

The Company includes revenues received for shipping and handling in operating revenues. Expenses paid for shipping and handling are recorded as part of cost of goods sold.

STOCK-BASED COMPENSATION

As described in note 6, the Company has elected to follow the accounting provisions of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, for stock-based compensation and to furnish the pro forma disclosures required under SFAS No. 123, Accounting for Stock-Based Compensation.

Had compensation costs for the stock options issued been determined based on estimated fair value at the award dates, as prescribed by SFAS No. 123, the Company's net income for 2001 through 2003 would have decreased as presented in the table below. This may not be representative of the pro forma effects for future years if additional options are granted.

(in thousands, except per share amounts)	**2003**	2002	2001
Net income			
As reported	$ 39,656	$ 46,128	$ 43,603
Total stock-based employee compensation expense determined under fair value-based method for all awards net of related tax effects	(984)	(1,038)	(833)
Pro forma	$ 38,672	$ 45,090	$ 42,770
Basic earnings per share			
As reported	$ 1.52	$ 1.80	$ 1.69
Pro forma	$ 1.48	$ 1.76	$ 1.66
Diluted earnings per share			
As reported	$ 1.51	$ 1.79	$ 1.68
Pro forma	$ 1.47	$ 1.75	$ 1.64

USE OF ESTIMATES

The Company uses estimates based on the best information available in recording transactions and balances resulting from business operations. Estimates are used for such items as depreciable lives, asset impairment evaluations, tax provisions, collectability of trade accounts receivable, self-insurance programs, environmental liabilities, unbilled electric revenues, valuations of forward energy contracts, unscheduled power exchanges, service contract maintenance costs, percentage-of-completion and actuarially determined benefit costs. As better information becomes available (or actual amounts are known), the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

RECLASSIFICATIONS

Certain prior year amounts have been reclassified to conform to 2003 presentation. Such reclassifications had no impact on net income, shareholders' equity or cash flows provided from operations.

CASH EQUIVALENTS

The Company considers all highly liquid debt instruments purchased with maturity of 90 days or less to be cash equivalents.

INVESTMENTS

At December 31, 2003 and 2002 the Company had investments of $4,616,000 and $5,359,000, respectively, in limited partnerships that invest in tax-credit qualifying affordable housing projects. These investments provided the Company with tax credits of $1,412,000 in 2003 and $1,418,000 in both 2002 and 2001. The balance of investments at December 31, 2003 consists of $2,378,000 in additional investments accounted for under the equity method and $4,149,000 in other investments accounted for under the cost method, with $837,000 related to participation in economic development loan pools. The balance of investments at December 31, 2002 consists of $2,476,000 in additional investments accounted for under the equity method and $6,055,000 in other investments accounted for under the cost method, with $1,303,000 related to participation in economic development loan pools. See further discussion under note 11.

INVENTORIES

The electric segment inventories are reported at average cost. All other segments' inventories are stated at the lower of cost (first-in, first-out) or market. Inventories consist of the following:

(in thousands)	**December 31, 2003**	December 31, 2002
Finished goods	$ 20,349	$ 15,795
Work in process	6,234	1,438
Raw material, fuel and supplies	30,383	26,921
Total inventories	$ 56,966	$ 44,154

SHORT-TERM DEBT

There was $30,000,000 in short-term debt outstanding as of December 31, 2003 and 2002. The average interest rate paid on short-term debt was 1.7% in 2003 and 2.2% in 2002. The interest rate on short-term debt outstanding on December 31, 2003 was 1.5%.

GOODWILL AND INTANGIBLE ASSETS

The Company adopted SFAS No. 142, Goodwill and Other Intangible Assets, on January 1, 2002. SFAS No. 142 eliminates the requirement to amortize goodwill and indefinite-lived intangible assets, requiring instead that those assets be measured for impairment at least annually, and more often when events indicate that an impairment exists. Intangible assets with finite lives will continue to be amortized over their estimated useful lives and reviewed for impairment in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets.

In adopting SFAS No. 142, the Company has performed the transitional reassessment and impairment tests required as of January 1, 2002 and determined that goodwill was not impaired and therefore no write-off was necessary. If goodwill had not been amortized in 2001, net income would have been higher by $2.45 million that year.

The following table presents the effects of not amortizing goodwill on reported net income and basic and diluted earnings per share.

(in thousands, except per share amounts)	**2003**	2002	2001
Net income:			
Reported net income	$ 39,656	$ 46,128	$ 43,603
Add back: goodwill amortization, net of tax	–	–	2,449
Adjusted net income	$ 39,656	$ 46,128	$ 46,052
Basic earnings per share:			
Reported basic earnings per share	$ 1.52	$ 1.80	$ 1.69
Add back: goodwill amortization, net of tax	–	–	0.10
Adjusted basic earnings per share	$ 1.52	$ 1.80	$ 1.79
Diluted earnings per share:			
Reported diluted earnings per share	$ 1.51	$ 1.79	$ 1.68
Add back: goodwill amortization, net of tax	–	–	0.09
Adjusted diluted earnings per share	$ 1.51	$ 1.79	$ 1.77

The changes in the carrying amount of goodwill by segment are as follows:

(in thousands)	Balance December31, 2002	Adjustment to goodwill acquired in 2002	Goodwill acquired in 2003	Goodwill impairment in 2003	Balance December31, 2003
Plastics	$ 19,302	$ –	$ –	$ –	$ 19,302
Manufacturing	8,609	(377)	–	–	8,232
Health services	22,409	–	1,924	–	24,333
Other business operations	14,237	–	6,702	(250)	20,689
Total	$ 64,557	$ (377)	$ 8,626	$ (250)	$ 72,556

The Company had recorded $250,000 in goodwill related to the acquisition of an energy management firm in 2002. Based on an offer to purchase this entity in the fourth quarter of 2003, the Company determined the goodwill related to this entity was impaired and, accordingly, recorded a $250,000 charge to operating income in the fourth quarter of 2003.

Intangible assets with finite lives are being amortized over average lives that vary from one to five years. The amortization expense for these intangible assets was $630,000 for 2003, $535,000 for 2002 and $414,000 for 2001. The estimated annual amortization expense for these intangible assets for the next five years is: $709,000 for 2004, $502,000 for 2005, $365,000 for 2006, $241,000 for 2007 and $189,000 for 2008.

Total other intangibles as of December 31 are as follows:

2003 *(in thousands)*	Gross carrying amount	Accumulated amortization	Net carrying amount
Amortized intangible assets:			
Covenants not to compete	$ 2,610	$ 1,483	$ 1,127
Other intangible assets including contracts	2,367	1,118	1,249
Total	$ 4,977	$ 2,601	$ 2,376
Nonamortized intangible assets:			
Brand/trade name	$ 4,720	$ –	$ 4,720
2002 *(in thousands)*			
Amortized intangible assets:			
Covenants not to compete	$ 1,920	$ 1,143	$ 777
Other intangible assets including contracts	2,079	884	1,195
Total	$ 3,999	$ 2,027	$ 1,972
Nonamortized intangible assets:			
Brand name	$ 3,620	$ –	$ 3,620

The Company periodically evaluates the recovery of intangible assets based on an analysis of undiscounted future cash flows. Evaluations of all intangible assets including goodwill completed in January 2004 indicated that none of the intangible assets reported on the Company's consolidated balance sheet as of December 31, 2003 is impaired.

ADOPTION OF NEW ACCOUNTING PRONOUNCEMENTS

SFAS No. 143: The FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations (ARO), which provides accounting requirements for retirement obligations associated with tangible long-lived assets. The Company adopted SFAS No. 143 on January 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal constructions under the doctrine of promissory estoppel. Adoption of SFAS No. 143 changed the accounting for ARO costs of the utility's generating plants. SFAS No. 143 requires the present value of the future decommissioning cost to be recognized as a liability on the balance sheet with an offsetting amount being added to the capitalized cost of the related long-lived asset. The liability will be accreted to its present value each month and the capitalized cost will be depreciated over the useful life of the related asset.

The Company's asset retirement obligations include site restoration, the closure of ash pits and the removal of storage tanks and asbestos at certain electric utility generating plants. The Company has legal obligations associated with retirement of other long-lived assets used in its electric operations that cannot be reasonably estimated because the useful lives of those assets are not determinable. There are no assets legally restricted for the settlement of any of the Company's asset retirement obligations. The Company reclassified $35.4 million in accumulated reserves related to estimated removal costs from accumulated depreciation and amortization to a regulatory liability on the face of its Consolidated Balance Sheet as of December 31, 2002.

The present value of the legal asset retirement obligations as of December 31, 2003 of $1,595,000 is included in Other noncurrent liabilities on the Company's December 31, 2003 Consolidated Balance Sheet. The $1,595,000 liability includes the original obligation of $377,000 plus accumulated accretion expense of $1,113,000 from the date the obligation arose through January 1, 2003, plus $105,000 of additional accumulated accretion expense for 2003. Since the recovery of these estimated removal costs, which include accretion, has been provided for through the recovery of depreciation expense included as a component of current electric retail rates, there is no cumulative effect on income to be recorded related to the adoption of this accounting principle. The difference between current accretion expense and depreciation expense based on approved rates will accumulate as a regulatory asset until the actual cost to settle the asset retirement obligation has been incurred. At that time, the associated regulatory asset will be transferred to the associated regulatory liability account as required by regulatory accounting rules. The effects of the transitional noncash transactions described above are not reflected in the Company's consolidated statement of cash flows for the year ended December 31, 2003.

The following table shows the amount of the asset retirement obligation liability that would have been included in Other noncurrent liabilities in prior periods had the requirements of SFAS No. 143 been in effect in those periods.

	As of December 31,	
(in thousands)	2002	2001
As reported	–	–
Pro forma	$ 1,490	$ 1,392

SFAS No. 149: The FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, in April 2003. The statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. This statement is effective for contracts entered into or modified after June 30, 2003. With the issuance of SFAS No. 149, any forward contracts for the purchase or sale of energy entered into after June 30, 2003 that do not meet the definition of a capacity contract and are subject to unplanned netting, referred to as a book out in the utility industry, are not eligible for the normal purchases and sales exception provided for under SFAS No. 133 and modified by SFAS No. 149. These contracts are considered derivatives and are now subject to mark-to-market accounting. This classification applies to virtually all of the Company's forward wholesale purchases and sales of energy, which, prior to the issuance of SFAS No. 149, qualified for the normal purchases and sales exception from mark-to-market accounting treatment on the basis that it was probable that these contracts would not settle net and would result in physical delivery. As a result of the issuance of SFAS No. 149, unrealized gains and losses on forward purchases and sales of energy are now recorded by the Company. All provisions of this statement have been applied prospectively.

The Company recorded $4.1 million in net marked-to-market gains on derivative energy contracts in 2003, which reflects the difference between the contracted prices for forward purchases and sales of energy and the fair market values of contracts with matching terms and characteristics from the time the contracts are entered into until they are settled. As of December 31, 2003, $2.1 million in recognized marked-to-market net gains was unrealized. The Company expects 98% of these gains to be realized within the first six months of 2004. A portion of net unrealized marked-to-market gains is not reflected in current income but has been deferred under regulatory accounting treatment until realized at the time of physical delivery.

EITF Issue 03-11: At the July 31, 2003 EITF meeting, EITF Issue 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, and Not "Held for Trading Purposes" as Defined in Issue No. 02-3, was discussed. The EITF reached a consensus by agreeing that determining whether realized gains and losses on derivative contracts not "held for trading purposes" should be reported on a net or gross basis is a matter of judgment that depends on the relevant facts and circumstances. The FASB ratified the EITF consensus at its August 13, 2003 meeting. The reporting requirements of EITF Issue 03-11 are applicable to financial statement presentation in the fourth quarter of 2003. The Company determined that the net method of reporting was appropriate for its forward energy contracts. Revenue from the Company's wholesale sales of energy purchased from other suppliers is now reflected net of the related purchase power costs in electric revenues on the Company's Consolidated Statements of Income for the years 2003, 2002 and 2001. The effects of the application of EITF Issue 03-11 and reclassification of prior years' reported revenues are shown in the table under Revenue Recognition in note 1. The application of the reporting requirements of EITF Issue 03-11 had no effect on the Company's consolidated net income, financial position or cash flows.

FASB Interpretation (FIN) No. 46 (revised December 2003), Consolidation of Variable Interest Entities, is an interpretation of Accounting Research Bulletin No. 51, that addresses consolidation by business enterprises of variable interest entities which have certain characteristics related to equity at risk and rights and obligations to profits and losses. The effective date for application of certain provisions of FIN 46 has been deferred until the first quarter of 2004 for interests in variable interest entities created before February 1, 2003 and held by a public entity that has not previously applied the provisions of FIN 46. Implementation of FIN 46 will have no impact on the Company's consolidated net income, financial position, or cash flows.

SFAS No. 132 (revised 2003), Employers' Disclosures about Pensions and Other Postretirement Benefits, was revised in 2003 to require additional footnote disclosures about the assets, obligations, cash flows and net periodic benefit cost to defined benefit pension plans and other defined benefit postretirement plans. The additional disclosures include information describing the types of plan assets, investment strategy, measurement dates, plan obligations, cash flows and components of net periodic benefit cost recognized during interim periods. This statement is effective for financial statements with fiscal years ending after December 15, 2003. The additional disclosures required under SFAS No. 132 are included in note 10 to these financial statements.

2. Business Combinations, Dispositions and Segment Information

On November 1, 2003 the Company acquired the assets and operations of Foley Company (Foley) for $12.3 million in cash. Foley is a mechanical and prime contracting firm based in Kansas City, Missouri, that provides a range of specialty contracting including design-and-build services for new construction, retrofitting, process piping, equipment settings, and instrumentation and control systems. Major clients include water and wastewater treatment plants, hospital and pharmaceutical facilities, power generation plants, and other industrial and manufacturing projects across a multi-state service area. Foley Company had gross revenues of $44.8 million in 2002. This acquisition expands the Company's construction services to a broader geographic region. Foley is included in the other business operations segment.

In 2003, the Company also acquired Topline Medical, Inc. and North Star Medical Systems, Inc. The aggregate price paid for the companies in 2003, neither of which was individually material, was $1.9 million in cash. These acquisitions will allow the health services segment to increase sales opportunities with an expanded line of products.

Below is a condensed balance sheet disclosing the preliminary allocation of the purchase price assigned to each major asset and liability category for the companies acquired in 2003.

(in thousands)	Foley	Others
Assets		
Current assets	$ 9,847	$ 675
Plant	3,793	45
Goodwill	6,702	1,924
Other intangible assets	1,653	102
Total assets	$ 21,995	$ 2,746
Liabilities and equity		
Current liabilities	$ 8,618	$ 669
Long-term debt	–	136
Other long-term liabilities	1,095	–
Equity	12,282	1,941
Total liabilities and equity	$ 21,995	$ 2,746

The above allocations are subject to adjustment. Goodwill related to the Foley acquisition is not deductible for income tax purposes. The goodwill related to the other acquisitions is deductible for income tax purposes over 15 years. Other intangible assets related to the Foley acquisition includes a $1,100,000 nonamortizable trade name and $553,000 in intangible assets being amortized over 5 years. Other intangible assets related to the other acquisitions are being amortized over 4 years.

On May 1, 2002 the Company acquired 100% of the outstanding stock of Computed Imaging Service, Inc. (CIS) of Houston, Texas for 158,257 shares of Otter Tail Corporation common stock and approximately $1.2 million in cash. CIS provides computed tomography and magnetic resonance imaging mobile services, interim rental, and sales and service of new, used and refurbished diagnostic imaging equipment. CIS serves hospitals and other healthcare facilities in the south-central United States. The acquisition of CIS allows the Company to expand its existing health services operations into another region of the country. CIS annual revenues were approximately $5.9 million in 2001.

On May 28, 2002 the Company acquired 100% of the outstanding stock of ShoreMaster, Inc. (ShoreMaster), of Fergus Falls, Minnesota for 303,124 shares of Otter Tail Corporation common stock and $2.3 million in cash. ShoreMaster is a leading manufacturer of waterfront equipment ranging from residential-use boatlifts and docks to commercial marina systems. The acquisition of ShoreMaster is expected to provide diversification and growth opportunities for the Company's manufacturing segment. ShoreMaster's annual revenues were approximately $20 million in 2001.

On October 1, 2002 the Company acquired 100% of the outstanding stock of Galva Foam Marine Industries, Inc. (Galva Foam), of Camdenton, Missouri for 256,940 shares of Otter Tail Corporation common stock and approximately $1.0 million in cash. Galva Foam is a leading manufacturer of waterfront equipment ranging from residential boatlifts and docks to commercial marina systems. The acquisition of Galva Foam in combination with the May 2002 acquisition of ShoreMaster expands the market reach of the Company's waterfront manufacturing product line nationwide with both saltwater and freshwater products. Galva Foam had annual revenues of approximately $13 million in 2001.

In 2002, the Company also acquired two other businesses, neither of which was individually material, one in energy management services and the other in health services. The total purchase price for these businesses was approximately $2 million in cash.

Below is a condensed balance sheet disclosing the fair value assigned to each major asset and liability category for the companies acquired in 2002.

(in thousands)	CIS	ShoreMaster	Galva Foam	Others
Assets				
Current assets	$ 1,439	$ 9,510	$ 4,953	$ 131
Plant	3,975	4,599	1,713	298
Goodwill	5,847	4,292	2,650	1,616
Other intangible assets	30	4,461	41	60
Total assets	$ 11,291	$ 22,862	$ 9,357	$ 2,105
Liabilities and equity				
Current liabilities	$ 1,747	$ 9,642	$ 2,304	$ 32
Long-term debt	2,584	2,723	–	–
Other long-term liabilities	707	797	372	–
Equity	6,253	9,700	6,681	2,073
Total liabilities and equity	$ 11,291	$ 22,862	$ 9,357	$ 2,105

All of the 2003 and 2002 acquisitions were accounted for using the purchase method of accounting. The pro forma effect of these acquisitions on 2002 and 2001 revenues, net income or earnings per share was not significant.

On September 4, 2001 the Company acquired the assets and operations of Interim Solutions and Sales, Inc. and Midwest Medical Diagnostics, Inc. of Minneapolis, Minnesota. These companies operate as a division of DMS Imaging, Inc. and provide mobile diagnostic imaging services on an interim basis for computed tomography and magnetic resonance imaging, fee-per-exam options and sales of previously owned imaging equipment. Revenues for 2000 were approximately $3.1 million. The excess of the purchase price over the net assets acquired was $2.2 million.

On September 10, 2001 the Company acquired the assets and operations of Nuclear Imaging, Ltd., of Sioux Falls, South Dakota. Nuclear Imaging provides mobile nuclear medicine, positron emission tomography and bone densitometry services to more than 120 healthcare facilities in the Midwest. Nuclear Imaging is a subsidiary of DMS Imaging, Inc. Revenues for 2000 were approximately $6.9 million. The excess of the purchase price over the net assets acquired was $4.8 million.

On November 1, 2001 the Company acquired the assets and operations of Titan Steel Corporation of Salt Lake City, Utah. Titan is a fabricator of steel products engaged in custom operations. Titan is an operating division of St. George Steel Fabrication, Inc. Revenues for 2000 were approximately $9 million. The excess of the purchase price over the net assets acquired was immaterial.

The above acquisitions of Interim Solutions and Sales, Inc., Midwest Medical Diagnostics, Inc., Nuclear Imaging, Ltd. and Titan Steel Corporation were accounted for using the purchase method of accounting under SFAS No. 141. Under the transition provision of SFAS No. 142, no goodwill was amortized for these acquisitions during 2001.

On February 28, 2001 the Company acquired all of the outstanding stock of T.O. Plastics, Inc. in exchange for 451,066 newly issued shares of the Company's common stock. T.O. Plastics, Inc. custom manufactures returnable pallets, material and handling trays and horticultural containers. It has three facilities in Minnesota and one facility in South Carolina.

On September 28, 2001 the Company acquired all of the outstanding stock of St. George Steel Fabrication, Inc. in exchange for 270,370 newly issued shares of the Company's common stock. St. George Steel is a fabricator of steel products engaged in custom and proprietary operations located in Utah.

The above two acquisitions were accounted for as pooling-of-interests. Since the St. George Steel acquisition was initiated prior to June 30, 2001 pooling-of-interest accounting was allowed under the transition provision of SFAS No. 141.

SEGMENT INFORMATION

The accounting policies of the segments are described under note 1—Summary of Significant Accounting Policies. The Company's business operations consist of five segments based on products and services. Electric includes the electric utility operating in Minnesota, North Dakota and South Dakota.

Plastics consists of businesses involved in the production of polyvinylchloride (PVC) and polyethylene (PE) pipe in the Upper Midwest and Southwest regions of the United States.

Manufacturing consists of businesses involved in the production of waterfront equipment, wind towers, frame-straightening equipment and accessories for the auto repair industry, custom plastic pallets, material and handling trays, horticultural containers, fabrication of steel products, contract machining, and metal parts stamping and fabrication located in the Upper Midwest, Missouri and Utah.

Health services include businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment, and related supplies and accessories. These businesses also provide service maintenance, mobile diagnostic imaging, mobile positron emission tomography and nuclear medicine imaging, portable x-ray imaging and rental of diagnostic medical imaging equipment to various medical institutions located in 42 states.

Other business operations consists of businesses in electrical and telephone construction contracting, specialty contracting including design and build services for new construction, transportation, telecommunications, entertainment, energy services, and natural gas marketing, as well as the portion of corporate administrative and general expenses that is not allocated to other segments. The electrical and telephone construction contracting companies and energy services and natural gas marketing business operate primarily in the central region of the Unites States. The telecommunications companies operate in central and northeast Minnesota and the transportation company operates in 48 states and 6 Canadian provinces.

The Company evaluates the performance of its business segments and allocates resources to them based on earnings contribution and return on total invested capital. Information for the business segments for 2003, 2002 and 2001 is presented in the following table.

(in thousands)	2003	2002	2001
Operating revenue			
Electric	$ 267,494	$ 244,005	$ 232,720
Plastics	86,009	82,931	63,216
Manufacturing	177,805	142,390	123,436
Health services	100,912	93,420	79,129
Other business operations	123,475	84,627	80,667
Intersegment eliminations	(2,456)	(1,036)	—
Total	$ 753,239	$ 646,337	$ 579,168

(in thousands)	2003	2002	2001
Depreciation and amortization			
Electric	$ 26,008	$ 24,910	$ 24,272
Plastics	2,126	1,760	3,229
Manufacturing	7,708	6,525	5,139
Health services	5,137	4,410	3,517
Other business operations	4,933	5,008	5,943
Total	$ 45,962	$ 42,613	$ 42,100
Operating income			
Electric	$ 57,537	$ 53,879	$ 57,150
Plastics	4,013	10,841	(1,391)
Manufacturing	8,133	9,477	12,175
Health services	5,248	8,654	6,862
Other business operations	(3,771)	(534)	2,688
Total operating income	$ 71,160	$ 82,317	$ 77,484
Other income and deductions—net	1,292	1,717	2,193
Interest charges	17,866	17,845	15,991
Income before income taxes	$ 54,586	$ 66,189	$ 63,686
Earnings available for common shares			
Electric	$ 33,411	$ 31,244	$ 31,065
Plastics	2,019	5,668	(1,628)
Manufacturing	3,885	4,524	6,117
Health services	2,464	4,555	4,213
Other business operations	(2,858)	(599)	1,843
Total	$ 38,921	$ 45,392	$ 41,610
Capital expenditures			
Electric	$ 28,177	$ 45,842	$ 34,992
Plastics	3,984	5,592	1,572
Manufacturing	9,903	15,049	10,516
Health services	5,427	3,874	3,282
Other business operations	3,243	5,176	3,234
Total	$ 50,734	$ 75,533	$ 53,596
Identifiable assets			
Electric	$ 609,190	$ 586,231	$ 559,185
Plastics	58,538	54,926	45,649
Manufacturing	138,493	114,120	67,033
Health services	67,587	64,785	50,560
Other business operations	112,615	94,050	95,351
Total	$ 986,423	$ 914,112	$ 817,778

No single external customer accounts for 10% or more of the Company's revenues. Substantially all sales and long-lived assets of the Company are within the United States.

3. Rate Matters

In 2001, the Minnesota Legislature exempted certain generation machinery and attached equipment from state personal property tax. The law also requires that any property tax savings resulting from this exemption be refunded to utility customers. As a result of this law, $272,600 in 2001 property tax savings was refunded to Minnesota retail electric customers in 2002. On January 1, 2003 a Property Tax Reduction Rider became effective which reduces base electric rates by 0.27% to reflect ongoing tax savings.

On December 29, 2000 the North Dakota Public Service Commission (NDPSC) approved a performance-based ratemaking plan that links allowed earnings in North Dakota to seven defined performance standards in the areas of price, electric service reliability, customer satisfaction and employee safety. The plan is in place for 2001 through 2005, unless suspended or terminated by the NDPSC or the Company. This plan provides the opportunity for the electric utility to raise its allowed rate of return and shares income with customers when earnings exceed the allowed return. During 2001, the electric utility achieved a rate of return on equity that exceeded targets under the plan which resulted in a sharing of the income between shareholders and customers and led to a $662,300 refund to North Dakota retail electric customers in 2002. Because the electric utility's 2002 rate of return was within the allowable range defined in the plan, no sharing occurred in 2003. The electric utility's 2003 rate of return is expected to be within the allowable range defined in the plan.

4. Regulatory Assets and Liabilities

The following table indicates the amount of regulatory assets and liabilities recorded on the Company's Consolidated Balance Sheets:

(in thousands)	**December 31, 2003**	December 31, 2002
Regulatory assets:		
Deferred income taxes	$ 12,750	$ 10,238
Debt expenses and reacquisition premiums	3,863	4,323
Deferred conservation program costs	882	844
Plant acquisition costs	285	329
Deferred marked-to-market losses	1,802	—
Accrued cost-of-energy revenue	3,693	768
Accumulated ARO accretion/ depreciation adjustment	117	—
Total regulatory assets	$ 23,392	$ 16,502
Regulatory liabilities:		
Accumulated reserve for estimated removal costs	$ 33,579	$ 35,376
Deferred income taxes	7,496	8,960
Deferred marked-to-market gains	1,684	—
Gain on sale of division office building	167	173
Total regulatory liabilities	$ 42,926	$ 44,509
Net regulatory liability position	$ 19,534	$ 28,007

The regulatory assets and liabilities related to deferred income taxes are the result of the adoption of SFAS No. 109, Accounting for Income Taxes. Debt expenses and reacquisition premiums are being recovered from customers over the remaining original lives of the reacquired debt issues, the longest of which is 19 years. Deferred conservation program costs included in Deferred debits—Other represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. Plant acquisition costs included in Deferred debits—Other will be amortized over the next 7 years. Accrued cost-of-energy revenue included in Accrued utility revenues will be recovered over the next nine months. All deferred marked-to-market gains and losses are related to forward purchases and sales of energy scheduled for delivery in 2004. The accumulated reserve for estimated removal costs is reduced for actual removal costs incurred. The remaining regulatory assets and liabilities are being recovered from electric customers over the next 30 years.

If for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities that no longer meet such criteria would be removed from the consolidated balance sheet and included in the consolidated statement of income as an extraordinary expense or income item in the period in which the application of SFAS No. 71 ceases.

5. Forward Energy Contracts Classified as Derivatives

With the issuance of SFAS No. 149, all of the electric utility's wholesale purchases and sales of energy under forward contracts that do not meet the definition of capacity contracts are considered derivatives subject to mark-to-market accounting. The electric utility's objective in entering into forward contracts for the purchase and sale of energy is to optimize the use of its generating and transmission facilities and leverage its knowledge of wholesale energy markets in the region to maximize financial returns for the benefit of both its customers and shareholders. The electric utility's intent upon entering into these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. Although these contracts are classified as derivatives, the electric utility does not use them for hedging and does not presently hold these contracts for trading purposes.

In 2003, the electric utility recorded wholesale sales of electricity totaling 3,782,899 mwhs. Of this total, 597,870 mwhs (15.8%) came from company-owned generation and 3,185,029 mwhs (84.2%) came from wholesale purchases. Net settlements, or book outs, constituted 9.5% of 2003 mwh sales by volume. Electric revenues for 2003 include $29,530,000 related to wholesale electric sales and net unrealized derivative gains on forward energy contracts broken down as follows:

(in thousands)		
Wholesale sales from company-owned generation		$ 18,428
Wholesale sales of purchased power at contract and market	$ 121,303	
Contract and market cost of purchased power resold	(114,259)	
Net margins on wholesale sales of purchased power		7,044
Marked-to-market gains on settled contracts	2,978	
Marked-to-market losses on settled contracts	(977)	
Net marked-to-market gain on settled contracts		2,001
Unrealized marked-to-market gains on open contracts	6,338	
Unrealized marked-to-market losses on open contracts	(4,281)	
Net unrealized marked-to-market gain on open contracts		2,057
Wholesale electric revenue		$29,530

A portion of gains and losses related to open forward energy contracts marked to market as derivative assets and derivative liabilities on the Company's Consolidated Balance Sheet at December 31, 2003 are deferred under regulatory accounting treatment. There is a $5,443,000 derivative asset and $1,684,000 deferred derivative gain and regulatory liability, and a $3,504,000 derivative liability and $1,802,000 deferred derivative loss and regulatory asset related to open forward energy contracts on the Company's Consolidated Balance Sheet at December 31, 2003. The derivative asset and derivative liability represent the difference between the contracted price and December 31, 2003 market price of forward energy contracts, of which over 93% are scheduled for settlement prior to May 1, 2004.

6. Common Shares and Earnings Per Share

NEW ISSUANCES

Common stock issuances during 2003 included 47,552 shares issued as a result of stock options exercised, 2,169 shares issued as directors' compensation and 90,900 shares of restricted stock issued as officers' and directors' compensation. In order to maintain a balanced capital structure consistent with the risk profile of the Company's diversified mix of businesses, the Company began issuing new shares of common stock in January 2004 to meet the requirements of its employee stock purchase plan and dividend reinvestment program and share purchase plan rather than purchasing shares on the open market.

STOCK INCENTIVE PLAN

Under the 1999 Stock Incentive Plan (Incentive Plan) a total of 2,600,000 common shares were authorized for granting stock awards. The Incentive Plan provides for the grant of options, performance awards, restricted stock, stock appreciation rights and other types of stock grants or stock-based awards. The exercise price of the stock options is equal to the fair market value per share at the date of the grant. Options granted to outside directors are exercisable immediately and all other options and restricted stock granted as of December 31, 2003 vest ratably over a four-year period. The options expire ten years after the date of the grant. The Company accounts for the Incentive Plan under APB No. 25.

Presented below is a summary of the stock options activity:

Stock Option Activity	2003		2002		2001	
	Options	Average exercise price	Options	Average exercise price	Options	Average exercise price
Outstanding, beginning of year	1,360,721	$ 24.68	1,265,042	$ 22.62	787,316	$ 19.55
Granted	222,750	27.24	278,750	31.34	582,000	26.33
Exercised	47,700	20.21	130,797	19.71	74,936	19.44
Forfeited	4,646	23.09	52,274	22.83	29,338	22.17
Outstanding, year-end	1,531,125	$ 25.16	1,360,721	24.68	1,265,042	22.62
Exercisable, year-end	791,661	$ 22.97	449,385	$ 21.75	257,369	$ 19.83
Fair value of options granted during year	$ 5.42		$ 7.07		$ 5.88	

The fair values of the options granted were estimated using the Black-Scholes option-pricing model under the following assumptions:

	2003	2002	2001
Risk-free interest rate	3.7%	5.2%	5.5%
Expected lives	7 years	7 years	7 years
Expected volatility	26.3%	26.0%	24.9%
Dividend yield	4.0%	4.0%	4.0%

The following table summarizes information about options outstanding as of December 31, 2003:

	Options outstanding			Options exercisable	
Range of exercise prices	Outstanding as of 12/31/03	Weighted-average remaining contractual life (yrs)	Weighted-average exercise price	Exercisable as of 12/31/03	Weighted-average exercise price
$18.80-$21.94	495,125	5.7	$ 19.48	437,250	$ 19.44
$21.95-$25.07	–	–	–	–	–
$25.08-$26.77	520,750	7.3	$ 26.25	276,750	$ 26.25
$26.78-$31.34	515,250	8.7	$ 29.53	77,661	$ 31.13

In addition to the stock options granted, 90,900, 85,800 and 1,681 shares of restricted stock were granted during 2003, 2002 and 2001, respectively. The total compensation cost recognized in income for stock-based employee compensation awards was $1,110,000 in 2003, $879,000 in 2002 and $125,000 in 2001. See note 1 for pro forma stock option information.

EMPLOYEE STOCK PURCHASE PLAN

The 1999 Employee Stock Purchase Plan (Purchase Plan) allows eligible employees to purchase the Company's common shares at 85% of the lower market price at either the beginning or the end of each six-month purchase period. Of the 400,000 common shares authorized for purchase under the Purchase Plan, 131,225 were still available for purchase as of January 1, 2004. To provide shares for the Purchase Plan, common shares were purchased in the open market totaling 66,724 shares in 2003, 57,997 shares in 2002 and 56,612 shares in 2001.

DIVIDEND REINVESTMENT AND SHARE PURCHASE PLAN

On August 30, 1996 the Company filed a shelf registration statement with the Securities and Exchange Commission (SEC) for the issuance of up to 2,000,000 common shares pursuant to the Company's Automatic Dividend Reinvestment and Share Purchase Plan (the Plan), which permits shares purchased by shareholders or customers who participate in the Plan to be either new issue common shares or common shares purchased in the open market. From June 1999 through December 2002, common shares needed for the Plan were purchased in the open market.

SHAREHOLDER RIGHTS PLAN

On January 27, 1997 the Company's Board of Directors declared a dividend of one preferred share purchase right (Right) for each outstanding common share held of record as of February 10, 1997. One Right was also issued with respect to each common share issued after February 10, 1997. Each Right entitles the holder to purchase from the Company one one-hundredth of a share of newly created Series A Junior Participating Preferred Stock at a price of $70, subject to certain adjustment. The Rights are exercisable when, and are not transferable apart from the Company's common shares until, a person or group has acquired 15% or more, or commenced a tender or exchange offer for 15% or more, of the Company's common shares. If the specified percentage of the Company's common shares is acquired, each Right will entitle the holder (other than the acquiring person or group) to receive, on exercise, common shares of either the Company or the acquiring company having value equal to two times the exercise price of the Right. The Rights are redeemable by the Company's Board of Directors in certain circumstances and expire on January 27, 2007.

EARNINGS PER SHARE

Basic earnings per common share are calculated by dividing earnings available for common shares by the average number of common shares outstanding during the period. Diluted earnings per common share are calculated by adjusting outstanding shares, assuming conversion of all potentially dilutive stock options.

7. Retained Earnings Restriction

The Company's Articles of Incorporation, as amended, contain provisions that limit the amount of dividends that may be paid to common shareholders by the amount of any declared but unpaid dividends to holders of the Company's cumulative preferred shares. Under these provisions none of the Company's retained earnings were restricted at December 31, 2003.

8. Commitments and Contingencies

At December 31, 2003 the electric utility had commitments under contracts in connection with construction programs aggregating approximately $2,929,000. For capacity and energy requirements, the electric utility has agreements extending through 2008 at annual costs of approximately $16,708,000 in 2004, $15,307,000 in 2005, $14,755,000 in 2006, $14,771,000 in 2007 and $14,848,000 in 2008.

The electric utility has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire between 2004 and 2016. In total, the electric utility is committed to the minimum purchase of approximately $85,893,000 or to make payments in lieu thereof, under these contracts. The cost-of-energy adjustment mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

The amounts of future operating lease payments are as follows:

(in thousands)	Electric	Nonelectric	Total
2004	$ 1,661	$ 19,033	$ 20,694
2005	1,661	16,144	17,805
2006	1,661	10,364	12,025
2007	1,661	5,815	7,476
2008	1,661	1,651	3,312
Later years	1,377	2,508	3,885
Total	$ 9,682	$ 55,515	$ 65,197

Rent expense was $25,684,000, $22,282,000 and $20,242,000, for 2003, 2002 and 2001, respectively.

The Company occasionally is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all currently pending matters will not be material.

9. Short-term and Long-term Borrowings

SHORT-TERM DEBT

On August 25, 2003 the Company's line of credit was increased from $50 million to $70 million. This line is available to support borrowings of the Company's nonelectric operations. This line of credit bears interest at the rate of LIBOR plus 0.5% and expires on April 28, 2004. The Company does not anticipate any difficulties in renewing this line of credit. The Company's bank line of credit is a key source of operating capital and can provide interim financing of working capital and other capital requirements, if needed. The Company's obligations under this line of credit are guaranteed by a 100%-owned subsidiary of the Company that owns substantially all of the Company's nonelectric companies. As of December 31, 2003, $30 million of the $70 million line was in use.

The interest rate under the line of credit is subject to adjustment in the event of a change in ratings on the Company's senior unsecured debt, up to LIBOR plus 0.8% if the ratings on the Company's senior unsecured debt fall to BBB+ or below (Standard & Poor's) or Baa1 or below (Moody's). The line of credit also provides for accelerated repayment in the event the Company's long-term senior unsecured debt is rated below BBB- (Standard & Poor's) or Baa3 (Moody's).

LONG-TERM DEBT

On September 24, 2003 the Company borrowed $16.3 million under a loan agreement with Lombard US Equipment Finance Corporation in the form of an unsecured note. The terms of the note require quarterly principal payments in the amount of $582,143 commencing in January 2004 with a final installment due on October 2, 2006, the stated maturity date of the note. The term of the note can be extended for additional one-year periods following the stated maturity date through October 1, 2010. The note bears interest at a variable rate of 3-month LIBOR plus 1.43% on the unpaid principal balance with interest payments due quarterly commencing on October 1, 2003 until the principal balance is repaid in full. The Company used proceeds from the note to pay down borrowings under the Company's line of credit that were used to finance acquisitions and capital expenditures of its nonelectric subsidiaries. The covenants associated with the note are consistent with existing credit facilities. There are no rating triggers associated with this note.

In 2003, $25,000 of Mercer County, North Dakota pollution control refunding revenue bonds 4.85%, due September 1, 2022 were redeemed for estate settlement purposes and retired.

In 2002, the Company filed with the SEC a shelf registration statement for $200 million of unsecured debt securities. On September 27, 2002 the Company issued $65 million of senior unsecured notes under the shelf registration statement. The offering consisted of $40 million of 5.625% insured senior notes due 2017 and $25 million of 6.80% senior notes due 2032. Net proceeds from these issues were used to retire the Company's remaining first mortgage bonds and to repay short-term debt used to finance a portion of the costs related to the new gas-fired combustion turbine plant constructed by the electric utility.

The Company has the ability to issue up to an additional $135 million of unsecured debt securities from time to time under its shelf registration statement on file with the SEC. Proceeds from subsequent debt issuances under the shelf registration, if any, may be used for other general corporate purposes, including working capital, capital expenditures, debt repayment, the financing of possible acquisitions or stock repurchases.

The Company's 6.63% senior notes contain an investment grade put that could require the Company to prepay this series with a make-whole premium if the Company's senior unsecured debt is rated below Baa3 (Moody's) or BBB- (Standard & Poor's). The Company's obligations under the 6.63% senior notes are guaranteed by a 100%-owned subsidiary of the Company that owns substantially all of the Company's nonelectric companies. The Company's Grant County and Mercer County pollution control refunding revenue bonds require that the Company grant to Ambac Assurance Corporation, under a financial guaranty insurance policy relating to the bonds, a security interest in the assets of the electric utility if the rating on the Company's senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's). The Company believes the risk of the downgrade events described in this paragraph occurring is remote based on the current bond ratings of the Company combined with its strong debt-to-equity ratio and ability to generate cash from operations.

The aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2003 for each of the next five years are $9,718,000 for 2004, $7,420,000 for 2005, $14,872,000 for 2006, $50,985,000 for 2007 and $445,000 for 2008.

COVENANTS

The Company's line of credit, its $90 million 6.63% senior notes due 2011 and Lombard US Equipment Finance note contain covenants that require the Company to maintain a debt-to-total capitalization ratio not in excess of 60% and an interest and dividend coverage ratio of at least 1.5 to 1. The 6.63% senior notes also require that priority debt not be in excess of 20% of total capitalization.

As of December 31, 2003 the Company was in compliance with all of the covenants under its line of credit and its other debt obligations.

10. Pension Plan and Other Postretirement Benefits

PENSION PLAN

The Company's noncontributory funded pension plan covers substantially all electric utility and corporate employees. The plan provides 100% vesting after five vesting years of service and for retirement compensation at age 65, with reduced compensation in cases of retirement prior to age 62. The Company reserves the right to discontinue the plan but no change or discontinuance may affect the pensions theretofore vested. The Company's policy is to fund pension costs accrued. All past service costs have been provided for.

The pension plan has a trustee who is responsible for pension payments to retirees. Four investment managers are responsible for managing the plan's assets. An independent actuary performs the necessary actuarial valuations for the plan.

The plan assets consist of common stock and bonds of public companies, U.S. government securities, cash and cash equivalents. None of the plan assets are invested in common stock, preferred stock or debt securities of the Company.

The following tables provide a reconciliation of the changes in the plan's benefit obligations and fair value of assets over the two-year period ended December 31, 2003 and a statement of the funded status as of December 31 of both years:

(in thousands)	**2003**	2002
Reconciliation of benefit obligation:		
Obligation at January 1	$ 145,262	$ 124,523
Service cost	3,779	3,120
Interest cost	9,491	9,269
Benefit payments	(8,190)	(7,760)
Plan amendments	—	2,770
Actuarial loss	3,817	13,340
Obligation at December 31	$ 154,159	$ 145,262
Reconciliation of fair value of plan assets:		
Fair value of plan assets at January 1	$ 113,803	$ 138,794
Actual return on plan assets	27,198	(17,231)
Benefit payments	(8,190)	(7,760)
Fair value of plan assets at December 31	$ 132,811	$ 113,803
Funded status	$ (21,348)	$ (31,459)
Unrecognized net actuarial loss	22,533	32,981
Unrecognized prior service cost	7,025	8,195
Net amount recognized	$ 8,210	$ 9,717

The following table provides the amounts recognized in the Consolidated Balance Sheets as of December 31:

(in thousands)	**2003**	2002
Prepaid pension cost	$ 8,210	$ 9,717
Additional minimum liability	—	(15,149)
Net pension asset/(liability)	$ 8,210	$ (5,432)
Intangible asset	—	8,195
Accumulated other comprehensive loss	—	6,954
Net amount recognized	$ 8,210	$ 9,717

Additional information on the status of the pension plan as of December 31:

(in thousands)	**2003**	2002
Projected benefit obligation	$ 154,159	$ 145,262
Accumulated benefit obligation	130,072	119,235
Fair value of plan assets	132,811	113,803

Components of net periodic pension benefit cost:

(in thousands)	**2003**	2002	2001
Service cost—benefit earned during the period	$ 3,779	$ 3,120	$ 2,544
Interest cost on projected benefit obligation	9,491	9,269	8,766
Expected return on assets	(12,933)	(14,957)	(14,610)
Amortization of transition asset	—	(73)	(235)
Amortization of prior-service cost	1,170	1,285	1,107
Amortization of net gain	—	(1,284)	(1,900)
Net periodic pension cost/(income)	$ 1,507	$ (2,640)	$ (4,328)

The change in the additional minimum liability included in other comprehensive loss was ($6,954,000) in 2003 and $6,954,000 in 2002.

Weighted-average assumptions used to determine benefit obligations at December 31:

	2003	2002
Discount rate	6.25%	6.75%
Rate of increase in future compensation level	3.75%	4.25%

Weighted-average assumptions used to determine net periodic pension cost for the year ended December 31:

	2003	2002
Discount rate	6.75%	7.50%
Long-term rate of return on plan assets	8.50%	9.50%
Rate of increase in future compensation level	4.25%	4.25%

To develop the expected long-term rate of return on assets assumption, the Company considered the historical returns and the future expectations for returns for each asset class, as well as the target asset allocation of the pension portfolio.

The assumed rate of return on pension fund assets for the determination of 2004 net periodic pension cost is 8.5%.

The Company's pension plan weighted-average asset allocations at December 31, 2003 and 2002, by asset category are as follows:

Asset Category	**2003**	2002
Enhanced core equity securities	53.3%	47.4%
Small capitalization equity securities	10.6%	8.7%
International equity securities	13.1%	10.6%
Total equity securities	77.0%	66.7%
Fixed-income securities	23.0%	33.3%
	100.0%	100.0%

The following objectives guide the decisions and investment strategy of the Company's pension committee for the pension plan (the Plan).

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of Otter Tail Corporation.
- The Plan's assets should be invested with the objective of meeting current and future payment requirements while minimizing annual contributions and their volatility.
- The asset strategy reflects the desire to meet current and future benefit payments.

The asset allocation strategy developed by the Company's pension committee is based on the current needs of the Plan, the investment objectives listed above, the investment preferences and risk tolerance of the committee and a desired degree of diversification.

The asset allocation strategy contains guideline percentages, at market value, of the total Plan invested in various asset classes. The strategic target allocation shown in the table below is a guide that will at times not be reflected in actual asset allocations that may be dictated by prevailing market conditions, independent actions of the pension committee and/or investment managers, and required cash flows to and from the Plan. The tactical range shown below provides flexibility for the investment managers' portfolios to vary around the target allocation without the need for immediate rebalancing. The Company's pension committee monitors actual asset allocations and directs contributions and withdrawals toward maintaining the targeted allocation percentages listed in the table below.

Security class	Strategic Target	Tactical Range
Enhanced core equity securities	48%	40%-55%
Small capitalization equity securities	12%	9%-15%
International equity securities	10%	5%-15%
Total equity securities	70%	60%-80%
Fixed-income securities	30%	20%-40%

Cash Flows: The Company is not required to make a contribution to the pension plan in 2004, but is currently considering future funding options.

EXECUTIVE SURVIVOR AND SUPPLEMENTAL RETIREMENT PLAN (ES&SRP)

The Company has an unfunded, nonqualified benefit plan for executive officers and certain key management employees. This plan provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their death for a 15-year postretirement period. Life insurance carried on certain plan participants is payable to the Company on the employee's death. There are no plan assets in this nonqualified benefit plan due to the nature of the plan.

The following tables provide a reconciliation of the changes in the plan's benefit obligations over the two-year period ended December 31, 2003 and a statement of the funded status as of December 31 of both years:

(in thousands)	**2003**	2002
Reconciliation of benefit obligation:		
Obligation at January 1	$ 20,309	$ 14,365
Service cost	417	(51)
Interest cost	1,426	1,175
Plan amendments	1,083	(182)
Actuarial loss	2,242	5,566
Early retirement	–	240
Benefit payments	(1,026)	(804)
Obligation at December 31	$ 24,451	$ 20,309
Funded status:		
Funded status at December 31	$ (24,451)	$ (20,309)
Unrecognized prior-service cost	1,772	836
Unrecognized net actuarial loss	11,961	10,292
Net amount recognized	$ (10,718)	$ (9,181)

The following table provides the amounts recognized in the Consolidated Balance Sheets as of December 31:

(in thousands)	**2003**	2002
Accrued benefit liability	$ (16,919)	$ (15,052)
Intangible asset	1,772	836
Accumulated other comprehensive loss	4,429	5,035
Net amount recognized	$ (10,718)	$ (9,181)

Additional information on the ES&SRP defined benefit pension plan as of December 31:

(in thousands)	**2003**	2002
Projected benefit obligation	$ 24,451	$ 20,309
Accumulated benefit obligation	16,919	15,052
Fair value of plan assets	–	–

Components of net periodic pension benefit cost:

(in thousands)	**2003**	2002	2001
Service cost—benefit earned during the period	$ 417	$ (51)	$ (76)
Interest cost on projected benefit obligation	1,426	1,175	956
Amortization of prior-service cost	147	86	191
Recognized net actuarial loss	573	398	117
Net periodic pension cost	$ 2,563	$ 1,608	$ 1,188
Early retirement benefit	–	240	–
Total	$ 2,563	$ 1,848	$ 1,188

The change in the additional minimum liability included in other comprehensive loss was ($606,000) in 2003 and $3,060,000 in 2002.

Weighted-average assumptions used to determine benefit obligations at December 31:

	2003	2002
Discount rate	6.25%	6.75%
Rate of increase in future compensation level	5.88%	5.63%

Weighted-average assumptions used to determine net periodic pension cost for the year ended December 31:

	2003	2002
Discount rate	6.75%	7.50%
Rate of increase in future compensation level	5.63%	4.50%

Cash Flows: The ES&SRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The Company expects to make contributions/benefit payments of $1,147,000 to plan participants in 2004.

POSTRETIREMENT BENEFITS

The Company provides a portion of health insurance and life insurance benefits for retired electric utility and corporate employees. Substantially all of the Company's electric utility and corporate employees may become eligible for health insurance benefits if they reach age 55 and have 10 years of service. On adoption of SFAS No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions, in January 1993, the Company elected to recognize its transition obligation related to postretirement benefits earned of approximately $14,964,000 over a period of 20 years. There are no plan assets.

The following tables provide a reconciliation of the changes in the plan's benefit obligations over the two-year period ended December 31, 2003 and a statement of the funded status as of December 31 of both years:

(in thousands)	**2003**	2002
Reconciliation of benefit obligation:		
Obligation at January 1	$ 39,318	$ 28,550
Service cost	1,009	615
Interest cost	2,619	2,166
Benefit payments	(2,981)	(2,436)
Participant premium payments	1,051	953
Plan amendments	–	(285)
Actuarial loss	992	9,755
Obligation at December 31	$ 42,008	$ 39,318
Funded status:		
Funded status at December 31	$ (42,008)	$ (39,318)
Unrecognized transition obligation	6,734	7,482
Unrecognized prior-service cost	700	395
Unrecognized loss	11,344	11,059
Net amount recognized	$ (23,230)	$ (20,382)

The net amounts recognized are shown on the Consolidated Balance Sheets as of December 31, 2003 and 2002 under the title of Other postretirement benefits liability.

Components of net periodic postretirement benefit cost:

(in thousands)	2003	2002	2001
Service cost	$ 1,009	$ 615	$ 681
Interest cost	2,619	2,166	1,768
Amortization of transition obligation	748	748	748
Amortization of prior-service cost	(305)	(305)	111
Amortization of net loss/(gain)	708	–	(51)
Net periodic postretirement benefit cost	$ 4,779	$ 3,224	$ 3,257

Weighted-average assumptions used to determine benefit obligations at December 31:

	2003	2002
Discount rate	6.25%	6.75%

Weighted-average assumptions used to determine net periodic postretirement benefit cost for the year ended December 31:

	2003	2002
Discount rate	6.75%	7.50%

Assumed healthcare cost-trend rates as of December 31:

	2003	2002
Healthcare cost-trend rate assumed for next year	11.0%	12.0%
Rate at which the cost-trend rate is assumed to decline	5.0%	5.0%
Year that the rate reaches the ultimate trend rate	2010	2010

Assumed healthcare cost-trend rates have a significant effect on the amounts reported for healthcare plans. A one-percentage-point change in assumed healthcare cost-trend rates for 2003 would have the following effects:

(in thousands)	1 point increase	1 point decrease
Effect on total of service and interest cost	$ 528	$ (611)
Effect on the postretirement benefit obligation	$ 5,153	$ (4,263)

Cash Flows: The Company expects to contribute $2.4 million net of expected employee contributions for the payment of retiree medical benefits in 2004.

MEDICARE PRESCRIPTION DRUG, IMPROVEMENT AND MODERNIZATION ACT OF 2003 (THE ACT)

The Company's postretirement medical plan provides prescription drug coverage for Medicare-eligible retirees. The Company's accumulated postretirement benefit obligation (APBO) and net cost recognized for other postemployment benefits (OPEB) do not reflect the effects of the Act. The provisions of the Act provide for a federal subsidy for plans that provide prescription drug benefits and meet certain qualifications, and alternatively would allow prescription drug plan sponsors to coordinate with the Medicare benefit. Specific authoritative guidance is pending from the FASB and Federal Government, and when that guidance is issued, it could require the Company to change its actuarially determined APBO and net cost for OPEB.

LEVERAGED EMPLOYEE STOCK OWNERSHIP PLAN

The Company has a leveraged employee stock ownership plan for the benefit of all its electric utility employees. Contributions made by the Company were $1,030,000 for 2003 and $1,100,000 for both 2002 and 2001.

11. Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value:

CASH AND SHORT-TERM INVESTMENTS

The carrying amount approximates fair value because of the short-term maturity of those instruments.

OTHER INVESTMENTS

The carrying amount approximates fair value. A portion of other investments is in financial instruments that have variable interest rates that reflect fair value. The remainder of other investments is accounted for by the equity method which, in the case of operating losses, results in a reduction of the carrying amount.

LONG-TERM DEBT

The fair value of the Company's long-term debt is estimated based on the current rates available to the Company for the issuance of debt. About $30.6 million of the Company's long-term debt, which is subject to variable interest rates, approximates fair value.

(in thousands)	December 31, 2003		December 31, 2002	
	Carrying amount	Fair value	Carrying amount	Fair value
Cash and short-term investments	$ 7,305	$ 7,305	$ 9,937	$ 9,937
Other investments	11,143	11,143	13,890	13,890
Long-term debt	(265,193)	(292,604)	(258,229)	(277,261)

12. Property, Plant and Equipment

(December 31, in thousands)	2003	2002
Electric plant:		
Production	$ 346,890	$ 314,093
Transmission	175,953	172,610
Distribution	272,909	268,400
General	79,612	80,279
Electric plant	875,364	835,382
Less accumulated depreciation and amortization	368,899	357,555
Electric plant net of accumulated depreciation	506,465	477,827
Construction work in progress	13,938	39,123
Net electric plant	$ 520,403	$ 516,950
Nonelectric operations plant	$ 193,858	$ 178,656
Less accumulated depreciation and amortization	84,892	74,828
Nonelectric plant net of accumulated depreciation	108,966	103,828
Construction work in progress	3,956	2,484
Net nonelectric operations plant	$ 112,922	$ 106,312
Net plant	$ 633,325	$ 623,262

The estimated service lives for rate-regulated properties is 5 to 65 years. For nonelectric property the estimated useful lives are from 3 to 40 years.

	Service Life Range	
(years)	Low	High
Electric fixed assets:		
Production plant	34	62
Transmission plant	40	55
Distribution plant	15	55
General plant	5	65
Nonelectric fixed assets	3	40

13. Income Taxes

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2003, 2002 and 2001) to net income before total income tax expense for the following reasons:

(in thousands)	**2003**	2002	2001
Tax computed at federal statutory rate	$ 19,105	$ 23,167	$ 22,290
Increases (decreases) in tax from:			
State income taxes net of federal income tax benefit	2,011	2,441	2,564
Investment tax credit amortization	(1,152)	(1,152)	(1,176)
Differences reversing in excess of federal rates	(1,283)	(1,055)	(503)
Dividend received/paid deduction	(707)	(699)	(674)
Affordable housing tax credits	(1,412)	(1,418)	(1,418)
Permanent and other differences	(1,632)	(1,223)	(1,000)
Total income tax expense	$ 14,930	$ 20,061	$ 20,083
Overall effective federal and state income tax rate	27.4%	30.3%	31.5%
Income tax expense includes the following:			
Current federal income taxes	$ 11,665	$ 18,651	$ 21,110
Current state income taxes	3,141	3,856	3,107
Deferred federal income taxes	2,709	15	(2,247)
Deferred state income taxes	(21)	109	707
Affordable housing tax credits	(1,412)	(1,418)	(1,418)
Investment tax credit amortization	(1,152)	(1,152)	(1,176)
Total	$ 14,930	$ 20,061	$ 20,083

The Company's deferred tax assets and liabilities were composed of the following on December 31, 2003 and 2002:

(in thousands)	**2003**	2002
Deferred tax assets		
Amortization of tax credits	$ 7,437	$ 8,345
Vacation accrual	1,926	1,836
Unearned revenue	1,592	1,420
Benefit liabilities	18,085	15,690
Cost of removal	13,096	13,797
Differences related to property	6,079	5,239
Transfer to regulatory liability	63	618
Other	2,068	2,956
Total deferred tax assets	$ 50,346	$ 49,901
Deferred tax liabilities		
Differences related to property	$ (129,076)	$ (123,021)
Excess tax over book pension	(3,260)	(3,855)
Transfer to regulatory asset	(12,751)	(10,237)
Other	(3,323)	(2,448)
Total deferred tax liabilities	$ (148,410)	$ (139,561)
Deferred income taxes	$ (98,064)	$ (89,660)

14. Quarterly Information (unaudited)

Because of changes in the number of common shares outstanding and the impact of diluted shares, the sum of the quarterly earnings per common share may not equal total earnings per common share.

Three Months Ended	**March 31**		**June 30**		**September 30**		**December 31**	
(in thousands, except per share data)	**2003**	2002	**2003**	2002	**2003**	2002	**2003**	2002
Operating revenues *(a)*	$ 172,149	$ 145,262	$ 180,057	$ 160,001	$ 200,895	$ 166,399	$ 200,138	$ 174,675
Operating income	18,302	18,935	14,920	19,848	22,302	22,979	15,636	20,555
Net income	9,862	10,032	8,434	10,587	11,961	12,882	9,399	12,627
Earnings available for common shares	9,678	9,848	8,250	10,403	11,777	12,698	9,216	12,443
Basic earnings per share	$ .38	$ .40	$ .32	$ .41	$ .46	$ .50	$ .36	$ .49
Diluted earnings per share	.38	.40	.32	.41	.46	.50	.36	.48
Dividends paid per common share	.27	.265	.27	.265	.27	.265	.27	.265
Price range:								
High	$ 28.59	$ 31.80	$ 28.90	$ 34.90	$ 28.41	$ 31.50	$ 28.50	$ 29.23
Low	23.76	25.75	25.27	28.50	25.60	22.82	25.92	25.22
Average number of common shares outstanding–basic	25,592	24,668	25,673	25,117	25,708	25,328	25,719	25,589
Average number of common shares outstanding–diluted	25,730	24,919	25,855	25,412	25,869	25,497	25,876	25,781

(a) Restated to reflect EITF Issue 03-11 reporting requirements.

CONSOLIDATED STATISTICAL SUPPLEMENT

Operating Ratios

(in thousands)	**2003**	2002	2001	2000	1999	1998	1993
Operating revenues *(a)*	$ 753,239	$ 646,337	$ 579,168	$ 544,369	$ 459,110	$ 412,570	$ 253,849
Operating expenses *(b)*	$ 682,079	$ 564,020	$ 501,684	$ 470,121	$ 390,897	$ 354,034	$ 199,863
Operating ratio	90.6	87.3	86.6	86.4	85.1	85.8	78.7

Selected Common Share Data

(in thousands)	**2003**	2002	2001	2000	1999	1998	1993
Earnings available for common shares	$ 38,921	$ 45,392	$ 41,610	$ 39,163	$ 43,067	$ 32,162	$ 24,892
Average number of shares—diluted	25,826	25,397	24,832	24,649	24,575	23,596	22,360
Diluted earnings per share	$ 1.51	$ 1.79	$ 1.68	$ 1.59	$ 1.75	$ 1.36	$ 1.11
Common dividends	$ 27,730	$ 26,729	$ 25,256	$ 24,328	$ 23,554	$ 22,642	$ 18,783
Dividends paid per share	$ 1.08	$ 1.06	$ 1.04	$ 1.02	$ 0.99	$ 0.96	$ 0.84
Payout ratio	72%	59%	62%	64%	57%	71%	76%
Market price:							
High	$ 28.90	$ 34.90	$ 31.00	$ 29.00	$ 22.78	$ 21.28	$ 20.63
Low	$ 23.76	$ 22.82	$ 23.00	$ 17.75	$ 17.00	$ 15.06	$ 15.31
Common price/earnings ratio:							
High	19.1	19.5	18.5	18.2	13.0	15.7	18.6
Low	15.7	12.7	13.7	11.2	9.7	11.1	13.8
Book value per common share	$ 12.98	$ 12.25	$ 11.33	$ 10.71	$ 10.12	$ 9.47	$ 7.62

Selected Data and Ratios

	2003	2002	2001	2000	1999	1998	1993
Net income (in thousands)	$ 39,656	$ 46,128	$ 43,603	$ 41,042	$ 45,295	$ 34,520	$ 27,369
Interest coverage before taxes	4.2x	4.7x	5.1x	4.6x	5.8x	4.1x	4.1x
Effective income tax rate (percent)	27	30	32	31	35	33	34
Capital ratios:							
Long-term debt and current maturities (percent)	44.0	44.7	46.5	41.4	40.2	41.5	45.7
Preferred stock (percent)	2.5	2.6	2.8	6.6	7.1	8.6	10.1
Common equity (percent)	53.5	52.7	50.7	52.0	52.7	49.9	44.2
	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Capitalization

(in thousands)	**2003**	2002	2001	2000	1999	1998	1993
Long-term debt and current maturities	$ 274,911	$ 265,919	$ 256,306	$ 209,416	$ 189,433	$ 186,840	$ 175,919
Preferred stock	15,500	15,500	15,500	33,500	33,500	38,831	38,831
Common stock equity:							
Par	128,619	127,961	123,267	122,871	122,857	59,398	55,901
Premium	26,515	24,135	1,526	50	—	39,919	30,336
Unearned compensation	(3,313)	(1,946)	(151)	(226)	(301)	—	—
Retained earnings	182,066	163,315	154,666	140,576	126,210	125,759	84,209
Total common equity	$ 333,887	$ 313,465	$ 279,308	$ 263,271	$ 248,766	$ 225,076	$ 170,446
Total capitalization including current maturities	$ 624,298	$ 594,884	$ 551,114	$ 506,187	$ 471,699	$ 450,747	$ 385,196
Income before interest charges (includes AFC borrowed)	$ 58,137	$ 64,871	$ 59,972	$ 58,177	$ 60,601	$ 46,302	$ 41,250
Percent return on capitalization	9.3	10.9	10.9	11.5	12.8	10.3	10.7
Percent return on average common equity	12.2	15.3	15.5	15.4	18.4	15.0	14.9

Times Interest Earned and Preferred Dividend Coverage

	2003	2002	2001	2000	1999	1998	1993
Before income taxes:							
Long-term debt interest *(c)*	4.4	5.1	5.2	4.8	6.0	4.3	4.2
After income taxes:							
Long-term debt interest *(d)*	3.5	3.9	3.9	3.6	4.3	3.3	3.2
Long-term debt interest and preferred dividends *(e)*	3.3	3.7	3.5	3.2	3.7	2.8	2.7
Preferred dividends *(f)*	54.0	62.7	21.9	21.9	20.3	13.0	11.0

(a) Restated to reflect EITF Issue 03-11 reporting requirements.
(b) Excludes income taxes
(c) Income before interest charges + income taxes ÷ long-term debt interest
(d) Income before interest charges ÷ long-term debt interest
(e) Income before interest charges ÷ long-term debt interest and preferred dividends
(f) Net income ÷ preferred dividends

ELECTRIC UTILITY STATISTICAL SUPPLEMENT

Depreciation Reserve

(in thousands)	2003	2002	2001	2000	1999	1998	1993
Electric plant in service	$ 875,364	$ 835,382	$ 810,470	$ 795,357	$ 779,037	$ 770,887	$ 679,282
Depreciation reserve *(a)*	$ 368,899	$ 357,555	$ 341,004	$ 323,447	$ 308,138	$ 297,738	$ 228,491
Reserve to electric plant *(a)* (percent)	42.1	42.8	42.1	40.7	39.6	38.6	33.6
Composite depreciation rate (percent)	3.07	3.08	3.06	3.06	3.06	3.12	2.95

Ratio of Debt to Electric Plant

(in thousands)	2003	2002	2001	2000	1999	1998	1993
Electric plant:							
Gross *(b)*	$ 889,302	$ 874,505	$ 835,564	$ 805,896	$ 790,016	$ 781,382	$ 687,623
Net *(a)*	$ 520,403	$ 516,950	$ 494,560	$ 482,449	$ 481,878	$ 483,644	$ 459,132
Debt *(c)*	$ 166,975	$ 166,975	$ 155,485	$ 152,617	$ 153,502	$ 154,384	$ 141,838
Ratio to electric plant–net *(a)* (percent)	32	32	31	32	32	32	31

Peak Demand and Net Generating Capability

	2003	2002	2001	2000	1999	1998	1993
Peak demand (kw)	668,703	640,220	630,262	642,826	628,259	635,174	589,239
Net generating capability (kw):							
Steam	555,085	557,308	557,400	559,093	561,006	556,851	545,499
Combustion turbines	136,915	87,358	89,085	90,344	91,071	90,634	87,993
Hydro	4,380	4,336	4,365	4,296	3,991	4,109	4,030
Total generating capability	696,380	649,002	650,850	653,733	656,068	651,594	637,522

Electric Investment

	2003	2002	2001	2000	1999	1998	1993
Electric utility plant–net *(a) (d)* (in thousands)	$ 520,403	$ 516,950	$ 494,560	$ 482,449	$ 481,878	$ 483,644	$ 459,132
Total retail electric revenue (in thousands)	$ 217,439	$ 206,870	$ 199,101	$ 188,879	$ 181,733	$ 187,279	$ 170,404
Total retail electric customers	127,474	127,093	126,548	126,687	126,231	125,655	122,375
Investment per dollar revenue *(a)*	$ 2.39	$ 2.50	$ 2.48	$ 2.55	$ 2.65	$ 2.58	$ 2.69
Investment per customer *(a)*	$ 4,082	$ 4,067	$ 3,908	$ 3,808	$ 3,817	$ 3,849	$ 3,752

Output Kilowatt-hours

(in thousands)	2003	2002	2001	2000	1999	1998	1993
Net generated	3,672,616	3,548,413	3,765,265	3,610,301	3,546,048	3,202,143	2,744,422
Purchased and net interchange	5,898,456	4,135,932	3,224,662	2,724,190	2,099,207	2,446,034	1,877,886
Total *(e)*	9,571,072	7,684,345	6,989,927	6,334,491	5,645,255	5,648,177	4,622,308

(a) Prior years are restated to reflect reclassification of reserve for estimated removal costs from accumulated depreciation to a regulatory liability.
(b) Includes construction work in progress
(c) Includes sinking fund requirements and current maturities
(d) Electric plant in service less accumulated provision for depreciation plus construction work in progress
(e) Not including wheeled energy

JOHN D. ERICKSON (45-23)*
President and
Chief Executive Officer

LAURIS N. MOLBERT (46-9)
Executive Vice President and
Chief Operating Officer

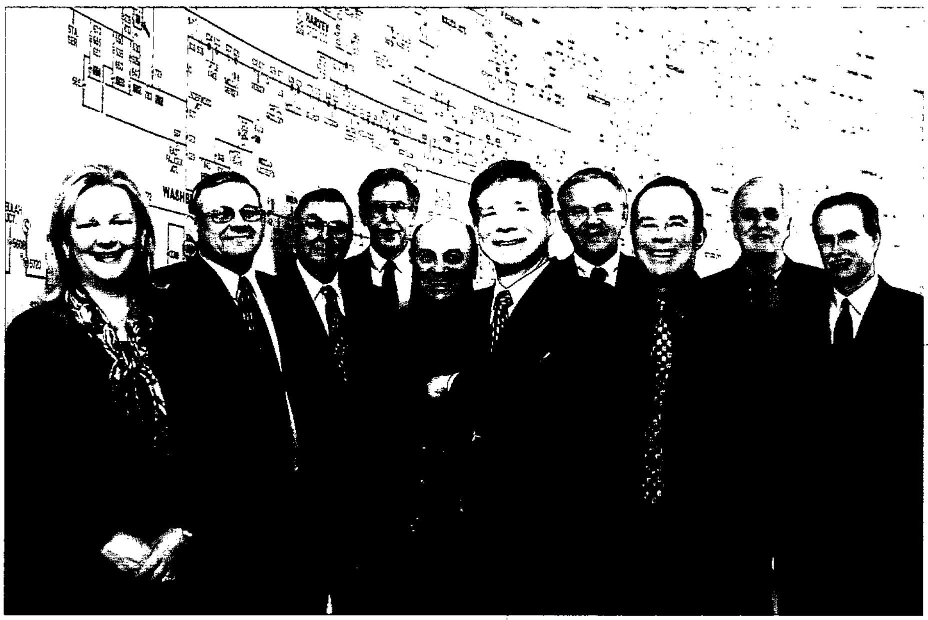
KEVIN G. MOUG (44-7)
Chief Financial Officer and
Treasurer

GEORGE A. KOECK (51-4)
Corporate Secretary and
General Counsel

(Ages-years of service) are as of the 2004 Annual Meeting of Shareholders.


LEFT TO RIGHT: JOHN ERICKSON, GEORGE KOECK, KEVIN MOUG, LAURIS MOLBERT

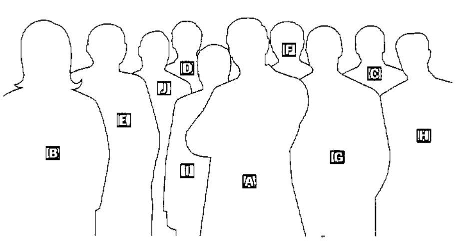
OFFICERS



DIRECTORS

A–Audit Committee
C–Compensation Committee
CG–Corporate Governance Committee
E–Executive Committee

***(Ages-years as director) are as of the 2004 Annual Meeting of Shareholders.*



A **JOHN MACFARLANE** (64-21)** E
Chairman of the Board of Directors
Fergus Falls, Minnesota
Retired President and Chief Executive Officer, Otter Tail Corporation

B **KAREN M. BOHN** (50-4 months) A/CG
Edina, Minnesota
President and Chief Executive Officer, Galeo Group, LLC
(management consulting firm)

C **THOMAS M. BROWN** (73-13) C/CG
Minneapolis, Minnesota
Retired Partner, Dorsey & Whitney LLP
(law firm)

D **DENNIS R. EMMEN** (70-20) A/C
Fergus Falls, Minnesota
Retired Senior Vice President, Finance, Treasurer and Chief Financial Officer, Otter Tail Power Company

E **MAYNARD D. HELGAAS**
Jamestown, North Dakota
Retired from board on December 31, 2003

F **ARVID R. LIEBE** (62-9) C/CG/E
Milbank, South Dakota
President, Liebe Drug, Inc. (retail business)
Owner, Liebe Farms, Inc.

G **KENNETH L. NELSON** (62-14) A
Perham, Minnesota
President and Chief Executive Officer, Barrel O' Fun, Inc., Kenny's Candy Inc., Tuffy's Pet Foods, Inc.
(snack and pet foods manufacturers)

H **NATHAN I. PARTAIN** (47-11) A/C/E
Chicago, Illinois
President, Chief Executive Officer, and Chief Investment Officer, DNP Select Income Fund, Inc.
(closed-end utility income fund)
Executive Vice President, Duff & Phelps Investment Management Co.

I **GARY J. SPIES** (62-3) A/CG
Fergus Falls, Minnesota
Chairman and President, Service Food, Inc., and Spies, Inc.
(retail business)
Partner, Fergus Falls Development Company and Midwest Regional Development Company, LLC
(land and housing development)

J **ROBERT N. SPOLUM** (73-13) A/E
Fargo, North Dakota
Retired Chairman, President, and Chief Executive Officer, Melroe Company
(industrial equipment manufacturer)
Principal, Robert N. Spolum & Associates
(business consultants)

SHAREHOLDER SERVICES

2004 ANNUAL MEETING OF SHAREHOLDERS

Monday, April 12, 2004
10 A.M., CST
Bigwood Event Center
921 Western Avenue
Fergus Falls, Minnesota

EX-DIVIDEND	RECORD	PAYMENT
Feb. 11	Feb. 13	P Mar. 1
		C Mar. 10
May 12	May 14	P June 1
		C June 10
Aug. 11	Aug. 13	P Sept. 1
		C Sept. 10
Nov. 12	Nov. 15	P Dec. 1
		C Dec. 10

CASH INVESTMENT AND SELL DATES FOR DIVIDEND REINVESTMENT

Jan. 2	Feb. 2	Mar. 1
April 1	May 3	June 1
July 1	Aug. 2	Sept. 1
Oct. 1	Nov. 1	Dec. 1

Nasdaq	OTTR
Senior unsecured debt ratings	
Moody's Investor Service	A2/negative
Standard & Poor's	A-/negative
Year-end stock price	$26.73
Year-end price/earnings ratio	17.7
Year-end market-to-book ratio	2.1
Annual dividend yield	4%
Shares outstanding	25.7 million
Market capitalization (as of December 31, 2003)	$688 million
2003 average daily trading volume	31,750
Institutional holdings (shares as of December 31, 2003)	5.6 million

OTTER TAIL CORPORATION STOCK LISTING

Otter Tail Corporation common stock trades on The Nasdaq Stock Market. The daily closing price is printed in *The Wall Street Journal, Minneapolis Star Tribune, Fargo Forum* and other major daily newspapers. Our ticker symbol is OTTR. You also can find our daily stock price on our web site, www.ottertail.com. Shareholders who sign up for internet account access can view their account information online by visiting www.investor.ottertail.com.

DIVIDENDS

Otter Tail Corporation has paid dividends on our common shares each quarter since 1938 without interruption or reduction and has increased them annually since 1975. 2003 dividends were $1.08 per share. The indicated annual rate for 2004 is $1.10. The 2003 yield was 4% and the 2003 payout ratio was 72%. Total return has compounded at an average rate of 9.75% per year for the past ten years.

DIVIDEND REINVESTMENT

The corporation's Dividend Reinvestment and Share Purchase Plan provides shareholders of record with a convenient method for purchasing shares of Otter Tail Corporation common stock. About 71% of eligible shareowners holding about 17% of our eligible common shares are enrolled. Through this plan, participants may have their dividends automatically reinvested in additional shares without paying any brokerage commissions or service charges. Shareholders may contribute a minimum of $10 and a maximum of $5,000 per month. Automatic withdrawal from a checking or savings account is available for this service. Shareholders may sell up to 25 shares a month through the plan. For more information, contact Shareholder Services.

ELECTRONIC DIVIDEND DEPOSIT

Shareholders, including institutional holders, can arrange for direct electronic deposit of their dividends to their checking or savings accounts. Electronic deposit is safe, reliable and convenient. For authorization materials, contact Shareholder Services.

PROTECTING STOCK CERTIFICATES

Since replacing missing certificates is a costly and time-consuming process, shareholders should keep a separate record of the certificate number, purchase date, date of issue, price paid and exact registration name. If you're enrolled in the Dividend Reinvestment and Share Purchase Plan, you have the option of depositing your common certificates into your plan account.

TRANSFER AGENTS

Common and preferred:
Shareholder Services
Otter Tail Corporation
P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: 800-664-1259 or 218-739-8479

Common only:
Shareowner Services
Wells Fargo Bank, N.A.
P.O. Box 64854
St. Paul, MN 55164-0854
Phone: 800-468-9716 or 651-450-4064

OTTERTAIL CORPORATION

WWW.OTTERTAIL.COM

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NASDAQ: OTTR