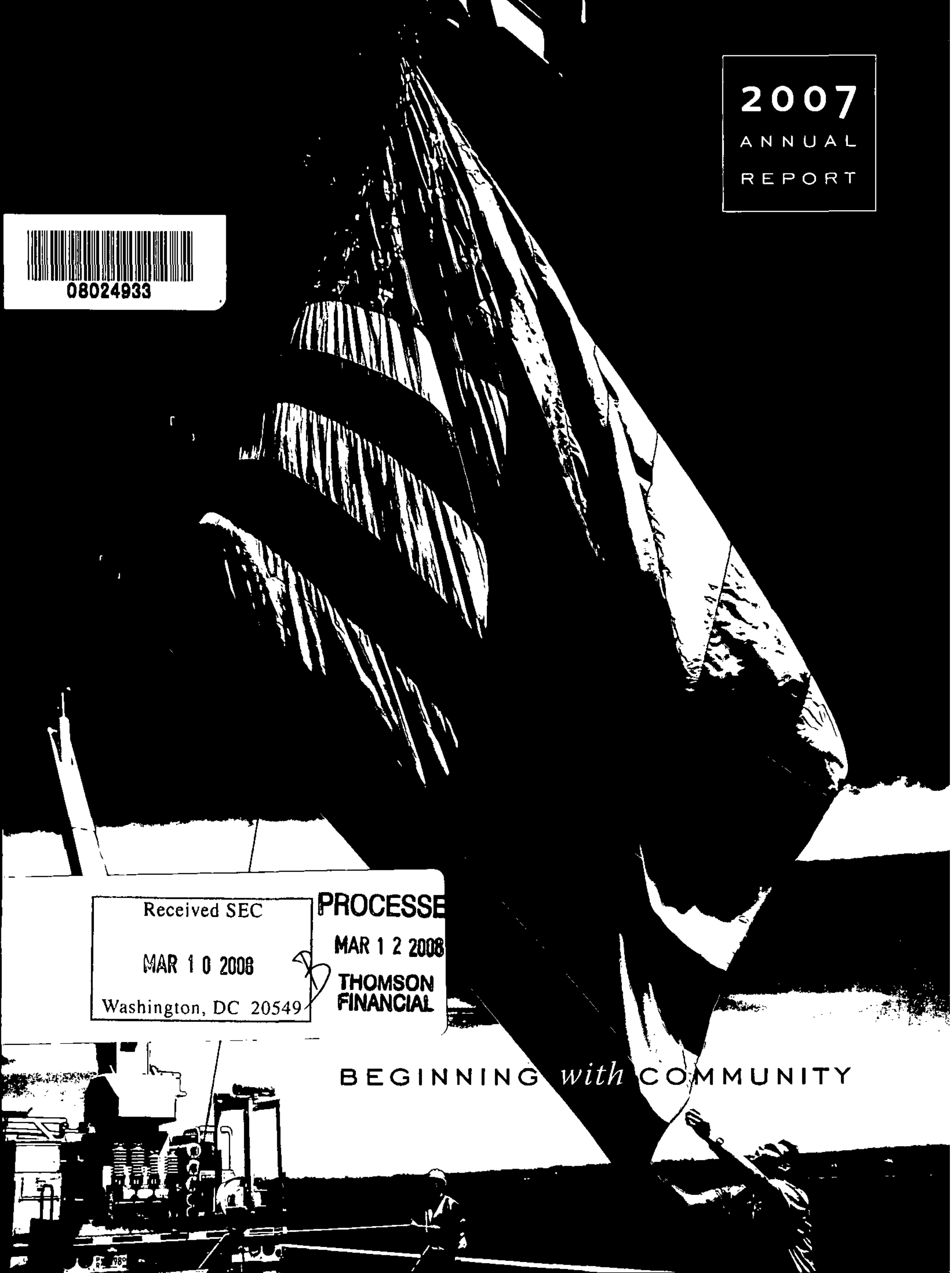


2007 ANNUAL REPORT

BEGINNING *with* COMMUNITY

HIGHLIGHTS OF THE YEAR

	2007	2006	Percent Change
CONSOLIDATED OPERATIONS			
Total Operating Revenues	$ 1,238,887,000	$ 1,104,954,000	12.1
Net Income from Continuing Operations	53,961,000	50,750,000	6.3
Net Income	53,961,000	51,112,000	5.6
Basic Earnings Per Share	1.79	1.71	4.7
Diluted Earnings Per Share from Continuing Operations	1.78	1.69	5.3
Diluted Earnings Per Share	1.78	1.70	4.7
Dividends Per Common Share	1.17	1.15	1.7
Return on Average Common Equity	10.5%	10.6%	(0.9)
Book Value Per Common Share	17.51	16.62	5.4
Cash Flow from Continuing Operations	84,812,000	79,207,000	7.1
Number of Common Shares Outstanding	29,849,789	29,521,770	1.1
Number of Common Shareholders	14,509	14,692	(1.2)
Closing Stock Price	34.60	31.16	11.0
Total Return (share price appreciation plus dividends)	14.8%	11.5%	28.7
Total Market Value of Common Stock	1,032,803,000	919,898,000	12.3
Total Employees (all companies and corporate, includes temporary and part-time)	4,300	3,935	9.3
ELECTRIC OPERATIONS			
Operating Revenues:			
Retail	$ 276,894,000	$ 260,926,000	6.1
Wholesale—Net of Purchased Power Costs	25,640,000	25,965,000	(1.3)
Other	20,624,000	18,812,000	9.6
Total Electric Operating Revenues	$ 323,158,000	$ 305,703,000	5.7
Total Retail Electric Sales (kwh)	4,123,831,000	3,990,854,000	3.3
Operating Income	45,755,000	50,111,000	(8.7)
Customers	129,342	129,070	0.2
Gross Plant Investment	1,062,689,000	949,191,000	12.0
Total Assets	813,565,000	689,653,000	18.0
Capital Expenditures	104,288,000	35,207,000	196.2
Employees (includes temporary and part-time)	714	700	2.0
NONELECTRIC OPERATIONS			
Operating Revenues	$ 915,729,000	$ 799,251,000	14.6
Operating Income	55,019,000	47,686,000	15.4
Total Assets	641,189,000	568,997,000	12.7
Capital Expenditures	57,697,000	34,241,000	68.5
Employees (includes temporary and part-time)	3,533	3,181	11.1

ON THE COVER

[illegible] Power Company [illegible] and Fergus Falls [illegible] Minnesota National Guard [illegible]

IT ALL BEGINS WITH

COMMUNITY

WE IMPROVE THE COMMUNITIES WHERE WE WORK AND LIVE.

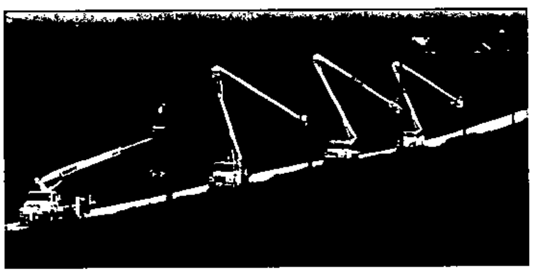
This is a core value that guides us every day, present since the very beginning.

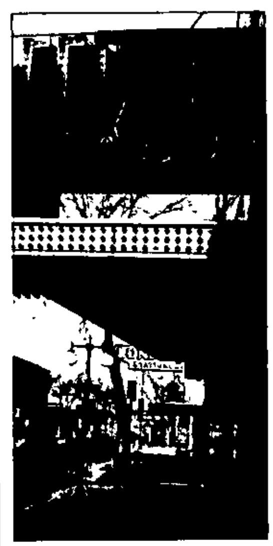
A century ago, our founders chose to build a power dam near Fergus Falls, Minnesota. In 1909 electricity began flowing to area communities, signaling the start of service by Otter Tail Power Company.

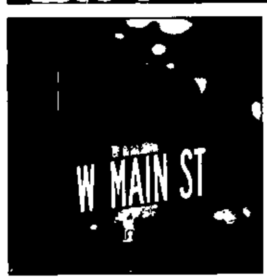
Our power company has grown to deliver low-cost reliable electricity to communities across Minnesota, North Dakota and South Dakota.

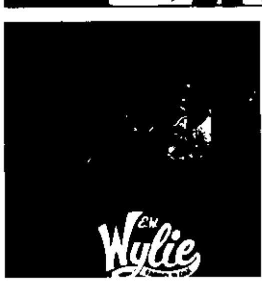
We began to diversify in the late 1980s by acquiring well-run companies outside the regulated electric industry. In this way, we could expand in new directions to increase shareholder value.

Today, we have added many new businesses and fortified the fabric of hundreds of communities. Otter Tail Corporation now reaches customers around the world through our diversified operations. We build these businesses with a deep conviction to bring value to our customers, shareholders and employees. In doing so, we help communities grow and prosper.









AND EVERYONE BENEFITS.

CONSERVING RESOURCES

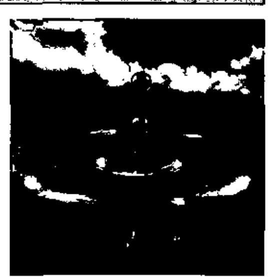
DMI FOREMAN BRUCE LENERTZ, WEST FARGO, NORTH DAKOTA

WE BUY 100% CERTIFIED RENEWABLE ENERGY
Green-e.org

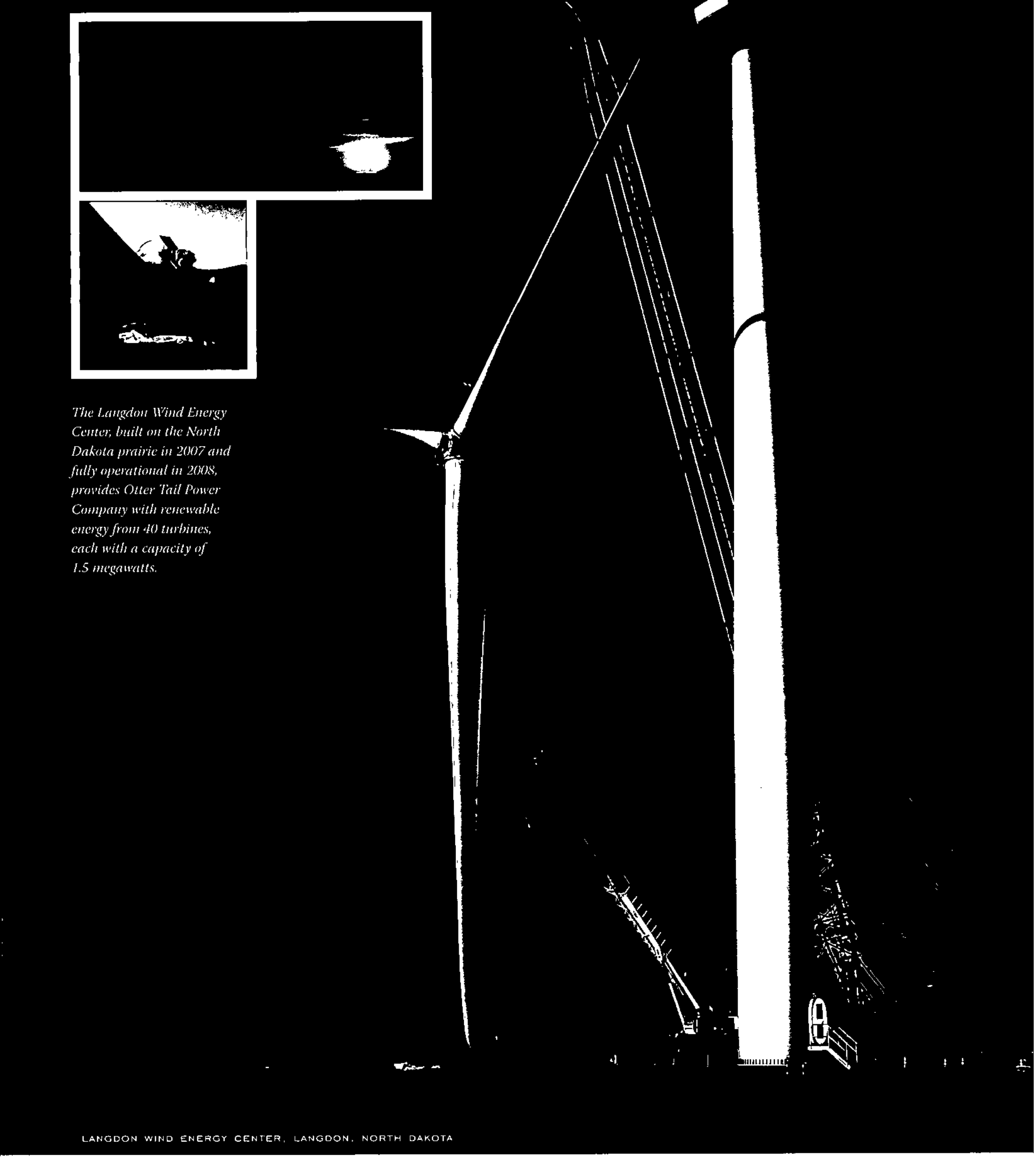
DMI INDUSTRIES COMBINES LEADERSHIP WITH STEWARDSHIP IN THE RENEWABLE ENERGY SECTOR. THE WIND TOWER MANUFACTURER OFFSETS 100% OF EMISSIONS FROM ELECTRICITY CONSUMED AT ITS THREE PLANTS BY PURCHASING GREEN-E CERTIFIED WIND ENERGY CREDITS.

Using in-house regrinding systems, T.O. Plastics produces durable 100% recyclable horticultural trays manufactured from 90% post-production scrap.

Idaho Pacific purifies and recycles wastewater from its potato processing plant in Prince Edward Island, Canada, so effectively that overall water use dropped by 50% in recent years. The excess purified water is discharged safely into the ocean.



Otter Tail Power Company is monitoring customer experiences from home energy makeovers for data to enhance energy efficiency education.



The Langdon Wind Energy Center, built on the North Dakota prairie in 2007 and fully operational in 2008, provides Otter Tail Power Company with renewable energy from 40 turbines, each with a capacity of 1.5 megawatts.

LANGDON WIND ENERGY CENTER, LANGDON, NORTH DAKOTA

UPHOLDING ENVIRONMENTAL COMMITMENTS ▫ Otter Tail Power Company's commitment to environmental stewardship includes energy conservation, demand-side management programs, renewable energy development, power plant efficiency improvements and participation in energy research. Plans for a balanced mix of energy generation include accelerating the development of wind power. As an owner and purchaser of wind power from the Langdon Wind Energy Center in North Dakota, Otter Tail Power Company added 60 more megawatts to its renewable energy resources in early 2008. ▫

GIVING BACK

BTD AQUATIC CENTER, DETROIT LAKES, MINNESOTA

DMS Interim Solutions rolls up to the hospital in Americus, Georgia, with a mobile CT scanner. The operating unit of DMS Health Group delivered a rent-free unit after a devastating string of tornadoes severely damaged the town and hospital early in 2007.

KEEPING A COMMUNITY FOCUS ▫ BTD Manufacturing is one of the largest employers in Detroit Lakes, Minnesota, and employees believe deeply in making the community a better place to live, work and play. The BTD Aquatic Center, located in the Detroit Lakes Community and Cultural Center, is one of the many ways the parts manufacturer puts its positive stamp on the town. Otter Tail Corporation and the 12 Otter Tail companies collectively provide about $1 million annually to worthy charities, nonprofits and educational institutions. ▪

[illegible]

[illegible]

DMI Industries heightens wind energy awareness by sponsoring events such as the KidWind Project, a hands-on experience for area science teachers.

TY GLASS, A STUDENT AT THE ANNE CARLSEN CENTER FOR CHILDREN, JAMESTOWN, NORTH DAKOTA

STUDENTS AT THE ANNE CARLSEN CENTER FOR CHILDREN IN JAMESTOWN, NORTH DAKOTA, WILL NURTURE GARDENS YEAR-ROUND WITH THE ADDITION OF A THERAPEUTIC GREENHOUSE OPENING IN THE SPRING OF 2008. OTTER TAIL POWER COMPANY, A MAJOR DONOR FOR THE PROJECT, ALSO HELPED TO DESIGN THE GREENHOUSE FOR MAXIMUM ENERGY EFFICIENCY.

DMI RECRUITMENT BILLBOARD, TULSA, OKLAHOMA

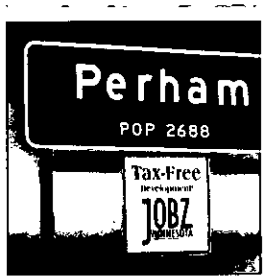
IN OUR COMMUNITIES

CREATING OPPORTUNITY

WITH THE OPENING OF A NEW DMI WIND TOWER PLANT IN OKLAHOMA, COMPELLING RECRUITMENT MESSAGES DREW SEVERAL HUNDRED APPLICANTS FOR THE INITIAL JOBS. DMI ALSO CONTINUES TO GROW AT ITS OTHER LOCATIONS, ADDING STAFF AND PRODUCTION CAPACITY AT ITS PLANTS IN NORTH DAKOTA AND ONTARIO.

BTD Manufacturing gets high scores for employee development. Among the many programs BTD offers is an in-house business leadership course administered by the local technical college. Weekly videoconferencing classes draw together 26 students from two BTD locations in Minnesota.

Northern Pipe Products is expanding its second plant, located in Hampton, Iowa, to increase product offerings and overall plant capacity. Sister company Vinyltech also is driving a major expansion at its Phoenix pipe production plant.



Perham, Minnesota, is a small town with big plans for growth, thanks to the efforts of civic leaders, legislators and Otter Tail Power Company. Through their combined actions, anchor businesses such as snack food manufacturer Barrel O' Fun are able to expand; and new businesses such as Redline, an ATV manufacturer, are drawn to the thriving community.

TERRY STALLMAN OF OTTER TAIL POWER COMPANY VISITS WITH REDLINE ENGINEER LUKE EVENSON, AND BARREL O' FUN CONTROLLER/SYSTEMS MANAGER KEVIN KEIL, WHO IS ALSO THE MAYOR OF PERHAM, MINNESOTA

MAKING ECONOMIC DEVELOPMENT WORK ▫ The success of Otter Tail Power Company is tied directly to the success of hundreds of businesses large and small across its vast service territory. At no charge to the community seeking assistance, Otter Tail's economic development staff works closely with state and civic leaders to secure financing, find business sites and help develop a prepared workforce. The power company currently has committed $884,000 to loan pools in 34 communities and has provided millions of dollars in grants and loans since 1990 to assist new businesses and to retain existing businesses. ▫

OUR MISSION

To create value for our customers, shareholders and employees by working together to grow our companies:

- 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.
- For employees, by providing opportunities in a challenging, rewarding environment.

TO OUR SHAREHOLDERS

Commitment to community is a value deeply ingrained in how we do business. We believe in improving the communities where we work and live. The prior pages highlight many examples of how Otter Tail companies reach out as committed corporate citizens. And our 2007 financial results show we were successful at creating value for our shareholders, customers and employees.

I am pleased to report that the collective performance from our 12 operating companies produced solid results. We maintained a strong balance sheet, capital structure and cash flows. Our financial outcomes for 2007 are as follows:

- Operating revenues reached a record level of more than $1.2 billion.
- Net income increased to $54 million.
- Earnings per share were $1.78.
- The common dividend paid in 2007 increased to $1.17 per share, providing a dividend yield of 3.8%.
- Our stock price went up 11% in 2007, producing a total return to shareholders of 14.8% in combination with the dividend.

In early 2008, our Board of Directors raised the dividend to an indicated annual rate of $1.19 from $1.17 in 2007. For decades shareholders have relied on dependable Otter Tail dividends, paid without interruption since 1938 and providing annual increases since 1975. Our shareholder value grew at a compounded annual rate of 10.7% over the past 10 years.

For the third consecutive year, *Public Utilities Fortnightly* recognized Otter Tail Corporation as one of the nation's top-performing energy companies. Ratings are based on three-year averages of profitability, dividend yield, cash flow, return on equity, return on assets and sustainable growth. We also appeared on the Mergent Dividend Achievers list, which recognizes organizations that reliably deliver dividend increases.

DIVERSIFIED, DECENTRALIZED AND DISCIPLINED

We value the focus and commitment of the leadership teams and employees across our 12 operating companies. They worked hard to achieve goals and provide results leading to solid earnings in 2007. Each year we expect some of our companies will perform better than others. At its most basic level, this is why diversification works. We balance risk more effectively because we are not unduly impacted by economic swings within one industry or business. After nearly 20 years of diversification, our track record of growth—in revenues, earnings, dividends and shareholder value—shows this remains the right direction.

Our decentralized business model focuses on talent and execution. The leadership at our operating companies applies keen industry experience and skills to produce sound results. Strategy is developed under the guidance of platform leaders, who also help set corporate direction. In this way, we strike the right balance between decentralization and discipline.

2007 PLATFORM OVERVIEW

Otter Tail Power Company provided a solid foundation, and our nonelectric businesses continued to add to our growth in 2007.

- **ELECTRIC PLATFORM**
  Our core electric business performed well, contributing 45% of consolidated net income in 2007. Otter Tail Power Company has a long history of stable financial performance and effective management to contain costs, conserve electricity and keep rates among the lowest in the nation. Those management goals will not change. However, as energy use continues to grow and costs for providing electric service escalate, our power company will request rate increases within its three-state service territory. For the first time since 1986, Otter Tail Power Company proposed an increase in its Minnesota base rates. An interim rate increase took effect late in 2007, and a final ruling is expected from the Minnesota Public Utilities Commission in August 2008.
- **MANUFACTURING PLATFORM**
  Led by DMI Industries and ShoreMaster, this platform had earnings growth of nearly 19% year over year. BTD Manufacturing continued to deliver strong performance.
- **HEALTH SERVICES PLATFORM**
  DMS Health Group experienced a challenging year in its diagnostic imaging unit, as did other companies in this sector.
- **FOOD INGREDIENT PROCESSING PLATFORM**
  Idaho Pacific, our potato processing company, achieved a significant turnaround through cost reduction and improved efficiencies, coupled with more favorable market conditions.
- **INFRASTRUCTURE PRODUCTS AND SERVICES PLATFORM**
  While earnings from plastics were lower than the prior year due to an anticipated softening in the market, our two pipe companies exceeded our expectations. Our trucking and construction companies produced mixed results.

OUR VISION

To be a recognized leader in growing great companies and developing talented people.

OUR VALUES

Integrity	We conduct business responsibly and honestly.
Safety	We provide safe workplaces and require safe work practices.
People	We build respectful relationships and create an environment where talented people thrive.
Performance	We strive for excellence, act on opportunity and deliver on commitments.
Community	We improve the communities where we work and live.

We continually look at potential acquisitions and invest when the opportunities will add value to our existing platforms. During 2007, we acquired two small companies that smoothly integrated into current operations within our manufacturing platform. Much of the growth within Otter Tail Corporation over the next few years is expected to come from major capital investments at our existing companies.

CAPITAL PROJECTS SPUR GROWTH

The Langdon Wind Energy Center, the largest wind farm in North Dakota to date, is a joint undertaking by Otter Tail Power Company, neighboring utility Minnkota Power Cooperative and FPL Energy of Florida, the nation's foremost wind developer. The 106 turbines, each with a generating capacity of 1.5 megawatts, all were turning brisk prairie winds into energy by early 2008. Otter Tail Power Company owns 27 of the turbines and purchases energy from an additional 13, bringing its generating capacity from the wind farm to 60 megawatts. This investment boosts our utility's portfolio of renewable resources, a key element of a balanced energy mix.

The nationwide surge in wind energy projects has created exciting expansion activity at DMI Industries, our fastest-growing operating company. DMI acquired and renovated a plant site in Oklahoma for its third wind tower manufacturing facility. The new site will help increase DMI's annual combined tower production to support up to 3,000 megawatts of installed wind project capacity.

A major growth opportunity is the baseload power plant proposed to be built next to the existing Big Stone Plant in South Dakota with Otter Tail Power Company as lead developer. Big Stone II and its associated transmission are necessary to ensure regional electric reliability as well as to allow delivery of electricity generated from additional sources, including wind farms. If approved, the new coal-fired plant would more than double electricity output at the site and would use advanced technology to effectively control emission levels.

ENERGY AND THE ENVIRONMENT

Energy and the environment are high-profile topics for the American public. People expect reliable, affordable electricity produced and delivered by electric suppliers in a safe and environmentally responsible manner. These are reasonable expectations. The challenge lies in meeting the expectations while addressing current realities in the energy industry.

Energy use is rising more rapidly than infrastructure capacity. Additional generation and transmission investments are needed to address higher demand and maintain reliability. There are five energy resource options: coal, natural gas, nuclear, renewables and energy efficiency. No single resource is the answer. To meet the future energy challenge, our nation needs a balanced mix of all these resources.

Concerns about climate change are driving public policy to reduce carbon dioxide (CO_2) emissions from coal plants, vehicles and other sources. Actions are underway to control greenhouse gas emissions, and I believe that is a wise course. The electric industry has led all sectors in reducing greenhouse gas emissions, and Otter Tail Power Company has decreased CO_2 intensity by approximately 11% since 1990. Renewable resources accounted for 9% of Otter Tail's electricity generation in 2007, a percentage that is growing with the addition of new wind sources. Our power company is a leader in energy conservation and since 1992 has helped customers conserve more than 1 million megawatt-hours of electricity. And our wind tower company, DMI Industries, is anticipating—and responding to—the changing needs of the booming wind energy industry.

Ultimately, controlling climate change is a public policy matter. In shaping that public policy we must consider some important points. First, ensuring a reliable and affordable electric supply to meet rising demand. Second, maintaining competitiveness of U.S. companies by making changes at a pace the economy can digest. Third, developing energy-efficiency programs and pollution-control technologies that are cost effective. And fourth, creating international partnerships to address the global issue of climate change. All of these are considerations in finding an appropriate balance.

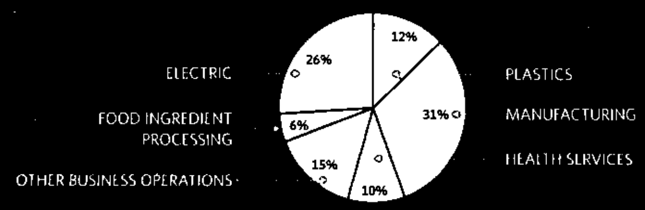
People want reliable, affordable electricity produced with limited environmental impact. These are the expectations we deliver on every day. And we will continue to balance and meet those expectations with the best information and the most efficient commercially proven technologies available.

BEGINNING WITH COMMUNITY

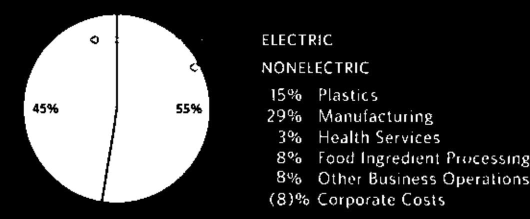
Throughout our diversified organization, we are a community of dedicated people working together to grow great companies and create value for our shareholders, customers and employees. Our commitment to community has a tremendous positive impact where we work and live, as we pursue successful growth with responsible stewardship. We will continue to strive to provide you with a dependable long-term investment. On behalf of the more than 4,000 employees across our 12 operating companies, we thank you for your confidence in Otter Tail Corporation.

John Erickson | President and CEO | February 2008

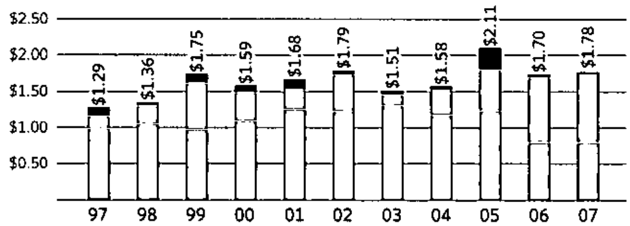
REVENUES



NET INCOME



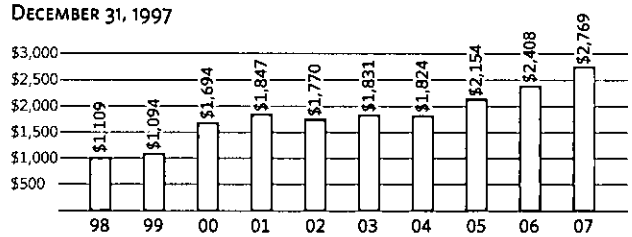
Earnings Per Share Growth



Earnings per share have grown at a compounded annual rate of 3.3% over the past ten years.

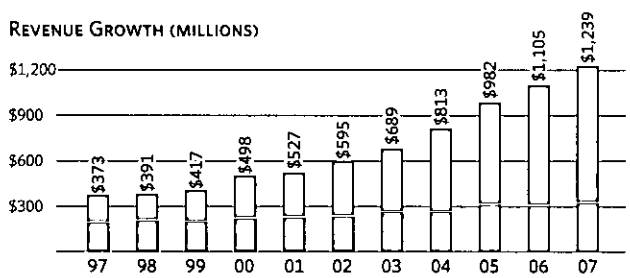
☐ Electric ☐ Nonelectric continuing operations ■ Nonelectric discontinued operations

Growth of $1,000 Investment in Otter Tail Common Stock made December 31, 1997



Shareholder value has grown at a compounded annual rate of 10.7% over the past ten years.

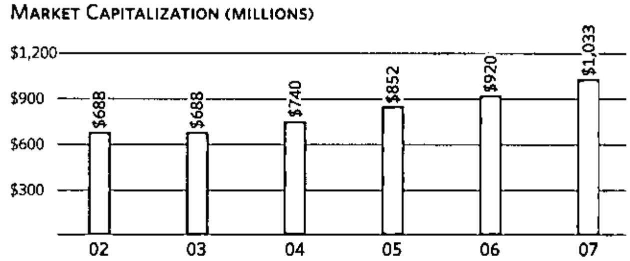
Revenue Growth (millions)



Total company revenue has grown at a compounded annual rate of 12.8% over the past ten years.

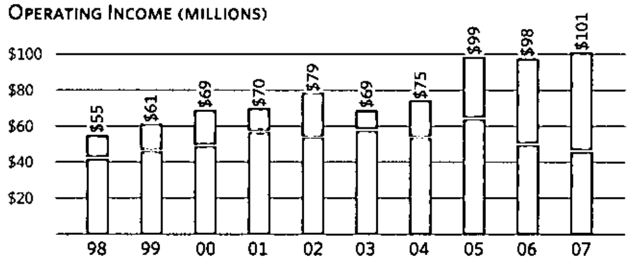
☐ Electric ☐ Nonelectric continuing operations

Market Capitalization (millions)



Our market capitalization has increased 50% over the past five years. Over that same period of time, we've paid out $158 million in common dividends.

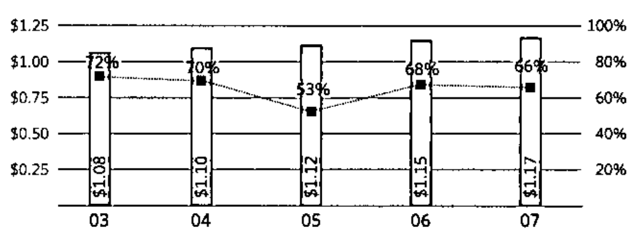
Operating Income (millions)



Operating income has grown at a compounded annual rate of 5.8% over the past ten years.

☐ Electric ☐ Nonelectric continuing operations

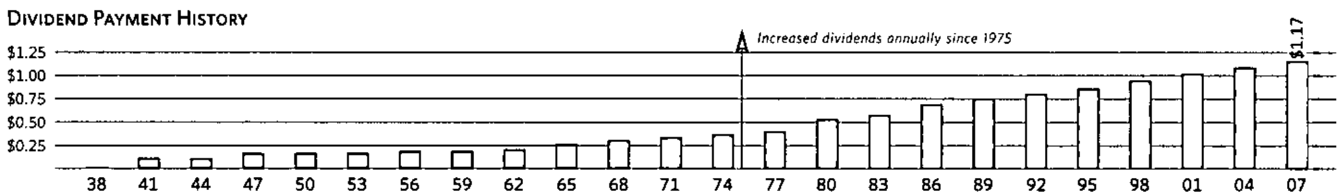
Dividend Payout Ratio



Over the past five years, dividends have increased while the average payout rate has been 66%. In 2005, earnings per share included $0.34 related to a net gain on the sale of discontinued operations.

☐ Dividend ■ Payout Ratio

Dividend Payment History



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

OTTER TAIL CORPORATION

ELECTRIC

Otter Tail Power Company
Electric utility
Fergus Falls, MN / 1907
Chuck MacFarlane
714 employees
www.otpco.com

MANUFACTURING

BTD Manufacturing, Inc.
Metal fabricator
Detroit Lakes, MN / 1995
Paul Gintner
448 employees
www.btdmfg.com

DMI Industries, Inc.
Wind tower/heavy steel manufacturer
West Fargo, ND / 1990
Chuck Hoge
635 employees
www.dmiindustries.com

ShoreMaster, Inc.
Waterfront equipment manufacturer
Fergus Falls, MN / 2002
Erik Ahlgren
392 employees
www.shoremaster.com

T.O. Plastics, Inc.
Custom plastic parts manufacturer
Clearwater, MN / 2001
Mike Vallafskey
220 employees
www.toplastics.com

HEALTH SERVICES

DMS Health Group
Diagnostic imaging services and equipment sales
Fargo, ND / 1993
Paul Wilson
494 employees
www.dmshg.com

FOOD INGREDIENT PROCESSING

Idaho Pacific Holdings, Inc.
Dehydrated potato processor
Ririe, ID / 2004
Dick Nickel
437 employees
www.idahopacific.com

INFRASTRUCTURE PRODUCTS AND SERVICES

PLASTICS

Northern Pipe Products, Inc.
PVC/PE pipe manufacturer
Fargo, ND / 1995
Wayne Voorhees
118 employees
www.northernpipe.com

Vinyltech Corporation
PVC pipe manufacturer
Phoenix, AZ / 2000
Steve Laskey / 67 employees
www.vtpipe.com

OTHER BUSINESSES

Construction

Foley Company
Mechanical and prime contractor
Kansas City, MO / 2003
Chris Callegari / 219 employees
www.foleycompany.com

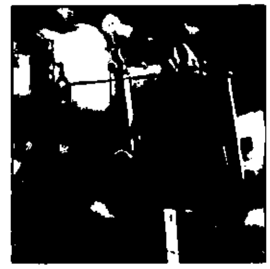
Midwest Construction Services, Inc.
Electrical and transmission constructor
Moorhead, MN / 1992
Paul Bruhn / 321 employees
www.mwcsi.com

Transportation

E.W. Wylie Corporation
Flatbed and specialized contract and common carrier
West Fargo, ND / 1999
Brian Gast / 173 employees
74 owner/operators
www.wylietrucking.com

CHART LEGEND

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



ELECTRIC

ON IN MORE WAYS THAN ONE

Day and night, Otter Tail Power Company is on for hundreds of communities, working to meet customers' energy needs safely, reliably, affordably and in an environmentally responsible manner. And employees continued to be right on target in 2007.

An excellent safety record reflects constant vigilance. In May 2007, the Minnesota Safety Council presented an outstanding achievement award for continuous safety performance to Otter Tail Power Company, the only utility to receive such recognition for entire company operations. The power company was also a leader in safety nationwide with the lowest number of injuries for its utility peer group in the annual safety survey compiled by the Edison Electric Institute.

Customer service is another measure where employee commitment makes all the difference. Among new initiatives was the Voice of the Customer program, an opportunity for customers to take part in a telephone survey immediately following a call regarding service. Nearly 3,000 customers left feedback in 2007, giving a stellar 97% positive rating to Otter Tail Power Company's customer service representatives.

The most tangible way for a utility to be on for its customers is to provide reliable electricity. Crews quickly responded when power interruptions occurred, keeping the average total outage time for the year to less than 66 minutes per customer. This outcome is below the average total outage time experienced at peer utilities. And with major commitments ahead for plant construction, transmission and wind energy, the power company is preparing now for continued energy reliability.

WIND ENERGY INCREASES WITH OWNERSHIP

A purchaser of wind power for many years, Otter Tail Power Company increased its commitment to renewable energy in 2007. Along with Minnkota Power Cooperative and major wind energy developer FPL Energy, Otter Tail Power Company helped erect North Dakota's largest wind farm in 2007. The Langdon Wind Energy Center is a 106-turbine facility with the capacity to generate 159 megawatts. Otter Tail Power Company owns 27 of the 1.5-megawatt turbines and purchases the electricity produced from another 13 turbines at the site, providing the power company a combined generating capacity of 60 megawatts.

The Langdon project represents the largest investment in new generation made by the power company in nearly three decades. The company's resource plan projects at least 260 megawatts of wind-generating capability by 2015, and the Langdon Wind Energy Center is pivotal to that goal. Otter Tail Power Company is well on its way to achieving compliance with legislated standards for renewable energy. The wind farm also brings a welcome economic lift to Langdon and the surrounding region, which is served by Otter Tail Power Company.

BIG STONE II WOULD DOUBLE OUTPUT, REDUCE EMISSIONS

Work continues on securing necessary permits for Big Stone II, a new coal-fired plant proposed to be built next to the existing 450-megawatt Big Stone Plant in northeastern South Dakota. Otter Tail Power Company, the lead developer of the plant, would own Big Stone II with four other utilities. Collectively, the customer base of the participating utilities represents more than 1 million people across five states in the Upper Midwest.

Big Stone II is projected to have a nominal generating capacity of approximately 500 to 580 megawatts, depending on final ownership requirements. Big Stone II participants also will need to build and upgrade transmission facilities in Minnesota and South Dakota to allow delivery of power from the new plant and other projects in development. Nearly 80 other pending regional generation projects, including new wind power, have included these proposed lines as part of their transmission plans. Big Stone II would provide the voltage stability and the expanded transmission necessary to help achieve Minnesota's mandate of 25% energy generation from renewable resources by 2025.

Big Stone II is designed to be both highly efficient and environmentally responsible. With the addition of the new plant, the power station's generating capacity would more than double while reducing, or holding steady, emissions of sulfur dioxide, nitrogen oxides and mercury. And by using advanced technology the new plant would emit 20% less CO_2 than existing coal-fired power plants in the region. Big Stone II would provide a sound energy future in our region by balancing consumers' requirements for reliable and affordable electricity with concerns for a healthy environment and reduced carbon emissions. If permits are approved, Big Stone II would come on line in mid-2013.

TRANSMISSION TARGETS SET

CapX 2020, short for capacity expansion by 2020, is a joint transmission-planning effort among 11 utilities that own transmission lines in Minnesota and the surrounding region. Planning studies show the region will see substantial electric load growth, and more transmission will be necessary for renewable energy in the coming decade. The proposed CapX 2020 high-voltage transmission lines will help meet these increased demands on infrastructure.

The first proposed group of CapX 2020 projects is made up of three 345-kilovolt transmission lines and one 230-kilovolt line and associated substations. Otter Tail Power Company is the lead utility for the 230-kilovolt line which, if approved, would extend for 68 miles between Bemidji and Grand Rapids in north central Minnesota. The CapX 2020 regulatory approval process is underway in Minnesota and also will be sought for those projects extending into surrounding states.

RATE INCREASE REVIEW UNDERWAY IN MINNESOTA

The nation's cost of living has risen nearly 90% since 1986, yet Otter Tail Power Company has not raised base rates in Minnesota and South Dakota since then or in North Dakota since 1982. Energy use has grown, despite the power company's conservation measures, load management and operating efficiencies. The ever-rising costs associated with producing and delivering electricity are driving the need for a rate increase.

Otter Tail Power Company filed for review of its Minnesota rates in October 2007 and received approval for an interim increase to take effect at the end of November. This provides a transition to a final rate decision, which is expected in August 2008 from the Minnesota Public Utilities Commission.

FUTURE DIRECTION

The commitment to deliver reliable, affordable electricity safely and in an environmentally responsible manner will keep Big Stone II and the expansion of renewable resources and transmission at the strategic forefront. As the Minnesota rate case winds up, the process will start again in North Dakota by late 2008 and in South Dakota within the next two years. Otter Tail Power Company also is preparing to mark 100 years of providing electricity in 2009 by developing special stewardship projects in each of the three states it serves.

OTTER TAIL POWER COMPANY ◻ provides reliable, low-cost and environmentally responsible electricity to more than 129,000 customers in Minnesota, North Dakota and South Dakota. Owned generating capability is approximately 716 megawatts. Owned generation includes 3 coal-fired steam plants, 6 hydroelectric plants, 4 combustion turbine generators and 27 wind turbines. In 2007, more than 9% of the energy generated to serve customers came from renewable and nontraditional sources.

MANUFACTURING

DMI INDUSTRIES GROWS WITH THREE PLANTS

Targeted growth and capital investments at DMI Industries resulted in strong performance for 2007. Productivity improved at its plant in West Fargo, North Dakota, and its Fort Erie, Ontario, plant produced higher volume and increased throughput. The addition of plate processing, plate rolling and blast/paint equipment at Fort Erie allowed DMI to increase capacity and manufacture larger tower sections at that site, which reaches a broad service territory in Canada and the northeastern United States.

DMI selected a site near Tulsa, Oklahoma, for its third plant in 2007. This strategic move solidified the company's position as one of the largest wind tower manufacturers on the continent and allowed further expansion into south central and southwestern markets. The Oklahoma plant began producing towers in early 2008.

DMI received top honors for commercial achievement in 2007 from the American Wind Energy Association. The award was given in recognition of DMI's efforts to increase domestic manufacturing of wind-related products in the United States. It is the first North Dakota-based company to be recognized by the Center for Resource Solutions as a buyer of Green-e certified renewable energy credits. DMI also was named a Green Power Partner by the U.S. Environmental Protection Agency.

During 2007 DMI broadened its customer base, which now includes many of the major turbine manufacturers in the wind energy industry.

BTD MANUFACTURING EXPANDS MARKET REACH

BTD Manufacturing achieved steady revenue growth in 2007, adding relationships with original equipment manufacturers in a variety of industries. Strong positive trends in labor productivity, capacity and production quality led to improved margins for the parts manufacturer. Performance Tool, a BTD business that makes medium to large dies, reached record sales levels. In May 2007, BTD acquired Pro Engineering, a metal stamping and fabrication business in Minneapolis.

SHOREMASTER DELIVERS RECORD RESULTS

ShoreMaster delivered a year of record sales from its residential waterfront products, successfully improving distribution and marketing systems within its dealer network. The commercial business, which designs and builds marina systems, also had record results and maintained solid backlogs at the company's plants in Florida, Missouri and California. With the acquisition of Aviva Sports, ShoreMaster gained a new product line of innovative recreational water toys.

Early in 2008, ShoreMaster moved from a leased site to an owned facility for its California plant. ShoreMaster was awarded a contract to be part of the development team for a world-class marina on Peninsula Papagayo in Costa Rica. The project will involve ShoreMaster's plants on both coasts and gives the company a heightened profile in the Latin American waterfront market.

T.O. PLASTICS IMPROVES PRODUCTIVITY

T.O. Plastics secured new target accounts and invested in systems to improve productivity. Two larger thermoforming production lines with high-speed throughput were installed in 2007, replacing older lines. Improvements in extrusion processes and controls resulted in greater yields and higher quality plastic sheet. Mike Vallafskey was appointed president at the start of 2008. With the assistance of an experienced and capable management team, which added new talent in 2007, he will position the company for its next stage of growth.

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.

DMI INDUSTRIES, INC. □ manufactures wind towers and other heavy steel-fabricated products.

SHOREMASTER, INC. ■ produces and markets residential and commercial waterfront equipment, ranging from boatlifts and docks to full marina systems.

T.O. PLASTICS, INC. ■ manufactures extruded and thermoformed plastic products, including custom parts for customers in several industries and its own line of horticulture containers.

HEALTH SERVICES

DMS IMAGING FOCUSES ON EFFICIENCIES

To create operational efficiencies in a challenging marketplace, DMS Imaging consolidated two regional offices and assessed route changes for the mobile imaging fleet to reduce any excess capacity. The imaging business announced the addition of digital mammography to its mobile services, allowing faster response and more detailed review by radiologists over traditional film-based exams. The service will be offered initially to hospitals and clinics in northeastern North Dakota and northwestern Minnesota before expanding to additional markets.

DMS Imaging also continued to forge successful relationships with major hospital multisystems and healthcare group purchasing organizations. In November 2007, the imaging business signed a three-year agreement with University HealthSystem Consortium, an alliance of approximately 90% of the nation's nonprofit academic medical centers.

DMS HEALTH TECHNOLOGIES STRENGTHENS TIES

DMS Health Technologies continued to strengthen its long-term partnership with Philips Medical Systems, the manufacturer of high-tech medical products. Philips equipment and service support are the primary products offered by DMS Health Technologies. Philips also selected DMS service technicians to install the first Release 3 cardiac cath lab in a North American-based hospital. This is now the master training hub for Philips application specialists on the continent.

DMS HEALTH GROUP ▫ is composed of two primary business units that deliver 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. DMS Health Technologies also is a major distributor for Philips Medical Systems.

DMS IMAGING ▫ provides shared diagnostic medical imaging services for MRI, CT, nuclear medicine, PET/CT, ultrasound, mammography and bone density testing. Delivery of services is through DMS Imaging mobile units with options available for interim and fixed-site delivery. DMS Imaging also provides portable X-ray, ultrasound and EKG services.

FOOD INGREDIENT PROCESSING

IDAHO PACIFIC ACHIEVES TURNAROUND

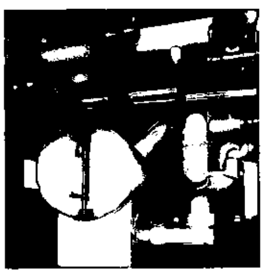
Idaho Pacific achieved a record year of sales, production and financial performance in 2007, a significant turnaround from the challenges of recent years.

With adequate crop supplies and stronger demand across international and U.S. markets, the company experienced improved margins overall at its operations in Idaho, Colorado and Prince Edward Island, Canada. The three plants were able to extend the processing season due to ample potato supply, another factor contributing to an increase in pounds of product sold. Plant efficiencies and more stable natural gas costs also led to improved performance.

Management continued to align product sales into a more favorable mix, working to diversify and increase the company's customer base. Major new customers were added during the year, and long-term customer relationships were strengthened. Shifts in currency exchange rates led to favorable export pricing, and sales increased in several international markets.

IDAHO PACIFIC HOLDINGS, INC. ▫ manufactures and supplies dehydrated potato products to food-manufacturing customers in the snack food, foodservice and bakery industries.

INFRASTRUCTURE PRODUCTS AND SERVICES



PLASTICS

NORTHERN PIPE PRODUCTS, INC. ▫ manufactures and sells PVC and polyethylene pipe used in municipal and rural water, wastewater and storm drainage 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, wastewater and water reclamation systems in the south central, southwestern and western regions of the United States.

OTHER BUSINESS OPERATIONS

CONSTRUCTION

FOLEY COMPANY ▫ provides mechanical and prime contracting for water and wastewater treatment plants, hospital and pharmaceutical facilities, power generation plants and other public, commercial and industrial 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.

TRANSPORTATION

E.W. WYLIE CORPORATION ▫ operates a fleet of 209 trucks (135 company trucks and 74 owner/operator trucks) as a flatbed and specialized contract and common carrier across the Lower 48 United States and Canada.

PIPE COMPANIES SET FOR EXPANSION

In response to customers, Northern Pipe Products announced plans to produce large-diameter PVC pipe at its plant in Hampton, Iowa. The company will add extrusion capacity for PVC sewer and water pressure pipe in diameters up to 27 inches. When completed in the fall of 2008, the expansion will increase production capacity by more than 25%.

Demand for water and wastewater pipe during 2007 remained high in the Southwest, Phoenix-based Vinyltech's primary sales territory. Vinyltech continued progress on a plant expansion project, expected to boost production capacity by 40% after completion in 2008. The expansion will include a new resin-blending system and two additional extrusion lines.

CONSTRUCTION COMPANIES GEAR UP

In the 2007 ranking of the top 600 specialty contractors compiled by *Engineering News Record*, Foley moved up to 251 and Midwest Construction Services was listed at 354.

With industrial construction activity on the rise and strong backlogs in place, Foley Company turned in record revenues and earnings for 2007. Crews began environmental upgrades at a central Missouri power plant, mechanical renovations at a major Kansas City medical center and completed work on the Sprint Center sports arena in downtown Kansas City. Foley is the general contractor overseeing reconstruction of the Sioux City, Iowa, municipal wastewater treatment plant. The Missouri-based construction firm serves a multistate area and pursued further expansion into southwestern market opportunities during the year.

Midwest Construction Services continued to gain visibility in the renewable energy sector through its subsidiary, Ventus Energy Systems, which completed work on installations throughout the Upper Midwest. Another subsidiary, Aerial Contractors, delivered steady gains in performance as it worked to meet the growing demand for power transmission, substations and telecommunication infrastructure.

TRANSPORTATION INTRODUCES SITES, SERVICES

E.W. Wylie opened a terminal in Minneapolis to tap into the trucking and recruiting potential of another metro market in addition to its locations in Iowa, Colorado and Texas, and moved into new headquarters in West Fargo, North Dakota. The trucking firm introduced heavy haul service to better respond to and broaden its customer base, adding equipment capable of moving oversized heavy machinery and large infrastructure building components. Brian Gast, a transportation executive with extensive industry experience, was named president of E.W. Wylie early in 2008.

FINANCIAL REVIEW

SELECTED CONSOLIDATED FINANCIAL DATA

(in thousands, except number of shareholders and per-share data)	2007	2006	2005	2004	2003	2002	1997
Revenues							
Electric	$ 323,478	$ 306,014	$ 312,985	$ 266,385	$ 267,494	$ 244,005	$ 197,406
Plastics	149,012	163,135	158,548	115,426	86,009	82,931	24,953
Manufacturing	381,599	311,811	244,311	201,615	157,401	119,880	48,570
Health Services	130,670	135,051	123,991	114,318	100,912	93,420	66,859
Food Ingredient Processing	70,440	45,084	38,501	14,023	—	—	—
Other Business Operations (1)	185,730	145,603	105,821	102,516	78,094	56,113	35,329
Corporate Revenues and Intersegment Eliminations (1)	(2,042)	(1,744)	(2,288)	(1,247)	(921)	(924)	—
Total Operating Revenues	$ 1,238,887	$1,104,954	$ 981,869	$ 813,036	$ 688,989	$ 595,425	$ 373,117
Net Income from Continuing Operations	53,961	50,750	53,902	40,502	38,297	44,297	29,092
Net Income from Discontinued Operations	—	362	8,649	1,693	1,359	1,831	3,254
Net Income	53,961	51,112	62,551	42,195	39,656	46,128	32,346
Operating Cash Flow from Continuing Operations	84,812	79,207	90,348	54,410	76,464	71,584	67,551
Operating Cash Flow—							
Continuing and Discontinued Operations	84,812	80,246	95,800	56,301	76,955	76,797	69,398
Capital Expenditures—Continuing Operations	161,985	69,448	59,969	49,484	48,783	73,442	39,885
Total Assets	1,454,754	1,258,650	1,181,496	1,134,148	986,423	914,112	689,818
Long-Term Debt	342,694	255,436	258,260	261,805	262,311	254,015	179,575
Redeemable Preferred	—	—	—	—	—	—	18,000
Basic Earnings Per Share—Continuing Operations (2)	1.79	1.70	1.82	1.53	1.47	1.73	1.15
Basic Earnings Per Share—Total (2)	1.79	1.71	2.12	1.59	1.52	1.80	1.29
Diluted Earnings Per Share—Continuing Operations (2)	1.78	1.69	1.81	1.52	1.46	1.72	1.15
Diluted Earnings Per Share—Total (2)	1.78	1.70	2.11	1.58	1.51	1.79	1.29
Return on Average Common Equity	10.5%	10.6%	13.9%	12.0%	12.2%	15.3%	14.9%
Dividends Per Common Share	1.17	1.15	1.12	1.10	1.08	1.06	0.93
Dividend Payout Ratio	66%	68%	53%	70%	72%	59%	72%
Common Shares Outstanding—Year End	29,850	29,522	29,401	28,977	25,724	25,592	23,462
Number of Common Shareholders (3)	14,509	14,692	14,801	14,889	14,723	14,503	13,753

Notes: (1) Beginning in 2007 corporate revenues and expenses are no longer reported as components of Other Business Operations. Prior years have been restated accordingly.
(2) Based on average number of shares outstanding.
(3) Holders of record at year end.

SELECTED ELECTRIC OPERATING DATA

	2007	2006	2005	2004	2003	2002	1997
Revenues (thousands)							
Residential	$ 92,254	$ 86,950	$ 83,740	$ 76,365	$ 75,689	$ 72,180	$ 66,102
Commercial and Farms	111,960	101,895	100,677	88,853	88,550	84,143	74,520
Industrial	68,648	65,370	61,235	54,159	48,315	45,803	41,323
Sales for Resale	25,640	25,965	46,397	27,228	29,702	18,295	3,402
Other Electric	24,976	25,834	20,936	19,780	25,238	23,584	12,059
Total Electric	$ 323,478	$ 306,014	$ 312,985	$ 266,385	$ 267,494	$ 244,005	$ 197,406
Kilowatt-Hours Sold (thousands)							
Residential	1,218,026	1,170,841	1,162,765	1,119,067	1,141,612	1,130,770	1,064,579
Commercial and Farms	1,515,635	1,453,664	1,428,059	1,386,358	1,396,638	1,383,129	1,260,840
Industrial	1,321,249	1,297,287	1,233,948	1,197,534	1,108,021	1,106,241	1,099,641
Other	68,921	69,062	69,663	70,105	70,071	70,447	57,324
Total Retail	4,123,831	3,990,854	3,894,435	3,773,064	3,716,342	3,690,587	3,482,384
Sales for Resale	1,648,841	2,778,460	2,778,431	3,845,299	3,786,397	3,049,786	602,493
Total	5,772,672	6,769,314	6,672,866	7,618,363	7,502,739	6,740,373	4,084,877
Annual Retail Kilowatt-Hour Sales Growth	3.3%	2.5%	3.2%	1.5%	0.7%	2.4%	1.4%
Heating Degree Days	9,050	8,260	8,656	9,132	9,132	9,065	9,469
Cooling Degree Days	482	517	423	228	515	623	459
Average Revenue Per Kilowatt-Hour							
Residential	7.57¢	7.43¢	7.20¢	6.82¢	6.63¢	6.38¢	6.21¢
Commercial and Farms	7.39¢	7.01¢	7.05¢	6.41¢	6.34¢	6.08¢	5.91¢
Industrial	5.20¢	5.04¢	4.96¢	4.52¢	4.36¢	4.14¢	3.76¢
All Retail	6.71¢	6.54¢	6.39¢	5.95¢	5.85¢	5.61¢	5.33¢
Customers							
Residential	101,750	101,657	101,176	100,952	100,515	100,092	98,479
Commercial and Farms	26,500	26,343	26,211	26,157	25,900	25,950	25,646
Industrial	42	42	44	40	40	41	36
Other	1,050	1,028	1,035	1,069	1,079	1,074	1,030
Total Electric Customers	129,342	129,070	128,466	128,218	127,534	127,157	125,191
Residential Sales							
Average Kilowatt-Hours Per Customer (4)	12,100	11,706	11,749	11,251	11,525	11,504	11,001
Average Revenue Per Residential Customer	$ 893.01	$ 862.99	$ 776.48	$ 766.99	$ 756.83	$ 732.64	$ 683.07

Notes: (4) Based on average number of customers during the year.

OVERVIEW

Otter Tail Corporation and our subsidiaries form a diverse group of businesses with operations classified into six segments: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations. Our primary financial goals are to maximize earnings and cash flows and to allocate capital profitably toward growth opportunities that will increase shareholder value. Meeting these objectives enables us to preserve and enhance our financial capability by maintaining desired capitalization ratios and a strong interest coverage position and preserving solid credit ratings on outstanding securities, which, in the form of lower interest rates, benefits both our customers and shareholders.

Our strategy is straightforward: Reliable utility performance combined with growth opportunities at all our businesses provides long-term value. This includes growing our core electric utility business which provides a strong base of revenues, earnings and cash flows. In addition, we look to our nonelectric operating companies to provide organic growth as well. Organic, internal growth comes from new products and services, market expansion and increased efficiencies. We expect much of our growth in the next few years will come from major capital investments at our existing companies. We adhere to strict guidelines when reviewing acquisition candidates. Our aim is to add companies that will produce an immediate positive impact on earnings and provide long-term growth potential. We believe that owning well-run, profitable companies across different industries will bring more growth opportunities and more balance to results. In doing this, we also avoid concentrating business risk within a single industry. All our operating companies operate under a decentralized business model with disciplined corporate oversight.

We assess the performance of our operating companies over time, using the following criteria:

- ability to provide returns on invested capital that exceed our weighted average cost of capital over the long term; and
- assessment of an operating company's business and potential for future earnings growth.

We are a committed long-term owner and therefore we do not acquire companies in pursuit of short-term gains. However, we will divest operating companies that do not meet these criteria over the long term.

The following major events occurred in our company in 2007:

- Our annual consolidated revenues topped $1.2 billion for the first time in our history.
- We reported record earnings in our manufacturing and food ingredient processing segments.
- Construction expenditures totaled $162 million, including expenditures for the electric utility's portion of the Langdon wind project and DMI Industries, Inc.'s new wind tower manufacturing facility near Tulsa, Oklahoma.
- We continued work with other regional utilities on the planning and permitting process for a nominally rated 500-580 megawatt coal-fired electric generating plant (Big Stone II) on the site of the existing Big Stone Plant.
- The electric utility filed a general rate case in Minnesota in October 2007. The last general rate case filing in Minnesota was in 1986.

Major growth strategies and initiatives in our company's future include:

- Planned capital budget expenditures of up to $899 million for the years 2008-2012 of which $759 million is for capital projects at the electric utility, including $336 million related to Big Stone II, $106 million for wind generation and associated transmission projects and $67 million for anticipated expansion of transmission capacity in Minnesota (CapX 2020). See "Capital Requirements" section for further discussion.
- Pursuing the regulatory approvals, financing and other arrangements necessary to build Big Stone II.
- Adding more renewable resources to our electric resource mix.
- Completion of the Minnesota general rate case and rate filings in North Dakota and South Dakota.
- The continued investigation and evaluation of organic growth and strategic acquisition opportunities.

The following table summarizes our consolidated results of operations for the years ended December 31:

(in thousands)	2007	2006
Operating Revenues:		
Electric	$ 323,158	$ 305,703
Nonelectric	915,729	799,251
Total Operating Revenues	$ 1,238,887	$1,104,954
Net Income from Continuing Operations:		
Electric	$ 24,498	$ 24,181
Nonelectric	29,463	26,569
	53,961	50,750
Net Income from Discontinued Operations	—	362
Total Net Income	$ 53,961	$ 51,112

The 12.1% increase in consolidated revenues in 2007 compared with 2006 reflects significant revenue growth from our manufacturing segment, construction companies and food ingredient processing segment. Revenues increased $69.8 million in our manufacturing segment in 2007 mainly due to increased sales of wind towers and waterfront products. Our construction companies' revenues grew by $40.2 million in 2007 as a result of increased construction activity. Food ingredient processing revenues increased $25.4 million as a result of a 29.5% increase in the volume of products sold combined with an increase in product prices. Revenues in the electric segment increased $17.5 million mainly due to an $8.4 million increase in fuel clause adjustment (FCA) revenues related to an increase in fuel and purchased power costs in 2007 and a 3.3% increase in retail megawatt-hour (mwh) sales in 2007. Revenues from our health services segment decreased $4.4 million in 2007, reflecting a shift from traditional dealership distribution of products in 2006 to more commission-based compensation for sales in 2007. Revenues decreased by $14.1 million in our plastics segment in 2007 as a result of lower pipe sales prices driven by a decline in polyvinyl chloride (PVC) resin prices.

Record net income from our manufacturing segment and an $8.5 million turnaround in net income at our food ingredient processing business more than offset decreases in net income from our plastics, other business operations and health services segments.

Following is a more detailed analysis of our operating results by business segment for the three years ended December 31, 2007, 2006 and 2005, followed by our outlook for 2008, a discussion of our financial position at the end of 2007 and risk factors that may affect our future operating results and financial position.

RESULTS OF OPERATIONS

This discussion and analysis should be read in conjunction with our consolidated financial statements and related notes found elsewhere in this report. See note 2 to our consolidated financial statements for a complete description of our lines of business, locations of operations and principal products and services.

Amounts presented in the segment tables that follow for 2007, 2006 and 2005 operating revenues, cost of goods sold and other nonelectric operating expenses will not agree with amounts presented in the consolidated statements of income due to the elimination of intersegment transactions. The amounts of intersegment eliminations by income statement line item are listed below:

(in thousands)	2007	2006	2005
Operating Revenues:			
Electric	$ 320	$ 311	$ 361
Nonelectric	1,722	1,433	1,927
Cost of Goods Sold	1,539	1,433	2,070
Other Nonelectric Expenses	503	311	218

ELECTRIC

The following table summarizes the results of operations for our electric segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Retail Sales Revenues	$ 276,894	6	$ 260,926	5	$ 248,939
Wholesale Revenues	22,306	(13)	25,514	(39)	41,953
Net Marked-to-Market Gains	3,334	639	451	(90)	4,444
Other Revenues	20,944	10	19,123	8	17,649
Total Operating Revenues	$ 323,478	6	$ 306,014	(2)	$ 312,985
Production Fuel	60,482	3	58,729	5	55,927
Purchased Power—System Use	74,690	28	58,281	(1)	58,828
Other Operation and Maintenance Expenses	107,041	3	103,548	4	99,904
Depreciation and Amortization	26,097	1	25,756	6	24,397
Property Taxes	9,413	(2)	9,589	(5)	10,043
Operating Income	$ 45,755	(9)	$ 50,111	(22)	$ 63,886

2007 compared with 2006

The $16.0 million increase in retail electric sales revenues in 2007 compared with 2006 includes a net increase of $8.4 million in FCA revenues mainly related to an increase in purchased power costs in the fourth quarter of 2007 to replace generation lost during a scheduled major maintenance shutdown of our Big Stone Plant. The increase in retail revenues also includes $7.6 million related to a 3.3% increase in retail mwh sales. Residential mwh sales increased 4.0% due, in part, to a 9.6% increase in heating degree days. Increased oil and ethanol production in our electric service territory and surrounding regions contributed to a 3.1% increase in commercial and industrial mwh sales. The increase in FCA revenues related to increases in fuel and purchased power costs for system use between the years was $14.4 million. The $8.4 million net increase in FCA revenues includes the effects of $6.0 million in FCA adjustments and refunds in 2006 and 2007 that were not related to increases in fuel and purchased power costs between the years.

A 30.6% decline in wholesale mwh sales from company-owned generation in 2007 compared with 2006 resulted in a $2.8 million decrease in wholesale revenues despite a 26.7% increase in the price per mwh sold from company-owned generating units. In 2006, advance purchases of electricity in anticipation of normal winter weather resulted in increased wholesale electric sales in January 2006, when the weather was unseasonably mild. Advance purchases of electricity in anticipation of coal supply constraints at Big Stone and Hoot Lake plants in the second quarter of 2006 freed up more generation for wholesale sales when coal supplies improved in May 2006. Net revenues from energy trading activities, including net mark-to-market gains on forward energy contracts, were $5.3 million in 2007 compared with $2.8 million in 2006. The $2.5 million increase in revenue from energy trading activities reflects a $3.5 million increase in profits from purchased power resold and net settlements of forward energy contracts and a $2.9 million increase in net mark-to-market gains on forward energy contracts, offset by a $3.9 million decrease in profits related to the purchase and sale of financial transmission rights (FTRs).

The $1.8 million increase in other electric operating revenues in 2007 compared with 2006 is related to increases in revenues of $0.8 million from electric system planning and construction work performed for other companies, $0.5 million from integrated transmission agreements and $0.4 million for reimbursement of system operations costs from the Midwest Independent Transmission System Operator (MISO).

The $1.8 million increase in fuel costs in 2007 compared with 2006 reflects an 8.7% increase in the cost of fuel per mwh generated offset by a 5.3% decrease in mwhs generated. Generation used for wholesale electric sales decreased 30.6% while generation for retail sales decreased 0.8% between the years. Fuel costs for the electric utility's combustion turbines increased $2.0 million due to an 86.1% increase in mwhs generated from those units. Fuel costs per mwh increased at all of the electric utility's steam turbine generating units as a result of increases in coal and coal transportation costs between the years. Much of the increase in coal and coal transportation costs is related to higher diesel fuel prices. Over 90% of the fuel cost increases associated with generation to serve retail electric customers is subject to recovery through the FCA component of retail rates.

The $16.4 million increase in purchased power—system use (to serve retail customers) in 2007 compared with 2006 is due to a 22.1% increase in mwh purchases for system use combined with a 4.9% increase in the cost per mwh purchased. The increase in mwh purchases was a result of power purchased to replace generation lost during the scheduled major maintenance shutdown of our Big Stone Plant in the fourth quarter of 2007.

The $3.5 million increase in other operation and maintenance expenses for 2007 compared with 2006 includes increases of:
(1) $1.1 million in labor and benefit costs related to wage and salary increases averaging approximately 3.8% and an increase in employee numbers between the periods, (2) $1.0 million in costs related to contracted construction work performed for other companies,
(3) $0.7 million in external costs related to rate case preparation and
(4) $0.6 million in tree-trimming expenditures.

2006 compared with 2005

The $12.0 million increase in retail electric sales revenues in 2006 compared with 2005 is due mainly to a $9.5 million increase in FCA revenues related to increases in fuel and purchased power costs for system use and to a $3.6 million increase in FCA revenue related to the 2006 reversal of a $1.9 million FCA refund provision recorded in December 2005. The refund provision is related to MISO costs subject to collection through the FCA in Minnesota. In December 2005, the Minnesota Public Utilities Commission (MPUC) issued an order denying recovery of certain MISO-related costs through the FCA and requiring a refund of amounts previously collected. In February 2006, the MPUC reconsidered its order and eliminated the refund requirement. In December 2006, the MPUC ordered the refund of $0.4 million in MISO schedule 16 and 17 administrative costs that had been collected through the FCA, allowing for deferred recovery of those costs in the electric utility's next general rate case which was filed on October 1, 2007. The FCA revenues also include $2.6 million in unrecovered fuel and purchased power costs under an FCA true-up mechanism established by order of the MPUC. The Minnesota FCA true-up relates to costs incurred from July 2004 through June 2006 that were recovered from Minnesota customers from August 2006 through July 2007. The electric utility currently is accruing for the Minnesota FCA true-up on a monthly basis along with its regular monthly FCA accrual.

Retail mwh sales increased 2.5% between the years as a result of increased sales to industrial customers mainly due to increased consumption by pipeline customers as higher oil prices led to an increase in the volume of product being transported from Canada and the Williston basin. A 9.8% decline in the price of wholesale mwh sales from company-owned generation in 2006 compared with 2005 resulted in a $1.7 million decrease in revenues despite a 3.4% increase in mwh sales from company-owned generating units. Advance purchases of electricity in anticipation of normal winter weather resulted in increased wholesale electric sales in January 2006 due to unseasonably mild weather. Wholesale sales from company-owned generation were curtailed in February and March 2006 as generation levels were restricted due to coal supply constraints at Big Stone and Hoot Lake plants. Advance purchases of electricity in anticipation of continuing coal supply constraints in the second quarter of 2006 supplemented increased generation when coal supplies improved in May, providing additional resources for wholesale sales.

Net revenue from energy trading activities, including net mark-to-market gains on forward energy contracts, were $2.8 million in 2006 compared with $21.6 million in 2005. The $18.8 million decrease in revenue from energy trading activities reflects an $11.4 million reduction in net profits from virtual transactions, a $4.5 million reduction in profits from purchased power resold and a $4.0 million decrease in net mark-to-market gains on forward energy contracts, offset by a $1.1 million increase in profits from investments in FTRs. With the inception of the MISO Day 2 markets in April 2005, the MISO introduced two new types of contracts, virtual transactions and FTRs. Virtual transactions are of two types: (1) a Virtual Demand Bid, which is a bid to purchase energy in the MISO's Day-Ahead Market that is not backed by physical load; (2) a Virtual Supply Offer, which is an offer submitted by a market participant in the Day-Ahead Market to sell energy not supported by a physical injection or reduction in withdrawals in commitment by a resource. An FTR is a financial contract that entitles its holder to a stream of payments, or charges, based on transmission congestion charges calculated in the MISO's Day-Ahead Market. A market participant can acquire an FTR from several sources: the annual or monthly FTR allocation based on existing entitlements, the annual or monthly FTR auction, the FTR secondary market or FTRs granted in conjunction with a transmission service request. An FTR is structured to hedge a market participant's exposure to uncertain cash flows resulting from congestion of the transmission system. Profits from virtual transactions were $1.2 million in 2006 compared with $12.7 million in 2005 as the MISO market matured and became more efficient and as a result of a reduction in virtual transactions due to uncertainties related to the status of Revenue Sufficiency Guarantee charges in the MISO's Transmission and Energy Markets Tariff. In 2006, we recorded a net loss on purchased power resold of $1.8 million compared with a net gain of $2.7 million in 2005. Of the $2.9 million in net mark-to-market gains recognized on open forward energy contracts at December 31, 2005, $2.1 million was realized and $0.8 million was reversed in the first nine months of 2006 as market prices on forward electric contracts declined in response to decreased demand for electricity due, in part, to regional winter weather that was milder than expected.

The $2.8 million increase in fuel costs in 2006 compared with 2005 reflects a 3.2% increase in the cost of fuel per mwh generated combined with a 1.8% increase in mwhs generated. Generation used for wholesale electric sales increased 3.4% while generation for retail sales increased 1.3% between the periods. Fuel costs per mwh increased at the Coyote Station and Hoot Lake Plant as a result of increases in coal and coal transportation costs between the years. Much of the increase in coal and coal transportation costs is related to higher diesel fuel prices. The mix of available generation resources in 2006 compared with 2005 also contributed to the increase in the cost of fuel per mwh generated. Big Stone Plant's generation increased 12.9% between the years while Coyote Station's generation was down 5.9%. In the second quarter of 2006, Coyote Station, our lowest cost baseload plant, was off-line for five weeks for scheduled maintenance. In the second quarter of 2005, the higher cost Big Stone Plant was shut down for seven weeks for scheduled maintenance.

The $0.5 million decrease in purchased power—system use in 2006 compared with 2005 is due to a 20.9% reduction in mwh purchases for system use mostly offset by a 25.2% increase in the cost per mwh purchased for system use.

The $3.6 million increase in other operation and maintenance expenses for 2006 compared with 2005 resulted primarily from $2.0 million in increased operating and maintenance costs at the electric utility's generation plants, including Coyote Station, which was shut down for five weeks of scheduled maintenance in the second quarter of 2006, and $1.4 million in increased costs related to contract work performed for other area utilities. Depreciation expense increased $1.4 million in 2006 compared with 2005 as a result of an increase in effective depreciation rates in 2006 and increases in electric plant in service. The $0.5 million decrease in property taxes reflects lower property valuations in Minnesota and South Dakota.

PLASTICS

The following table summarizes the results of operations for our plastics segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 149,012	(9)	$ 163,135	3	$ 158,548
Cost of Goods Sold	124,344	(2)	126,374	4	121,245
Operating Expenses	7,223	(29)	10,239	(6)	10,939
Depreciation and Amortization	3,083	10	2,815	12	2,511
Operating Income	$ 14,362	(39)	$ 23,707	(1)	$ 23,853

2007 compared with 2006

The $14.1 million decrease in plastics operating revenues in 2007 compared with 2006 reflects an 18.8% decrease in the price per pound of pipe sold, partially offset by a 12.5% increase in pounds of pipe sold between the years. The decrease in pipe prices and cost of goods sold reflects the effect of a 15.7% decrease in PVC resin prices between the years. The $3.0 million decrease in plastics segment operating expenses reflects a decrease in employee incentives directly related to the decreases in operating margins between the years. The increase in depreciation and amortization expense is the result of $5.5 million in capital additions in 2006, mainly for production equipment.

2006 compared with 2005

The $4.6 million increase in plastics operating revenues in 2006 compared with 2005 reflects a 12.6% increase in the price per pound of PVC and polyethylene pipe sold offset by an 8.8% decrease in pounds of pipe sold between the years. The increase in prices reflects the effect of a 13.7% increase in PVC resin costs per pound of PVC pipe shipped between the years. The decrease in pounds of pipe sold reflects a significant decrease in sales in the third and fourth quarters of 2006 compared with the third and fourth quarters of 2005, reflecting record demand for PVC pipe in the last half of 2005, as sales were affected by concerns over the adequacy of resin supply following the 2005 Gulf Coast hurricanes. The increase in cost of goods sold is a result of higher resin costs. The decrease in plastics segment operating expenses is due to lower selling, general and administrative expenses between the years. The increase in depreciation and amortization expense is related to capital additions in 2005 and 2006, mainly for production equipment.

MANUFACTURING

The following table summarizes the results of operations for our manufacturing segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 381,599	22	$ 311,811	28	$ 244,311
Cost of Goods Sold	300,146	22	246,649	27	194,264
Operating Expenses	35,278	33	26,508	11	23,872
Depreciation and Amortization	13,124	18	11,076	17	9,447
Operating Income	$ 33,051	20	$ 27,578	65	$ 16,728

2007 compared with 2006

The increase in revenues in our manufacturing segment in 2007 compared with 2006 relates to the following:

- Revenues at DMI Industries, Inc. (DMI), our manufacturer of wind towers, increased $48.0 million (35.2%) as a result of increased productivity at the West Fargo plant and increased production levels at the Ft. Erie plant compared with initial start-up levels beginning in May 2006.

- Revenues at ShoreMaster, Inc. (ShoreMaster), our waterfront equipment manufacturer, increased $15.9 million (26.4%) between the years due to increased production and sales of commercial products and higher residential sales during the peak selling season. The Aviva Sports product line, acquired by ShoreMaster in February 2007, contributed $3.7 million to the increase in revenues.
- Revenues at BTD Manufacturing Inc. (BTD), our metal parts stamping and fabrication company, increased $3.5 million (4.5%) between the years, mainly as a result of the May 2007 acquisition of Pro Engineering, LLC (Pro Engineering).
- Revenues at T.O. Plastics, Inc. (T.O. Plastics), our manufacturer of thermoformed plastic and horticultural products, increased $2.4 million (6.4%) between the years as a result of greater demand for both custom and horticultural products.

The increase in cost of goods sold in our manufacturing segment in 2007 compared with 2006 relates to the following:

- Cost of goods sold at DMI increased $39.8 million between the years, including increases of $30.4 million in material and supplies, $6.8 million in labor and benefit costs and $2.6 million in other direct manufacturing costs. The increase in cost of goods sold is directly related to DMI's increase in production and sales activity, including operations at the Ft. Erie facilities which commenced in May 2006.
- Cost of goods sold at ShoreMaster increased $9.2 million between the years as a result of increases in material and labor costs directly related to the increase in commercial and residential product sales as well as the acquisition of the Aviva Sports product line in February 2007, which contributed $2.9 million to cost of goods sold in 2007.
- Cost of goods sold at BTD increased $2.8 million between the years as a result of the acquisition of Pro Engineering in May 2007, partially offset by a decrease in costs at BTD's other manufacturing facilities related to a decrease in unit sales between the years.
- Cost of goods sold at T.O. Plastics increased $2.1 million, mainly driven by an increase in volume, as compared to 2006, and higher material costs.

The increase in operating expenses in our manufacturing segment in 2007 compared with 2006 relates to the following:

- Operating expenses at DMI increased $3.0 million, including $2.0 million in 2007 pre-production start-up costs at its new plant in Oklahoma and increases in expenses related to full operations at the Ft. Erie facility. The new plant in Oklahoma started producing towers in January 2008.
- Operating expenses at ShoreMaster increased $3.9 million as a result of increases in labor, benefits, sales expenses and professional services, of which $1.7 million is related to the Aviva Sports product line acquired in February 2007 and $1.3 million is related to facility relocation and legal expenses.
- Operating expenses at BTD increased $1.3 million between the years as a result of increases in labor and other expenses, mainly related to the acquisition of Pro Engineering in May 2007, and the reduction of a legal settlement reserve in 2006.
- Operating expenses at T.O. Plastics increased by $0.6 million between the years mainly as a result of leadership succession costs and increases in professional service expenditures.

Depreciation expense increased between the years mainly as a result of 2006 capital additions at DMI's Ft. Erie and West Fargo plants.

2006 compared with 2005

The increase in revenues in our manufacturing segment in 2006 compared with 2005 relates to the following:

- Revenues at DMI increased $64.0 million (88.4%) as a result of increases in production and sales activity due in part to plant additions, including initial operations at the Ft. Erie, Ontario facility which generated $25.3 million in revenue in 2006, its first year of operations, and continued improvements in productivity and capacity utilization.
- Revenues at ShoreMaster increased $3.2 million (5.7%) between the years due to price increases driven by higher material costs (especially aluminum) and due to the acquisition of Southeast Floating Docks in May 2005.
- Revenues at T.O. Plastics increased $0.7 million (1.9%) between the periods as a result of a 0.9% increase in unit sales combined with a 1.5% increase in revenue per unit sold.
- Revenues at BTD decreased $0.4 million (0.5%) between the periods. However, BTD's operating income increased $3.6 million due, in part, to productivity improvements between the years.

The increase in cost of goods sold in our manufacturing segment in 2006 compared with 2005 relates to the following:

- Cost of goods sold at DMI increased $51.5 million between the years, including increases of $39.6 million in material costs, $9.2 million in labor and benefit costs and $2.7 million in tools and supplies expenditures. The increase in cost of goods sold is directly related to the increase in DMI's production and sales activity and initial operation and start up costs at its Ft. Erie facility.
- Cost of goods sold at ShoreMaster increased $2.4 million between the years as a result of increases in labor, material (especially aluminum) and other direct costs and a full year of operations relating to the acquisition of Southeast Floating Docks, which occurred in May 2005.
- Cost of goods sold at T.O. Plastics increased $2.0 million, reflecting $1.0 million in material cost increases and $0.8 million in increased labor and benefit costs between the years.
- Cost of goods sold at BTD decreased $3.3 million between the years mainly due to a decrease in labor costs between the years due to a reduction in the number of production employees, a decrease in overtime pay between the years and a reduction in production hours in December 2006. Productivity gains at BTD were achieved through efforts to better utilize and allocate available labor resources.

The increase in operating expenses in our manufacturing segment in 2006 compared with 2005 relates to the following:

- Operating expenses at DMI increased $2.7 million as a result of increases in labor, professional services and maintenance expenses mainly related to initial operation and start-up costs at the Ft. Erie plant.
- ShoreMaster's operating expenses increased $0.2 million between the years.
- T.O. Plastics' operating expenses increased $0.2 million between the years.
- BTD's operating expenses decreased $0.4 million between the years.

Depreciation expense increased between the years as a result of $21.1 million in capital additions from October 2005 through September 2006 at all four manufacturing companies. Capital additions at DMI's Ft. Erie plant totaled $8.0 million in 2006.

HEALTH SERVICES

The following table summarizes the results of operations for our health services segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 130,670	(3)	$ 135,051	9	$ 123,991
Cost of Goods Sold	99,612	(4)	104,108	15	90,327
Operating Expenses	23,691	4	22,745	3	21,989
Depreciation and Amortization	3,937	8	3,660	(9)	4,038
Operating Income	$ 3,430	(24)	$ 4,538	(41)	$ 7,637

2007 compared with 2006

The $4.4 million decrease in health services operating revenues in 2007 compared with 2006 reflects a $3.2 million decrease in revenues from scanning and other related services as a result of a $2.8 million decrease in revenues from rental and interim installations and transportation services and a 9.2% decrease in the number of scans performed between the years. Revenues from equipment sales and servicing decreased $1.2 million between the years as a decrease in traditional dealership distribution of products was mostly offset by increases in manufacturer representative commissions on more manufacturer-direct sales. The decrease in health services revenue was more than offset by the decrease in health services cost of goods sold due to the decrease in traditional dealership distribution of products and $3.2 million in decreases to labor, warranty and other direct costs of sales. The $0.9 million increase in operating expenses is mainly due to increased labor and sales and marketing expenditures. The increase in depreciation and amortization expense is due to capital additions in 2006 and 2007.

2006 compared with 2005

The $11.1 million increase in health services operating revenues in 2006 compared with 2005 reflects an $8.0 million increase in imaging revenues combined with a $3.1 million increase in revenues from sales and servicing of diagnostic imaging equipment. On the imaging side of the business, $3.5 million of the $8.0 million increase in revenue came from imaging services where the revenue per scan increased 15.7% between the years while the number of scans completed decreased 8.9%. Revenues from rentals and interim installations of scanning equipment along with providing technical support services for those rental and interim installations increased $4.5 million between the years. The increase in health services revenue was more than offset by the $13.8 million increase in health services cost of goods sold, mainly as a result of increases in costs of equipment purchased for resale, increases in unit rental and sublease costs related to units that were out of service in the first six months of 2006 and increases in labor and other direct costs. The $0.8 million increase in operating expenses is mainly due to increases in property tax expenses. The $0.4 million decrease in depreciation and amortization expense is the result of certain assets reaching the ends of their depreciable lives. When these assets are replaced, they are generally replaced with assets leased under operating leases.

FOOD INGREDIENT PROCESSING

The following table summarizes the results of operations for our food ingredient processing segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 70,440	56	$ 45,084	17	$ 38,501
Cost of Goods Sold	56,591	28	44,233	43	30,930
Operating Expenses	3,135	7	2,920	15	2,533
Depreciation and Amortization	3,952	5	3,759	11	3,399
Operating Income (Loss)	$ 6,762	216	$ (5,828)	(456)	$ 1,639

2007 compared with 2006

The $25.4 million increase in food ingredient processing revenues in 2007 compared with 2006 reflects a 29.5% increase in pounds of product sold combined with a 20.7% increase in the price per pound sold. A reduction in the value of the U.S. dollar relative to certain foreign currencies in 2007 and a poor European potato crop in 2006 led to favorable export pricing and sales increases in Europe, Latin America and the Pacific Rim in 2007. The increase in revenues was only partially offset by a 27.9% increase in cost of goods sold. The cost per pound of product sold decreased 1.2% between the years. The increase in operating expenses between the years is mainly due to increases in employee benefit and travel expenses. The increase in depreciation and amortization expense is related to $1.8 million in capital additions in 2006.

2006 compared with 2005

The $6.6 million increase in food ingredient processing revenues in 2006 compared with 2005 reflects a 15.3% increase in sales price per pound of product combined with a 1.5% increase in pounds of product sold between the years. The food ingredient processing segment was negatively impacted by raw potato supply shortages in Idaho and Prince Edward Island in 2006. Higher than expected raw product costs related to the supply shortages resulted in operating inefficiencies and a 40.8% increase in the cost per pound of product sold. The increase in operating expenses is due to an increase in selling and administrative expenses between the years. Consistent with trends in the industry, operating income for 2006 was less than expected due to raw potato supply shortages, increasing raw material costs and the increasing value of the Canadian dollar relative to the U.S. dollar.

OTHER BUSINESS OPERATIONS

The following table summarizes the results of operations for our other business operations segment for the years ended December 31:

(in thousands)	2007	% change	2006	% change	2005
Operating Revenues	$ 185,730	28	$ 145,603	38	$ 105,821
Cost of Goods Sold	133,393	45	91,806	36	67,711
Operating Expenses	42,462	1	41,867	16	36,020
Depreciation and Amortization	2,058	(12)	2,330	5	2,225
Operating Income (Loss)	$ 7,817	(19)	$ 9,600		$ (135)

2007 compared with 2006

The increase in operating revenues in 2007 compared with 2006 in our other business operations is due to the following:

- Revenues at Midwest Construction Services, Inc. (MCS), our electrical design and construction services company, increased $22.9 million (49.9%) between the years as a result of an increase in volume of jobs in 2007.
- Revenues at Foley Company (Foley), a mechanical and prime contractor on industrial projects, increased $17.3 million (26.9%) between the years due to an increase in the volume of jobs in progress.
- Revenues at E.W. Wylie Corporation (Wylie), our flatbed trucking company, were unchanged between the years.

The increase in cost of goods sold in 2007 compared with 2006 is due to the following:

- Cost of goods sold at MCS increased $25.0 million mainly due to increases in material, subcontractor, direct labor and insurance costs related to the increase in volume of jobs between the years. Lower than expected margins on certain construction projects at MCS was the main factor contributing to the decrease in operating income between the years.
- Cost of goods sold at Foley increased $16.6 million mainly due to increases in direct labor, employee benefits, subcontractor and material costs as a result of the increased volume of work performed between the years.

The increase in operating expenses in 2007 compared with 2006 is due to the following:

- Operating expenses at MCS were unchanged between the years.
- Operating expenses at Foley increased $0.5 million between the years as a result of increased labor, benefit and insurance expenses. Also, Foley's 2006 expenses reflect the recovery of $0.2 million in bad debts.
- Operating expenses at Wylie were unchanged between the years.

The decrease in depreciation and amortization expense in 2007 compared with 2006 reflects the effects of a decision by Wylie to lease rather than buy replacement trucks for its fleet.

2006 compared with 2005

The increase in operating revenues in our other business operations in 2006 compared with 2005 is due to the following:

- Revenues at Foley increased $33.3 million (106.4%) due to an increase in the volume of work performed between the years.
- Revenues at Wylie increased $4.5 million (14.8%) between the years mainly due to an 8.4% net increase in miles driven by owner-operated and company-operated trucks. Miles driven by owner-operated trucks increased 50.3% while miles driven by company-operated trucks decreased 9.3% between the periods. Wylie's increased revenues also reflect higher rates related to increased fuel costs recovered through fuel surcharges between the years for both owner-operated and company-operated trucks.
- Revenues at MCS increased $2.3 million (5.2%) between the years as a result of increased activity on several wind projects in the fourth quarter of 2006.

The increase in cost of goods sold in our other business operations in 2006 compared with 2005 is due to the following:

- Foley's cost of goods sold increased $28.3 million mainly in the areas of materials, subcontractor and labor costs as a result of an increase in the volume of work performed between the years.
- Cost of goods sold at MCS decreased $4.2 million mainly due to a reduction in material and labor costs between the years mostly related to a job completed in 2005 on which large losses were incurred as a result of higher than expected costs.

The increase in operating expenses in the other business operations segment is due to the following:

- Wylie's revenue increase was entirely offset by a $4.5 million increase in operating expenses, including $4.0 million in contractor costs related to higher fuel costs combined with an increase in miles driven by owner-operated trucks between the years and $0.5 million in increased insurance costs.
- Foley's operating expenses increased $0.7 million between the years as a result of increases in employee benefit costs.
- MCS operating expenses increased $1.0 million between the years, mainly due to increases in employee benefit costs.

The increase in depreciation and amortization expense in 2006 compared with 2005 is mainly related to equipment purchases at Foley in 2005 and 2006.

CORPORATE

Corporate includes items such as corporate staff and overhead costs, the results of the company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate is not an operating segment. Rather it is added to operating segment totals to reconcile to totals on our consolidated statements of income.

(in thousands)	2007	% change	2006	% change	2005
Operating Expenses	$ 9,824	(13)	$ 11,322	(22)	$ 14,572
Depreciation and Amortization	579	(1)	587	33	441

2007 compared with 2006

Corporate operating expenses decreased $1.5 million as a result of a combination of lower insurance costs at our captive insurance company and lower health insurance plan costs.

2006 compared with 2005

Corporate operating expenses decreased $3.2 million as a result of lower health insurance plan costs, improved claims experience in our captive insurance company and a gain on the sale of property in 2006.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS

Other income and deductions increased by $2.5 million in 2007 compared with 2006 and decreased by $2.2 million in 2006 compared with 2005, mainly due to a noncash charge of $3.3 million in 2006 related to the disallowance of a portion of capitalized costs of funds used during construction from the electric utility's rate base.

CONSOLIDATED INTEREST CHARGES

Interest expense increased $1.4 million in 2007 compared with 2006 as a result of a net increase of $87 million in long-term debt in 2007. Short-term debt interest expense increased by $1.8 million in 2007 as a result of an increase in the average daily balance of short-term debt outstanding and higher interest rates. Increases in interest expense on both long-term and short-term debt were partially offset by a $2.4 million increase in capitalized interest in 2007. Interest expense increased $1.0 million in 2006 compared with 2005 primarily as a result of increased interest rates on short-term debt.

CONSOLIDATED INCOME TAXES

The 3.2% increase in income tax expense from continuing operations in 2007 compared to 2006 is due, in part, to a 5.2% increase in income from continuing operations before income taxes. Our effective tax rate on income from continuing operations was 34.1% for 2007 compared with 34.8% for 2006.

The 3.2% decrease in income tax expense from continuing operations in 2006 compared to 2005 is due, in part, to a 4.9% decrease in income from continuing operations before income taxes. Our effective tax rate on income from continuing operations was 34.8% for 2006 compared with 34.2% for 2005.

DISCONTINUED OPERATIONS

In 2006, we sold the natural gas marketing operations of OTESCO, our energy services subsidiary. Discontinued operations includes the operating results of OTESCO's natural gas marketing operations for 2006 and 2005. Discontinued operations also includes an after-tax gain on the sale of OTESCO's natural gas marketing operations of $0.3 million in 2006.

In 2005, we sold Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Discontinued operations includes the operating results of MIS, SGS and CLC for 2005. Discontinued operations also includes an after-tax gain on the sale of MIS of $11.9 million, an after-tax loss on the sale of SGS of $1.7 million and an after-tax loss on the sale of CLC of $0.2 million in 2005.

The following table presents operating revenues, expenses, including interest and other income and deductions, and income taxes, included on a net basis in income from discontinued operations on our 2006 and 2005 consolidated statements of income.

(in thousands)	2006	2005
Operating Revenues	$ 28,234	$ 80,988
Expenses	28,180	81,601
Goodwill Impairment Loss	—	1,003
Income Tax Expense (Benefit)	28	(261)
Income (Loss) from Discontinued Operations	$ 26	$ (1,355)

The $1.0 million goodwill impairment loss in 2005 was for the write-off of goodwill at OTESCO related to its natural gas marketing operations in the third quarter of 2005 as a result of a reassessment of its future cash flows in light of rising natural gas prices and greater market volatility in future prices for natural gas.

The following table presents the pre-tax and net-of-tax gains and losses recorded on the sales of OTESCO's natural gas marketing operations in 2006 and MIS, SGS and CLC in 2005.

	2006	2005			
(in thousands)	OTESCO-Gas	MIS	SGS	CLC	Total
Gain (Loss) on Sale	$ 560	$ 19,025	$ (2,919)	$ (271)	$ 15,835
Income Tax (Expense) Benefit	(224)	(7,107)	1,168	108	(5,831)
Net Gain (Loss) on Sale	$ 336	$ 11,918	$ (1,751)	$ (163)	$ 10,004

IMPACT OF INFLATION

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

Our plastics, manufacturing, health services, food ingredient processing, and other business operations consist entirely of unregulated businesses. Increased operating costs are reflected in product or services pricing with any limitations on price increases determined by the marketplace. 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 or other pricing pressures, with a possible adverse effect on our profitability, especially where increases in these costs exceed price increases on finished products. In recent years, our operating companies have faced strong inflationary and other pricing pressures with respect to steel, fuel, resin, lumber, concrete, aluminum and health care costs, which have been partially mitigated by pricing adjustments.

□ 2008 EXPECTATIONS

We anticipate 2008 diluted earnings per share to be in a range from $1.85 to $2.10. Contributing to the earnings guidance for 2008 are the following items:

- We expect increased levels of net income from our electric segment in 2008. This increase is based on having lower cost generation available for the year, as there are no plant shutdowns planned for Big Stone Plant or Coyote Station in 2008, and additional rate base investment from the Langdon wind project. The increase also assumes the interim rate increase of $7.1 million, or 5.41%, which is part of the rate case filed with the MPUC. These interim rates remain in effect for all Minnesota customers until the MPUC makes a final determination on the electric utility's request, which is expected to occur by August 1, 2008. If final rates are lower than interim rates, the electric utility will refund customers the difference with interest. If final rates are higher than interim rates, the higher rates will become effective as of the date of the MPUC order approving those rates.
- We expect our plastics segment's 2008 performance to be at or below normal levels. Announced capacity expansions are not expected to come on line until the fourth quarter of 2008.
- We expect increased levels of net income in our manufacturing segment in 2008 as a result of increased capacity and productivity related to recent expansions and acquisitions, and the start-up of DMI's wind tower manufacturing plant in Oklahoma in 2008. Backlog in place in the manufacturing segment to support 2008 revenues is approximately $295 million compared with $241 million one year ago. The wind energy tower manufacturing business accounts for a substantial portion of the 2008 backlog.
- We expect improvement in net income from our health services segment in 2008 as it focuses on improving its mix of imaging assets and asset utilization rates.
- We expect our food ingredient processing business to have increased net income due to higher operating margins in 2008. This business has backlog in place for 2008 of 51.5 million pounds compared with 52.8 million pounds one year ago.
- We expect our other business operations segment to have higher net income in 2008 compared with 2007. Backlog in place for the construction businesses is $77 million for 2008 compared with $74 million for the same period one year ago.
- Corporate general and administrative costs are expected to increase in 2008.

Our outlook for 2008 is dependent on a variety of factors and is subject to the risks and uncertainties discussed under "Risk Factors and Cautionary Statements."

□ LIQUIDITY

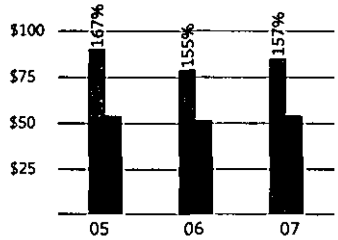
We believe our financial condition is strong and that our cash, other liquid assets, operating cash flows, access to capital markets through our universal shelf registration and borrowing ability because of solid credit ratings, when taken together, provide adequate resources to fund ongoing operating requirements and future capital expenditures related to expansion of existing businesses and development of new projects. Additional equity or debt financing will be required in the period 2008 through 2012 given our current capital expansion plans over this period. See "Capital Resources" section for further discussion. Also, our operating cash flow and access to capital markets can be impacted by macroeconomic factors outside our control. In addition, our borrowing costs can be impacted by short-term and long-term debt ratings assigned to us by independent rating agencies, which in part are based on certain credit measures such as interest coverage and leverage ratios.

We have achieved a high degree of long-term liquidity by maintaining desired capitalization ratios and solid credit ratings, implementing cost-containment programs and investing in projects that provide returns in excess of our weighted average cost of capital.

Cash provided by operating activities of continuing operations was $84.8 million in 2007 compared with $79.2 million in 2006. The $5.6 million increase in cash provided by operating activities of continuing operations reflects a $2.8 million increase in net income and a $2.8 million increase in depreciation and amortization expense.

Cash used for working capital items was $28.5 million in 2007 compared with $30.4 million in 2006, a decrease of $1.9 million. Major uses of funds for working capital items in 2007 were an increase in receivables of $18.9 million, an increase in other current assets of $14.6 million and a decrease in payables of $2.5 million, offset by a decrease in inventories of $8.4 million. The increase in receivables includes $14.8 million at DMI related to increased sales of wind towers and $5.0 million from our construction companies related to increased activity and billings in 2007. The increase in other current assets includes an $8.6 million increase in accrued FCA and unbilled revenues at the electric utility, mainly related to an increase in purchased power costs in the fourth quarter of 2007 to replace generation lost during a scheduled major maintenance shutdown of our Big Stone Plant. The increase in other current assets also includes an increase in costs in excess of billings of $2.8 million at DMI related to increased levels of wind tower production and $2.1 million at the construction companies related to an increase in work volume between the years. DMI's costs and estimated earnings in excess of billings stood at $36.2 million as of December 31, 2007 related to costs incurred on work in progress on major wind tower contracts. Our cash flows from operations will be positively impacted as these amounts are billed and collected. The decrease in inventories reflects reductions in the value of finished goods and raw materials inventory of $5.3 million at our plastic pipe companies due to a 19% decrease in pounds of pipe in inventory combined with a decrease in resin prices between the years. The decrease in inventories also reflects a $2.3 million decrease in raw material and work in process inventory at DMI due to better inventory management.

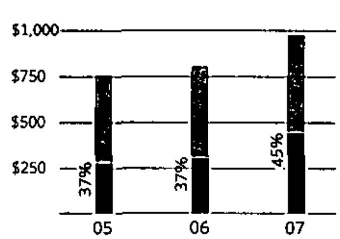
Cash Realization Ratios— Continuing Operations



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

■ Cash Flows from Continuing Operations
■ Net Income from Continuing Operations

Interest Bearing Debt as a Percent of Total Capital



Otter Tail has maintained a 37-45 percent interest-bearing debt to total capital ratio for the past five years.

■ Total Capital
■ Interest-Bearing Debt (includes short-term debt)

Net cash used in investing activities of continuing operations was $164.0 million in 2007 compared with $67.5 million in 2006. Cash used for capital expenditures increased by $92.5 million between the years. Cash used for capital expenditures at the electric utility increased by $69.1 million between the years mainly related to construction of 27 wind turbines near Langdon, North Dakota and replacement of the flue-gas treatment system at our Big Stone Plant in 2007. Cash used for capital expenditures at DMI increased $20.8 million between the years mainly due to the purchase of property and equipment for a new wind tower manufacturing facility near Tulsa, Oklahoma, which became operational in January 2008. We completed two acquisitions in 2007 for a combined purchase price of $6.8 million.

Net cash provided by financing activities was $113.2 million in 2007 compared with net cash used in financing activities of $13.3 million in 2006. We received proceeds of $203.4 million in cash from the issuance of debt, net of debt issuance expenses, and paid $118.2 million to retire or refinance debt in 2007. We also increased borrowings under our line of credit by $56.1 million in 2007 and received $7.7 million in proceeds from the issuance of 298,601 shares of common stock for stock options exercised in 2007. Proceeds from borrowings and common stock issuance in excess of cash used to retire long-term debt were used to fund construction expenditures and acquisitions along with cash from operating activities in excess of dividends paid. We paid $35.5 million in common and preferred dividends in 2007 compared with $34.6 million in 2006. The increase is due to an increase in common shares outstanding and a two cent per share increase in common dividends paid between the years.

□ CAPITAL REQUIREMENTS

We have a capital expenditure program for expanding, upgrading and improving our plants and operating equipment. Typical uses of cash for capital expenditures are investments in electric generation facilities, transmission and distribution lines, manufacturing facilities and upgrades, equipment used in the manufacturing process, purchase of diagnostic medical equipment, transportation equipment and computer hardware and information systems. The capital expenditure program is subject to review and is revised in light of changes in demands for energy, technology, environmental laws, regulatory changes, business expansion opportunities, the costs of labor, materials and equipment and our consolidated financial condition.

Consolidated capital expenditures were $162 million in 2007, $69 million in 2006 and $60 million in 2005. Estimated capital expenditures for 2008 are $135 million and the total capital expenditures for the five-year period 2008 through 2012 are estimated to be approximately $899 million, which includes $336 million for our share of expected expenditures for construction of the planned Big Stone II electric generating plant and related transmission assets if all necessary permits and approvals are granted on a timely basis, and $67 million for CapX 2020 projects. The breakdown of 2005, 2006 and 2007 actual and 2008 through 2012 estimated capital expenditures by segment is as follows:

(in millions)	2005	2006	2007	2008	2008–2012
Electric	$ 30	$ 35	$ 104	$ 94	$ 759
Plastics	4	5	3	13	21
Manufacturing	16	20	43	18	80
Health Services	3	5	5	2	11
Food Ingredient Processing	3	2	—	4	18
Other Business Operations	4	2	6	4	9
Corporate	—	—	1	—	1
Total	$ 60	$ 69	$ 162	$ 135	$ 899

The following table summarizes our contractual obligations at December 31, 2007 and the effect these obligations are expected to have on our 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 Obligations	$ 346	$ 3	$ 6	$ 101	$ 236
Interest on Long-Term Debt Obligations	273	21	41	35	176
Operating Lease Obligations	138	43	69	19	7
Capacity and Energy Requirements	162	23	35	11	93
Coal Contracts (required minimums)	183	51	89	16	27
Postretirement Benefit Obligations	56	3	7	7	39
Other Purchase Obligations	43	43	—	—	—
Total Contractual Cash Obligations	$1,201	$ 187	$ 247	$ 189	$ 578

Interest on $10.4 million of variable-rate debt outstanding on December 31, 2007 was projected based on the interest rates applicable to that debt instrument on December 31, 2007. Postretirement Benefit Obligations include estimated cash expenditures for the payment of retiree medical and life insurance benefits and supplemental pension benefits under our unfunded Executive Survivor and Supplemental Retirement Plan, but do not include amounts to fund our noncontributory funded pension plan as we are not currently required to make a contribution to that plan.

□ CAPITAL RESOURCES

Financial flexibility is provided by operating cash flows, our universal shelf registration, unused lines of credit, strong financial coverages, solid credit ratings, and alternative financing arrangements such as leasing. We have the ability to issue up to $256 million of common stock, cumulative preferred stock, debt and certain other securities from time to time under our universal shelf registration statement filed with the Securities and Exchange Commission. Additional equity or debt financing will be required in the period 2008 through 2012 given the expansion plans related to our electric segment to fund the construction of the proposed new Big Stone II generating station at the Big Stone Plant site and proposed new wind generation projects, in the event we decide to reduce borrowings under our lines of credit, refund or retire early any of our 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 us. If adequate funds are not available on acceptable terms, our businesses, results of operations and financial condition could be adversely affected.

Our $150 million line of credit pursuant to a Credit Agreement dated as of April 26, 2006 with U.S. Bank National Association, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, Harris Nesbitt Financing, Inc., Keybank National Association, Union Bank of California, N.A., Bank of America, N.A., Bank Hapoalim B.M., and Bank of the West was scheduled to expire on April 26, 2009 but was terminated and replaced by a new $200 million credit agreement (the Varistar Credit Agreement) entered into by Varistar Corporation (Varistar), our wholly-owned subsidiary, on October 2, 2007. Varistar entered into the Varistar Credit Agreement with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. The Varistar Credit Agreement is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Varistar Credit Agreement expires on October 2, 2010. Borrowings under the line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on Varistar's adjusted cash flow leverage ratio (as defined in the Varistar Credit Agreement). The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in our credit ratings. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Outstanding letters of credit issued by Varistar can reduce the amount available for borrowing under the line by up to $30 million. As of December 31, 2007, $95.0 million of the $200 million line of credit was in use and $14.9 million was restricted from use to cover outstanding letters of credit.

Otter Tail Corporation, dba Otter Tail Power Company and U.S. Bank National Association entered into a Credit Agreement (the Electric Utility Credit Agreement) providing for a separate $75 million line of credit. This line of credit is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of our senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement is subject to renewal on September 1, 2008. As of December 31, 2007 no money was borrowed under the Electric Utility Credit Agreement.

At closings completed in August 2007 and October 2007, we issued $155 million aggregate principal amount of senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The net proceeds from this initial closing were used to repay borrowings under our $150 million line of credit that was terminated on October 2, 2007. We issued and sold the remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes at a second closing on October 1, 2007. The net proceeds from the second closing were used to retire $40 million aggregate principal amount of our 5.625% Series of Insured Senior Notes due October 1, 2017 and $25 million aggregate principal amount of our 6.80% Series of Senior Notes due October 1, 2032 on October 15, 2007, to pay down lines of credit and to fund capital expenditures.

In February 2007, we entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which we agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of our senior notes due November 30, 2017 (the Cascade Note). On December 14, 2007 we issued the Cascade Note. The Cascade Note bears interest at a rate of 5.778% per annum. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of our $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The proceeds of this financing were used to redeem our $50 million 6.375% Senior Debentures due December 1, 2007. Cascade owned approximately 8.6% of our outstanding common stock as of December 31, 2007.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement and the 2001 Note Purchase Agreement states we may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require us to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states we must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of the Company.

The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement contain a number of restrictions on us and our subsidiaries. In each case these include restrictions on our ability and the ability of our subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

The Electric Utility Company Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement and the Lombard US Equipment Finance note contain covenants by us not to permit our debt-to-total capitalization ratio to exceed 60% or permit our interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, our interest coverage ratio) to be less than 1.5 to 1. The note purchase agreements further restrict us from allowing our priority debt to exceed 20% of total capitalization. Financial covenants in the Varistar Credit Agreement require Varistar to maintain a fixed charge coverage ratio of not less than 1.25 to 1 and to not permit its cash flow leverage ratio to exceed 3.0 to 1. We and Varistar were in compliance with all of the covenants under our financing agreements as of December 31, 2007.

Our obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of our subsidiaries. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Our Grant County and Mercer County Pollution Control Refunding Revenue Bonds require that we 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 our senior unsecured debt is downgraded to Baa2 or below (Moody's) or BBB or below (Standard & Poor's).

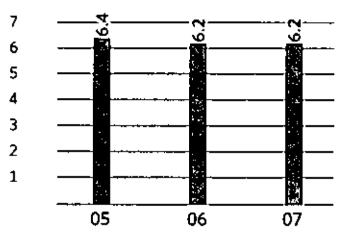
Our securities ratings at December 31, 2007 were:

	Moody's Investors Service	Standard & Poor's
Senior Unsecured Debt	A3	BBB+
Preferred Stock	Baa2	BBB-
Outlook	Negative	Negative

In July 2007, Moody's changed its outlook on our company from stable to negative, citing risks of recovery associated with planned capital expenditures in the electric segment as a major factor contributing to its outlook change. In September 2007, Standard & Poor's changed its outlook on our company from stable to negative, citing continued growth of nonregulated businesses and a large capital spending program in the electric segment as the reasons for its outlook change. Our disclosure of these securities ratings is not a recommendation to buy, sell or hold our securities. Downgrades in these securities ratings could adversely affect our company. Further, downgrades could increase our borrowing costs resulting in possible reductions to net income in future periods and increase the risk of default on our debt obligations.

Our ratio of earnings to fixed charges from continuing operations, which includes imputed finance costs on operating leases, was 3.5x for 2007 compared to 3.9x for 2006 and our long-term debt interest coverage ratio before taxes was 6.2x for both 2007 and 2006. During 2008, we expect these coverage ratios to be consistent with 2007 levels assuming 2008 net income meets our expectations.

Long-Term Debt Interest Coverage
(times interest earned before tax)



Otter Tail has maintained coverage ratios in excess of its debt covenant requirements.

☐ OFF-BALANCE-SHEET ARRANGEMENTS

We do 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. We are not exposed to any financing, liquidity, market or credit risk that could arise if we had such relationships.

☐ RISK FACTORS AND CAUTIONARY STATEMENTS

We are including the following factors and cautionary statements in this Annual Report to make applicable and to take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by us or on our behalf. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, we may publish or otherwise make available forward-looking statements of this nature. All these forward-looking statements, whether written or oral and whether made by us or on our behalf, are also expressly qualified by these factors and cautionary statements. Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for us to predict all of the factors, nor can we assess the effect of each factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The following factors and the other matters discussed herein are important factors that could cause actual results or outcomes for our company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

GENERAL

Federal and state environmental regulation could require us to incur substantial capital expenditures and increased operating costs.
We are subject to federal, state and local environmental laws and regulations relating to air quality, water quality, waste management, natural resources and health safety. These laws and regulations regulate the modification and operation of existing facilities, the construction and operation of new facilities and the proper storage, handling, cleanup and disposal of hazardous waste and toxic substances. Compliance with these legal requirements requires us to commit significant resources and funds toward environmental monitoring, installation and operation of pollution control equipment, payment of emission fees and securing environmental permits. Obtaining environmental permits can entail significant expense and cause substantial construction delays. Failure to comply with environmental laws and regulations, even if caused by factors beyond our control, may result in civil or criminal liabilities, penalties and fines.

Existing environmental laws or regulations may be revised and new laws or regulations may be adopted or become applicable to us. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

Volatile financial markets and changes in our debt ratings could restrict our ability to access capital and increase our borrowing costs and pension plan expenses.
We rely on access to both short- and long-term capital markets as a source of liquidity for capital requirements not satisfied by cash flows from operations. If we are not able to access capital at competitive rates, the ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access one or more financial markets.

Changes in the U.S. capital markets could also have significant effects on our pension plan. Our pension income or expense is affected by factors including the market performance of the assets in the master pension trust maintained for the pension plans for some of our employees, the weighted average asset allocation and long-term rate of return of our pension plan assets, the discount rate used to determine the service and interest cost components of our net periodic pension cost and assumed rates of increase in our employees' future compensation. If our pension plan assets do not achieve positive rates of return, or if our estimates and assumed rates are not accurate, our earnings may decrease because net periodic pension costs would rise and we could be required to provide additional funds to cover our obligations to employees under the pension plan.

Our plans to grow and diversify through acquisitions may not be successful, which could result in poor financial performance.
As part of our business strategy, we intend to acquire new businesses. We may not be able to identify appropriate acquisition candidates or successfully negotiate, finance or integrate acquisitions. If we are unable to make acquisitions, we may be unable to realize the growth we anticipate. Future acquisitions could involve numerous risks including: difficulties in integrating the operations, services, products and personnel of the acquired business; and the potential loss of key employees, customers and suppliers of the acquired business. If we are unable to successfully manage these risks of an acquisition, we could face reductions in net income in future periods.

Our plans to grow our nonelectric businesses could be limited by state law.
Our plans to acquire and grow our nonelectric businesses could be adversely affected by legislation in one or more states that may attempt to limit the amount of diversification permitted in a holding company system that includes a regulated utility company or affiliated nonelectric companies.

ELECTRIC

We may experience fluctuations in revenues and expenses related to our electric operations, which may cause our financial results to fluctuate and could impair our ability to make distributions to shareholders or scheduled payments on our debt obligations.
A number of factors, many of which are beyond our control, may contribute to fluctuations in our revenues and expenses from electric operations, causing our net income to fluctuate from period to period. These risks include fluctuations in the volume and price of sales of electricity to customers or other utilities, which may be affected by factors such as mergers and acquisitions of other utilities, geographic location of other utilities, transmission costs (including increased costs related to operations of regional transmission organizations), changes in the manner in which wholesale power is sold and purchased, unplanned interruptions at our generating plants, the effects of regulation and legislation, demographic changes in our customer base and changes in our customer demand or load growth. Electric wholesale margins have been significantly and adversely affected by increased efficiencies in the MISO market. Electric wholesale trading margins could also be adversely affected by losses due to trading activities. Other risks include weather conditions or changes in weather patterns (including severe weather that could result in damage to our assets), fuel and purchased power costs and the rate of economic growth or decline in our service areas. A decrease in revenues or an increase in expenses related to our electric operations may reduce the amount of funds available for our existing and future businesses, which could result in increased financing requirements, impair our ability to make expected distributions to shareholders or impair our ability to make scheduled payments on our debt obligations.

As of December 31, 2007 the electric utility has capitalized $8.2 million in costs related to the planned construction of a second electric generating unit at our Big Stone Plant site. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

Actions by the regulators of our electric operations could result in rate reductions, lower revenues and earnings or delays in recovering capital expenditures.
We are subject to federal and state legislation, government regulations and regulatory actions that may have a negative impact on our business and results of operations. The electric rates that we are allowed to charge for our electric services are one of the most important items influencing our financial position, results of operations and liquidity. The rates that we charge our electric customers are subject to review and determination by state public utility commissions in Minnesota, North Dakota and South Dakota. We are also regulated by the Federal Energy Regulatory Commission. An adverse decision by one or more regulatory commissions concerning the level or method of determining electric utility rates, the authorized returns on equity, implementation of enforceable federal reliability standards or other regulatory matters, permitted business activities (such as ownership or operation of nonelectric businesses) or any prolonged delay in rendering a decision in a rate or other proceeding (including with respect to the recovery of capital expenditures in rates) could result in lower revenues and net income.

Future operating results of our electric segment will be impacted by the outcome of a rate case filed in Minnesota on October 1, 2007 requesting a final overall increase in Minnesota retail electric rates of 6.7%. The filing included a request for an interim rate increase of 5.4%, which went into effect on November 30, 2007. Interim rates will remain in effect for all Minnesota customers until the MPUC makes a final determination on the electric utility's request, which is expected by August 1, 2008. If final rates are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

Certain costs currently included in the FCA in retail rates may be excluded from recovery through the FCA but may be subject to recovery through rates established in a general rate case. Further, all, or portions of, gross margins on asset-based wholesale electric sales may become subject to refund through the FCA as a result of a general rate case. Recovery of MISO schedule 16 and 17 administrative costs associated with providing electric service to Minnesota and North Dakota customers are currently being deferred pending the results of our current general rate case in Minnesota and our next general rate case in North Dakota scheduled to be filed in November or December of 2008. If we are not granted recovery of $1.4 million in deferred costs as of December 31, 2007 we could be required to recognize these costs immediately in expense at the time recovery is denied.

We may not be able to respond effectively to deregulation initiatives in the electric industry, which could result in reduced revenues and earnings.
We may not be able to respond in a timely or effective manner to the changes in the electric industry that may occur as a result of regulatory initiatives to increase wholesale competition. These regulatory initiatives may include further deregulation of the electric utility industry in wholesale markets. Although we do not expect retail competition to come to the states of Minnesota, North Dakota and South Dakota in the foreseeable future, we expect competitive forces in the electric supply segment of the electric business to continue to increase, which could reduce our revenues and earnings.

Our electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.
Operation of electric generating facilities involves risks which can adversely affect energy output and efficiency levels. Most of our generating capacity is coal-fired. We rely on a limited number of suppliers of coal, making us vulnerable to increased prices for fuel as existing contracts expire or in the event of unanticipated interruptions in fuel supply. We are a captive rail shipper of the BNSF Railway for shipments of coal to our Big Stone and Hoot Lake plants, making us vulnerable to increased prices for coal transportation from a sole supplier. Higher fuel prices result in higher electric rates for our retail customers through fuel clause adjustments and could make us less competitive in wholesale electric markets. Operational risks also include facility shutdowns due to breakdown or failure of equipment or processes, labor disputes, operator error and catastrophic events such as fires, explosions, floods, intentional acts of destruction or other similar occurrences affecting our electric generating facilities. The loss of a major generating facility would require us to find other sources of supply, if available, and expose us to higher purchased power costs.

Changes to regulation of generating plant emissions, including but not limited to carbon dioxide (CO_2) emissions, could affect our operating costs and the costs of supplying electricity to our customers.
Existing or new laws or regulations addressing climate change or reductions of greenhouse gas emissions by federal or state authorities, such as mandated levels of renewable generation or mandatory reductions in CO_2 emission levels or taxes on CO_2 emissions, that result in increases in electric service costs could negatively impact our net income, financial position and operating cash flows if such costs cannot be recovered through rates granted by ratemaking authorities in the states where the electric utility provides service or through increased market prices for electricity.

PLASTICS

Our plastics operations are highly dependent on a limited number of vendors for PVC resin and a limited supply of PVC resin. The loss of a key vendor, or any interruption or delay in the supply of PVC resin, could result in reduced sales or increased costs for our plastics business.
We rely on a limited number of vendors to supply the PVC resin used in our plastics business. Two vendors accounted for approximately 95% of our total purchases of PVC resin in 2007 and approximately 99% of our total purchases of PVC resin in 2006. In addition, the supply of PVC resin may be limited primarily due to manufacturing capacity and the limited availability of raw material components. A majority of U.S. resin production plants are located in the Gulf Coast region, which may increase the risk of a shortage of resin in the event of a hurricane or other natural disaster in that region. The loss of a key vendor or any interruption or delay in the availability or supply of PVC resin could disrupt our ability to deliver our plastic products, cause customers to cancel orders or require us to incur additional expenses to obtain PVC resin from alternative sources, if such sources are available.

We compete against a large number of other manufacturers of PVC pipe and manufacturers of alternative products. Customers may not distinguish our products from those of our competitors.
The plastic pipe industry is highly fragmented and competitive due to the large number of producers and the fungible nature of the product. We compete not only against other PVC pipe manufacturers, but also against ductile iron, steel, concrete and clay pipe manufacturers. Due to shipping costs, competition is usually regional instead of national in scope, and the principal areas of competition are a combination of price, service, warranty and product performance. Our inability to compete effectively in each of these areas and to distinguish our plastic pipe products from competing products may adversely affect the financial performance of our plastics business.

Reductions in PVC resin prices can negatively affect our plastics business.
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. Reductions in PVC resin prices could negatively affect PVC pipe prices, profit margins on PVC pipe sales and the value of PVC pipe held in inventory.

MANUFACTURING

Competition from foreign and domestic manufacturers, the price and availability of raw materials, fluctuations in foreign currency exchange rates, the availability of production tax credits and general economic conditions could affect the revenues and earnings of our manufacturing businesses.
Our manufacturing businesses are subject to risks associated with competition from foreign and domestic manufacturers that have excess capacity, labor advantages and other capabilities that may place downward pressure on margins and profitability. Raw material costs for items such as steel, lumber, concrete, aluminum and resin have increased significantly and may continue to increase. Our manufacturers may not be able to pass on the cost of such increases to their respective customers. Each of our manufacturing companies has significant customers and concentrated sales to such customers. If our relationships with significant customers should change materially, it would be difficult to immediately and profitably replace lost sales. Fluctuations in foreign currency exchange rates could have a negative impact on the net income and competitive position of our wind tower manufacturing operations in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars. We believe the demand for wind towers that we manufacture will depend primarily on the existence of either renewable portfolio standards or the Federal Production Tax Credit for wind energy. This credit is scheduled to expire on December 31, 2008. Our wind tower manufacturer and electrical contractor could be adversely affected if the tax credit in not extended or renewed.

HEALTH SERVICES

Changes in the rates or methods of third-party reimbursements for our diagnostic imaging services could result in reduced demand for those services or create downward pricing pressure, which would decrease our revenues and earnings.
Our health services businesses derive significant revenue from direct billings to customers and third-party payors such as Medicare, Medicaid, managed care and private health insurance companies for our diagnostic imaging services. Moreover, customers who use our diagnostic imaging services generally rely on reimbursement from third-party payors. Adverse changes in the rates or methods of third-party reimbursements could reduce the number of procedures for which we or our customers can obtain reimbursement or the amounts reimbursed to us or our customers.

Our health services operations has a dealership and other agreements with Philips Medical from which it derives significant revenues from the sale and service of Philips Medical diagnostic imaging equipment.
This agreement can be terminated on 180 days written notice by either party for any reason. It also includes other compliance requirements. If this agreement were terminated within the notice provisions or we were not able to renew such agreements or comply with the agreement, the financial results of our health services operations would be adversely affected.

Technological change in the diagnostic imaging industry could reduce the demand for diagnostic imaging services and require our health services operations to incur significant costs to upgrade its equipment.
Although we believe substantially all of our diagnostic imaging systems can be upgraded to maintain their state-of-the-art character, the development of new technologies or refinements of existing technologies might make our existing systems technologically or economically obsolete, or cause a reduction in the value of, or reduce the need for, our systems.

Actions by regulators of our health services operations could result in monetary penalties or restrictions in our health services operations.
Our health services operations are subject to federal and state regulations relating to licensure, conduct of operations, ownership of facilities, addition of facilities and services and payment of services. Our failure to comply with these regulations, or our inability to obtain and maintain necessary regulatory approvals, may result in adverse actions by regulators with respect to our health services operations, which may include civil and criminal penalties, damages, fines, injunctions, operating restrictions or suspension of operations. Any such action could adversely affect our financial results. Courts and regulatory authorities have not fully interpreted a significant number of these laws and regulations, and this uncertainty in interpretation increases the risk that we may be found to be in violation. Any action brought against us for violation of these laws or regulations, even if successfully defended, may result in significant legal expenses and divert management's attention from the operation of our businesses.

FOOD INGREDIENT PROCESSING

Our company that processes dehydrated potato flakes, flour and granules, Idaho Pacific Holdings, Inc. (IPH), competes in a highly competitive market and is dependent on adequate sources of potatoes for processing.
The market for processed, dehydrated potato flakes, flour and granules is highly competitive. The profitability and success of our potato processing company is dependent on superior product quality, competitive product pricing, strong customer relationships, raw material costs, natural gas prices and availability and customer demand for finished goods. In most product categories, our company competes with numerous manufacturers of varying sizes in the United States.

The principal raw material used by our potato processing company is washed process-grade potatoes from growers. These potatoes are unsuitable for use in other markets due to imperfections. They are not subject to the United States Department of Agriculture's general requirements and expectations for size, shape or color. While our food ingredient processing company has processing capabilities in three geographically distinct growing regions, there can be no assurance it will be able to obtain raw materials due to poor growing conditions, a loss of key growers and other factors. A loss or shortage of raw materials or the necessity of paying much higher prices for raw materials or natural gas could adversely affect the financial performance of this company. Fluctuations in foreign currency exchange rates could have a negative impact on our potato processing company's net income and competitive position because approximately 31% of its sales in 2007 were outside the United States and the Canadian plant pays its operating expenses in Canadian dollars.

We currently have $24.3 million of goodwill and a $3.3 million nonamortizable trade name recorded on our balance sheet related to the acquisition of IPH in 2004. If conditions of low sales prices, high energy and raw material costs and a shortage of raw potato supplies return, as experienced in 2006, and the increased value of the Canadian dollar relative to the U.S. dollar persists or operating margins do not improve according to our projections, the reductions in anticipated cash flows from this business may indicate that its fair value is less than its book value resulting in an impairment of goodwill and nonamortizable intangible assets and a corresponding charge against earnings.

OTHER BUSINESS OPERATIONS

Our construction companies may be unable to properly bid and perform on projects.
The profitability and success of our construction companies require us to identify, estimate and timely bid on profitable projects. The quantity and quality of projects up for bids at any time is uncertain. Additionally, once a project is awarded, we must be able to perform within cost estimates that were set when the bid was submitted and accepted. A significant failure or an inability to properly bid or perform on projects could lead to adverse financial results for our construction companies.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

At December 31, 2007 we had limited exposure to market risk associated with interest rates and commodity prices and limited exposure to market risk associated with changes in foreign currency exchange rates. Outstanding trade accounts receivable of the Canadian operations of IPH are not at risk of valuation change due to changes in foreign currency exchange rates because the Canadian company transacts all sales in U.S. dollars. However, IPH does have market risk related to changes in foreign currency exchange rates because approximately 31% of IPH sales in 2007 were outside the United States and the Canadian operations of IPH pays its operating expenses in Canadian dollars. DMI has market risk related to changes in foreign currency exchange rates at its plant in Ft. Erie, Ontario because the plant pays its operating expenses in Canadian dollars.

The majority of our consolidated 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. We manage our 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, 2007 we had $10.4 million of long-term debt subject to variable interest rates. Assuming no change in our financial structure, if variable interest rates were to average one percentage point higher or lower than the average variable rate on December 31, 2007, annualized interest expense on variable rate long-term debt and pre-tax earnings would change by approximately $104,000.

We have not used interest rate swaps to manage net exposure to interest rate changes related to our portfolio of borrowings. We maintain a ratio of fixed-rate debt to total debt within a certain range. It is our policy to enter into interest rate transactions and other financial instruments only to the extent considered necessary to meet our stated objectives. We do not enter into interest rate transactions for speculative or trading purposes.

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 electricity. As of December 31, 2007 the electric utility had recognized, on a pretax basis, $632,000 in net unrealized gains on open forward contracts for the purchase and sale of electricity. Due to the nature of electricity and the physical aspects of the electricity transmission system, unanticipated events affecting the transmission grid can cause transmission constraints that result in unanticipated gains or losses in the process of settling transactions.

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 or brokers used by the electric utility's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service. Of the forward energy sales contracts that are marked to market as of December 31, 2007, 97.6% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $56,000 in unrealized gains recognized on the open sales contracts.

We have 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. With the advent of the MISO Day 2 market in April 2005, we made several changes to our energy risk management policy to recognize new trading opportunities created by this new market. Most of the changes were in new volumetric limits and loss limits to adequately manage the risks associated with these new opportunities. In addition, we implemented a Value at Risk (VaR) limit to further manage market price risk. Exposure to price risk on any open positions as of December 31, 2007 was not material.

The following tables show the effect of marking to market forward contracts for the purchase and sale of electricity on our consolidated balance sheet as of December 31, 2007 and the change in our consolidated balance sheet position from December 31, 2006 to December 31, 2007:

(in thousands)	December 31, 2007
Current Asset—Marked-to-Market Gain	$ 5,210
Regulatory Asset—Deferred Marked-to-Market Loss	771
Total Assets	5,981
Current Liability—Marked-to-Market Loss	(5,078)
Regulatory Liability—Deferred Marked-to-Market Gain	(271)
Total Liabilities	(5,349)
Net Fair Value of Marked-to-Market Energy Contracts	$ 632

(in thousands)	December 31, 2007
Fair Value at Beginning of Year	$ 203
Amount Realized on Contracts Entered into in 2006 and Settled in 2007	(203)
Changes in Fair Value of Contracts Entered into in 2006	—
Net Fair Value of Contracts Entered into in 2006 at Year End 2007	—
Changes in Fair Value of Contracts Entered into in 2007	632
Net Fair Value at End of Year	$ 632

The $632,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market on December 31, 2007 is expected to be realized on physical settlement as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2008	4th Quarter 2008	Total
Net Gain	$ 118	$ 514	$ 632

We have credit risk associated with the nonperformance or nonpayment by counterparties to our forward energy purchases and sales agreements. We have 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. Our credit risk with our largest counterparty on delivered and marked-to-market forward contracts as of December 31, 2007 was $0.5 million. As of December 31, 2007 we had a net credit risk exposure of $1.5 million from eight counterparties with investment grade credit ratings and one counterparty that has not been rated by an external credit rating agency but has been evaluated internally and assigned an internal credit rating equivalent to investment grade. We had no exposure at December 31, 2007 to counterparties with credit ratings below investment grade. Counterparties with investment grade credit ratings have minimum credit ratings of BBB- (Standard & Poor's), Baa3 (Moody's) or BBB- (Fitch).

The $1.5 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 electricity scheduled for delivery after December 31, 2007. Individual counterparty exposures are offset according to legally enforceable netting arrangements.

IPH has market risk associated with the price of fuel oil and natural gas used in its potato dehydration process as IPH may not be able increase prices for its finished products to recover increases in fuel costs. In the third quarter of 2006, IPH entered into forward natural gas contracts on the New York Mercantile Exchange market to hedge its exposure to fluctuations in natural gas prices related to approximately 50% of its anticipated natural gas needs through March 2007 for its Ririe, Idaho and Center, Colorado dehydration plants. These forward contracts were derivatives subject to mark-to-market accounting but they did not qualify for hedge accounting treatment. IPH includes net changes in the market values of these forward contracts in net income as components of cost of goods sold in the period of recognition. Of the $371,000 in unrealized marked-to-market losses on forward natural gas contracts IPH had outstanding on December 31, 2006, $62,000 was reversed and $309,000 was realized on settlement in the first quarter of 2007.

□ CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

Our 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 our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. 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.

We use 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, valuation of forward energy contracts, unbilled electric revenues, MISO electric market residual load adjustments, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs and liabilities. 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 more significant judgments and estimates used in the preparation of our consolidated financial statements.

PENSION AND OTHER POSTRETIREMENT BENEFITS OBLIGATIONS AND COSTS

Pension and postretirement benefit liabilities and expenses for our 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 our pension and postretirement benefit plans and related assumptions is included in note 12 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 our 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 our benefit expenses in the year of the change. Also, a reduction in the expected rate of return on pension plan assets in our 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.

The pension benefit cost for 2008 for our noncontributory funded pension plan is expected to be $3.3 million compared to $4.5 million in 2007. The estimated discount rate used to determine annual benefit cost accruals will be 6.25% in 2008; the discount rate used in 2007 was 6.00%. In selecting the discount rate, we consider the yields of fixed income debt securities, which have ratings of "Aa" published by recognized rating agencies, along with bond matching models specific to our plans as a basis to determine the rate.

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 2007, all other factors being held constant: a 0.25 increase (or decrease) in the discount rate would have decreased (or increased) our 2007 pension benefit cost by $600,000; a 0.25 increase (or decrease) in the assumed rate of increase in future compensation levels would have increased (or decreased) our 2007 pension benefit cost by $540,000; a 0.25 increase (or decrease) in the expected long-term rate of return on plan assets would have decreased (or increased) our 2007 pension benefit cost by $380,000.

Increases or decreases in the discount rate or in retiree healthcare cost inflation rates could significantly change our projected postretirement healthcare benefit costs. A 0.25 increase (or decrease) in the discount rate would have decreased (or increased) our 2007 postretirement medical benefit costs by $70,000. See note 12 to consolidated financial statements for the cost impact of a change in medical cost inflation rates.

We believe the estimates made for our pension and other postretirement benefits are reasonable based on the information that is known at the point in time the estimates are made. These estimates and assumptions are subject to a number of variables and are subject to change.

REVENUE RECOGNITION

Our construction companies and two of our 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 labor costs incurred to total estimated labor costs at our wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. The duration of the majority of these contracts is less than a year. Revenues recognized on jobs in progress as of December 31, 2007 were $325 million. Any expected losses on jobs in progress at year-end 2007 have been recognized. We believe 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

Our electric utility's forward contracts for the purchase and sale of electricity are derivatives subject to mark-to-market accounting under accounting principles generally accepted in the United States. 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 or brokers used by the electric utility's power services' personnel responsible for contract pricing, as well as prices gathered from daily settlement prices published by the Intercontinental Exchange. For certain contracts, prices at illiquid trading points are based on a basis spread between that trading point and more liquid trading hub prices. Prices are benchmarked to forward price curves and indices acquired from a third party price forecasting service, and, as such, are estimates. Of the forward energy sales contracts that are marked to market as of December 31, 2007, 97.6% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $56,000 in unrealized gains recognized on the open sales contracts. All of the forward energy contracts for the purchase and sale of electricity marked to market as of December 31, 2007 are scheduled for settlement prior to December 1, 2008.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

Our operating companies encounter risks associated with sales and the collection of the associated accounts receivable. As such, they record provisions for accounts receivable that are considered to be uncollectible. In order to calculate the appropriate monthly provision, the operating companies primarily utilize historical rates 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, operating companies compare identified credit risks with allowances that have been established using historical experience and adjust allowances accordingly. In circumstances where an operating company is aware of a specific customer's inability to meet financial obligations, the operating company records a specific allowance for bad debts to reduce the net recognized receivable to the amount it reasonably believes will be collected.

We believe the accounting estimates 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 2007, $2.2 million of bad debt expense (0.18% of total 2007 revenue of $1.2 billion) was recorded and the allowance for doubtful accounts was $3.8 million (2.5% of trade accounts receivable) as of December 31, 2007. 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 in our consolidated allowance for doubtful accounts based on one percentage point of outstanding trade receivables at December 31, 2007 would result in a $1.6 million increase or decrease in bad debt expense.

Although an estimated allowance for doubtful accounts on our operating companies' 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 largely due to stringent risk management criteria related to these sales. 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 2.78% in 2007, 2.82% in 2006 and 2.74% in 2005. 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 our nonelectric operations are carried at historical cost or at the then-current replacement cost 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. We believe the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries in which our nonelectric companies operate or innovations in technology could result in a reduction of the estimated useful lives of our nonelectric operating companies' property, plant and equipment or in an impairment write-down of the carrying value of these properties.

TAXATION

We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments could result in the recognition of a liability for potential adverse outcomes regarding uncertain tax positions that we have taken. While we believe our liability for uncertain tax positions as of December 31, 2007 reflects the most likely probable expected outcome of these tax matters in accordance with FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*, and Statement of Financial Accounting Standards (SFAS) No. 109, *Accounting for Income Taxes*, the ultimate outcome of such matters could result in additional adjustments to our consolidated financial statements. However, we do not believe such adjustments would be material.

Deferred income taxes are provided for revenue and expenses which are recognized in different periods for income tax and financial reporting purposes. We assess our deferred tax assets for recoverability based on both historical and anticipated earnings levels. We have not recorded a valuation allowance related to the probability of recovery of our deferred tax assets as we believe reductions in tax payments related to these assets will be fully realized in the future.

ASSET IMPAIRMENT

We are 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. We apply 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.

We believe 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, 2007 an assessment of the carrying values of our long-lived assets and other intangibles indicated that these assets were not impaired.

GOODWILL IMPAIRMENT

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.

We believe 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 goodwill be analyzed for impairment on an annual basis using the assumptions that apply at the time the analysis is updated.

We evaluate goodwill for impairment on an annual basis and as conditions warrant. As of December 31, 2007 an assessment of the carrying values of our goodwill indicated no impairment.

PURCHASE ACCOUNTING

Through December 31, 2008, under SFAS No. 141, *Business Combinations*, we will account for our acquisitions under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed are recorded at their respective fair values. The excess of purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The recorded values of assets and liabilities are based on third party estimates and valuations when available. The remaining values are based on management's judgments and estimates, and, accordingly, our consolidated financial position or results of operations may be affected by changes in estimates and judgments.

Acquired assets and liabilities assumed that are subject to critical estimates include property, plant and equipment and intangible assets.

The fair value of property, plant and equipment is based on valuations performed by qualified internal personnel and/or outside appraisers. Fair values assigned to plant and equipment are based on several factors including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase.

Intangible assets are identified and valued using the guidelines of SFAS No. 141. The fair value of intangible assets is based on estimates including royalty rates, customer attrition rates and estimated cash flows.

While the allocation of purchase price is subject to a high degree of judgment and uncertainty, we do not expect the estimates to vary significantly once an acquisition is complete. We believe our estimates have been reasonable in the past as there have been no significant valuation adjustments to the final allocation of purchase price.

Beginning in 2009, we will account for acquisitions under the requirements of SFAS No. 141 (revised 2007), *Businesses Combinations*, issued in December 2007. SFAS No. 141(R) replaces the term "purchase method of accounting" with "acquisition method of accounting" and requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values.

◻ KEY ACCOUNTING PRONOUNCEMENTS

SFAS No. 123(R) (revised 2004), *Share-Based Payment*, issued in December 2004, is a revision of SFAS No. 123, *Accounting for Stock-based Compensation*, and supersedes Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees*. Beginning in January 2006, we adopted SFAS No. 123(R) on a modified prospective basis. We are required to record stock-based compensation as an expense on our income statement over the period earned based on the fair value of the stock or options awarded on their grant date. The application of SFAS No. 123(R) reporting requirements resulted in recording incremental after-tax compensation expense in 2006 as follows:

- $163,000, net-of-tax, for non-vested stock options that were outstanding on December 31, 2005.
- $235,000 for the 15% discount offered under our Employee Stock Purchase Plan.

See note 7 to consolidated financial statements for additional discussion. For years prior to 2006, we reported our stock-based compensation under the requirements of APB No. 25 and furnished related pro forma footnote information required under SFAS No. 123.

In November 2005, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) No. FAS 123(R)-3, *Transition Election Related to Accounting for Tax Effects of Share-Based Payment Awards.* We elected to adopt the alternative transition method provided in FSP No. FAS 123(R)-3 for calculating the tax effects of stock-based compensation. The alternative transition method includes simplified methods to determine the beginning balance of the additional paid-in capital (APIC) pool related to the tax effects of stock-based compensation, and to determine the subsequent impact on the APIC pool and the statement of cash flows of the tax effects of stock-based awards that were fully vested and outstanding upon the adoption of SFAS No. 123(R).

FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109,* was issued by the FASB in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes.* We adopted FIN No. 48 on January 1, 2007 and have recognized, in our consolidated financial statements, the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%. FIN No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. Only tax positions that meet the "more-likely-than-not" threshold on the reporting date may be recognized. See additional discussion under Income Taxes in note 15 to the consolidated financial statements that follow.

SFAS No. 157, *Fair Value Measurements,* was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. Other than additional footnote disclosures related to the use of fair value measurements in the areas of derivatives, goodwill and asset impairment evaluations and financial instruments, we do not expect the adoption of SFAS No. 157 to have a significant impact on our consolidated balance sheet, income statement or statement of cash flows.

SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* was issued by the FASB in September 2006. SFAS No. 158 requires employers to recognize, on a prospective basis, the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and to recognize, as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits and transition assets or obligations that have not been recognized as components of net periodic benefit cost. SFAS No. 158 also requires additional disclosures in the notes to financial statements. SFAS No. 158 will not change the amount of net periodic benefit expense recognized in an entity's income statement. It is effective for fiscal years ending after December 15, 2006. We determined the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, we charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation,* rather than to Accumulated Other Comprehensive Loss in equity as prescribed by SFAS No. 158. Application of this standard had the following effects on our December 31, 2006 consolidated balance sheet:

(in thousands)	2006
Decrease in Executive Survivor and Supplemental Retirement Plan Intangible Asset	$ (767)
Increase in Regulatory Assets (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are subject to recovery through electric rates)	36,736
Increase in Pension Benefit and Other Postretirement Liability	(34,714)
Increase in Deferred Tax Liability	(502)
Decrease in Accumulated Other Comprehensive Loss (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are not subject to recovery through electric rates) (increase to equity)	(753)

The adoption of this standard did not affect compliance with debt covenants maintained in our financing agreements.

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115,* was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. As of December 31, 2007 we had not opted, nor do we currently plan to opt, to apply fair value accounting to any financial instruments or other items that we are not currently required to account for at fair value.

SFAS No. 141(R), *Businesses Combinations,* was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations,* and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008—January 1, 2009 for Otter Tail Corporation. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141's guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

MANAGEMENT'S REPORT REGARDING INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management is responsible for the preparation and integrity of the consolidated financial statements and representations in this annual report. The consolidated financial statements of Otter Tail Corporation (the Company) have been prepared in conformity with generally accepted accounting principles applied on a consistent basis and include some amounts that are based on informed judgments and best estimates and assumptions of management.

In order to assure the consolidated financial statements are prepared in conformance with generally accepted accounting principles, management is responsible for establishing and maintaining adequate internal controls over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). These internal controls are designed only to provide reasonable 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 has completed its assessment of the effectiveness of the Company's internal controls over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework* to conduct the required assessment of the effectiveness of the Company's internal controls over financial reporting.

There have not been any changes in the Company's internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fiscal year to which this report relates that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Based on this assessment, we believe that, as of December 31, 2007 the Company's internal controls over financial reporting are effective based on those criteria.

The Company's independent registered public accounting firm, Deloitte & Touche LLP, audited the Company's consolidated financial statements included in this annual report and issued an attestation report on the Company's internal controls over financial reporting.

John Erickson, President and Chief Executive Officer

Kevin Moug, Chief Financial Officer and Treasurer
February 20, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2007 and 2006, and the related consolidated statements of income, common shareholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. We also have audited the Company's internal control over financial reporting as of December 31, 2007 based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report Regarding Internal Controls Over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control— Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in note 1 to the consolidated financial statements, effective December 31, 2006, the Corporation adopted the recognition and disclosure provisions of Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP | Minneapolis, Minnesota | February 20, 2008

CONSOLIDATED STATEMENTS OF INCOME—FOR THE YEARS ENDED DECEMBER 31

(in thousands, except per-share amounts)	2007	2006	2005
Operating Revenues			
Electric	$ 323,158	$ 305,703	$ 312,624
Nonelectric	915,729	799,251	669,245
Total Operating Revenues	1,238,887	1,104,954	981,869
Operating Expenses			
Production Fuel—Electric	60,482	58,729	55,927
Purchased Power—Electric System Use	74,690	58,281	58,828
Electric Operation and Maintenance Expenses	107,041	103,548	99,904
Cost of Goods Sold—Nonelectric (excludes depreciation; included below)	712,547	611,737	502,407
Other Nonelectric Expenses	121,110	115,290	109,707
Depreciation and Amortization	52,830	49,983	46,458
Property Taxes—Electric	9,413	9,589	10,043
Total Operating Expenses	1,138,113	1,007,157	883,274
Operating Income	100,774	97,797	98,595
Other Income and Deductions	2,012	(440)	1,773
Interest Charges	20,857	19,501	18,459
Income from Continuing Operations Before Income Taxes	81,929	77,856	81,909
Income Taxes—Continuing Operations	27,968	27,106	28,007
Net Income from Continuing Operations	53,961	50,750	53,902
Discontinued Operations			
Income (Loss) from Discontinued Operations			
Net of Taxes of $28 in 2006 and ($261) in 2005	—	26	(352)
Goodwill Impairment Loss	—	—	(1,003)
Gain on Disposition of Discontinued Operations			
Net of Taxes of $224 in 2006 and $5,831 in 2005	—	336	10,004
Net Income from Discontinued Operations	—	362	8,649
Net Income	53,961	51,112	62,551
Preferred Dividend Requirements	736	736	735
Earnings Available for Common Shares	$ 53,225	$ 50,376	$ 61,816
Average Number of Common Shares Outstanding—Basic	29,681	29,394	29,223
Average Number of Common Shares Outstanding—Diluted	29,970	29,664	29,348
Basic Earnings Per Share:			
Continuing Operations (net of preferred dividend requirements)	$ 1.79	$ 1.70	$ 1.82
Discontinued Operations	—	0.01	0.30
	$ 1.79	$ 1.71	$ 2.12
Diluted Earnings Per Share:			
Continuing Operations (net of preferred dividend requirements)	$ 1.78	$ 1.69	$ 1.81
Discontinued Operations	—	0.01	0.30
	$ 1.78	$ 1.70	$ 2.11
Dividends Per Common Share	$ 1.17	$ 1.15	$ 1.12

See accompanying notes to consolidated financial statements.

(in thousands)	2007	2006
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 39,824	$ 6,791
Accounts Receivable:		
Trade (less allowance for doubtful accounts of $3,811 for 2007 and $2,964 for 2006)	151,446	135,011
Other	14,934	10,265
Inventories	97,214	103,002
Deferred Income Taxes	7,200	8,069
Accrued Utility and Cost-of-Energy Revenues	32,501	23,931
Costs and Estimated Earnings in Excess of Billings	42,234	38,384
Other	15,299	9,611
Assets of Discontinued Operations	—	289
Total Current Assets	400,652	335,353
Investments	10,057	8,955
Other Assets	24,500	20,991
Goodwill	99,242	98,110
Other Intangibles—Net	20,456	20,080
Deferred Debits		
Unamortized Debt Expense and Reacquisition Premiums	6,986	6,133
Regulatory Assets and Other Deferred Debits	38,837	50,419
Total Deferred Debits	45,823	56,552
Plant		
Electric Plant in Service	1,028,917	930,689
Nonelectric Operations	257,590	239,269
Total	1,286,507	1,169,958
Less Accumulated Depreciation and Amortization	506,744	479,557
Plant—Net of Accumulated Depreciation and Amortization	779,763	690,401
Construction Work in Progress	74,261	28,208
Net Plant	854,024	718,609
Total	$ 1,454,754	$ 1,258,650

See accompanying notes to consolidated financial statements.

CONSOLIDATED BALANCE SHEETS, DECEMBER 31

(in thousands, except share data)	2007	2006
LIABILITIES AND EQUITY		
Current Liabilities		
Short-Term Debt	$ 95,000	$ 38,900
Current Maturities of Long-Term Debt	3,004	3,125
Accounts Payable	141,390	120,195
Accrued Salaries and Wages	29,283	28,653
Accrued Federal and State Income Taxes	—	2,383
Other Accrued Taxes	11,409	11,509
Other Accrued Liabilities	13,873	10,495
Liabilities of Discontinued Operations	—	197
Total Current Liabilities	293,959	215,457
Pensions Benefit Liability	39,429	44,035
Other Postretirement Benefits Liability	30,488	32,254
Other Noncurrent Liabilities	23,228	18,866
Commitments (note 9)		
Deferred Credits		
Deferred Income Taxes	105,813	112,740
Deferred Tax Credits	16,761	8,181
Regulatory Liabilities	62,705	63,875
Other	275	281
Total Deferred Credits	185,554	185,077
Capitalization (page 42)		
Long-Term Debt, Net of Current Maturities	342,694	255,436
Class B Stock Options of Subsidiary	1,255	1,255
Cumulative Preferred Shares	15,500	15,500
Common Shares, Par Value $5 Per Share—Authorized, 50,000,000 Shares; Outstanding, 2007—29,849,789 Shares; 2006—29,521,770 Shares	149,249	147,609
Premium on Common Shares	108,885	99,223
Retained Earnings	263,332	245,005
Accumulated Other Comprehensive Income (Loss)	1,181	(1,067)
Total Common Equity	522,647	490,770
Total Capitalization	882,096	762,961
Total	$ 1,454,754	$ 1,258,650

See accompanying notes to consolidated financial statements.

(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, 2004	28,976,919	$ 144,885	$ 87,865	$ (2,577)	$ 199,427	$ (390)	$ 429,210
Common Stock Issuances, Net of Expenses	456,211	2,281	8,483	(529)			10,235
Common Stock Retirements	(31,907)	(160)	(756)				(916)
Amortization of Unearned Compensation—Stock Awards				1,386			1,386
Comprehensive Income:							
Net Income					62,551		62,551
Unrealized Loss on Marketable Equity Securities (net-of-tax)						(23)	(23)
Foreign Currency Exchange Translation (net-of-tax)						437	437
SFAS No. 87 Minimum Pension Liability Adjustment (net-of-tax)						(6,163)	(6,163)
Total Comprehensive Income							56,802
Tax Benefit for Exercise of Stock Options			596				596
Stock Incentive Plan Performance Award Accrual			943				943
Premium on Purchase of Stock for Employee Purchase Plan			(363)				(363)
Cumulative Preferred Dividends					(735)		(735)
Common Dividends					(32,728)		(32,728)
Balance, December 31, 2005	29,401,223	$ 147,006	$ 96,768	$ (1,720)	$ 228,515	$ (6,139)	$ 464,430
Common Stock Issuances, Net of Expenses	136,917	685	1,837				2,522
Common Stock Retirements	(16,370)	(82)	(378)				(460)
SFAS No. 123(R) Reclassifications (note 7)			(2,490)	1,720			(770)
Comprehensive Income:							
Net Income					51,112		51,112
Unrealized Gain on Marketable Equity Securities (net-of-tax)						56	56
Foreign Currency Exchange Translation (net-of-tax)						6	6
SFAS No. 87 Minimum Pension Liability Adjustment (net-of-tax)						4,257	4,257
Total Comprehensive Income							55,431
SFAS No. 158 Items (net-of-tax)							
Reversal of 12/31/06 Minimum Pension Liability Balance						3,296	3,296
Unrecognized Postretirement Benefit Costs						(24,585)	(24,585)
Unrecognized Costs Classified as Regulatory Assets						22,042	22,042
Tax Benefit for Exercise of Stock Options			288				288
Stock Incentive Plan Performance Award Accrual			2,404				2,404
Vesting of Restricted Stock Granted to Employees			1,096				1,096
Premium on Purchase of Stock for Employee Purchase Plan			(302)				(302)
Cumulative Preferred Dividends					(736)		(736)
Common Dividends					(33,886)		(33,886)
Balance, December 31, 2006	29,521,770	$ 147,609	$ 99,223	$ —	$ 245,005	$ (1,067)(a)	$ 490,770
Common Stock Issuances, Net of Expenses	336,508	1,683	6,018				7,701
Common Stock Retirements	(8,489)	(43)	(252)				(295)
Comprehensive Income:							
Net Income					53,961		53,961
Unrealized Gain on Marketable Equity Securities (net-of-tax)						4	4
Foreign Currency Exchange Translation (net-of-tax)						2,019	2,019
SFAS No. 158 Items (net-of-tax):							
Amortization of Unrecognized Postretirement Benefit Costs						165	165
Actuarial Gains and Regulatory Allocations Adjustments						60	60
Total Comprehensive Income							56,209
Tax Benefit for Exercise of Stock Options			1,092				1,092
Stock Incentive Plan Performance Award Accrual			2,213				2,213
Vesting of Restricted Stock Granted to Employees			860				860
Premium on Purchase of Stock for Employee Purchase Plan			(269)				(269)
Cumulative Effect of Adoption of FIN No. 48					(118)		(118)
Cumulative Preferred Dividends					(736)		(736)
Common Dividends					(34,780)		(34,780)
Balance, December 31, 2007	29,849,789	$ 149,249	$ 108,885	$ —	$ 263,332	$ 1,181(a)	$ 522,647

(a) Accumulated Other Comprehensive Income (Loss) on December 31 is comprised of the following:

2006 *(in thousands)*	Before Tax	Tax Effect	Net-of-Tax
Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (4,238)	$ 1,695	$ (2,543)
Foreign Currency Exchange Translation	2,430	(972)	1,458
Unrealized Gain on Marketable Equity Securities	30	(12)	18
Net Accumulated Other Comprehensive Loss	$ (1,778)	$ 711	$ (1,067)

2007 *(in thousands)*	Before Tax	Tax Effect	Net-of-Tax
Unamortized Actuarial Losses and Transition Obligation Related to Pension and Postretirement Benefits	$ (3,863)	$ 1,545	$ (2,318)
Foreign Currency Exchange Translation	5,795	(2,318)	3,477
Unrealized Gain on Marketable Equity Securities	36	(14)	22
Net Accumulated Other Comprehensive Income	$ 1,968	$ (787)	$ 1,181

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS—FOR THE YEARS ENDED DECEMBER 31

(in thousands)	2007	2006	2005
Cash Flows from Operating Activities			
Net Income	$ 53,961	$ 51,112	$ 62,551
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Net Gain on Sale of Discontinued Operations	—	(336)	(10,004)
(Income) Loss from Discontinued Operations	—	(26)	1,355
Depreciation and Amortization	52,830	49,983	46,458
Deferred Tax Credits	(1,169)	(1,146)	(1,150)
Deferred Income Taxes	4,366	(1,258)	(9,223)
Change in Deferred Debits and Other Assets	6,505	(38,499)	8,865
Discretionary Contribution to Pension Plan	(4,000)	(4,000)	(4,000)
Change in Noncurrent Liabilities and Deferred Credits	481	45,340	1,321
Allowance for Equity (Other) Funds Used During Construction	—	2,529	(723)
Change in Derivatives Net of Regulatory Deferral	(800)	3,083	(2,615)
Stock Compensation Expense	2,986	2,404	2,388
Other—Net	(1,837)	418	1,118
Cash (Used for) Provided by Current Assets and Current Liabilities:			
Change in Receivables	(18,903)	(15,713)	(9,715)
Change in Inventories	8,407	(14,345)	(12,500)
Change in Other Current Assets	(14,616)	(17,409)	(13,908)
Change in Payables and Other Current Liabilities	(2,556)	23,022	32,682
Change in Interest and Income Taxes Payable	(843)	(5,952)	(2,552)
Net Cash Provided by Continuing Operations	84,812	79,207	90,348
Net Cash Provided by Discontinued Operations	—	1,039	5,452
Net Cash Provided by Operating Activities	84,812	80,246	95,800
Cash Flows from Investing Activities			
Capital Expenditures	(161,985)	(69,448)	(59,969)
Proceeds from Disposal of Noncurrent Assets	12,486	5,233	4,193
Acquisitions—Net of Cash Acquired	(6,750)	—	(11,223)
(Increases) Decreases in Other Investments	(7,745)	(3,326)	4,171
Net Cash Used in Investing Activities—Continuing Operations	(163,994)	(67,541)	(62,828)
Net Proceeds from Sale of Discontinued Operations	—	1,960	34,185
Net Cash Provided by Investing Activities—Discontinued Operations	—	—	602
Net Cash Used in Investing Activities	(163,994)	(65,581)	(28,041)
Cash Flows from Financing Activities			
Change in Checks Written in Excess of Cash	—	(11)	(3,329)
Net Short-Term Borrowings (Repayments)	56,100	22,900	(23,950)
Proceeds from Issuance of Common Stock, Net of Issuance Expenses	7,733	2,444	9,690
Payments for Retirement of Common Stock and Class B Stock of Subsidiary	(305)	(463)	(939)
Proceeds from Issuance of Long-Term Debt	205,129	149	368
Debt Issuance Expenses	(1,762)	(458)	(140)
Payments for Retirement of Long-Term Debt	(118,171)	(3,287)	(7,232)
Dividends Paid	(35,516)	(34,621)	(33,463)
Net Cash Provided by (Used in) Financing Activities—Continuing Operations	113,208	(13,347)	(58,995)
Net Cash Used in Financing Activities—Discontinued Operations	—	—	(2,996)
Net Cash Provided by (Used in) Financing Activities	113,208	(13,347)	(61,991)
Effect of Foreign Exchange Rate Fluctuations on Cash	(993)	43	(338)
Net Change in Cash and Cash Equivalents	33,033	1,361	5,430
Cash and Cash Equivalents at Beginning of Year—Continuing Operations	6,791	5,430	—
Cash and Cash Equivalents at End of Year—Continuing Operations	$ 39,824	$ 6,791	$ 5,430

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION, DECEMBER 31

(in thousands, except share data)	2007	2006
Long-Term Debt		
Senior Unsecured Notes 6.63%, due December 1, 2011	$ 90,000	$ 90,000
Senior Debentures 6.375%, due December 1, 2007	—	50,000
Senior Unsecured Note 5.778%, due November 30, 2017	50,000	—
Insured Senior Notes 5.625%, due October 1, 2017 (retired October 15, 2007)	—	40,000
Senior Notes 6.80%, due October 1, 2032 (retired October 15, 2007)	—	25,000
Senior Unsecured Notes 6.47%, Series D, due August 20, 2037	50,000	—
Senior Unsecured Notes 6.37%, Series C, due August 20, 2027	42,000	—
Senior Unsecured Notes 5.95%, Series A, due August 20, 2017	33,000	—
Senior Unsecured Notes 6.15%, Series B, due August 20, 2022	30,000	—
Mercer County, North Dakota Pollution Control Refunding Revenue Bonds 4.85%, due September 1, 2022	20,705	20,735
Pollution Control Refunding Revenue Bonds, Variable, 3.97% at December 31, 2007, due December 1, 2012	10,400	10,400
Lombard US Equipment Finance Note 6.76%, due October 2, 2010	6,986	9,314
Grant County, South Dakota Pollution Control Refunding Revenue Bonds 4.65%, due September 1, 2017	5,185	5,185
Obligations of Varistar Corporation—Various up to 8.25% at December 31, 2007	7,891	8,424
Total	346,167	259,058
Less:		
Current Maturities	3,004	3,125
Unamortized Debt Discount	469	497
Total Long-Term Debt	342,694	255,436
Class B Stock Options of Subsidiary	1,255	1,255
Cumulative Preferred Shares—Without Par Value (Stated and Liquidating Value $100 a Share)—Authorized 1,500,000 Shares; nonvoting and redeemable at the option of the Company		
Series Outstanding: — Call Price December 31, 2007		
$3.60, 60,000 Shares — $102.25	6,000	6,000
$4.40, 25,000 Shares — $102.00	2,500	2,500
$4.65, 30,000 Shares — $101.50	3,000	3,000
$6.75, 40,000 Shares — $102.025	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	522,647	490,770
Total Capitalization	$ 882,096	$ 762,961

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, Food Ingredient Processing and Other Business Operations. 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*. Such 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 electric utility 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. The amount of interest capitalized on electric utility plant was $2,276,000 in 2007, $202,000 in 2006 and $190,000 in 2005. 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 2.78% in 2007, 2.82% in 2006 and 2.74% in 2005. Gains or losses on group 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 replacement cost if acquired in a business combination accounted for under the purchase method of accounting, and are depreciated on a straight-line basis over the assets' estimated useful lives (3 to 40 years). The cost of additions includes contracted work, direct labor and materials, allocable overheads and capitalized interest. The amount of interest capitalized on nonelectric plant was $390,000 in 2007, $31,000 in 2006 and none in 2005. 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 balance sheets include the Company's ownership interests in the assets and liabilities of Big Stone Plant (53.9%) and Coyote Station (35.0%). The following amounts are included in the December 31, 2007 and 2006 consolidated balance sheets:

(in thousands)	Big Stone Plant	Coyote Station
December 31, 2007		
Electric Plant in Service	$ 136,493	$ 147,724
Accumulated Depreciation	(72,342)	(83,417)
Net Plant	$ 64,151	$ 64,307
December 31, 2006		
Electric Plant in Service	$ 124,965	$ 147,319
Accumulated Depreciation	(75,872)	(80,336)
Net Plant	$ 49,093	$ 66,983

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. If the sum of the expected future net cash flows is 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 in the periods when the temporary differences reverse. The Company amortizes tax credits over the estimated lives of related property. Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109*, was issued in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes*. The Company adopted FIN No. 48 on January 1, 2007 and has recognized, in its consolidated financial statements, the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%.

REVENUE RECOGNITION

Due to the diverse business operations of the Company, revenue recognition depends on the product produced and sold or service performed. 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 recognition is deferred until such obligations are fulfilled. Provisions for sales 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, marked-to-market and realized gains and losses are recognized on a net basis in revenue in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted. Gains and losses on forward energy contracts subject to regulatory treatment, if any, are deferred and recognized on a net basis in revenue in the period realized.

For the Company's operating companies recognizing revenue on certain products when shipped, those operating companies 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 fuel clause adjustment (FCA)—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 FCA.

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

The Company's unrealized gains and losses on forward energy contracts that do not meet 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. Under SFAS No. 133 as amended and interpreted, the Company's forward energy contracts that do not meet the definition of a capacity contract and are subject to unplanned netting do not qualify for the normal purchase and sales exception from mark-to-market accounting. 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. See note 5 for further discussion.

Plastics operating revenues are recorded when the product is shipped.

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

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 imaging operations are recorded on a fee-per-scan basis when the scan is performed.

Food Ingredient Processing revenues are recorded when the product is shipped.

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 Company's consolidated revenues recorded under the percentage-of-completion method were 30.1% in 2007, 25.1% in 2006 and 17.9% in 2005. The method used to determine the progress of completion is based on the ratio of labor costs incurred to total estimated labor costs at the Company's wind tower manufacturer, square footage completed to total bid square footage for certain floating dock projects and costs incurred to total estimated costs on all other construction projects. 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 table summarizes costs incurred and billings and estimated earnings recognized on uncompleted contracts:

(in thousands)	December 31, 2007	December 31, 2006
Costs Incurred on Uncompleted Contracts	$ 286,358	$ 257,370
Less Billings to Date	(292,692)	(284,273)
Plus Estimated Earnings Recognized	38,275	35,955
	$ 31,941	$ 9,052

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, 2007	December 31, 2006
Costs and Estimated Earnings in Excess of Billings on Uncompleted Contracts	$ 42,234	$ 38,384
Billings in Excess of Costs and Estimated Earnings on Uncompleted Contracts	(10,293)	(29,332)
	$ 31,941	$ 9,052

Costs and Estimated Earnings in Excess of Billings at DMI Industries, Inc. (DMI) were $36,161,000 as of December 31, 2007. This amount is related to costs incurred on wind towers in the process of completion on major contracts under which the customer is not billed until towers are completed and ready for shipment.

FOREIGN CURRENCY TRANSLATION

The functional currency for the operations of the Canadian subsidiary of Idaho Pacific Holdings, Inc. (IPH) is the Canadian dollar. This subsidiary realizes foreign currency transaction gains or losses on settlement of receivables related to its sales, which are mostly in U.S. dollars, and on exchanging U.S. currency for Canadian currency for its Canadian operations. This subsidiary recorded foreign currency transaction losses of $656,000 ($393,000 net-of-tax) in U.S. dollars in 2007 as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar in 2007. Transaction gains and losses in 2006 and 2005 were not significant due to the relative stability of the currencies in those years. The translation of Canadian currency into U.S. dollars is performed for balance sheet accounts using exchange rates in effect at the balance sheet dates, except for the common equity accounts which are at historical rates, and for revenue and expense accounts using a weighted average exchange during the year. Gains or losses resulting from the translation are included in Accumulated Other Comprehensive Income (Loss) in the equity section of the Company's consolidated balance sheet.

The functional currency for the Canadian subsidiary of DMI, formed in November 2005, is the U.S. dollar. There are no foreign currency translation gains or losses related to this entity. However, this subsidiary may realize foreign currency transaction gains or losses on settlement of liabilities related to goods or services purchased in Canadian dollars. Foreign currency transaction losses related to balance sheet adjustments of Canadian dollar liabilities to U.S. dollar equivalents and realized losses on settlement of those liabilities were $102,000 ($61,000 net-of-tax) in U.S. dollars in 2007 as a result of the increase in the value of the Canadian dollar relative to the U.S. dollar in 2007.

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.

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, unbilled electric revenues, valuations of forward energy contracts, residual load adjustments related to purchase and sales transactions processed through the Midwest Independent Transmission System Operator (MISO) that are pending settlement, service contract maintenance costs, percentage-of-completion and actuarially determined benefits costs and liabilities. 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.

CASH EQUIVALENTS

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

SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION

(in thousands)	2007	2006	2005
Increases (Decreases) in Accounts Payable and Other Liabilities Related to Capital Expenditures	$ 23,514	$ 1,401	$ —
Cash Paid During the Year from Continuing Operations for:			
Interest (net of amount capitalized)	$ 18,155	$ 18,456	$ 17,637
Income Taxes	$ 25,906	$ 35,061	$ 39,548
Cash Paid During the Year from Discontinued Operations for:			
Interest	$ —	$ 91	$ 119
Income Taxes	$ —	$ 423	$ 323

INVESTMENTS

The following table provides a breakdown of the Company's investments at December 31, 2007 and 2006:

(in thousands)	December 31, 2007	December 31, 2006
Cost Method:		
Economic Development Loan Pools	$ 655	$ 569
Other	1,303	1,518
Equity Method:		
Affordable Housing Partnerships	1,851	2,228
Marketable Securities Classified as Available-for-Sale	6,248	4,640
Total Investments	$ 10,057	$ 8,955

The Company has investments in eleven limited partnerships that invest in tax-credit-qualifying affordable-housing projects that provided tax credits of $285,000 in 2007, $839,000 in 2006 and $1,324,000 in 2005. The Company owns a majority interest in eight of the eleven limited partnerships with a total investment of $1,837,000. FIN No. 46, *Consolidation of Variable Interest Entities*, requires full consolidation of the majority-owned partnerships. However, the Company includes these entities on its consolidated financial statements on an equity method basis due to immateriality. Consolidating these entities would have represented less than 0.5% of total assets, 0.1% of total revenues and (0.3%) of operating income for the Company as of, and for the year ended, December 31, 2007 and would have no impact on the Company's 2007 consolidated net income as the amount is the same under both the equity and full consolidation methods.

The Company's marketable securities classified as available-for-sale are held for insurance purposes and are reflected at their market values on December 31, 2007. See further discussion under note 13.

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, 2007	December 31, 2006
Finished Goods	$ 38,952	$ 46,477
Work in Process	5,218	5,663
Raw Material, Fuel and Supplies	53,044	50,862
Total Inventories	$ 97,214	$ 103,002

GOODWILL AND INTANGIBLE ASSETS

The Company accounts for goodwill and other intangible assets in accordance with the requirements of SFAS No. 142, *Goodwill and Other Intangible Assets*, requiring goodwill and indefinite-lived intangible assets to be measured for impairment at least annually and more often when events indicate the assets may be impaired. Intangible assets with finite lives are 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.*

Changes in the carrying amount of Goodwill by segment are as follows:

(in thousands)	Balance December 31, 2006	Adjustment to Goodwill Acquired in 2004	Goodwill Acquired in 2007	Balance December 31, 2007
Plastics	$ 19,302	$ —	$ —	$ 19,302
Manufacturing	15,698	—	1,048	16,746
Health Services	24,328	—	—	24,328
Food Ingredient Processing	24,240	84	—	24,324
Other Business Operations	14,542	—	—	14,542
Total	$ 98,110	$ 84	$ 1,048	$ 99,242

The following table summarizes components of the Company's intangible assets as of December 31:

2007 *(in thousands)*	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized Intangible Assets:			
Covenants Not to Compete	$ 2,637	$ 2,113	$ 524
Customer Relationships	10,879	1,469	9,410
Other Intangible Assets Including Contracts	2,785	1,775	1,010
Total	$ 16,301	$ 5,357	$ 10,944
Nonamortized Intangible Assets:			
Brand/Trade Name	$ 9,512	$ —	$ 9,512
2006 *(in thousands)*			
Amortized Intangible Assets:			
Covenants Not to Compete	$ 2,198	$ 1,813	$ 385
Customer Relationships	10,574	1,016	9,558
Other Intangible Assets Including Contracts	2,083	1,291	792
Total	$ 14,855	$ 4,120	$ 10,735
Nonamortized Intangible Assets:			
Brand/Trade Name	$ 9,345	$ —	$ 9,345

Intangible assets with finite lives are being amortized on a straight-line basis over lives that vary from one to 25 years. The amortization expense for these intangible assets was $1,227,000 for 2007, $1,079,000 for 2006 and $1,077,000 for 2005. The estimated annual amortization expense for these intangible assets for the next five years is: $877,000 for 2008, $795,000 for 2009, $623,000 for 2010, $516,000 for 2011 and $507,000 for 2012.

NEW ACCOUNTING STANDARDS

SFAS No. 123(R) (revised 2004), *Share-Based Payment,* issued in December 2004, is a revision of SFAS No. 123, *Accounting for Stock-based Compensation,* and supersedes Accounting Principles Board Opinion (APB) No. 25, *Accounting for Stock Issued to Employees.* Beginning in January 2006, the Company adopted SFAS No. 123(R) on a modified prospective basis. The Company is required to record stock-based compensation as an expense on its income statement over the period earned based on the fair value of the stock or options awarded on their grant date. The application of SFAS No. 123(R) reporting requirements resulted in recording incremental after-tax compensation expense in 2006 as follows:

- $163,000, net-of-tax, in 2006 for non-vested stock options that were outstanding on December 31, 2005.
- $235,000 in 2006 for the 15% discount offered under the Company's Employee Stock Purchase Plan.

For years prior to 2006, the Company reported its stock-based compensation under the requirements of APB No. 25 and furnished related pro forma footnote information required under SFAS No. 123. See note 7 for additional discussion.

In November 2005, the FASB issued FASB Staff Position (FSP) No. FAS 123(R)-3, *Transition Election Related to Accounting for Tax Effects of Share-Based Payment Awards.* The Company elected to adopt the alternative transition method provided in FSP No. FAS 123(R)-3 for calculating the tax effects of stock-based compensation. The alternative transition method includes simplified methods to determine the beginning balance of the Additional Paid-In Capital (APIC) pool related to the tax effects of stock-based compensation, and to determine the subsequent impact on the APIC pool and the statement of cash flows of the tax effects of stock-based awards that were fully vested and outstanding upon the adoption of SFAS No. 123(R).

FIN No. 48, *Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109,* was issued by the FASB in June 2006. FIN No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS No. 109, *Accounting for Income Taxes.* The Company adopted FIN No. 48 on January 1, 2007 and has recognized, in its consolidated financial statements, the tax effects of all tax positions that are "more-likely-than-not" to be sustained on audit based solely on the technical merits of those positions as of December 31, 2007. The term "more-likely-than-not" means a likelihood of more than 50%. FIN No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. Only tax positions that meet the "more-likely-than-not" threshold on the reporting date may be recognized. See note 15 for additional discussion.

SFAS No. 157, *Fair Value Measurements,* was issued by the FASB in September 2006. SFAS No. 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 will be effective for fiscal years beginning after November 15, 2007. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements where fair value is the relevant measurement attribute. Accordingly, this statement does not require any new fair value measurements. Other than additional footnote disclosures related to the use of fair value measurements in the areas of derivatives, goodwill and asset impairment evaluations and financial instruments, the Company does not expect the adoption of SFAS No. 157 to have a significant impact on its consolidated balance sheet, income statement or statement of cash flows.

SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* was issued by the FASB in September 2006 and became effective for the Company in 2006. SFAS No. 158 requires employers to recognize, on a prospective basis, the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and to recognize, as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits and transition assets or obligations that have not been recognized as components of net periodic benefit cost. SFAS No. 158 also requires additional disclosures in the notes to financial statements. SFAS No. 158 did not change the amount of net periodic benefit expense recognized in an entity's income statement. The Company determined the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation,* rather than to Accumulated Other Comprehensive Loss in equity as prescribed by SFAS No. 158. Application of this standard had the following effects on the Company's December 31, 2006 consolidated balance sheet:

(in thousands)	2006
Decrease in Executive Survivor and Supplemental Retirement Plan Intangible Asset	$ (767)
Increase in Regulatory Assets (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are subject to recovery through electric rates)	36,736
Increase in Pension Benefit and Other Postretirement Liability	(34,714)
Increase in Deferred Tax Liability	(502)
Decrease in Accumulated Other Comprehensive Loss (for the unrecognized portions of net actuarial losses, prior service costs and transition obligations that are not subject to recovery through electric rates) (increase to equity)	(753)

The adoption of this standard did not affect compliance with debt covenants maintained in the Company's financing agreements.

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities—Including an Amendment of FASB Statement No. 115,* was issued by the FASB in February 2007. SFAS No. 159 provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses in earnings at each subsequent reporting date on items for which the fair value option has been elected. This statement also establishes presentation and disclosure requirements to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. As of December 31, 2007 the Company had not opted, nor does it currently plan to opt, to apply fair value accounting to any financial instruments or other items that it is not currently required to account for at fair value.

SFAS No. 141 (revised 2007), Businesses Combinations (SFAS No. 141(R)), was issued by the FASB in December 2007. SFAS No. 141(R) replaces SFAS No. 141, *Business Combinations,* and will apply prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008—January 1, 2009 for the Company. SFAS No. 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree). In addition to replacing the term "purchase method of accounting" with "acquisition method of accounting," SFAS No. 141(R) requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date, measured at their fair values as of that date, with limited exceptions. This guidance will replace SFAS No. 141's cost-allocation process, which requires the cost of an acquisition to be allocated to the individual assets acquired and liabilities assumed based on their estimated fair values. SFAS No. 141's guidance results in not recognizing some assets and liabilities at the acquisition date, and it also results in measuring some assets and liabilities at amounts other than their fair values at the acquisition date. For example, SFAS No. 141 requires the acquirer to include the costs incurred to effect an acquisition (acquisition-related costs) in the cost of the acquisition that is allocated to the assets acquired and the liabilities assumed. SFAS No. 141(R) requires those costs to be expensed as incurred. In addition, under SFAS No. 141, restructuring costs that the acquirer expects but is not obligated to incur are recognized as if they were a liability assumed at the acquisition date. SFAS No. 141(R) requires the acquirer to recognize those costs separately from the business combination.

2. BUSINESS COMBINATIONS, DISPOSITIONS AND SEGMENT INFORMATION

On February 19, 2007 the Company's wholly-owned subsidiary, ShoreMaster, Inc. (ShoreMaster), acquired the assets of the Aviva Sports product line for $2.0 million in cash. The Aviva Sports product line operates under Aviva Sports, Inc. (Aviva), a newly-formed wholly-owned subsidiary of ShoreMaster. The Aviva Sports product line is sold internationally and consists of products for consumer use in the pool, lake and yard, as well as commercial use at summer camps, resorts and large public swimming pools. The acquisition of the Aviva Sports product line fits well with the other product lines of ShoreMaster, a leading manufacturer and supplier of waterfront equipment.

On May 15, 2007 the Company's wholly-owned subsidiary, BTD Manufacturing, Inc. (BTD), acquired the assets of Pro Engineering, LLC (Pro Engineering) for $4.8 million in cash. Pro Engineering specializes in providing metal parts stampings to customers in the Midwest. The acquisition of Pro Engineering by BTD provides expanded growth opportunities for both companies.

Below, are condensed balance sheets, at the dates of the respective business combinations, disclosing the preliminary allocation of the purchase price assigned to each major asset and liability category of Aviva and Pro Engineering:

(in thousands)	Aviva	Pro Engineering
Assets		
Current Assets	$ 2,083	$ 1,956
Goodwill	—	1,048
Other Intangible Assets	870	396
Plant	—	1,600
Total Assets	$ 2,953	$ 5,000
Liabilities		
Current Liabilities	$ 988	$ 215
Noncurrent Liabilities	—	—
Total Liabilities	$ 988	$ 215
Cash Paid	$ 1,965	$ 4,785

Other Intangible Assets related to the Aviva acquisition include $83,000 for a nonamortizable brand name and $787,000 in intangible assets being amortized over various periods up to 15 years. Other Intangible Assets related to the Pro Engineering acquisition include $51,000 for a nonamortizable brand name and $345,000 in intangible assets being amortized over various periods up to 20 years.

The Company acquired no new businesses in 2006.

The Company paid cash of $10.5 million, net of cash acquired, for three businesses purchased in 2005.

All of the acquisitions described above were accounted for using the purchase method of accounting. Disclosure of pro forma information related to the results of operations of the entities acquired in 2007 for the periods presented in this report is not required due to immateriality.

In June 2006, OTESCO, the Company's energy services company, sold its gas marketing operations. In 2005, the Company sold Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Prior to disposition, OTESCO's gas marketing operations and MIS were included in the Other Business Operations segment and SGS and CLC were included in the Manufacturing segment. See note 16 on discontinued operations for further discussion.

SEGMENT INFORMATION

The accounting policies of the segments are described under note 1—Summary of Significant Accounting Policies. The Company's businesses have been classified into six segments based on products and services and reach customers in all 50 states and international markets. The six segments are: Electric, Plastics, Manufacturing, Health Services, Food Ingredient Processing and Other Business Operations.

Electric includes the production, transmission, distribution and sale of electric energy in Minnesota, North Dakota and South Dakota under the name Otter Tail Power Company (the electric utility). In addition, the electric utility is an active wholesale participant in the MISO markets. The electric utility operations have been the Company's primary business since incorporation. The Company's electric operations, including wholesale power sales, are operated as a division of Otter Tail Corporation.

All of the businesses in the following segments are owned by a wholly-owned subsidiary of the Company.

Plastics consists of businesses producing polyvinyl chloride and polyethylene pipe in the Upper Midwest and Southwest regions of the United States.

Manufacturing consists of businesses in the following manufacturing activities: production of waterfront equipment, wind towers, material and handling trays and horticultural containers, contract machining, and metal parts stamping and fabrication. These businesses have manufacturing facilities in Minnesota, North Dakota, South Carolina, Missouri, California, Florida, Oklahoma and Ontario, Canada and sell products primarily in the United States.

Health Services consists of businesses involved in the sale of diagnostic medical equipment, patient monitoring equipment and related supplies and accessories. These businesses also provide equipment maintenance, diagnostic imaging services and rental of diagnostic medical imaging equipment to various medical institutions located throughout the United States.

Food Ingredient Processing consists of IPH, which owns and operates potato dehydration plants in Ririe, Idaho; Center, Colorado; and Souris, Prince Edward Island, Canada. IPH produces dehydrated potato products that are sold in the United States, Canada and other countries.

Other Business Operations consists of businesses in residential, commercial and industrial electric contracting industries, fiber optic and electric distribution systems, wastewater and HVAC systems construction, transportation and energy services. These businesses operate primarily in the Central United States, except for the transportation company which operates in 48 states and 6 Canadian provinces.

Corporate includes items such as corporate staff and overhead costs, the results of the company's captive insurance company and other items excluded from the measurement of operating segment performance. Corporate assets consist primarily of cash, prepaid expenses, investments and fixed assets. Corporate is not an operating segment. Rather it is added to operating segment totals to reconcile to totals on the Company's consolidated financial statements.

No single external customer accounts for 10% or more of the Company's revenues. Substantially all of the Company's long-lived assets are within the United States except for a food ingredient processing dehydration plant in Souris, Prince Edward Island, Canada and a wind tower manufacturing plant in Ft. Erie, Ontario, Canada.

Percent of Sales Revenue by Country for the Year Ended December 31:

	2007	2006	2005
United States of America	96.9%	97.2%	97.8%
Canada	1.3%	1.3%	1.1%
All Other Countries	1.8%	1.5%	1.1%

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 on continuing operations for the business segments for 2007, 2006 and 2005 is presented in the following table.

(in thousands)	2007	2006	2005
Operating Revenue			
Electric	$ 323,478	$ 306,014	$ 312,985
Plastics	149,012	163,135	158,548
Manufacturing	381,599	311,811	244,311
Health Services	130,670	135,051	123,991
Food Ingredient Processing	70,440	45,084	38,501
Other Business Operations	185,730	145,603	105,821
Corporate Revenue and Intersegment Eliminations	(2,042)	(1,744)	(2,288)
Total	$1,238,887	$1,104,954	$ 981,869
Depreciation and Amortization			
Electric	$ 26,097	$ 25,756	$ 24,397
Plastics	3,083	2,815	2,511
Manufacturing	13,124	11,076	9,447
Health Services	3,937	3,660	4,038
Food Ingredient Processing	3,952	3,759	3,399
Other Business Operations	2,058	2,330	2,225
Corporate	579	587	441
Total	$ 52,830	$ 49,983	$ 46,458
Interest Charges			
Electric	$ 9,405	$ 10,315	$ 10,271
Plastics	970	814	1,080
Manufacturing	8,546	6,550	4,516
Health Services	883	910	822
Food Ingredient Processing	177	481	165
Other Business Operations	1,234	988	686
Corporate and Intersegment Eliminations	(358)	(557)	919
Total	$ 20,857	$ 19,501	$ 18,459
Income Before Income Taxes			
Electric	$ 37,422	$ 38,802	$ 55,984
Plastics	13,452	22,959	22,803
Manufacturing	24,503	21,148	12,242
Health Services	2,626	3,909	6,875
Food Ingredient Processing	5,912	(6,325)	1,482
Other Business Operations	6,762	8,666	(827)
Corporate	(8,748)	(11,303)	(16,650)
Total	$ 81,929	$ 77,856	$ 81,909
Earnings Available for Common Shares			
Electric	$ 23,762	$ 23,445	$ 36,566
Plastics	8,314	14,326	13,936
Manufacturing	15,632	13,171	7,589
Health Services	1,427	2,230	4,007
Food Ingredient Processing	4,386	(4,115)	329
Other Business Operations	4,049	5,257	(488)
Corporate	(4,345)	(4,300)	(8,772)
Total	$ 53,225	$ 50,014	$ 53,167
Capital Expenditures			
Electric	$ 104,288	$ 35,207	$ 30,479
Plastics	3,305	5,504	3,636
Manufacturing	42,786	20,048	16,112
Health Services	5,276	4,720	3,095
Food Ingredient Processing	47	1,762	2,952
Other Business Operations	5,589	1,779	3,086
Corporate	694	428	609
Total	$ 161,985	$ 69,448	$ 59,969
Identifiable Assets			
Electric	$ 813,565	$ 689,653	$ 654,175
Plastics	77,971	80,666	76,573
Manufacturing	274,780	219,336	177,969
Health Services	64,824	66,126	67,066
Food Ingredient Processing	91,966	94,462	96,023
Other Business Operations	72,258	67,110	55,341
Corporate	59,390	41,008	40,648
Discontinued Operations	—	289	13,701
Total	$1,454,754	$1,258,650	$1,181,496

D3. RATE AND REGULATORY MATTERS

MINNESOTA

General Rate Case—The electric utility filed a general rate case in Minnesota on October 1, 2007 requesting an interim rate increase of 5.4% effective November 30, 2007 and a final total rate increase of approximately 11%. However, the electric utility is proposing to share asset-based wholesale margins through the FCA, so the final overall customer impact would be an increase of approximately 6.7%. The electric utility's interim rate request was approved and will remain in effect for all Minnesota customers until the Minnesota Public Utilities Commission (MPUC) makes a final determination on the final request, which is expected by August 1, 2008. If the MPUC approves final rates that are lower than interim rates, the electric utility will refund Minnesota customers the difference with interest.

Capacity Expansion 2020 (CapX 2020) Mega Certificate of Need—On August 16, 2007 the eleven CapX 2020 utilities asked the MPUC to determine the need for three 345-kilovolt transmission lines. These lines would help ensure continued reliable electricity service in Minnesota and the surrounding region by upgrading and expanding the high-voltage transmission network and providing capacity for more wind energy resources to be developed in southern and western Minnesota, eastern North Dakota and South Dakota. The proposed lines would span more than 600 miles and represent one of the largest single transmission initiatives in the region in several years. The MPUC is expected to decide if the lines are needed by early 2009. The MPUC would determine routes for the new lines in separate proceedings. Portions of the lines would also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. After regulatory need is established and routing decisions are complete (expected in 2009 or 2010), construction will begin. The lines would be expected to be completed three or four years later. Great River Energy and Xcel Energy are leading the project, and Otter Tail Power Company and eight other utilities are involved in permitting, building and financing. The electric utility's 2008 - 2012 capital budgets include $67 million for CapX 2020 expenditures.

Renewable Energy Standards, Conservation and Renewable Resource Riders—In February 2007, the Minnesota legislature passed a renewable energy standard requiring the electric utility to generate or procure sufficient renewable generation such that the following percentages of total retail electric sales to Minnesota customers come from qualifying renewable sources: 12% by 2012; 17% by 2016; 20% by 2020 and 25% by 2025. Under certain circumstances and after consideration of costs and reliability issues, the MPUC may modify or delay implementation of the standards.

Under the Next Generation Energy Act passed by the Minnesota legislature in May 2007, an automatic adjustment mechanism was established to allow Minnesota electric utilities to recover charges incurred to satisfy the requirements of the renewable energy standards. The MPUC is now authorized to approve a rate schedule rider to recover the costs of qualifying renewable energy projects to supply renewable energy to Minnesota customers. Cost recovery for qualifying renewable energy projects can now be authorized outside of a rate case proceeding, provided that such renewable projects have received previous MPUC approval in an integrated resource plan or certificate of need proceeding before the MPUC. Renewable resource costs eligible for recovery may include return or investment, depreciation, operation and maintenance costs, taxes, renewable energy delivery costs and other related expenses.

The electric utility has requested approval of a renewable resource rider that would allow recovery of eligible and prudently incurred costs for its qualifying renewable energy project investments. The proposed rider would cover the Minnesota jurisdictional portion of such eligible costs. The electric utility expects to receive MPUC approval of its proposed rider in 2008.

In addition, the Minnesota Public Utilities Act provides a similar mechanism for automatic adjustment outside of a general rate proceeding to recover the costs of new electric transmission facilities. The MPUC may approve a tariff to recover the Minnesota jurisdictional costs of new transmission facilities that have been previously approved by the MPUC in a certificate of need proceeding or certified by the MPUC as a Minnesota priority transmission project. Such transmission cost recovery riders would allow a return on investments at the level approved in the utility's last general rate case. The electric utility is also preparing to file a proposed rider to recover its share of costs of transmission infrastructure upgrades projects. The electric utility currently expects to file its transmission cost recovery tariff and receive MPUC approval during 2008.

Recovery of MISO Costs—In December 2005, the MPUC issued an order denying the electric utility's request to allow recovery of certain MISO-related costs through the FCA in Minnesota retail rates and requiring a refund of amounts previously collected pursuant to an interim order issued in April 2005. The electric utility recorded a $1.9 million reduction in revenue and a refund payable in December 2005 to reflect the refund obligation. On February 9, 2006 the MPUC decided to reconsider its December 2005 order. The MPUC's final order was issued on February 24, 2006 requiring jurisdictional investor-owned utilities in the state to participate with the Minnesota Department of Commerce (MNDOC) and other parties in a proceeding that would evaluate suitability of recovery of certain MISO Day 2 energy market costs through the FCA. The February 24, 2006 order eliminated the refund provision from the December 2005 order and allowed that any MISO-related costs not recovered through the FCA may be deferred for a period of 36 months, with possible recovery through base rates in the utility's next general rate case. As a result, the electric utility recognized $1.9 million in revenue and reversed the refund payable in February 2006. The Minnesota utilities and other parties submitted a final report to the MPUC in July 2006.

In an order issued on December 20, 2006 the MPUC stated that except for schedule 16 and 17 administrative costs, discussed below, each petitioning utility may recover the charges imposed by the MISO for MISO Day 2 operations (offset by revenues from Day 2 operations via net accounting) through the calculation of the utility's FCA from the period April 1, 2005 through a period of at least three years after the date of the order. The MPUC also ordered the utilities to refund schedule 16 and 17 costs collected through the FCA since the inception of MISO Day 2 Markets in April 2005 and stated that each petitioning utility may use deferred accounting for MISO schedule 16 and 17 costs incurred since April 1, 2005. That deferred accounting may continue for ongoing schedule 16 and 17 costs, without the accumulation of interest, until the earlier of March 1, 2009 or the utility's next electric rate case. According to the order, a utility may, in its next rate case, seek to recover schedule 16 and 17 costs at an appropriate level of base rate recovery, provided it shows those costs were prudently incurred, reasonable, resulted in benefits justifying recovery and not already recovered through other rates. Also, a utility may seek to recover schedule 16 and 17 costs and associated amortizations through interim rates pending the resolution of a general rate case, subject to final MPUC approval. Pursuant to this December 20, 2006 order, the electric utility was ordered to refund $446,000 in MISO schedule 16 and 17 costs to Minnesota retail customers through the FCA over a twelve-month period beginning in January 2007. As of December 31, 2007 the electric utility had refunded $407,000 of the $446,000 and deferred $855,000 in MISO schedule 16 and 17 costs. The electric utility has also requested recovery of the deferred costs and recovery of the ongoing costs in its pending general rate case. The Residential and Small Business Utilities Division of the Office of the Attorney General (RUD-OAG) has appealed the December 20, 2006 order to the Minnesota Court of Appeals.

Minnesota Annual Automatic Adjustment Report on Energy Costs (AAA Report)—The MNDOC and the electric utility identified two operational situations which are not covered in the approved method for allocating MISO costs contained in the final December 20, 2006 MPUC order discussed above. One relates to plants not expected to be available for retail but that produce energy in certain hours, resulting in wholesale sales. The other situation is the sale of Financial Transmission Rights (FTRs) not needed for retail load. For the period July 1, 2005 through June 30, 2007 the electric utility determined its Minnesota customers' portion of costs associated with these situations to be $765,000. The data was provided to the MNDOC during the course of the MNDOC's review of the AAA Report. The electric utility offered to refund $765,000 to its Minnesota customers to settle this and other issues raised by the MNDOC in the AAA Report docket before the MPUC and the MNDOC accepted the offer in October 2007 and recommended that the MPUC include the refund in its final order. The electric utility also agreed to modifications to the MISO Day 2 cost allocations that were resolved in the MPUC's December 20, 2006 order. The electric utility agreed to make some of those modifications retroactive back to January 1, 2007. The MPUC accepted the electric utility's refund offer and modifications and closed this docket on February 6, 2008. In December 2007, the electric utility recorded a liability and a reduction to revenue of $805,000 for the amount of the refund offer and similar revenues collected subsequent to June 30, 2007.

Claims of Improper Regulatory Filings—In September 2004, the Company provided a letter to the MPUC summarizing issues and conclusions of an internal investigation completed by the Company related to claims of allegedly improper regulatory filings brought to the attention of the Company by certain individuals. On November 30, 2004 the electric utility filed a report with the MPUC responding to these claims. In 2005, the Energy Division of the MNDOC, the RUD-OAG and the claimants filed comments in response to the report, to which the electric utility filed reply comments. A hearing before the MPUC was held on February 28, 2006. As a result of the hearing, the electric utility agreed that within 90 days it would file a revised Regulatory Compliance Plan, an updated Corporate Cost Allocation Manual and documentation of the definitions of its chart of accounts. The electric utility filed these documents with the MPUC in the second quarter of 2006. The electric utility received comments on its filings from the MNDOC and the claimants and filed reply comments in August 2006.

The MNDOC recommended accepting the revised Regulatory Compliance Plan and the chart of accounts definition. The electric utility filed supplemental comments related to its Corporate Allocation Manual in November 2006. The electric utility also agreed to file a general rate case in Minnesota on or before October 1, 2007. At a MPUC hearing on January 25, 2007 all remaining open issues were resolved. The MPUC accepted the electric utility's compliance filing with minor changes, agreed to allow the electric utility to calculate corporate cost allocations as proposed, determined not to conduct any further review at this time and required the electric utility to include all of the Company's short-term debt in its calculations of allowance for funds used during construction. The electric utility agreed to provide the MPUC the results of the current FERC operational audit when available, compare the corporate allocation method to a commonly accepted methodology in the next rate case, and provide the results of the Company's investigation relating to a 2007 hotline complaint. The Company recorded a noncash charge to Other Income and Deductions of $3.3 million in 2006 related to the disallowance of a portion of capitalized costs of funds used during construction from the electric utility's rate base. On December 12, 2007 the MPUC issued its order closing the investigation subject to the Company's continuing responsibility to file the report on its FERC operational audit as soon as it becomes available and subject to any further development of the record required in the electric utility's pending general rate case.

NORTH DAKOTA

In February 2005, the electric utility filed a petition with the North Dakota Public Service Commission (NDPSC) to seek recovery of certain MISO-related costs through the FCA. The NDPSC granted interim recovery through the FCA in April 2005, but similar to the decision of the MPUC, conditioned the relief as being subject to refund until the merits of the case are determined. In August 2007, the NDPSC approved a settlement agreement between the electric utility and an intervener representing several large industrial customers in North Dakota. When the MISO Day 2 energy market began in April 2005, the characterization of some of the electric utility's energy costs changed, though the essential nature of those costs did not. Fuel and purchased energy costs incurred to serve retail customers are recoverable through the FCA in North Dakota. Under the approved settlement agreement, the electric utility will refund to North Dakota customers the schedule 16 and 17 costs collected through the FCA since April 2005. The electric utility can defer recognition of these costs and request recovery of them in its next general rate case. Purchase Power - Electric System Use expense was reduced and an offsetting regulatory asset was established for the amount of the refund. The refund amount of $493,000 was credited to North Dakota customers through the FCA beginning in October 2007. Also as part of the settlement, the electric utility agreed to file a general rate case in North Dakota between November 1 and December 31, 2008. As of December 31, 2007 the electric utility had deferred $576,000 in MISO schedule 16 and 17 costs in North Dakota pending the allowed recovery of those costs in its next rate case.

FEDERAL

Revenue Sufficiency Guarantee (RSG) Charges—On April 25, 2006 the FERC issued an order requiring MISO to refund to customers, with interest, amounts related to real-time RSG charges that were not allocated to day-ahead virtual supply offers in accordance with MISO's Transmission and Energy Markets Tariff (TEMT) going back to the commencement of MISO Day 2 markets in April 2005. On May 17, 2006 the FERC issued a Notice of Extension of Time, permitting MISO to delay compliance with the directives contained in its April 2006 order, including the requirement to refund to customers the amounts due, with interest, from April 1, 2005 and the requirement to submit a compliance filing. The Notice stated that the order on rehearing would provide the appropriate guidance regarding the timing of compliance filing. On October 26, 2006 the FERC issued an order on rehearing of the April 25, 2006 order, stating it would not require refunds related to real-time RSG charges that had not been allocated to day-ahead virtual supply offers in accordance with MISO's TEMT going back to the commencement of the MISO Day 2 market in April 2005. However, the FERC ordered prospective allocation of RSG charges to virtual transactions consistent with the TEMT to prevent future inequity and directed MISO to propose a charge that assesses RSG costs to virtual supply offers based on the RSG costs that virtual supply offers cause within 60 days of the October 26, 2006 order. On December 27, 2006 the FERC issued an order granting rehearing of the October 26, 2006 order.

On March 15, 2007 the FERC issued an order denying requests for rehearing of the RSG rehearing order dated October 27, 2006. In the March 15, 2007 order on rehearing, the FERC stated that its findings in the April 25, 2006 RSG order that virtual offers should share in the allocation of RSG costs, per the terms of the currently effective tariff, served as notice to market participants that virtual offers, for those market participants withdrawing energy, were liable for RSG charges. FERC clarified that the RSG rehearing order's waiver of refunds applies to the period before that order, from market start-up in April 2005 until April 24, 2006. After that date, virtual supply offers are liable for RSG costs and therefore, to the extent virtual supply offers were not assessed RSG costs, refunds are due for the period starting April 25, 2006.

On November 5, 2007 the FERC issued two orders related to the RSG proceeding. In the first order, the FERC accepted the MISO's April 17, 2007 RSG compliance filing to comply with the FERC's March 15, 2007 RSG order. The compliance reinserted language requiring the actual withdrawal of energy by market participants, restored the MISO's original TEMT language allocating RSG costs to virtual transactions, revised the effective date for allocation to imports, provided an explanation of its efforts to reflect partial-hour revenue determinations in its software development, and revised several definitions. The second related RSG order issued by FERC on November 5, 2007 was its order on rehearing on its April 25, 2006 order in which it rejected the MISO's proposal to remove references to virtual supply from the TEMT provisions related to calculating RSG charges (FERC Docket Nos. ER04-691-084 and ER04-691-086). In this order, the FERC denied the requests for rehearing of the RSG second rehearing order (the electric utility was one of the parties that sought rehearing) and FERC denied all requests for rehearing of the RSG compliance order.

In the RSG compliance order, the FERC rejected the MISO's proposal to allocate costs based on net virtual offers, i.e., virtual offers minus virtual bids, and clarified that the currently effective tariff, which allocates RSG costs to virtual supply offers, remains in effect. In the RSG second rehearing order, the FERC clarified that for those market participants withdrawing energy, to the extent virtual supply offers were not assessed RSG costs, refunds were due for the period starting April 25, 2006.

The electric utility recorded a $1.7 million ($1.0 million net-of-tax) charge to earnings in the first quarter of 2007 based on an internal estimate of the net impact of MISO reallocating RSG charges in response to the FERC order on rehearing. In May 2007, MISO informed affected market participants of the impact of reallocating charges based on its interpretation of the FERC order on rehearing. Based on MISO's interpretation of the order on rehearing, the electric utility estimated the reallocation of charges would not have a significant impact on earnings previously recognized by the electric utility. Accordingly, the electric utility revised its first quarter estimated charge of $1.7 million ($1.0 million net-of-tax) to zero in the second quarter of 2007. The electric utility is awaiting FERC's response to MISO's December 5, 2007 RSG compliance filing and cannot determine what financial impact, if any, the filing will have on the Company's consolidated results of operations. However, MISO has stated there will be no additional resettlements related to this matter.

Transmission Practices Audit—The Division of Operation Audits of the FERC Office of Market Oversight and Investigations (OMOI) commenced an audit of the electric utility's transmission practices in 2005. The purpose of the audit is to determine whether and how the electric utility's transmission practices are in compliance with the FERC's applicable rules and regulations and tariff requirements and whether and how the implementation of the electric utility's waivers from the requirements of Order No. 889 and Order No. 2004 restricts access to transmission information that would benefit the electric utility's off-system sales. The Division of Operation Audits of the OMOI has not issued an audit report. The Company cannot predict if the results of the audit will have any impact on the Company's consolidated financial statements.

BIG STONE II PROJECT

On June 30, 2005 the electric utility and a coalition of six other electric providers entered into several agreements for the development of a second electric generating unit, named Big Stone II, at the site of the existing Big Stone Plant near Milbank, South Dakota. The three primary agreements are the Participation Agreement, the Operation and Maintenance Agreement and the Joint Facilities Agreement. Central Minnesota Municipal Power Agency, Great River Energy, Heartland Consumers Power District, Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc., Southern Minnesota Municipal Power Agency and Western Minnesota Municipal Power Agency are parties to all three agreements. In September 2007, Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. The five remaining project participants decided to downsize the proposed plant's nominal generating capacity from 630 megawatts to between 500 and 580 megawatts. New procedural schedules have been established in the various project-related proceedings, which will take into consideration the optimal plant configuration decided on by the remaining participants. NorthWestern Corporation, one of the co-owners of the existing Big Stone Plant, is an additional party to the Joint Facilities Agreement.

The electric utility and the coalition of six other electric providers filed an application for a Certificate of Need for the Minnesota portion of the Big Stone II transmission line project on October 3, 2005 and filed an application for a Route Permit for the Minnesota portion of the Big Stone II transmission line project with the MPUC on December 9, 2005. Evidentiary hearings were conducted in December 2006 and all parties submitted legal briefs. The Administrative Law Judges (ALJs) on August 15, 2007 recommended approval of the Certificate of Need subject to potential conditions. The electric utility and project participants addressed the ALJs' recommended potential conditions in an August 31, 2007 proposed settlement agreement with the MNDOC that was entered into the record of the Certificate of Need/Route Permit dockets. The MPUC had not acted on the applications or the proposed settlement agreement when Great River Energy and Southern Minnesota Municipal Power Agency withdrew from the project. On October 19, 2007 the MPUC requested that the ALJs recommence proceedings in the matter and that the remaining project participants file testimony describing and supporting a revised Big Stone II project. The remaining five participants filed testimony on November 13, 2007. On December 3, 2007 the ALJs issued an order refining the scope of the additional proceedings. Evidentiary hearings were held on January 23-25, 2008. The electric utility anticipates the ALJs will issue their report and recommendation in March 2008 and the MPUC will decide the matters in April 2008. The electric utility's integrated resource plan (IRP) includes generation from Big Stone II beginning in 2013 to accommodate load growth and to replace expiring purchased power contracts and older coal-fired base-load generation units scheduled for retirement. In addition to approval of the Certificate of Need/Route Permit applications for the transmission line project, approval of this IRP is pending with the MPUC.

A filing in North Dakota for an advanced determination of prudence of Big Stone II was made by the electric utility in November 2006. Evidentiary hearings were held in June 2007. The NDPSC decision was delayed because of the change in ownership of the project. The administrative law judge in the matter scheduled supplemental hearings in April 2008.

The electric utility and the coalition of six other electric providers filed an Energy Conversion Facility Siting Permit Application for Big Stone II with the South Dakota Public Utilities Commission (SDPUC) on July 21, 2005. The permit was granted by the SDPUC on July 14, 2006 but was appealed by a group of interveners on the basis that carbon dioxide concerns had not been adequately addressed. In February 2007, a South Dakota circuit court judge issued an opinion affirming the decision of the SDPUC to grant the siting permit for Big Stone II. The permit was appealed to the South Dakota Supreme Court. On January 16, 2008 the South Dakota Supreme Court unanimously affirmed the SDPUC's decision to grant Big Stone II project participants a site permit. A permit application for the South Dakota portion of the transmission line for Big Stone II was filed with the SDPUC on January 16, 2006 and was approved by the SDPUC on January 2, 2007.

As of December 31, 2007 the electric utility has capitalized $8.2 million in costs related to the planned construction of Big Stone II. Should approvals of permits not be received on a timely basis, the project could be at risk. If the project is abandoned for permitting or other reasons, these capitalized costs and others incurred in future periods may be subject to expense and may not be recoverable.

04. 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, 2007	December 31, 2006
Regulatory Assets:		
Unrecognized Transition Obligation, Prior Service Costs and Actuarial Losses on Pension and Other Postretirement Benefits	$ 26,933	$ 36,736
Accrued Cost-of-Energy Revenue	19,452	10,735
Deferred Income Taxes	8,733	11,712
Reacquisition Premiums	3,745	2,694
MISO Schedule 16 and 17 Deferred Administrative Costs—MN	855	541
Deferred Marked-to-Market Losses	771	—
MISO Schedule 16 and 17 Deferred Administrative Costs—ND	576	—
Deferred Conservation Program Costs	518	1,036
Accumulated ARO Accretion/Depreciation Adjustment	345	249
Plant Acquisition Costs	107	151
Total Regulatory Assets	$ 62,035	$ 63,854
Regulatory Liabilities:		
Accumulated Reserve for Estimated Removal Costs	$ 57,787	$ 58,496
Deferred Income Taxes	4,502	5,228
Deferred Marked-to-Market Gains	271	—
Gain on Sale of Division Office Building	145	151
Total Regulatory Liabilities	$ 62,705	$ 63,875
Net Regulatory Liability Position	$ 670	$ 21

The regulatory asset related to the unrecognized transition obligation on postretirement medical benefits and prior service costs and actuarial losses on pension and other postretirement benefits represents benefit costs that will be subject to recovery through rates as they are expensed over the remaining service lives of active employees included in the plans. These unrecognized benefit costs were required to be recognized as components of Accumulated Other Comprehensive Loss in equity under SFAS No. 158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans*, adopted in December 2006, but were determined to be eligible for treatment as regulatory assets based on their probable recovery in future retail electric rates. Accrued Cost-of-Energy Revenue included in Accrued Utility and Cost-of-Energy Revenues will be recovered over the next nine months. The regulatory assets and liabilities related to Deferred Income Taxes result from changes in statutory tax rates accounted for in accordance with SFAS No. 109, *Accounting for Income Taxes.* Reacquisition Premiums included in Unamortized Debt Expense are being recovered from electric utility customers over the remaining original lives of the reacquired debt issues, the longest of which is 24.7 years. MISO Schedule 16 and 17 Deferred Administrative Costs—MN were excluded from recovery through the FCA in Minnesota in a December 2006 order issued by the MPUC. The MPUC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility's Minnesota general rate case filed on October 1, 2007. All deferred marked-to-market losses and gains are related to forward purchases of energy scheduled for delivery in January and February of 2008. MISO Schedule 16 and 17 Deferred Administrative Costs—ND were excluded from recovery through the FCA in North Dakota in an August 2007 order issued by the NDPSC. The NDPSC ordered the electric utility to refund MISO schedule 16 and 17 charges that had been recovered through the FCA since the inception of MISO Day 2 markets in April 2005, but allowed for deferral and possible recovery of those costs through rates established in the electric utility's next general rate case in North Dakota scheduled to be filed in November or December of 2008. Deferred Conservation Program Costs represent mandated conservation expenditures recoverable through retail electric rates over the next 1.5 years. Plant Acquisition Costs will be amortized over the next 2.4 years. The Accumulated Reserve for Estimated Removal Costs is reduced for actual removal costs incurred. The remaining regulatory assets and liabilities are being recovered from, or will be paid to, 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.

05. FORWARD ENERGY CONTRACTS CLASSIFIED AS DERIVATIVES

ELECTRICITY CONTRACTS

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 in entering into certain of these contracts is to settle them through the physical delivery of energy when physically possible and economically feasible. The electric utility also enters into certain contracts for trading purposes with the intent to profit from fluctuations in market prices through the timing of purchases and sales.

Electric revenues include $25,640,000 in 2007, $25,965,000 in 2006 and $46,397,000 in 2005 related to wholesale electric sales and net unrealized derivative gains on forward energy contracts and sales of financial transmission rights and daily settlements of virtual transactions in the MISO market, broken down as follows for the years ended December 31:

(in thousands)	2007	2006	2005
Wholesale Sales—Company-Owned Generation	$ 20,345	$ 23,130	$ 24,799
Revenue from Settled Contracts at Market Prices	389,643	385,978	474,882
Market Cost of Settled Contracts	(387,682)	(383,594)	(457,728)
Net Margins on Settled Contracts at Market	1,961	2,384	17,154
Marked-to-Market Gains on Settled Contracts	31,243	20,950	11,118
Marked-to-Market Losses on Settled Contracts	(28,541)	(20,702)	(9,590)
Net Marked-to-Market Gain on Settled Contracts	2,702	248	1,528
Unrealized Marked-to-Market Gains on Open Contracts	5,117	2,215	5,678
Unrealized Marked-to-Market Losses on Open Contracts	(4,485)	(2,012)	(2,762)
Net Unrealized Marked-to-Market Gain on Open Contracts	632	203	2,916
Wholesale Electric Revenue	$ 25,640	$ 25,965	$ 46,397

The following tables show the effect of marking to market forward contracts for the purchase and sale of energy on the Company's consolidated balance sheets:

(in thousands)	December 31, 2007	December 31, 2006
Current Asset—Marked-to-Market Gain	$ 5,210	$ 2,215
Regulatory Asset—Deferred Marked-to-Market Loss	771	—
Total Assets	5,981	2,215
Current Liability—Marked-to-Market Loss	(5,078)	(2,012)
Regulatory Liability—Deferred Marked-to-Market Gain	(271)	—
Total Liabilities	(5,349)	(2,012)
Net Fair Value of Marked-to-Market Energy Contracts	$ 632	$ 203

(in thousands)	Year ended December 31, 2007
Fair Value at Beginning of Year	$ 203
Amount Realized on Contracts Entered into in 2006 and Settled in 2007	(203)
Changes in Fair Value of Contracts Entered into in 2006	—
Net Fair Value of Contracts Entered into in 2006 at Year End 2007	—
Changes in Fair Value of Contracts Entered into in 2007	632
Net Fair Value at End of Year	$ 632

The $632,000 in recognized but unrealized net gains on the forward energy purchases and sales marked to market as of December 31, 2007 is expected to be realized on physical settlement or settled by an offsetting agreement with the counterparty to the original contract as scheduled over the following quarters in the amounts listed:

(in thousands)	1st Quarter 2008	4th Quarter 2008	Total
Net Gain	$ 118	$ 514	$ 632

Of the forward energy sales contracts that are marked to market as of December 31, 2007, 97.6% are offset by forward energy purchase contracts in terms of volumes and delivery periods, with $56,000 in unrealized gains recognized on the open sales contracts.

NATURAL GAS CONTRACTS

In the third quarter of 2006, IPH entered into forward natural gas swaps on the New York Mercantile Exchange (NYMEX) market to hedge its exposure to fluctuations in natural gas prices related to approximately 50% of its anticipated natural gas needs through March 2007 for its Ririe, Idaho and Center, Colorado dehydration plants. These forward contracts were derivatives subject to mark-to-market accounting but they did not qualify for hedge accounting treatment as cash flow hedges because the changes in the NYMEX prices did not correspond closely enough to changes in natural gas prices at the locations of physical delivery. Therefore, IPH included net changes in the market values of these forward contracts in net income as components of cost of goods sold in the period of recognition.

Cost of goods sold in the food ingredient processing segment includes $542,000 in losses in 2006, of which $171,000 was realized, related to IPH's forward natural gas contracts on NYMEX as a result of declining natural gas prices in 2006. The net fair value of contracts held as of December 31, 2006 was ($371,000). Of the $371,000 in unrealized marked-to-market losses on forward natural gas contracts IPH had outstanding on December 31, 2006, $62,000 was reversed and $309,000 was realized on settlement in the first quarter of 2007.

06. COMMON SHARES AND EARNINGS PER SHARE

Following is a reconciliation of the Company's common shares outstanding from December 31, 2006 through December 31, 2007:

Common Shares Outstanding, December 31, 2006	29,521,770
Issuances:	
Stock Options Exercised	298,601
Directors' Compensation:	
Restricted Shares	15,200
Unrestricted Shares	885
Vesting of Restricted Stock Units	4,522
Restricted Shares Issued for Employee Compensation	17,300
Retirements:	
Shares Withheld for Individual Income Tax Requirements	(8,409)
Restricted Shares Forfeited	(80)
Common Shares Outstanding, December 31, 2007	29,849,789

STOCK INCENTIVE PLAN

The 1999 Stock Incentive Plan, as amended (Incentive Plan), provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, performance awards, and other stock and stock-based awards. A total of 3,600,000 common shares are authorized for granting stock awards under the Incentive Plan, which terminates on December 13, 2013.

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 market price at the end of each six-month purchase period. The number of common shares authorized to be issued under the Purchase Plan is 900,000, of which 397,156 were still available for purchase as of December 31, 2007. At the discretion of the Company, shares purchased under the Purchase Plan can be either new issue shares or shares purchased in the open market. To provide shares for the Purchase Plan, 52,558 common shares were purchased in the open market in 2007, 53,258 common shares were purchased in the open market in 2006 and 69,401 common shares were purchased in the open market in 2005 The shares to be purchased by employees participating in the Purchase Plan are not considered dilutive for the purpose of calculating diluted earnings per share during the investment period.

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 2003, common shares needed for the Plan were purchased in the open market. From January through October 2004 new shares were issued for this Plan. Starting in November 2004 the Company began purchasing common shares in the open market. Through December 31, 2007, 944,507 common shares had been issued to meet the requirements of the Plan.

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 15, 1997. One Right was also issued with respect to each common share issued after February 15, 1997. The Rights expired pursuant to their terms on January 27, 2007.

EARNINGS PER SHARE

Basic earnings per common share are calculated by dividing earnings available for common shares by the weighted 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. Stock options with exercise prices greater than the market price are excluded from the calculation of diluted earnings per common share. Nonvested restricted shares granted to the Company's directors and employees are considered dilutive for the purpose of calculating diluted earnings per share but are considered contingently returnable and not outstanding for the purpose of calculating basic earnings per share. Underlying shares related to nonvested restricted stock units granted to employees are considered dilutive for the purpose of calculating diluted earnings per share. Shares expected to be awarded for stock performance awards granted to executive officers are considered dilutive for the purpose of calculating diluted earnings per share.

Excluded from the calculation of diluted earnings per share are the following outstanding stock options which had exercise prices greater than the average market price for the years ended December 31, 2007, 2006 and 2005:

Year	Options Outstanding	Range of Exercise Prices
2007	—	NA
2006	210,250	$29.74—$31.34
2005	237,624	$28.66—$31.34

□ 7. SHARE-BASED PAYMENTS

On January 1, 2006 the Company adopted the accounting provisions of SFAS No. 123(R) (revised 2004), *Share-Based Payment*, on a modified prospective basis. SFAS No. 123(R) is a revision of SFAS No. 123, *Accounting for Stock-based Compensation*, and supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employees*. Under SFAS No. 123(R), the Company records stock-based compensation as an expense on its income statement over the period earned based on the estimated fair value of the stock or options awarded on their grant date. The Company elected the modified prospective method of adopting SFAS No. 123(R), under which prior periods are not retroactively revised. The valuation provisions of SFAS No. 123(R) apply to awards granted after the effective date. Estimated stock-based compensation expense for awards granted prior to the effective date but that remain nonvested on the effective date will be recognized over the remaining service period using the compensation cost estimated for the SFAS No. 123 pro forma disclosures. Additionally, the adoption of SFAS No. 123(R) resulted in the reclassification of $798,000 in credits related to outstanding restricted share-based compensation from equity on the Company's consolidated balance sheet to a liability on January 1, 2006 because of income tax withholding provisions in the share-based award agreements. The adoption of SFAS 123(R) also resulted in the elimination of Unearned Compensation from the equity section of the Company's consolidated balance sheet on January 1, 2006 by netting the account balance of $1,720,000 against Premium on Common Shares.

As of December 31, 2007 the total remaining unrecognized amount of compensation expense related to stock-based compensation was approximately $4.6 million (before income taxes), which will be amortized over a weighted-average period of 2.3 years.

The Company has six share-based payment programs. The effect of SFAS No. 123(R) accounting on each of these programs is explained in the following paragraphs.

PURCHASE PLAN

The Purchase Plan allows employees through payroll withholding to purchase shares of the Company's common stock at a 15% discount from the average market price on the last day of a six month investment period. Under SFAS 123(R), the Company is required to record compensation expense related to the 15% discount which was not required under APB No. 25. The 15% discount resulted in compensation expense of $257,000 in 2007 and $235,000 in 2006. The 15% discount is not taxable to the employee and is not a deductible expense for tax purposes for the Company.

STOCK OPTIONS GRANTED UNDER THE INCENTIVE PLAN

Since the inception of the Incentive Plan in 1999, the Company has granted 2,041,500 options for the purchase of the Company's common stock. All of the options granted had vested or were forfeited as of December 31, 2007. The exercise price of the options granted was the average market price of the Company's common stock on the grant date. These options were not compensatory under APB No. 25 accounting rules. Under SFAS No. 123(R) accounting, compensation expense is recorded based on the estimated fair value of the options on their grant date using a fair-value option pricing model. Under SFAS No. 123(R) accounting, the fair value of the options granted has been recorded as compensation expense over the requisite service period (the vesting period of the options). The estimated fair value of all options granted under the Incentive Plan has been based on the Black-Scholes option pricing model.

Under the modified prospective application of SFAS No. 123(R) accounting requirements, the difference between the intrinsic value of nonvested options and the fair value of those options of $362,000 on January 1, 2006 was recognized on a straight-line basis as compensation expense over the remaining 16 months of the options vesting period. Accordingly, the Company recorded compensation expense of $91,000 in 2007 and $271,000 in 2006 related to options that were not vested as of January 1, 2006.

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 2005 would have decreased as presented in the table below:

(in thousands, except per share amounts)	2005
Net Income	
As Reported	$ 62,551
Total Stock-Based Employee Compensation Expense Determined Under Fair Value-Based Method for All Awards Net of Related Tax Effects	(640)
Pro Forma	$ 61,911
Basic Earnings Per Share	
As Reported	$ 2.12
Pro Forma	$ 2.09
Diluted Earnings Per Share	
As Reported	$ 2.11
Pro Forma	$ 2.08

Presented below is a summary of the stock options activity:

Stock Option Activity	2007		2006		2005	
	Options	Average Exercise Price	Options	Average Exercise Price	Options	Average Exercise Price
Outstanding, Beginning of Year	1,091,238	$ 25.74	1,237,164	$ 25.58	1,508,277	$ 25.35
Granted	—	—	—	—	74,900	24.93
Exercised	298,601	25.73	107,458	22.88	257,948	22.90
Forfeited	5,500	28.85	38,468	28.60	88,065	28.79
Outstanding, End of Year	787,137	25.73	1,091,238	25.74	1,237,164	25.58
Exercisable, End of Year	787,137	25.73	1,049,713	25.69	1,095,272	25.16
Cash Received for Options Exercised	$ 7,682,000		$ 2,458,000		$ 5,911,000	
Fair Value of Options Granted During Year	none granted		none granted		$ 4.76	

The fair values of the options granted in 2005 were estimated using the Black-Scholes option-pricing model under the following assumptions:

	2005
Risk-Free Interest Rate	4.3%
Expected Lives	7 years
Expected Volatility	25.4%
Dividend Yield	4.4%

The following table summarizes information about options outstanding as of December 31, 2007:

Options Outstanding and Exercisable			
Range of Exercise Prices	Outstanding and Exercisable as of 12/31/07	Weighted-Average Remaining Contractual Life (yrs)	Weighted-Average Exercise Price
\$18.80–\$21.94	175,210	2.0	\$ 19.62
\$21.95–\$25.07	40,100	7.3	\$ 24.93
\$25.08–\$28.21	429,927	4.0	\$ 26.50
\$28.22–\$31.34	141,900	4.2	\$ 31.17

RESTRICTED STOCK GRANTED TO DIRECTORS

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to members of the Company's Board of Directors as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the four-year vesting period of the restricted shares based on the market value of the Company's common stock on the grant date. Under the modified prospective application of SFAS No. 123(R) accounting requirements, compensation expense related to nonvested restricted shares outstanding will be recorded based on the estimated fair value of the restricted shares on their grant dates. On April 9, 2007 the Compensation Committee of the Company's Board of Directors granted 15,200 shares of restricted stock to the Company's nonemployee directors under the Incentive Plan.

Presented below is a summary of the status of directors' restricted stock awards for the years ended December 31:

Directors' Restricted Stock Awards	2007		2006		2005	
	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value	Shares	Weighted Average Grant-Date Fair Value
Nonvested, Beginning of Year	32,775	\$ 27.27	27,000	\$ 26.32	22,600	\$ 27.61
Granted	15,200	\$ 35.04	19,800	\$ 28.24	11,700	\$ 24.93
Vested	13,875	\$ 27.10	14,025	\$ 26.82	7,300	\$ 28.09
Forfeited	—		—		—	
Nonvested, End of Year	34,100	\$ 30.80	32,775	\$ 27.27	27,000	\$ 26.32
Compensation Expense Recognized		\$ 454,000		\$ 401,000		\$ 261,000
Fair Value of Shares Vested in Year		\$ 376,000		\$ 376,000		\$ 205,000

RESTRICTED STOCK GRANTED TO EMPLOYEES

Under the Incentive Plan, restricted shares of the Company's common stock have been granted to employees as a form of compensation. Under APB No. 25 accounting rules, the Company had recognized compensation expense for these restricted stock grants, ratably, over the vesting periods of the restricted shares based on the market value of the Company's common stock on the grant date. Because of income tax withholding provisions in the restricted stock award agreements related to restricted stock granted to employees prior to 2006, the value of these grants is considered variable, which, under SFAS No. 123(R), will require the offsetting credit to compensation expense to be recorded as a liability. Under the modified prospective application of SFAS No. 123(R) accounting requirements and accounting rules for variable awards, compensation expense related to nonvested restricted shares granted to employees will be recorded based on the estimated fair value of the restricted shares on their grant dates and adjusted for the estimated fair value of any nonvested restricted shares on each subsequent reporting date. The reporting date fair value of nonvested restricted shares granted prior to 2006 under this program is based on the average market value of the Company's common stock on the reporting date—\$34.575 on December 31, 2007.

In 2006, under SFAS No. 123(R), the amount of compensation expense recorded related to nonvested restricted shares granted to employees was based on the estimated fair value of the restricted stock grants. In 2005, under APB No. 25, the amount of compensation expense recorded related to nonvested restricted shares granted to employees was based on the intrinsic value of the restricted stock grants. The equity account, Unearned Compensation, was credited when compensation expense was recorded related to these shares under APB No. 25 accounting. Under SFAS 123(R) accounting, a current liability account is credited when compensation expense is recorded. Accumulated liabilities related to nonvested restricted shares issued to employees under this program prior to 2006 will be reversed and credited to the Premium on Common Shares equity account as the shares vest.

In 2006, the income tax withholding provisions in the Company's restricted stock award agreements were revised to only allow withholding at statutory withholding rates. The fair value of restricted shares issued under the revised restricted stock award agreements is not considered a liability under SFAS No. 123(R), so compensation expense related to awards granted after 2005 will be based on their grant-date fair value and recognized over the vesting period of the awards with the offsetting credit charged directly to equity. On April 9, 2007 the Compensation Committee of the Company's Board of Directors granted 600 shares of restricted stock to a newly hired employee under the Incentive Plan. The restricted shares vest 50% on issuance and 50% on April 8, 2008 and are eligible for full dividend and voting rights. The grant-date fair value of the restricted shares was \$35.30 per share, the average market price of the shares on their grant date. On October 29, 2007 the Compensation Committee of the Company's Board of Directors granted 16,700 shares of restricted stock to the Company's executive officers under the Incentive Plan. The restricted shares vest 25% per year on April 8 of each year in the period 2008 through 2011 and are eligible for full dividend and voting rights. The grant-date fair value of the restricted shares was \$35.84 per share, the average market price of the shares on their grant date.

Presented below is a summary of the status of employees' restricted stock awards for the years ended December 31:

Employees' Restricted Stock Awards	2007 Shares	2007 Weighted Average Fair Value	2006 Shares	2006 Weighted Average Fair Value	2005 Shares	2005 Weighted Average Fair Value
Nonvested, Beginning of Year	31,666	$ 31.47	72,974	$ 28.91	103,340	$ 25.31
Granted	17,300	$ 35.82	—		9,000	$ 26.31
Variable/Liability Awards Vested	24,608	$ 35.09	41,308	$ 28.98	39,126	$ 25.08
Nonvariable Awards Vested	300	$ 35.30	—		—	
Forfeited	—		—		240	$ 26.68
Nonvested, End of Year	24,058	$ 35.46	31,666	$ 31.47	72,974	$ 28.91
Compensation Expense Recognized		$ 549,000		$ 815,000		$ 1,118,000
Fair Value of Variable Awards Vested/Liability Paid		$ 863,000		$ 1,197,000		$ 981,000
Fair Value of Nonvariable Awards Vested		$ 11,000		—		—

RESTRICTED STOCK UNITS GRANTED TO EMPLOYEES

On April 9, 2007 the Compensation Committee of the Company's Board of Directors granted 23,450 restricted stock units to key employees under the Incentive Plan payable in common shares on April 8, 2011, the date the units vest. The Company uses a Monte Carlo valuation method to determine the grant-date fair value of restricted stock units. The grant-date fair value of each restricted stock unit granted on April 9, 2007 was $30.07 per share. The weighted average contractual term of stock units outstanding as of December 31, 2007 is 2.8 years.

Presented below is a summary of the status of employees' restricted stock unit awards for the years ended December 31:

	2007 Restricted Stock Units	2007 Weighted-Average Grant-Date Fair Value	2006 Restricted Stock Units	2006 Weighted-Average Grant-Date Fair Value
Nonvested, Beginning of Year	38,615	$ 24.65	—	$ —
Granted	23,450	$ 30.07	47,425	$ 25.41
Converted	4,850	$ 26.95	7,450	$ 29.55
Forfeited	1,735	$ 27.03	1,360	$ 24.36
Nonvested, End of Year	55,480	$ 26.66	38,615	$ 24.65
Compensation Expense Recognized		$ 383,000		$ 427,000
Fair Value of Units Converted in Year		$ 131,000		$ 220,000

STOCK PERFORMANCE AWARDS GRANTED TO EXECUTIVE OFFICERS

The Compensation Committee of the Company's Board of Directors has approved stock performance award agreements under the Incentive Plan for the Company's executive officers. Under these agreements, the officers could be awarded shares of the Company's common stock based on the Company's total shareholder return relative to that of its peer group of companies in the Edison Electric Institute (EEI) Index over a three-year period beginning on January 1 of the year the awards are granted. The number of shares earned, if any, will be awarded and issued at the end of each three-year performance measurement period. The participants have no voting or dividend rights under these award agreements until the shares are issued at the end of the performance measurement period. Under APB No. 25 accounting, these awards were valued based on the average market price of the underlying shares of the Company's common stock on the award grant date, multiplied by the estimated probable number of shares to be awarded at the end of the performance measurement period with compensation expenses recorded ratably over the related three-year measurement period. Compensation expense recognized was adjusted at each reporting date subsequent to the grant date of the awards for the difference between the market value of the underlying shares on their grant date and the market value of the underlying shares on the reporting date. Under the modified prospective application of SFAS No. 123(R) accounting requirements, the amount of compensation expense that will be recorded subsequent to January 1, 2006 related to awards granted in 2004 and 2005 and outstanding on December 31, 2006 is based on the estimated grant-date fair value of the awards as determined under the Black-Scholes option pricing model.

On October 29, 2007 the Compensation Committee of the Company's Board of Directors granted performance share awards to the Company's executive officers under the Incentive Plan. Under these awards, the Company's executive officers could earn up to an aggregate of 109,000 common shares based on the Company's total shareholder return relative to the total shareholder return of the companies that comprise the EEI Index over the performance period of January 1, 2007 through December 31, 2009. The aggregate target share award is 54,500 shares. Actual payment may range from zero to 200 percent of the target amount. The executive officers have no voting or dividend rights related to these shares until the shares, if any, are issued at the end of the performance period. In accordance with SFAS No. 123(R), the Company will estimate the fair value of the common shares projected to be awarded on the date of grant under a Monte Carlo valuation method and record compensation expense over the remaining performance period.

The offsetting credit to amounts expensed related to the stock performance awards is included in common shareholders' equity. The table below provides a summary of amounts expensed for the stock performance awards:

Performance Period	Maximum Shares Subject To Award	Shares Used To Estimate Expense	Fair Value	Expense Recognized in the Year Ended December 31, 2007	2006	2005	Shares Awarded
2007–2009	109,000	67,263	$ 38.01	$ 852,000	$ —	$ —	
2006–2008	88,050	58,700	$ 25.95	508,000	508,000	—	
2005–2007	75,150	50,872	$ 22.10	375,000	375,000	490,000	62,625
2004–2006	70,500	23,500	$ 23.90	—	187,000	453,000	23,500
Total				$ 1,735,000	$ 1,070,000	$ 943,000	86,125

08. 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, 2007.

09. COMMITMENTS AND CONTINGENCIES

At December 31, 2007 the electric utility had commitments under contracts in connection with construction programs aggregating approximately $35,835,000. For capacity and energy requirements, the electric utility has agreements extending through 2032 at annual costs of approximately $23,111,000 in 2008, $22,929,000 in 2009, $11,377,000 in 2010, $5,565,000 in 2011 and $5,565,000 in 2012, and $93,286,000 for the years beyond 2012.

The electric utility has contracts providing for the purchase and delivery of a significant portion of its current coal requirements. These contracts expire in 2010 and 2016. In total, the electric utility is committed to the minimum purchase of approximately $183,209,000 or to make payments in lieu thereof, under these contracts. The FCA mechanism lessens the risk of loss from market price changes because it provides for recovery of most fuel costs.

IPH has commitments of approximately $7,200,000 for the purchase of a portion of its 2008 raw potato supply requirements.

The amounts of future operating lease payments are as follows:

(in thousands)	Electric	Nonelectric	Total
2008	$ 2,560	$ 40,722	$ 43,282
2009	2,560	37,504	40,064
2010	2,203	26,812	29,015
2011	1,446	14,008	15,454
2012	951	2,669	3,620
Later Years	3,206	3,603	6,809
Total	$ 12,926	$ 125,318	$ 138,244

The electric future operating lease payments are primarily related to coal rail-car leases. The nonelectric future operating lease payments are primarily related to medical imaging equipment. Rent expense from continuing operations was $47,904,000, $44,254,000 and $37,798,000 for 2007, 2006 and 2005, respectively.

The Company is a party to litigation arising in the normal course of business. The Company regularly analyzes current information and, as necessary, provides accruals for liabilities that are probable of occurring and that can be reasonably estimated. The Company believes the effect on its consolidated results of operations, financial position and cash flows, if any, for the disposition of all matters pending as of December 31, 2007 will not be material.

10. SHORT-TERM AND LONG-TERM BORROWINGS

SHORT-TERM DEBT

As of December 31, 2007 the Company had $95.0 million in short-term debt outstanding at a weighted average interest rate of 6.3%. As of December 31, 2006 the Company had $38.9 million in short-term debt outstanding at a weighted average interest rate of 5.7%. The average interest rate paid on short-term debt was 6.0% in 2007 and 5.8% in 2006.

The Company's $150 million line of credit pursuant to a Credit Agreement dated as of April 26, 2006 with U.S. Bank National Association, JPMorgan Chase Bank, N.A., Wells Fargo Bank, National Association, Harris Nesbitt Financing, Inc., Keybank National Association, Union Bank of California, N.A., Bank of America, N.A., Bank Hapoalim B.M., and Bank of the West was scheduled to expire on April 26, 2009 but was terminated and replaced by a new $200 million credit agreement (the Varistar Credit Agreement) entered into by Varistar Corporation (Varistar), a wholly-owned subsidiary of the Company, on October 2, 2007. Varistar entered into the Varistar Credit Agreement with the following banks: U.S. Bank National Association, as agent for the Banks and as Lead Arranger, Bank of America, N.A., Keybank National Association, and Wells Fargo Bank, National Association, as Co-Documentation Agents, and JPMorgan Chase Bank, N.A., Bank of the West and Union Bank of California, N.A. The Varistar Credit Agreement is an unsecured revolving credit facility that Varistar can draw on to support its operations. The Varistar Credit Agreement expires on October 2, 2010. Borrowings under the line of credit bear interest at LIBOR plus 1.25%, subject to adjustment based on Varistar's adjusted cash flow leverage ratio (as defined in the Varistar Credit Agreement). The Varistar Credit Agreement contains a number of restrictions on the businesses of Varistar and its material subsidiaries, including restrictions on their ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party and engage in transactions with related parties. The Varistar Credit Agreement does not include provisions for the termination of the agreement or the acceleration of repayment of amounts outstanding due to changes in the Company's credit ratings. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. Outstanding letters of credit issued by Varistar can reduce the amount available for borrowing under the line by up to $30 million. As of December 31, 2007, $95.0 million of the $200 million line of credit was in use and $14.9 million was restricted from use to cover outstanding letters of credit.

Otter Tail Corporation, dba Otter Tail Power Company and U.S. Bank National Association have a Credit Agreement (the Electric Utility Credit Agreement) providing for a separate $75 million line of credit. This line of credit is an unsecured revolving credit facility that the electric utility can draw on to support the working capital needs and other capital requirements of its electric operations. Borrowings under this line of credit bear interest at LIBOR plus 0.4%, subject to adjustment based on the ratings of the Company's senior unsecured debt. The Electric Utility Credit Agreement contains a number of restrictions on the business of the electric utility, including restrictions on its ability to merge, sell assets, incur indebtedness, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties. The Electric Utility Credit Agreement is subject to renewal on September 1, 2008. As of December 31, 2007 no money was borrowed under the Electric Utility Credit Agreement.

LONG-TERM DEBT

The Company has the ability to issue up to $256 million of common shares, cumulative preferred shares, debt and certain other securities from time to time under its universal shelf registration statement filed with the Securities and Exchange Commission on June 4, 2004 and declared effective on August 30, 2004. The Company issued no long-term debt under its universal shelf registration in 2007 or 2006.

At closings completed in August 2007 and October 2007, the Company issued $155 million aggregate principal amount of its senior unsecured notes, in a private placement transaction, to the purchasers named in a note purchase agreement (the 2007 Note Purchase Agreement) dated August 20, 2007. These notes were issued in four series: $33 million aggregate principal amount of 5.95% Senior Unsecured Notes, Series A, due 2017 (the Series A Notes); $30 million aggregate principal amount of 6.15% Senior Unsecured Notes, Series B, due 2022 (the Series B Notes); $42 million aggregate principal amount of 6.37% Senior Unsecured Notes, Series C, due 2027 (the Series C Notes); and $50 million aggregate principal amount of 6.47% Senior Unsecured Notes, Series D, due 2037 (the Series D Notes). On August 20, 2007, $12 million aggregate principal amount of the Series C Notes and $13 million aggregate principal amount of the Series D Notes were issued and sold pursuant to the 2007 Note Purchase Agreement. The net proceeds from this initial closing were used to repay borrowings under the Company's $150 million line of credit that was terminated on October 2, 2007. The remaining $30 million aggregate principal amount of the Series C Notes and $37 million aggregate principal amount of the Series D Notes, as well as the Series A Notes and the Series B Notes, were issued and sold by the Company at a second closing on October 1, 2007. The net proceeds from the second closing were used to retire $40 million aggregate principal amount of the Company's 5.625% Series of Insured Senior Notes due October 1, 2017 and $25 million aggregate principal amount of the Company's 6.80% Series of Senior Notes due October 1, 2032 on October 15, 2007, to pay down lines of credit and to fund capital expenditures.

In February 2007 the Company entered into a note purchase agreement (the Cascade Note Purchase Agreement) with Cascade Investment L.L.C. (Cascade) pursuant to which the Company agreed to issue to Cascade, in a private placement transaction, $50 million aggregate principal amount of the Company's senior notes due November 30, 2017 (the Cascade Note). On December 14, 2007 the Company issued the Cascade Note. The Cascade Note bears interest at a rate of 5.778% per annum. The terms of the Cascade Note Purchase Agreement are substantially similar to the terms of the note purchase agreement entered into in connection with the issuance of the Company's $90 million 6.63% senior notes due December 1, 2011 (the 2001 Note Purchase Agreement). The proceeds of this financing were used to redeem the Company's $50 million 6.375% Senior Debentures due December 1, 2007. Cascade owned approximately 8.6% of the Company's outstanding common stock as of December 31, 2007.

Each of the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement, and the 2001 Note Purchase Agreement states the Company may prepay all or any part of the notes issued thereunder (in an amount not less than 10% of the aggregate principal amount of the notes then outstanding in the case of a partial prepayment) at 100% of the principal amount prepaid, together with accrued interest and a make-whole amount. Each of the Cascade Note Purchase Agreement and the 2001 Note Purchase Agreement states in the event of a transfer of utility assets put event, the noteholders thereunder have the right to require the Company to repurchase the notes held by them in full, together with accrued interest and a make-whole amount, on the terms and conditions specified in the respective note purchase agreements. The 2007 Note Purchase Agreement states the Company must offer to prepay all of the outstanding notes issued thereunder at 100% of the principal amount together with unpaid accrued interest in the event of a change of control of the Company.

The 2001 Note Purchase Agreement, the 2007 Note Purchase Agreement and the Cascade Note Purchase Agreement contain a number of restrictions on the businesses of the Company and its subsidiaries. In each case these include restrictions on the ability of the Company and certain of its subsidiaries to merge, sell assets, create or incur liens on assets, guarantee the obligations of any other party, and engage in transactions with related parties.

The Company's obligations under the 2001 Note Purchase Agreement and the Cascade Note Purchase Agreement are guaranteed by certain of its subsidiaries. Varistar's obligations under the Varistar Credit Agreement are guaranteed by each of its material subsidiaries. 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 aggregate amounts of maturities on bonds outstanding and other long-term obligations at December 31, 2007 for each of the next five years are $3,004,000 for 2008, $2,915,000 for 2009, $2,606,000 for 2010, $90,087,000 for 2011 and $10,463,000 for 2012.

FINANCIAL COVENANTS

The Electric Utility Credit Agreement, the 2001 Note Purchase Agreement, the Cascade Note Purchase Agreement, the 2007 Note Purchase Agreement and the Lombard US Equipment Finance note contain covenants by the Company not to permit its debt-to-total capitalization ratio to exceed 60% or permit its interest and dividend coverage ratio (or in the case of the Cascade Note Purchase Agreement, the Company's interest coverage ratio) to be less than 1.5 to 1. The note purchase agreements further restrict the Company from allowing its priority debt to exceed 20% of total capitalization. Financial covenants in the Varistar Credit Agreement require Varistar to maintain a fixed charge coverage ratio of not less than 1.25 to 1 and to not permit its cash flow leverage ratio to exceed 3.0 to 1. The Company and Varistar were in compliance with all of the covenants under their financing agreements as of December 31, 2007.

11. CLASS B STOCK OPTIONS OF SUBSIDIARY

CLASS B STOCK OPTIONS OF SUBSIDIARY

In connection with the acquisition of IPH in August 2004, IPH management and certain other employees elected to retain stock options for the purchase of 1,112 IPH Class B common shares valued at $1.8 million. The options are exercisable at any time and the option holder must deliver cash to exercise the option. Once the options are exercised for Class B shares, the Class B shareholder cannot put the shares back to the Company for 181 days. At that time, the Class B common shares are redeemable at any time during the employment of the individual holder, subject to certain limits on the total number of Class B common shares redeemable on an annual basis. The Class B common shares are nonvoting, except in the event of a merger, and do not participate in dividends but have liquidation rights at par with the Class A common shares owned by the Company. The value of the Class B common shares issued on exercise of the options represents an interest in IPH that changes as defined in the agreement. In 2005, options for 357 IPH Class B common shares were exercised and the Class B common shares were redeemed by IPH 181 days after issuance. In 2006, two of the retained stock options were forfeited.

In 2006, IPH granted 305 additional options to purchase IPH Class B Common Stock to five employees at an exercise price of $2,085.88 per option. The options vested immediately on issuance. On the date the options were granted, the value of a share of IPH Class B common stock was estimated to be $1,041.71. Therefore, the grant-date fair value of the options was $0 and no expense or liability was recorded related to these options under SFAS No. 123(R). In 2007, 125 options that were granted in 2006 were forfeited as a result of voluntary terminations. As of December 31, 2007 there were 933 options outstanding with a combined exercise price of $691,000, of which 753 options were "in-the-money" with a combined exercise price of $316,000.

12. PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The following footnote reflects the adoption of SFAS No. 158, *Accounting for Defined Benefit Pension and Other Postretirement Plans*, in December 2006. The Company determined that the balance of unrecognized net actuarial losses, prior service costs and the SFAS No. 106 transition obligation related to regulated utility activities would be subject to recovery through rates as those balances are amortized to expense and the related benefits are earned. Therefore, the Company charged those unrecognized amounts to regulatory asset accounts under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, rather than to Accumulated Other Comprehensive Losses in equity as prescribed by SFAS No. 158.

Effective July 1, 2005 the Company remeasured its pension and other postretirement benefit plan obligations using the RP-2000 Combined Healthy Mortality table in place of the 1983 Group Annuity Mortality table (GAM '83) it used to measure its obligations and determine its annual costs under these plans in January 2005. The reason for the remeasurement was to update the mortality table to more accurately reflect current life expectancies of current employees and retirees included in the plans. Generally accepted accounting principles require that all assumptions used to measure plan obligations and determine annual plan costs be revised as of a remeasurement date. The following actuarial assumptions were updated as of the July 1, 2005 remeasurement date:

Key Assumptions and Data	January 1, 2005 through June 30, 2005	July 1, 2005 through December 31, 2005
Discount Rate	6.00%	5.25%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%
Social Security Wage Base	4.00%	3.50%
Rate of Inflation	3.00%	2.50%
Rate of Withdrawal	1% per year through age 54	2% per year through age 54
Mortality Table	GAM '83	RP-2000 projected to 2006
Market Value of Assets—Beginning of Period	$141,685,000	$142,547,832

Remeasuring the Company's pension and other postretirement benefit plan obligations as of July 1, 2005 under the revised assumptions had the effect of increasing the Company's 2005 projected pension plan costs by $1,364,000, increasing its 2005 projected Executive Survivor and Supplemental Retirement Plan costs by $123,000 and increasing its 2005 projected costs for postretirement benefits other than pensions by $137,000.

PENSION PLAN

The Company's noncontributory funded pension plan covers substantially all electric utility and corporate employees hired prior to January 1, 2006. 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 assists the Company in performing 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.

Components of net periodic pension benefit cost:

(in thousands)	2007	2006	2005
Service Cost—Benefit Earned During the Period	$ 4,837	$ 5,057	$ 4,695
Interest Cost on Projected Benefit Obligation	10,790	10,435	9,721
Expected Return on Assets	(12,948)	(12,288)	(12,071)
Amortization of Prior-Service Cost	742	742	726
Amortization of Net Actuarial Loss	1,091	1,844	1,364
Net Periodic Pension Cost	$ 4,512	$ 5,790	$ 4,435

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2007	2006
Regulatory Assets:		
Unrecognized Prior Service Cost	$ (4,018)	$ (4,748)
Unrecognized Actuarial Loss	(17,115)	(21,771)
Total Regulatory Assets	(21,133)	(26,519)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	(120)	(132)
Unrecognized Actuarial Loss	(511)	(606)
Total Accumulated Other Comprehensive Loss	(631)	(738)
Prepaid Pension Cost	7,493	8,005
Net Amount Recognized—Noncurrent Liability	$ (14,271)	$ (19,252)

Funded status as of December 31:

(in thousands)	2007	2006
Accumulated Benefit Obligation	$ (154,373)	$(153,816)
Projected Benefit Obligation	$ (185,206)	$(186,760)
Fair Value of Plan Assets	170,935	167,508
Funded Status	$ (14,271)	$ (19,252)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's benefit obligations and prepaid pension cost over the two-year period ended December 31, 2007:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ 167,508	$ 146,982
Actual Return on Plan Assets	8,013	24,856
Discretionary Company Contributions	4,000	4,000
Benefit Payments	(8,586)	(8,330)
Fair Value of Plan Assets at December 31	$ 170,935	$ 167,508
Estimated Asset Return	4.85%	17.24%
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 186,760	$ 181,587
Service Cost	4,837	5,057
Interest Cost	10,790	10,435
Benefit Payments	(8,586)	(8,330)
Actuarial Gain	(8,595)	(1,989)
Projected Benefit Obligation at December 31	$ 185,206	$ 186,760
Reconciliation of Prepaid Pension Cost:		
Prepaid Pension Cost at January 1	$ 8,005	$ 9,795
Net Periodic Pension Cost	(4,512)	(5,790)
Discretionary Company Contributions	4,000	4,000
Prepaid Pension Cost at December 31	$ 7,493	$ 8,005

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

	2007	2006
Discount Rate	6.25%	6.00%
Rate of Increase in Future Compensation Level	3.75%	3.75%

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

	2007	2006
Discount Rate	6.00%	5.75%
Long-Term Rate of Return on Plan Assets	8.50%	8.50%
Rate of Increase in Future Compensation Level	3.75%	3.75%

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.

Market-related value of plan assets—The Company's expected return on plan assets is determined based on the expected long-term rate of return on plan assets and the market-related value of plan assets.

The Company bases actuarial determination of pension plan expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation calculation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the fair value of assets. Since the market-related valuation calculation recognizes gain or losses over a five-year period, the future value of the market-related assets will be impacted as previously deferred gains or losses are recognized.

The assumed rate of return on pension fund assets for the determination of 2008 net periodic pension cost is 8.50%.

Measurement Dates:	2007	2006
Net Periodic Pension Cost	January 1, 2007	January 1, 2006
End of Year Benefit Obligations	January 1, 2007 projected to December 31, 2007	January 1, 2006 projected to December 31, 2006
Market Value of Assets	December 31, 2007	December 31, 2006

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost in 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 720
Amortization of Unrecognized Actuarial Loss	103
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	22
Amortization of Unrecognized Actuarial Loss	3
Total Estimated Amortization	$ 848

Cash flows—The Company is not required to make a contribution to the pension plan in 2008.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid out from plan assets:

(in thousands)		Years			
2008	2009	2010	2011	2012	2013-2017
$ 8,917	$ 9,073	$ 9,234	$ 9,641	$ 10,103	$ 59,365

The Company's pension plan asset allocations at December 31, 2007 and 2006, by asset category are as follows:

Asset Allocation	2007	2006
Large Capitalization Equity Securities	47.1%	49.3%
Small Capitalization Equity Securities	10.7%	11.6%
International Equity Securities	10.4%	10.6%
Total Equity Securities	68.2%	71.5%
Cash and Fixed-Income Securities	31.8%	28.5%
	100.0%	100.0%

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

- The Plan is managed to operate in perpetuity.
- The Plan will meet the pension benefit obligation payments of the Company.
- 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 while considering a prudent level of risk and diversification.

The asset allocation strategy developed by the Company's Retirement Plans Administrative 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 that follows 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 Retirement Plans Administrative Committee and/or investment managers, and required cash flows to and from the Plan. The tactical range provides flexibility for the investment managers' portfolios to vary around the target allocation without the need for immediate rebalancing.

The Company's Retirement Plans Administrative Committee monitors actual asset allocations and directs contributions and withdrawals toward maintaining the targeted allocation percentages listed in the table below.

Asset Allocation	Strategic Target	Tactical Range
Large Capitalization 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%

EXECUTIVE SURVIVOR AND SUPPLEMENTAL RETIREMENT PLAN (ESSRP)

The ESSRP is an unfunded, nonqualified benefit plan for executive officers and certain key management employees. The ESSRP provides defined benefit payments to these employees on their retirements for life or to their beneficiaries on their deaths 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.

On January 31, 2005 the Board of Directors of the Company amended and restated the ESSRP to reduce future benefits effective January 1, 2005, which resulted in reduced expense to the Company. Effective January 1, 2005 new participants in the ESSRP accrue benefits under a new formula. The new formula is the same as the formula used under the Company's qualified defined benefit pension plan but includes bonuses in the computation of covered compensation and is not subject to statutory compensation and benefit limits. Individuals who became participants in the ESSRP before January 1, 2005 will receive the greater of the old formula or the new formula until December 31, 2010. On December 31, 2010, their benefit under the old formula will be frozen. After 2010, they will receive the greater of their frozen December 31, 2010 benefit or their benefit calculated under the new formula. The amendments to the ESSRP also provide for increased service credits for certain participants and eliminate certain distribution features.

On December 19, 2006 the Board of Directors of the Company approved an amendment to the ESSRP effective January 1, 2006. The Amendment amends the ESSRP to provide that for each of the Company's Chief Executive Officer and Corporate Secretary, the "Normal Retirement Benefit" (as defined in the ESSRP) will be determined based on "Final Average Earnings" rather than "Final Annual Salary" (defined as the base Salary (as defined in the ESSRP) and annual bonus paid to the participant during the 12 months prior to termination or death). The ESSRP defines "Final Average Earnings" as the average of the participant's total cash payments (Salary (as defined in the ESSRP) and annual incentive bonus) paid during the highest consecutive 42 months in the 10 years prior to the date as of which the Final Average Earnings are determined.

Components of net periodic pension benefit cost:

(in thousands)	2007	2006	2005
Service Cost—Benefit Earned During the Period	$ 626	$ 426	$ 406
Interest Cost on Projected Benefit Obligation	1,451	1,303	1,267
Amortization of Prior-Service Cost	67	71	71
Amortization of Net Actuarial Loss	540	473	498
Net Periodic Pension Cost	$ 2,684	$ 2,273	$ 2,242

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2007	2006
Regulatory Assets:		
Unrecognized Prior Service Cost	$ 435	$ 496
Unrecognized Actuarial Loss	4,841	5,796
Total Regulatory Assets	5,276	6,292
Projected Benefit Obligation Liability—Net Amount Recognized	(25,158)	(24,783)
Accumulated Other Comprehensive Loss:		
Unrecognized Prior Service Cost	266	271
Unrecognized Actuarial Loss	2,954	3,162
Total Accumulated Other Comprehensive Loss	3,220	3,433
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (16,662)	$ (15,058)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations over the two-year period ended December 31, 2007 and a statement of the funded status as of December 31 of both years:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Employer Contributions	1,079	1,124
Benefit Payments	(1,079)	(1,124)
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 24,783	$ 23,271
Service Cost	626	426
Interest Cost	1,451	1,303
Benefit Payments	(1,079)	(1,124)
Plan Amendments	—	(53)
Actuarial (Gain) Loss	(623)	960
Projected Benefit Obligation at December 31	$ 25,158	$ 24,783
Reconciliation of Funded Status:		
Funded Status at December 31	$ (25,158)	$ (24,783)
Unrecognized Net Actuarial Loss	7,795	8,958
Unrecognized Prior Service Cost	701	767
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (16,662)	$ (15,058)

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

	2007	2006
Discount Rate	6.25%	6.00%
Rate of Increase in Future Compensation Level	4.70%	4.71%

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

	2007	2006
Discount Rate	6.00%	5.75%
Rate of Increase in Future Compensation Level	4.71%	4.69%

The estimated amounts of unrecognized net actuarial losses and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic pension cost for the ESSRP in 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Unrecognized Prior Service Cost	$ 42
Amortization of Unrecognized Actuarial Loss	298
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Unrecognized Prior Service Cost	25
Amortization of Unrecognized Actuarial Loss	182
Total Estimated Amortization	$ 547

Cash flows—The ESSRP is unfunded and has no assets; contributions are equal to the benefits paid to plan participants. The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

(in thousands)		Years			
2008	2009	2010	2011	2012	2013-2017
$ 1,109	$ 1,114	$ 1,113	$ 1,206	$ 1,258	$ 6,755

OTHER 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.

Components of net periodic postretirement benefit cost:

(in thousands)	2007	2006	2005
Service Cost—Benefit Earned During the Period	$ 1,098	$ 1,319	$ 1,307
Interest Cost on Projected Benefit Obligation	2,565	2,556	2,480
Amortization of Transition Obligation	748	748	748
Amortization of Prior-Service Cost	(206)	(305)	(305)
Amortization of Net Actuarial Loss	177	556	742
Expense Decrease Due to Medicare Part D Subsidy	(1,233)	(1,543)	(1,251)
Net Periodic Postretirement Benefit Cost	$ 3,149	$ 3,331	$ 3,721

The following table presents amounts recognized in the consolidated balance sheets as of December 31:

(in thousands)	2007	2006
Regulatory Asset:		
Unrecognized Transition Obligation	$ 3,658	$ 4,414
Unrecognized Prior Service Cost	1,781	1,588
Unrecognized Net Actuarial Gain	(4,915)	(2,077)
Net Regulatory Asset	524	3,925
Projected Benefit Obligation Liability—Net Amount Recognized	(30,488)	(32,254)
Accumulated Other Comprehensive Loss:		
Unrecognized Transition Obligation	83	75
Unrecognized Prior Service Cost	40	27
Unrecognized Net Actuarial Gain	(111)	(35)
Accumulated Other Comprehensive Loss	12	67
Cumulative Employer Contributions in Excess of Net Periodic Benefit Cost	$ (29,952)	$ (28,262)

The following tables provide a reconciliation of the changes in the fair value of plan assets and the plan's projected benefit obligations and accrued postretirement benefit cost over the two-year period ended December 31, 2007:

(in thousands)	2007	2006
Reconciliation of Fair Value of Plan Assets:		
Fair Value of Plan Assets at January 1	$ —	$ —
Actual Return on Plan Assets	—	—
Company Contributions	1,459	2,051
Benefit Payments (Net of Medicare Part D Subsidy)	(3,127)	(3,625)
Participant Premium Payments	1,668	1,574
Fair Value of Plan Assets at December 31	$ —	$ —
Reconciliation of Projected Benefit Obligation:		
Projected Benefit Obligation at January 1	$ 32,254	$ 36,757
Service Cost (Net of Medicare Part D Subsidy)	890	1,110
Interest Cost (Net of Medicare Part D Subsidy)	1,776	1,779
Benefit Payments (Net of Medicare Part D Subsidy)	(3,127)	(3,625)
Participant Premium Payments	1,668	1,574
Actuarial Gain	(2,973)	(5,341)
Projected Benefit Obligation at December 31	$ 30,488	$ 32,254
Reconciliation of Accrued Postretirement Cost:		
Accrued Postretirement Cost at January 1	$ (28,262)	$ (26,982)
Expense	(3,149)	(3,331)
Net Company Contribution	1,459	2,051
Accrued Postretirement Cost at December 31	$ (29,952)	$ (28,262)

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

	2007	2006
Discount Rate	6.25%	6.00%

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

	2007	2006
Discount Rate	6.00%	5.75%

Assumed healthcare cost-trend rates as of December 31:

	2007	2006
Healthcare Cost-Trend Rate Assumed for Next Year Pre-65	8.00%	9.00%
Healthcare Cost-Trend Rate Assumed for Next Year Post-65	9.00%	10.00%
Rate at Which the Cost-Trend Rate is Assumed to Decline	5.00%	5.00%
Year the Rate Reaches the Ultimate Trend Rate	2012	2012

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 2007 would have the following effects:

(in thousands)	1 Point Increase	1 Point Decrease
Effect on the Postretirement Benefit Obligation	$ 2,804	$ (2,423)
Effect on Total of Service and Interest Cost	$ 358	$ (293)
Effect on Expense	$ 418	$ (544)

Measurement Dates:	2007	2006
Net Periodic Postretirement Benefit Cost	January 1, 2007	January 1, 2006
End of Year Benefit Obligations	January 1, 2007 projected to December 31, 2007	January 1, 2006 projected to December 31, 2006

The estimated net amounts of unrecognized transition obligation and prior service costs to be amortized from regulatory assets and accumulated other comprehensive loss into the net periodic postretirement benefit cost in 2008 are:

(in thousands)	2008
Decrease in Regulatory Assets:	
Amortization of Transition Obligation	$ 732
Amortization of Unrecognized Prior Service Cost	205
Amortization of Unrecognized Actuarial Gain	(200)
Decrease in Accumulated Other Comprehensive Loss:	
Amortization of Transition Obligation	16
Amortization of Unrecognized Prior Service Cost	5
Amortization of Unrecognized Actuarial Gain	(4)
Total Estimated Amortization	$ 754

Cash flows—The Company expects to contribute $2.2 million net of expected employee contributions for the payment of retiree medical benefits and Medicare Part D subsidy receipts in 2008. The Company expects to receive a Medicare Part D subsidy from the Federal government of approximately $386,000 in 2008. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

(in thousands)		Years			
2008	2009	2010	2011	2012	2013-2017
$ 2,213	$ 2,266	$ 2,310	$ 2,294	$ 2,403	$ 13,263

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 $733,000 for 2007, $738,000 for 2006 and $830,000 for 2005.

□ 13. 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.

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 $10.4 million of the Company's long-term debt, which is subject to variable interest rates, approximates fair value.

	December 31, 2007		December 31, 2006	
(in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and Short-Term Investments	$ 39,824	$ 39,824	$ 6,791	$ 6,791
Other Investments	10,057	10,057	8,955	8,955
Long-Term Debt	(342,694)	(354,242)	(255,436)	(265,547)

□ 14. PROPERTY, PLANT AND EQUIPMENT

(in thousands)	December 31, 2007	December 31, 2006
Electric Plant		
Production	$ 439,541	$ 360,304
Transmission	191,949	189,683
Distribution	322,107	307,825
General	75,320	72,877
Electric Plant	1,028,917	930,689
Less Accumulated Depreciation and Amortization	401,006	388,254
Electric Plant Net of Accumulated Depreciation	627,911	542,435
Construction Work in Progress	33,772	18,503
Net Electric Plant	$ 661,683	$ 560,938
Nonelectric Operations Plant		
Equipment	$ 181,743	$ 168,917
Buildings and Leasehold Improvements	62,563	58,733
Land	13,284	11,619
Nonelectric Operations Plant	257,590	239,269
Less Accumulated Depreciation and Amortization	105,738	91,303
Nonelectric Plant Net of Accumulated Depreciation	151,852	147,966
Construction Work in Progress	40,489	9,705
Net Nonelectric Operations Plant	$ 192,341	$ 157,671
Net Plant	$ 854,024	$ 718,609

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.

(years)	Service Life Range Low	High
Electric Fixed Assets:		
Production Plant	34	62
Transmission Plant	40	55
Distribution Plant	15	55
General Plant	5	65
Nonelectric Fixed Assets:		
Equipment	3	12
Buildings and Leasehold Improvements	7	40

15. INCOME TAXES

The total income tax expense differs from the amount computed by applying the federal income tax rate (35% in 2007, 2006 and 2005) to net income before total income tax expense for the following reasons:

(in thousands)	2007	2006	2005
Tax Computed at Federal Statutory Rate	$ 28,675	$ 27,232	$ 28,325
Increases (Decreases) in Tax from:			
State Income Taxes Net of Federal Income Tax Benefit	2,913	2,261	1,906
Investment Tax Credit Amortization	(1,137)	(1,146)	(1,151)
Differences Reversing in Excess of Federal Rates	929	1,271	(15)
Dividend Received/Paid Deduction	(714)	(718)	(703)
Affordable Housing Tax Credits	(285)	(839)	(1,324)
Section 199 Domestic Production Activities Deduction	(1,159)	(524)	(451)
Permanent and Other Differences	(1,254)	(431)	1,420
Total Income Tax Expense	$ 27,968	$ 27,106	$ 28,007
Income Tax Expense— Discontinued Operations	$ —	$ 252	$ 5,570
Overall Effective Federal and State Income Tax Rate	34.1%	34.9%	34.9%
Income Tax Expense Includes the Following:			
Current Federal Income Taxes	$ 23,207	$ 26,276	$ 32,795
Current State Income Taxes	2,339	4,232	5,265
Deferred Federal Income Taxes	2,832	(937)	(7,112)
Deferred State Income Taxes	2,116	(189)	(899)
Affordable Housing Tax Credits	(285)	(839)	(1,324)
Investment Tax Credit Amortization	(1,137)	(1,146)	(1,151)
Foreign Income Taxes	(1,104)	(291)	433
Total	$ 27,968	$ 27,106	$ 28,007

The Company's deferred tax assets and liabilities were composed of the following on December 31, 2007 and 2006:

(in thousands)	2007	2006
Deferred Tax Assets		
Benefit Liabilities	$ 30,789	$ 29,418
Cost of Removal	22,537	22,813
Related to North Dakota Wind Tax Credits	12,999	—
SFAS No. 158 Liabilities	10,504	14,694
Differences Related to Property	8,703	7,923
Amortization of Tax Credits	4,505	5,231
Vacation Accrual	2,926	2,751
Unearned Revenue	1,733	2,013
Other	4,063	3,382
Total Deferred Tax Assets	$ 98,759	$ 88,225
Deferred Tax Liabilities		
Differences Related to Property	$ (166,445)	$ (160,635)
SFAS No. 158 Regulatory Asset	(10,504)	(14,694)
Transfer to Regulatory Asset	(8,732)	(11,712)
Related to North Dakota Wind Tax Credits	(4,340)	—
Excess Tax Over Book Pension	(2,953)	(3,153)
Other	(4,398)	(2,702)
Total Deferred Tax Liabilities	$ (197,372)	$ (192,896)
Deferred Income Taxes	$ (98,613)	$ (104,671)

On January 1, 2007 the Company adopted the provisions of FIN No. 48. The cumulative effect of adoption of FIN No. 48, which is reported as an adjustment to the beginning balance of retained earnings, was $118,000. As of the date of adoption, the total amount of unrecognized tax benefits for uncertain tax positions was $1,874,000. The amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate was $575,000 as of January 1, 2007.

The following table summarizes the activity related to our unrecognized tax benefits:

(in thousands)	Total
Balance at January 1, 2007	$ 1,874
Increases Related to Current Year Tax Positions	198
Expiration of the Statute of Limitations for the Assessment of Taxes	(1,566)
Balance at December 31, 2007	$ 506

The balance of unrecognized tax benefits as of December 31, 2007 would reduce our effective tax rate if recognized. The total amount of unrecognized tax benefits as of December 31, 2007 is not expected to change significantly within the next 12 months. The Company and its subsidiaries file a consolidated U.S. federal income tax return and various state and foreign income tax returns. As of December 31, 2007 the Company is no longer subject to U.S. federal income tax examinations by tax authorities for years before 2004. As of December 31, 2007 the Company's earliest open tax year in which an audit can be initiated by state taxing authorities in the Company's major operating jurisdictions is 2003 for Minnesota and 2004 for North Dakota. The Company classifies interest and penalties on tax uncertainties as components of the provision for income taxes. Amounts accrued for interest and penalties on tax uncertainties as of December 31, 2007 were not material.

16. DISCONTINUED OPERATIONS

In 2006, the Company sold the natural gas marketing operations of OTESCO, the Company's energy services subsidiary. Discontinued Operations includes the operating results of OTESCO's natural gas marketing operations for 2006 and 2005. Discontinued Operations also includes an after-tax gain on the sale of OTESCO's natural gas marketing operations of $0.3 million in 2006.

In 2005, the Company sold Midwest Information Systems, Inc. (MIS), St. George Steel Fabrication, Inc. (SGS) and Chassis Liner Corporation (CLC). Discontinued operations includes the operating results of MIS, SGS and CLC for 2005. Discontinued Operations also includes an after-tax gain on the sale of MIS of $11.9 million, an after-tax loss on the sale of SGS of $1.7 million and an after-tax loss on the sale of CLC of $0.2 million in 2005. OTESCO's natural gas marketing operations, MIS, SGS and CLC meet requirements to be reported as discontinued operations in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.*

The results of discontinued operations for the years ended December 31, 2006 and 2005 are summarized as follows:

2006 (in thousands)	OTESCO Gas
Operating Revenues	$ 28,234
Income Before Income Taxes	54
Gain on Disposition —Pretax	560
Income Tax Expense	252

2005 (in thousands)	OTESCO Gas	MIS	SGS	CLC	Total
Operating Revenues	$ 64,539	$ 3,773	$ 6,564	$ 6,112	$ 80,988
Income (Loss) Before Income Taxes	(84)	2,167	(1,740)	(956)	(613)
Goodwill Impairment Loss	(1,003)	—	—	—	(1,003)
Gain (Loss) on Disposition —Pretax	—	19,025	(2,919)	(271)	15,835
Income Tax (Benefit) Expense	(40)	7,975	(1,863)	(502)	5,570

The remaining assets and liabilities of Discontinued Operations as of December 31, 2006 were SGS's deferred tax assets of $289,000 and warranty reserves of $197,000 at estimated fair market values that were settled or disposed in 2007.

□ 17. ASSET RETIREMENT OBLIGATIONS (AROs)

The Company's AROs are related to coal-fired generation plants and 27 wind turbines erected near Langdon, North Dakota and include site restoration, closure of ash pits, and removal of storage tanks, structures, generators and asbestos. The Company has legal obligations associated with the retirement of a variety of other long-lived tangible assets used in electric operations where the estimated settlement costs are individually and collectively immaterial. The Company has no assets legally restricted for the settlement of any of its AROs.

During 2007, the Company recorded new obligations related to the removal of 27 wind turbines erected near Langdon, North Dakota and restoration of the tower sites but did not make any revisions to previously recorded obligations.

During 2006, the Company did not record any new obligation or make any revisions to previously recorded obligations. The Company settled a legal obligation for removal of asbestos at unit one of its Hoot Lake generating plant.

Reconciliations of carrying amounts of the present value of the Company's legal AROs, capitalized asset retirement costs and related accumulated depreciation and a summary of settlement activity for the years ended December 31, 2007 and 2006 are presented in the following table:

(in thousands)	2007	2006
Asset Retirement Obligations		
Beginning Balance	$ 1,335	$ 1,524
New Obligations Recognized	1,024	—
Adjustments Due to Revisions in Cash Flow Estimates	—	—
Accrued Accretion	88	85
Settlements	—	(274)
Ending Balance	$ 2,447	$ 1,335
Asset Retirement Costs Capitalized		
Beginning Balance	$ 285	$ 349
New Obligations Recognized	1,024	—
Adjustments Due to Revisions in Cash Flow Estimates	—	—
Settlements	—	(64)
Ending Balance	$ 1,309	$ 285
Accumulated Depreciation—Asset Retirement Costs Capitalized		
Beginning Balance	$ 178	$ 234
New Obligations Recognized	—	—
Adjustments Due to Revisions in Cash Flow Estimates	—	—
Accrued Depreciation	7	8
Settlements	—	(64)
Ending Balance	$ 185	$ 178
Settlements		
Original Capitalized Asset Retirement Cost—Retired	$ —	$ 64
Accumulated Depreciation	—	(64)
Asset Retirement Obligation	$ —	$ 274
Settlement Cost	—	(222)
Gain on Settlement—Deferred Under Regulatory Accounting	$ —	$ 52

□ 18. QUARTERLY INFORMATION (NOT AUDITED)

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 *(in thousands, except per share data)*	March 31 2007	March 31 2006	June 30 2007	June 30 2006	September 30 2007	September 30 2006	December 31 2007	December 31 2006
Operating Revenues (a)	$ 301,121	$ 257,807	$ 305,844	$ 279,904	$ 302,235	$ 280,542	$ 329,687	$ 286,701
Operating Income (a)	20,774	27,374	30,271	22,136	25,547	24,170	24,182	24,117
Net Income:								
Continuing Operations	10,408	14,855	16,103	11,137	13,332	13,476	14,118	11,282
Discontinued Operations	—	105	—	257	—	—	—	—
	10,408	14,960	16,103	11,394	13,332	13,476	14,118	11,282
Earnings Available for Common Shares:								
Continuing Operations	10,224	14,671	15,919	10,953	13,148	13,293	13,934	11,097
Discontinued Operations	—	105	—	257	—	—	—	—
	10,224	14,776	15,919	11,210	13,148	13,293	13,934	11,097
Basic Earnings Per Share:								
Continuing Operations	$ .35	$ .50	$ .54	$ .37	$ .44	$ .45	$ .47	$ .38
Discontinued Operations	—	—	—	.01	—	—	—	—
	.35	.50	.54	.38	.44	.45	.47	.38
Diluted Earnings Per Share:								
Continuing Operations	$ .34	$ .50	$ .53	$ .37	$ .44	$ .45	$ .46	$ .37
Discontinued Operations	—	—	—	.01	—	—	—	—
	.34	.50	.53	.38	.44	.45	.46	.37
Dividends Paid Per Common Share	.2925	.2875	.2925	.2875	.2925	.2875	.2925	.2875
Price Range:								
High	$ 35.00	$ 31.34	$ 37.06	$ 30.09	$ 39.39	$ 30.80	$ 37.88	$ 31.92
Low	31.06	27.32	30.22	25.78	28.96	26.50	32.82	28.60
Average Number of Common Shares Outstanding—Basic	29,503	29,326	29,686	29,393	29,746	29,413	29,790	29,445
Average Number of Common Shares Outstanding—Diluted	29,757	29,676	29,941	29,766	29,996	29,806	30,090	29,731

(a) From continuing operations.

OPERATING RATIOS

(in thousands)	2007	2006	2005	2004	2003	2002	1997
Operating Revenues	$ 1,238,887	$1,104,954	$ 981,869	$ 813,036	$ 688,989	$ 595,425	$ 373,117
Operating Expenses (a)	$ 1,138,113	$1,007,157	$ 883,274	$ 737,828	$ 620,026	$ 516,495	$ 315,730
Operating Ratio	91.9	91.1	90.0	90.7	90.0	86.7	84.6

SELECTED COMMON SHARE DATA

(in thousands)	2007	2006	2005	2004	2003	2002	1997
Earnings Available for Common Shares	$ 53,225	$ 50,376	$ 61,816	$ 41,459	$ 38,921	$ 45,392	$ 29,988
Average Number of Shares—Diluted	29,970	29,664	29,348	26,207	25,826	25,397	23,277
Diluted Earnings Per Share	$ 1.78	$ 1.70	$ 2.11	$ 1.58	$ 1.51	$ 1.79	$ 1.29
Common Dividends	$ 34,780	$ 33,886	$ 32,728	$ 28,528	$ 27,730	$ 26,729	$ 21,496
Dividends Paid Per Share	$ 1.17	$ 1.15	$ 1.12	$ 1.10	$ 1.08	$ 1.06	$ 0.93
Payout Ratio	66%	68%	53%	70%	72%	59%	72%
Market Price:							
High	$ 39.39	$ 31.92	$ 31.95	$ 27.50	$ 28.90	$ 34.90	$ 19.19
Low	$ 28.96	$ 25.78	$ 24.02	$ 23.77	$ 23.76	$ 22.82	$ 15.00
Common Price/Earnings Ratio:							
High	22.1	18.8	15.1	17.4	19.1	19.5	14.9
Low	16.3	15.2	11.4	15.0	15.7	12.7	11.6
Book Value Per Common Share	$ 17.51	$ 16.62	$ 15.80	$ 14.81	$ 12.98	$ 12.25	$ 8.96

SELECTED DATA AND RATIOS

	2007	2006	2005	2004	2003	2002	1997
Net Income (in thousands)	$ 53,961	$ 51,112	$ 62,551	$ 42,195	$ 39,656	$ 46,128	$ 32,346
Interest Coverage Before Taxes	4.7x	5.2x	5.7x	4.4x	4.1x	4.7x	3.4x
Effective Income Tax Rate (percent)	34	35	34	30	27	30	30
Capital Ratios:							
Long-Term Debt and Current Maturities (percent)	39.1	33.7	35.2	37.5	43.6	44.2	43.4
Preferred Stock and Other Equity (percent)	1.9	2.2	2.3	2.4	2.5	2.6	8.8
Common Equity (percent)	59.0	64.1	62.5	60.1	53.9	53.2	47.8
	100.0	100.0	100.0	100.0	100.0	100.0	100.0

CAPITALIZATION

(in thousands)	2007	2006	2005	2004	2003	2002	1997
Long-Term Debt and Current Maturities	$ 345,698	$ 258,561	$ 261,600	$ 267,821	$ 270,597	$ 260,302	$ 190,461
Preferred Stock and Other Equity	16,755	16,755	16,758	17,332	15,500	15,500	38,831
Common Stock Equity:							
Par	149,249	147,609	147,006	144,885	128,619	127,961	58,655
Premium	108,885	99,223	96,768	87,865	26,515	24,135	35,196
Unearned Compensation	—	—	(1,720)	(2,577)	(3,313)	(1,946)	—
Retained Earnings and Other Comprehensive Income (Loss)	264,513	243,938	222,376	199,037	182,066	163,315	116,305
Total Common Equity	$ 522,647	$ 490,770	$ 464,430	$ 429,210	$ 333,887	$ 313,465	$ 210,156
Total Capitalization Including Current Maturities	$ 885,100	$ 766,086	$ 742,788	$ 714,363	$ 619,984	$ 589,267	$ 439,448
Income Before Interest Charges (includes AFC borrowed)	$ 77,483	$ 70,484	$ 72,551	$ 58,863	$ 56,535	$ 62,575	$ 46,909
Percent Return on Capitalization	8.8	9.2	9.8	8.2	9.1	10.6	10.7
Percent Return on Average Common Equity	10.5	10.6	13.9	12.0	12.2	15.3	14.9

TIMES INTEREST EARNED AND PREFERRED DIVIDEND COVERAGE (a)

	2007	2006	2005	2004	2003	2002	1997
Before Income Taxes:							
Long-Term Debt Interest (b)	6.2	6.2	6.4	4.9	4.3	5.0	3.8
After Income Taxes:							
Long-Term Debt Interest (c)	4.6	4.5	4.6	3.8	3.4	3.8	3.0
Long-Term Debt Interest and Preferred Dividends (d)	4.4	4.3	4.4	3.6	3.3	3.7	2.6
Preferred Dividends (e)	73.3	69.0	73.3	55.0	52.1	60.2	12.3

(a) Excludes income taxes
(b) Income before interest charges + income taxes ÷ long-term debt interest
(c) Income before interest charges ÷ long-term debt interest
(d) Income before interest charges ÷ long-term debt interest and preferred dividends
(e) Net Income ÷ preferred dividends

DEPRECIATION RESERVE

(in thousands)	2007	2006	2005	2004	2003	2002	1997
Electric Plant in Service	$ 1,028,917	$ 930,689	$ 910,766	$ 890,200	$ 875,364	$ 835,382	$ 758,551
Depreciation Reserve	$ 401,006	$ 388,254	$ 374,786	$ 363,696	$ 368,899	$ 357,555	$ 280,634
Reserve to Electric Plant (percent)	39.0	41.7	41.2	40.9	42.1	42.8	37.0
Composite Depreciation Rate (percent)	2.78	2.82	2.74	2.77	3.07	3.08	3.08

RATIO OF DEBT TO ELECTRIC PLANT

(in thousands)	2007	2006	2005	2004	2003	2002	1997
Electric Plant:							
Gross (a)	$ 1,062,689	$ 949,192	$ 923,215	$ 902,412	$ 889,302	$ 874,505	$ 770,698
Net	$ 661,683	$ 560,938	$ 548,429	$ 538,716	$ 520,403	$ 516,950	$ 490,064
Debt (b)	$ 199,890	$ 166,975	$ 166,975	$ 166,975	$ 166,975	$ 166,975	$ 157,473
Ratio to Electric Plant—Net (a) (percent)	30	30	30	31	32	32	32

PEAK DEMAND AND NET GENERATING CAPABILITY

	2007	2006	2005	2004	2003	2002	1997
Peak Demand (kw)	704,940	690,243	665,064	686,044	668,703	640,220	635,529
Net Generating Capability (kw):							
Steam	549,800	549,350	559,175	554,330	555,085	557,308	555,026
Combustion Turbines	132,744	137,595	135,701	136,506	136,915	87,358	91,208
Hydro	4,338	4,294	4,244	4,327	4,380	4,336	4,374
Total Owned Generating Capability	686,882	691,239	699,120	695,163	696,380	649,002	650,608

ELECTRIC INVESTMENT

	2007	2006	2005	2004	2003	2002	1997
Electric Utility Plant—Net (c) (in thousands)	$ 661,683	$ 560,938	$ 548,429	$ 538,716	$ 520,403	$ 516,950	$ 490,064
Total Retail Electric Revenue (in thousands)	$ 276,894	$ 260,926	$ 248,939	$ 224,326	$ 217,439	$ 206,870	$ 185,577
Total Retail Electric Customers	129,302	129,026	128,406	128,157	127,474	127,093	125,142
Investment Per Dollar Revenue	$ 2.39	$ 2.15	$ 2.20	$ 2.40	$ 2.39	$ 2.50	$ 2.64
Investment Per Customer	$ 5,117	$ 4,347	$ 4,271	$ 4,204	$ 4,082	$ 4,067	$ 3,916

OUTPUT KILOWATT-HOURS

(in thousands)	2007	2006	2005	2004	2003	2002	1997
Net Generated	3,386,041	3,571,410	3,513,705	3,774,115	3,672,616	3,548,413	2,934,247
Purchased, Net Interchange and Financial Settlements	2,465,598	3,218,537	3,495,176	4,910,428	5,898,456	4,135,932	1,980,428
Total	5,851,639	6,789,947	7,008,881	8,684,543	9,571,072	7,684,345	4,914,675

(a) Includes construction work in progress
(b) Includes sinking fund requirements and current maturities
(c) Electric plant in service less accumulated provision for depreciation plus construction work in progress

SHAREHOLDER SERVICES

OTTER TAIL CORPORATION STOCK LISTING

Otter Tail Corporation common stock trades on the NASDAQ Global Select Market. The daily closing price is printed in *The Wall Street Journal*, Minneapolis *Star Tribune*, *The Forum* of Fargo-Moorhead 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.

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. 2007 dividends were $1.17 per share. The indicated annual rate for 2008 is $1.19. The 2007 yield was 3.8%, and the 2007 payout ratio was 66%. Total shareholder return grew at a compounded average annual rate of 10.7% for the past 10 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 77% of eligible shareowners holding about 14% of our eligible common shares are enrolled. Through this plan, participants may have their dividends automatically reinvested in additional shares without paying any brokerage fees or service charges. Shareholders also may contribute a minimum of $10 and a maximum of $10,000 per month. Automatic withdrawal from a checking or savings account is available for this service. Shareholders may sell up to 30 shares a month through the plan. For more information, contact Shareholder Services.

ELECTRONIC DIVIDEND DEPOSIT

Shareholders, including institutional holders, can arrange for electronic direct 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

Replacing missing certificates is a costly and time-consuming process so shareholders should keep a separate record of the certificate number, purchase date, date of issue, price paid and exact registration name. If you are 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
215 South Cascade Street | P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: 800-664-1259 or 218-739-8479
Fax: 218-998-3165
Email: sharesvc@ottertail.com

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

2008 ANNUAL MEETING OF SHAREHOLDERS

Monday, April 14, 2008
10:00 a.m., Central Time
Bigwood Event Center
921 Western Avenue
Fergus Falls, Minnesota

EX-DIVIDEND	RECORD	PAYMENT	
Feb. 13	Feb. 15	P	Mar. 1
		C	Mar. 10
May 13	May 15	P	May 31
		C	June 10
Aug. 13	Aug. 15	P	Aug. 30
		C	Sept. 10
Nov. 12	Nov. 14	P	Dec. 1
		C	Dec. 10

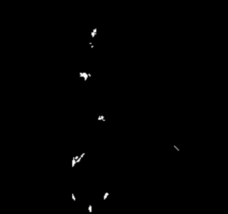
2008 CASH INVESTMENT AND SELL DATES FOR DIVIDEND REINVESTMENT

JAN. 2	FEB. 1	MAR. 3	APRIL 1
MAY 1	JUNE 2	JULY 1	AUG. 1
SEPT. 2	OCT. 1	NOV. 3	DEC. 1

KEY STATISTICS

NASDAQ	OTTR
Senior unsecured debt ratings	
Moody's Investor Service	A3/negative
Standard & Poor's	BBB+/negative
Year-end stock price	$34.60
Year-end price/earnings ratio	19.4
Year-end market-to-book ratio	2.0
Annual dividend yield	3.8%
Shares outstanding	29.8 million
Market capitalization (as of December 31, 2007)	$1.03 billion
2007 average daily trading volume	110,482
Institutional holdings (shares as of December 31, 2007)	14.2 million


John MacFarlane

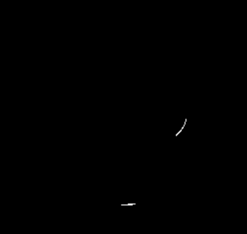

Karen Bohn


Dennis Emmen


John Erickson


Arvid Liebe


Edward McIntyre


Joyce Nelson Schuette


Nathan Partain


Gary Spies

JOHN C. MACFARLANE (68-25)* E, *Fergus Falls, Minnesota*
Chairman of the Board of Directors, Retired President and Chief Executive Officer, Otter Tail Corporation

KAREN M. BOHN (54-4) A/CG/E, *Edina, Minnesota*
President, Galeo Group, LLC (management consulting firm)

DENNIS R. EMMEN (74-24) A/C, *Fergus Falls, Minnesota*
Retired Senior Vice President, Finance, Treasurer and Chief Financial Officer, Otter Tail Power Company

JOHN D. ERICKSON (49-1), *Fergus Falls, Minnesota*
President and Chief Executive Officer, Otter Tail Corporation

ARVID R. LIEBE (66-13) C/CG/E, *Milbank, South Dakota*
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Retired Vice President and Chief Financial Officer, Xcel Energy (energy company)

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Retired Managing Director and Investment Banker, Piper Jaffray & Co (financial services)

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President and Chief Investment Officer, Duff & Phelps Investment Management Co., President, Chief Executive Officer and Chief Investment Officer, DNP Select Income Fund, Inc. (closed-end utility income fund)

GARY J. SPIES (66-7) A/CG, *Fergus Falls, Minnesota*
Chairman, Service Food, Inc (retail business); Vice President, Fergus Falls Development Company and Midwest Regional Development Company, LLC (land and housing development)

COMMITTEES A—Audit C—Compensation E—Executive CG—Corporate Governance
**(Age-years of service) are as of the 2008 Annual Meeting of Shareholders*

OFFICERS

JOHN D. ERICKSON (49-27)*
President and Chief Executive Officer

LAURIS N. MOLBERT (50-13)
Executive Vice President and Chief Operating Officer

KEVIN G. MOUG (48-11)
Chief Financial Officer and Treasurer

GEORGE A. KOECK (55-8)
General Counsel and Corporate Secretary


Left to right George Koeck, Kevin Moug, Lauris Molbert, John Erickson

VICE PRESIDENTS

CHARLES S. MACFARLANE (43-6)*
Electric Platform

CHARLES R. HOGE (51-5)
Manufacturing Platform

W. RICHARD NICKEL (65-3)
Food Ingredient Processing Platform

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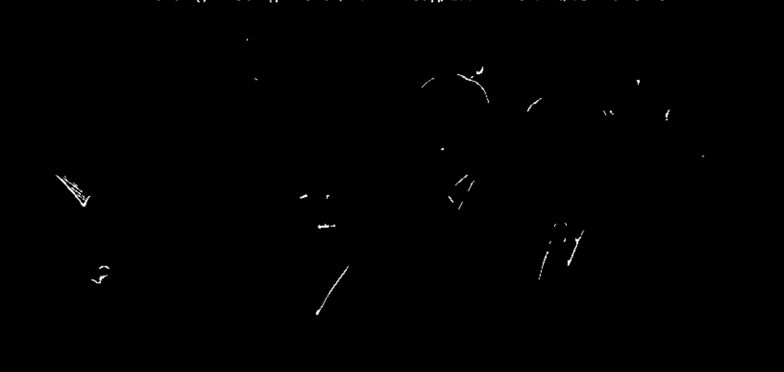
Human Resources and Strategy

SHANE N. WASLASKI (32-1)
Infrastructure Products and Services Platform

PAUL J. WILSON (49-2)
Health Services Platform


Left to right Paul Wilson, Charles Hoge, Lori Talafous, Shane Waslaski, Charles MacFarlane, Richard Nickel

OTTERTAIL
CORPORATION

SHAREHOLDER SERVICES
215 S. Cascade St., P.O. Box 496
Fergus Falls, MN 56538-0496
Phone: 800-664-1259 or 218-739-8479
Email: sharesvc@ottertail.com

WWW.OTTERTAIL.COM

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