we energies

231 W. Michigan St.
Milwaukee, WI 53290-0001
www.we-energies.com

March 29, 2007

10 CFR 50.71(b)

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
Renewed License Nos. DPR-24 and DPR-27

Submittal of 2006 Annual Financial Statements

In accordance with 10 CFR Section 50.71(b), enclosed is the 2006 annual report to stockholders of Wisconsin Electric Power Company, owner of Point Beach Nuclear Plant, Units 1 and 2. This report includes certified financial statements. Such annual report accompanies Wisconsin Electric's definitive information statement, which is being mailed to stockholders today.

Sincerely,

Keith H. Ecke

Keith H. Ecke
Assistant Corporate Secretary

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC

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Gale E. Klappa
Chairman, President and
Chief Executive Officer

231 W Michigan Street
Milwaukee, WI 53203

March 29, 2007

Dear Stockholder:

Wisconsin Electric Power Company, which does business under the trade name of We Energies, will hold its Annual Meeting of Stockholders on Monday, April 30, 2007, at 10:00 a.m., in Conference Room P449 of the Public Service Building, 231 West Michigan Street, Milwaukee, Wisconsin 53203. We are not soliciting proxies for this meeting, as over 99% of the voting stock is owned, and will be voted, by Wisconsin Electric Power Company's parent, Wisconsin Energy Corporation. If you wish, you may vote your shares of preferred stock in person at the meeting; however, the business session will be very brief.

As an alternative, you might consider attending Wisconsin Energy Corporation's Annual Meeting of Stockholders to be held Thursday, May 3, 2007, at 10:00 a.m., at The Pabst Theater, 144 East Wells Street, Milwaukee, Wisconsin 53202.

By attending this meeting, you would have the opportunity to meet many of the Wisconsin Electric Power Company officers and directors. Although you cannot vote your shares of Wisconsin Electric Power Company preferred stock at the Wisconsin Energy Corporation meeting, you may find the activities worthwhile. An admission ticket will be required to enter the meeting. To obtain an admission ticket, please contact Wisconsin Energy Corporation's Stockholder Services, 231 West Michigan Street, P.O. Box 1331, Milwaukee, Wisconsin 53201, or simply call 800-881-5882.

The annual report to stockholders is attached as Appendix A to this information statement. If you have any questions or would like a copy of the Wisconsin Energy Corporation annual report, please call our toll-free stockholder hotline at 800-881-5882.

Thank you for your support.

Sincerely,

Gale E. Klappa

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS

March 29, 2007

To the Stockholders of Wisconsin Electric Power Company:

The 2007 Annual Meeting of Stockholders of Wisconsin Electric Power Company will be held on Monday, April 30, 2007, at 10:00 a.m., in Conference Room P449 at the Public Service Building, 231 West Michigan Street, Milwaukee, Wisconsin 53203, for the following purposes:

1. To elect the ten members of the Board of Directors to hold office until the 2008 Annual Meeting of Stockholders; and

2. To consider any other matters which may properly come before the meeting.

Stockholders of record at the close of business on February 23, 2007, are entitled to vote. The following pages provide additional details about the meeting as well as other useful information.

By Order of the Board of Directors,

Anne K. Klisurich

Anne K. Klisurich
Vice President and Corporate Secretary

231 West Michigan Street
Milwaukee, Wisconsin 53203

INFORMATION STATEMENT

This information statement is being furnished to stockholders beginning on or about March 29, 2007, in connection with the annual meeting of stockholders of Wisconsin Electric Power Company ("WE" or the "Company") to be held on Monday, April 30, 2007 ("the Meeting"), at 10:00 a.m., in Conference Room P449 at the Public Service Building, 231 West Michigan Street, Milwaukee, Wisconsin 53203, and all adjournments or postponements of the Meeting, for the purposes listed in the preceding Notice of Annual Meeting of Stockholders. The WE annual report to stockholders is attached as Appendix A to this information statement.

We are not asking you for a proxy and you are requested not to send us a proxy. However, you may vote your shares of preferred stock at the Meeting.

VOTING SECURITIES

As of February 23, 2007, WE had outstanding 44,498 shares of $100 par value Six Per Cent. Preferred Stock; 260,000 shares of $100 par value 3.60% Serial Preferred Stock; and 33,289,327 shares of common stock. Each outstanding share of each class is entitled to one vote. Stockholders of record at the close of business on February 23, 2007 will be entitled to vote at the Meeting. In order to conduct the Meeting, a majority of the outstanding shares entitled to vote must be represented at the Meeting. This is known as a "quorum." All of WE's outstanding common stock owned by Wisconsin Energy Corporation ("WEC") will be represented at the Meeting.

All of WE's outstanding common stock, representing over 99% of its voting securities, is owned by its parent company, WEC, whose principal business address is 231 West Michigan Street, Milwaukee, Wisconsin 53203. A list of stockholders of record entitled to vote at the Meeting will be available for inspection by stockholders at WE's principal business office at 231 West Michigan Street, Milwaukee, Wisconsin 53203, prior to and at the Meeting.

ELECTION OF DIRECTORS

At the Meeting, there will be an election of ten directors. The individuals named below have been nominated by the WE Board of Directors (the "Board") to serve a one-year term expiring at the 2008 Annual Meeting of Stockholders and until they are re-elected or until their respective successors are duly elected and qualified. Currently, directors of WEC also serve as the directors of WE.

Although John F. Ahearne's age exceeds the Company's age guideline for non-employee directors, the guideline permits the Board to request a director to remain on the Board. The Board is nominating Director Ahearne on the basis that his expertise in the nuclear field is unique among Board members.

Pursuant to authority granted to the Board under the Bylaws, the Board increased the number of directors from nine to ten and elected Patricia W. Chadwick, President of Ravengate Partners, LLC, as a director effective June 26, 2006. The WEC Corporate Governance Committee recommended Ms. Chadwick for election. Ms. Chadwick was introduced to the WEC Corporate Governance Committee by Gale E. Klappa, Chairman of the Board, President and Chief Executive Officer.

Directors will be elected by a plurality of the votes cast by the shares entitled to vote, as long as a quorum is present. "Plurality" means that the individuals who receive the largest number of votes are elected as directors up to the maximum number of directors to be chosen. Therefore, shares not voted, whether by withheld authority or otherwise, have no effect in the election of directors.

Each nominee has consented to being nominated and to serve if elected. In the unlikely event that any nominee becomes unable to serve for any reason, the proxies will be voted for a substitute nominee selected by the WE Board upon the recommendation of the Corporate Governance Committee of WEC's Board of Directors.

Information About Nominees for Election to the Board of Directors for Terms Expiring in 2008.

Biographical information regarding each nominee is shown below. WE and Wisconsin Gas LLC (WG) do business as We Energies and are wholly-owned subsidiaries of Wisconsin Energy Corporation. Effective July 28, 2004, Wisconsin Gas Company converted to a Wisconsin limited liability company and changed its name to Wisconsin Gas LLC. References to service as a director of Wisconsin Gas LLC below include the time each director sat as a director of Wisconsin Gas Company. Ages are shown as of March 1, 2007.

John F. Ahearne. Age 72.

- Sigma Xi Center for Sigma Xi, The Scientific Research Society – Director of the Ethics Program since 1999. Director of the Sigma Xi Center from 1997 to 1999 and Executive Director from 1989 to 1997. The Sigma Xi Center is an organization that publishes *American Scientist,* provides grants to graduate students and conducts national meetings on major scientific issues.
- Resources for the Future – Adjunct Scholar since 1993. Resources for the Future is an economic research, non-profit institute.
- Duke University – Lecturer from 1995 to 2006. Adjunct Professor from 1996 to 2002.
- United States Nuclear Regulatory Commission – Commissioner from 1978 to 1983, serving as Chairman from 1979 to 1981.
- Director of Wisconsin Energy Corporation and Wisconsin Electric Power Company since 1994 and Wisconsin Gas LLC since 2000.

John F. Bergstrom. Age 60.

- Bergstrom Corporation – Chairman since 1982 and Chief Executive Officer since 1974. Bergstrom Corporation owns and operates numerous automobile sales and leasing companies.
- Director of Kimberly-Clark Corporation and Midwest Air Group, Inc.
- Director of Wisconsin Energy Corporation since 1987, Wisconsin Electric Power Company since 1985 and Wisconsin Gas LLC since 2000.

Barbara L. Bowles. Age 59.

- Profit Investment Management – Vice Chair since January 2006. Profit Investment Management is an investment advisory firm.
- The Kenwood Group, Inc. – Chairman since 2000. Chief Executive Officer from 1989 to December 2005. President from 1989 to 2000. The Kenwood Group is an investment advisory firm and is a subsidiary of Profit Investment Management.
- Director of Black & Decker Corporation and Dollar General Corporation.
- Director of Wisconsin Energy Corporation and Wisconsin Electric Power Company since 1998 and Wisconsin Gas LLC since 2000.

Patricia W, Chadwick. Age 58.

- Ravengate Partners, LLC – President since 1999. Ravengate Partners, LLC provides businesses and not-for-profit institutions with advice about the financial markets.
- Director of AMICA Mutual Insurance Company and ING Mutual Funds.
- Director of Wisconsin Energy Corporation, Wisconsin Electric Power Company and Wisconsin Gas LLC since June 2006.

Robert A. Cornog. Age 66.

- Snap-on Incorporated – Retired Chairman of the Board, President and Chief Executive Officer. Served from 1991 and retired as President and Chief Executive Officer in 2001. Retired as Chairman in 2002. Snap-on Incorporated is a developer, manufacturer and distributor of professional hand and power tools, diagnostic and shop equipment, and tool storage products.
- Director of Johnson Controls, Inc. and Oshkosh Truck Corporation.
- Director of Wisconsin Energy Corporation since 1993, Wisconsin Electric Power Company since 1994 and Wisconsin Gas LLC since 2000.

Curt S. Culver. Age 54.

- MGIC Investment Corporation – Chairman since 2005, Chief Executive Officer since 2000 and President from 1999 to January 2006. MGIC Investment Corporation is the parent of Mortgage Guaranty Insurance Corporation.
- Mortgage Guaranty Insurance Corporation – Chairman since 2005, Chief Executive Officer since 1999 and President from 1996 to January 2006. Mortgage Guaranty Insurance Corporation is a private mortgage insurance company.
- Director of MGIC Investment Corporation.
- Director of Wisconsin Energy Corporation, Wisconsin Electric Power Company and Wisconsin Gas LLC since 2004.

Thomas J. Fischer. Age 59.

- Fischer Financial Consulting LLC – Principal since 2002. Fischer Financial Consulting LLC provides consulting on corporate financial, accounting and governance matters.
- Arthur Andersen LLP – Retired as Managing Partner of the Milwaukee office in 2002. Served as Managing Partner from 1993 and as Partner from 1980. Arthur Andersen LLP was an independent public accounting firm.

- Director of Actuant Corporation, Badger Meter, Inc. and Regal-Beloit Corporation.
- Director of Wisconsin Energy Corporation, Wisconsin Electric Power Company and Wisconsin Gas LLC since 2005.

Gale E. Klappa. Age 56.
- Wisconsin Energy Corporation – Chairman of the Board and Chief Executive Officer since May 2004. President since April 2003.
- Wisconsin Electric Power Company – Chairman of the Board since May 2004. President and Chief Executive Officer since August 2003.
- Wisconsin Gas LLC – Chairman of the Board since May 2004. President and Chief Executive Officer since August 2003.
- The Southern Company – Executive Vice President, Chief Financial Officer and Treasurer from March 2001 to April 2003. Chief Strategic Officer from October 1999 to March 2001. The Southern Company is a public utility holding company serving the southeastern United States.
- Director of Joy Global Inc.
- Director of Wisconsin Energy Corporation, Wisconsin Electric Power Company and Wisconsin Gas LLC since 2003.

Ulice Payne, Jr. Age 51.
- Addison-Clifton, LLC – Managing Member since 2004. Addison-Clifton, LLC provides advisory services on global trade compliance.
- Milwaukee Brewers Baseball Club, Inc. – President and Chief Executive Officer from 2002 to 2003.
- Foley & Lardner – Managing Partner of the law firm's Milwaukee office from May 2002 to September 2002. A partner from 1998 to 2002.
- Director of Badger Meter, Inc. and Midwest Air Group, Inc. and Trustee of The Northwestern Mutual Life Insurance Company.
- Director of Wisconsin Energy Corporation, Wisconsin Electric Power Company and Wisconsin Gas LLC since 2003.

Frederick P. Stratton, Jr. Age 67.
- Briggs & Stratton Corporation – Chairman Emeritus since 2003. Chairman of the Board from 2001 to 2003. Chairman and Chief Executive Officer until 2001. Briggs & Stratton Corporation is a manufacturer of small gasoline engines.
- Director of Baird Funds, Inc., Midwest Air Group, Inc. and Weyco Group, Inc.
- Director of Wisconsin Energy Corporation since 1987, Wisconsin Electric Power Company since 1986 and Wisconsin Gas LLC since 2000.

OTHER MATTERS

The Board of Directors is not aware of any other matters that may properly come before the Meeting. The WE Bylaws set forth the requirements that must be followed should a stockholder wish to propose any floor nominations for director or floor proposals at annual or special meetings of stockholders. In the case of annual meetings, the Bylaws state, among other things, that notice and certain other documentation must be provided to WE at least 70 days and not more than 100 days before the scheduled date of the annual meeting. No such notices have been received by WE.

CORPORATE GOVERNANCE – FREQUENTLY ASKED QUESTIONS

Does WE have Corporate Governance Guidelines?	The WE Board of Directors follows WEC's Corporate Governance Guidelines that WEC has maintained since 1996. These Guidelines provide a framework under which the Board conducts its business. The Guidelines are available in the "Governance" section of WEC's website at www.wisconsinenergy.com and are available in print to any stockholder who requests them.
How are directors determined to be independent?	No director qualifies as independent unless the Board affirmatively determines that the director has no material relationship with the Company. WEC's Corporate Governance Guidelines provide that the WEC Board should consist of at least a two-thirds majority of independent directors and currently, directors of WEC also serve as the directors of WE.
What are the Board's standards of independence?	The guidelines the Board uses in determining director independence are located in Appendix A of WEC's Corporate Governance Guidelines. These standards of independence, which are summarized below, include those established by the New York Stock Exchange as well as a series of standards that are more comprehensive than New York Stock Exchange requirements.

To be considered by the Board as independent, the director:

- has not been an employee of the Company for the last five years;
- has not received, in the past three years, more than $100,000 per year in direct compensation from the Company, other than director fees or deferred compensation for prior service;
- has not been affiliated with or employed by a present or former internal or external auditor of the Company in the past three years;
- has not been an executive officer, in the past three years, of another company where any of the Company's present executives serve on that other company's compensation committee;
- in the past three years, has not been an employee of a company that makes payments to, or receives payments from, the Company for property or services in an amount which in any single fiscal year is the greater of $1 million or 2% of such other company's consolidated gross revenues;
- has not received, in the past three years, remuneration, other than *de minimus* remuneration, as a result of services as, or being affiliated with an entity that serves as, an advisor, consultant or legal counsel to the Company or to a member of the Company's senior management, or a significant supplier of the Company;
- has no personal service contract(s) with the Company or any member of the Company's senior management;
- is not an employee or officer with a not-for profit entity that receives 5% or more of its total annual charitable awards from the Company;
- has not had any business relationship with the Company, in the past three years, for which the Company has been required to make disclosure under certain rules of the Securities and Exchange Commission;
- is not employed by a public company at which an executive officer of the Company serves as a director; and
- does not have any beneficial ownership interest of 5% or more in an entity that has received remuneration, other than *de minimus* remuneration, from the Company, its subsidiaries or affiliates.

The Board also considers whether a director's immediate family members meet the above criteria, as well as whether a director has any relationships with the Company's affiliates for certain of the above criteria, when determining the director's independence. Any relationship between a director and the Company not meeting the above criteria is considered an immaterial relationship with the Company for purposes of determining independence. For purposes of the above discussion, "Company" refers to WEC and its subsidiaries, including WE.

Who are the independent directors?	The Board has affirmatively determined that Directors Ahearne, Bergstrom, Bowles, Chadwick, Cornog, Culver, Fischer, Payne and Stratton have no relationships within the Board's standards of independence noted above and otherwise have no material relationships with WE or WEC and are independent. This represents more than a two-thirds majority of the Board. Director Klappa is not independent due to his present employment with WEC and its affiliates. George Wardeberg, who did not stand for re-election at the 2006 Annual Meeting of Stockholders, was not independent due to his previous employment with WEC.
What are the committees of the Board?	The Board of Directors of WE has the following committees: Audit and Oversight, Compensation, Finance and Executive. All committees, except the Executive Committee, operate under a charter approved by the Board. The Audit and Oversight Committee and the Compensation Committee charters are posted at WEC's website at www.wisconsinenergy.com and are available in print to any stockholder who requests it. The members and the responsibilities of each committee are listed later in this information statement under the heading "Committees of the Board of Directors."

Are the Audit and Oversight and Compensation Committees comprised solely of independent directors?	Yes, these committees are comprised solely of independent directors, as determined under New York Stock Exchange rules and WEC's Corporate Governance Guidelines. In addition, the Board has determined that each member of the Audit and Oversight Committee is independent under the rules of the New York Stock Exchange applicable to audit committee members. The Audit and Oversight Committee is a separately designated committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934, as amended.
Do the non-management directors meet separately from management?	Yes, at every regularly scheduled Board meeting non-management (non-employee) directors have an opportunity to meet in executive session without any management present. All non-management directors are independent. Currently, Director Bowles presides at these sessions.
How can interested parties contact the members of the Board?	Correspondence may be sent to the directors, including the non-management directors, in care of the Corporate Secretary, Anne K. Klisurich, at the Company's principal business office, 231 West Michigan Street, P.O. Box 2046, Milwaukee, Wisconsin 53201. All communications received as set forth above will be opened by the Corporate Secretary for the sole purpose of confirming the contents represent a message to the Company's directors. All communication, other than advertising, promotion of a product or service, or patently offensive material, will be forwarded promptly to the addressee.
Does the Company have a written code of ethics?	Yes, all WE and WEC directors, executive officers and employees, including the principal executive, financial and accounting officers, have a responsibility to comply with WEC's Code of Business Conduct, to seek advice in doubtful situations and to report suspected violations. WEC's Code of Business Conduct addresses, among other things: conflicts of interest; confidentiality; fair dealing; protection and proper use of Company assets; and compliance with laws, rules and regulations (including insider trading laws). The Company has not provided any waiver to the Code for any director, executive officer or other employee. The Code of Business Conduct is posted in the "Governance" section of WEC's website at www.wisconsinenergy.com. It is also available in print to any stockholder upon request. The Company has contracted with an independent call center for employees to confidentially report suspected violations of the Code or other concerns regarding accounting, internal accounting controls or auditing matters.
Does the Company have policies and procedures in place to review and approve related party transactions?	The Company does not have a formal written policy regarding the review, approval or ratification of related party transactions. However, all employees, including executive officers and members of the Board, are required to comply with WEC's Code of Business Conduct. The Code addresses, among other things, what actions are required when potential conflicts of interest may arise, including those from related party transactions. Specifically, executive officers and members of the Board are required to obtain approval of the Audit and Oversight Committee chair (1) before obtaining any financial interest in or participating in any business relationship with any company, individual or concern doing business with WEC or any of its subsidiaries, including the Company (other than investments in public companies of no more than 5% of the officer's and director's annual income), (2) before participating in any joint venture, partnership or other business relationship with WEC or any of its subsidiaries, including the Company, (3) before serving as an officer or member of the board of any substantial outside for-profit organization, and (4) before accepting a position with a substantial non-profit organization. In addition, WEC's Code of Business Conduct requires employees to notify the Compliance Officer of situations where family members are a supplier or significant customer of WEC or the Company or employed by one. To the extent the Compliance Officer deems it appropriate, she will consult with the Audit and Oversight Committee chair in situations involving executive officers and members of the Board.
Does the Board evaluate CEO performance?	Yes, the Compensation Committee, on behalf of the Board, annually evaluates the performance of the CEO and reports the results to the Board. As part of this practice, the Compensation Committee requests that all non-employee directors provide their opinions to the Compensation Committee chair on the CEO's performance. The CEO is evaluated in a number of areas including leadership, vision, financial stewardship,

	strategy development, management development, effective communication with constituencies, demonstrated integrity and effective representation of the Company in community and industry affairs. The chair of the Compensation Committee shares the responses with the CEO. The process is also used by the Committee to determine appropriate compensation for the CEO. This procedure allows the Board to evaluate the CEO and to communicate the Board's expectations.
Does the Board evaluate its own performance?	Yes, the Board annually evaluates its own collective performance. Each director is asked to consider the performance of the Board on such things as: the establishment of appropriate corporate governance practices; providing appropriate oversight for key affairs of the Company (including its strategic plans, long-range goals, financial and operating performance and customer satisfaction initiatives); communicating the Board's expectations and concerns to the CEO; identifying threats and opportunities critical to the Company; and operating in a manner that ensures open communication, candid and constructive dialogue as well as critical questioning. WEC's Corporate Governance Committee uses the results of this process as part of its annual review of the Corporate Governance Guidelines and to foster continuous improvement of the Board's activities.
Is Board committee performance evaluated?	Yes, each committee, except the Executive Committee, conducts an annual performance evaluation of its own activities and reports the results to the Board. The evaluation compares the performance of each committee with the requirements of its charter. The results of the annual evaluations are used by each committee to identify both its strengths and areas where its governance practices can be improved. The committee may adjust its charter, with Board approval, based on the results of this evaluation.
Are all the members of the audit committee financially literate and does the committee have an "audit committee financial expert"?	Yes, the Board has determined that all of the members of WE's Audit and Oversight Committee are financially literate as required by New York Stock Exchange rules and qualify as audit committee financial experts within the meaning of Securities and Exchange Commission rules. Director Fischer serves on the audit committee of three other public companies. The Board determined that his service on these other audit committees will not impair Director Fischer's ability to effectively serve on the Audit and Oversight Committee. No other member of the Audit and Oversight Committee serves as an audit committee member of more than three public companies. For this purpose, the Company considers service on the audit committees of Wisconsin Electric Power Company, Wisconsin Energy Corporation and Wisconsin Gas LLC to be service on the audit committee of one public company because of the commonality of the issues considered by those committees.
What are the principal processes and procedures used by the Compensation Committee to determine executive and director compensation?	One of the principal responsibilities of the Compensation Committee is to provide a competitive, performance-based executive and director compensation program. This includes: (1) determining and periodically reviewing the Committee's compensation philosophy; (2) determining and reviewing the compensation paid to executive officers (including base salaries, incentive compensation and benefits); (3) oversight of the compensation and benefits to be paid to other officers and key employees; and (4) establishing and administering the Chief Executive Officer compensation package. The Compensation Committee is also charged with administering the compensation package of the non-employee directors. Although it has not chosen to do so, the Committee may delegate all or a portion of its duties and responsibilities to a subcommittee of the Committee. The Chief Executive Officer, after reviewing compensation data compiled by Towers Perrin, a compensation consulting firm, and each executive officer's individual experience, performance, responsibility and contribution to the results of the Company's operations, makes compensation recommendations to the Committee for all executive officers other than himself. The Compensation Committee is free to make adjustments as it deems appropriate. Although the Compensation Committee relies on compensation data regarding general industry and the energy services industry compiled by Towers Perrin, Towers Perrin does not recommend the amount or form of executive and director compensation. WEC engaged Towers Perrin to provide a variety of compensation-related services on a consolidated basis, one of which is to provide the compensation data. Towers Perrin was not engaged directly by the Compensation Committee. However, the Committee has unrestricted access to Towers Perrin and may retain its own compensation consultant at its discretion. For more information regarding our executive compensation processes and procedures, please refer to the "Compensation Discussion and

	Analysis" later in this information statement.
Does the Board have a nominating committee?	WE does not have a nominating committee. WE relies on WEC's Corporate Governance Committee for identifying and evaluating director nominees. The chair of the Committee coordinates this effort. The WEC Board has determined that all members of WEC's Corporate Governance Committee are independent under the guidelines it uses to determine director independence as well as under the New York Stock Exchange rules applicable to nominating committee members. The WEC Corporate Governance Committee operates under a charter approved by the WEC Board, a copy of which is posted in the "Governance" section of WEC's website at www.wisconsinenergy.com.
What is the process used to identify director nominees and how do I recommend a nominee to WEC's Corporate Governance Committee?	Candidates for director nomination may be proposed by stockholders, WEC's Corporate Governance Committee and other members of the Board. The Committee may pay a third party to identify qualified candidates; however, such a firm was not engaged with respect to the nominees listed in this information statement. No nominations or recommendations were received from holders of either series of the Company's preferred stock. Stockholders wishing to propose director candidates for consideration and recommendation by WEC's Corporate Governance Committee for election at the Company's 2008 Annual Meeting of Stockholders must submit the candidates' names and qualifications to WEC's Corporate Governance Committee no later than November 1, 2007, via the Corporate Secretary, Anne K. Klisurich, at the Company's principal business office, 231 West Michigan Street, P.O. Box 2046, Milwaukee, Wisconsin 53201.
What are the criteria and process used to evaluate director nominees?	WE relies on WEC's Corporate Governance Committee for identifying and evaluating director nominees. WEC's Corporate Governance Committee has not established minimum qualifications for director nominees; however, the criteria for evaluating all candidates, which are reviewed annually, include characteristics such as: proven integrity, mature and independent judgment, vision and imagination, ability to objectively appraise problems, ability to evaluate strategic options and risks, sound business experience and acumen, relevant technological, political, economic or social/cultural expertise, social consciousness, achievement of prominence in career, familiarity with national and international issues affecting WEC and the Company's businesses and contribution to the Board's desired diversity and balance. In evaluating director candidates, WEC's Corporate Governance Committee reviews potential conflicts of interest, including interlocking directorships and substantial business, civic and/or social relationships with other members of the Board that could impair the prospective Board member's ability to act independently from the other Board members and management. Once a person has been identified by WEC's Corporate Governance Committee as a potential candidate, the Committee may collect and review publicly available information regarding the person to assess whether the person should be considered further. If the Committee determines that the candidate warrants further consideration, the chair or another member of the Committee contacts the person. Generally, if the person expresses a willingness to be considered and to serve on the Board, the Committee requests information from the candidate, reviews the person's accomplishments and qualifications and conducts one or more interviews with the candidate. In certain instances, Committee members may contact one or more references provided by the candidate or may contact other members of the business community or other persons who may have greater firsthand knowledge of the candidate's accomplishments. The Committee evaluates all candidates, including those proposed by stockholders, using the criteria and process described above. The process is designed to provide the Board with a diversity of experience to allow it to effectively meet the many challenges WE and WEC face in today's changing business environment.
What is WE's policy regarding director attendance at annual meetings?	Directors are not expected to attend WE's annual meetings of stockholders, as they are only short business meetings. All directors are expected to attend WEC's annual meetings of stockholders. All current directors attended WEC's 2006 Annual Meeting, except for Director Chadwick who was not a member of the Board at the time.

COMMITTEES OF THE BOARD OF DIRECTORS

Members	Principal Responsibilities; Meetings
Audit and Oversight Thomas J. Fischer, Chair John F. Bergstrom Barbara L. Bowles Robert A. Cornog	• Oversee the integrity of the financial statements. • Oversee management compliance with legal and regulatory requirements. • Review, approve and evaluate the independent auditors' services. • Oversee the performance of the internal audit function and independent auditors. • Prepare the report required by the SEC for inclusion in the information statement. • Establish procedures for the submission of complaints and concerns regarding WE's accounting or auditing matters. • The Committee conducted six meetings in 2006.
Compensation John F. Bergstrom, Chair John F. Ahearne Ulice Payne, Jr.	• Identify through succession planning potential executive officers. • Provide a competitive, performance-based executive and director compensation program. • Set goals for the CEO, annually evaluate the CEO's performance against such goals and determine compensation adjustments based on whether these goals have been achieved. • The Committee conducted five meetings in 2006 and executed one signed, written unanimous consent.
Finance Curt S. Culver, Chair Patricia W. Chadwick Ulice Payne, Jr. Frederick P. Stratton, Jr.	• Review and monitor the Company's current and long-range financial policies and strategies, including its capital structure and dividend policy. • Authorize the issuance of corporate debt within limits set by the Board. • Discuss policies with respect to risk assessment and risk management. • Review, approve and monitor the Company's capital and operating budgets. • The Committee conducted three meetings in 2006.

WE relies on WEC's Corporate Governance Committee for identifying and evaluating director nominees. WEC's Corporate Governance Committee is also responsible for establishing and reviewing the WEC Corporate Governance Guidelines which are followed by the Board. The members of the Corporate Governance Committee are Barbara L. Bowles (Chair), Robert A. Cornog, Curt S. Culver and Frederick P. Stratton, Jr. WEC's Corporate Governance Committee conducted two meetings in 2006. The WEC Board dissolved its Nuclear Oversight Committee in 2005. The WEC and WE Boards named Director Ahearne as lead nuclear director.

The Board also has an Executive Committee which may exercise all powers vested in the Board except action regarding dividends or other distributions to stockholders, filling Board vacancies and other powers which by law may not be delegated to a committee or actions reserved for a committee comprised of independent directors. The members of the Executive Committee are Gale E. Klappa (Chair), John F. Bergstrom, Barbara L. Bowles, Robert A. Cornog and Frederick P. Stratton, Jr. The Executive Committee did not meet in 2006.

In addition to the number of committee meetings listed in the preceding table, the Board met seven times in 2006 and executed one signed, written unanimous consent. The average meeting attendance during the year was 93%. No director attended fewer than 84% of the total number of meetings of the Board and Board committees on which he or she served.

INDEPENDENT AUDITORS' FEES AND SERVICES

Deloitte & Touche served as the independent auditors for the Company for each of the five fiscal years in the period ending December 31, 2006. They have been selected by the Audit and Oversight Committee as independent auditors for the Company for the fiscal year ending December 31, 2007, subject to ratification by the stockholders of Wisconsin Energy Corporation at WEC's Annual Meeting of Stockholders on May 3, 2007.

Representatives of Deloitte & Touche are not expected to be present at the Meeting, but are expected to attend WEC's Annual Meeting of Stockholders on May 3, 2007. They will have an opportunity to make a statement at WEC's Annual Meeting, if they so desire, and are expected to respond to appropriate questions that may be directed to them.

Pre-Approval Policy. The Audit and Oversight Committee has a formal policy delineating its responsibilities for reviewing and approving, in advance, all audit, audit-related, tax and other services of the independent auditors. The Committee is committed to ensuring the independence of the auditors, both in appearance as well as in fact.

Under the pre-approval policy, before engagement of the independent auditors for the next year's audit, the independent auditors will submit a description of services anticipated to be rendered for the Committee to approve. Annual pre-approval will be deemed effective for a period of twelve months from the date of pre-approval, unless the Committee specifically provides for a different period. A fee level will be established for all permissible non-audit services. Any proposed non-audit services exceeding this level will require additional approval by the Committee.

The Audit and Oversight Committee delegated pre-approval authority to the Committee's chair. The Committee Chair shall report any pre-approval decisions at the next scheduled Committee meeting. Under the pre-approval policy, the Committee shall not delegate to management its responsibilities to pre-approve services performed by the independent auditors.

Under the pre-approval policy, prohibited non-audit services are services prohibited by the Securities and Exchange Commission or by the Public Company Accounting Oversight Board to be performed by the Company's independent auditors. These services include bookkeeping or other services related to the accounting records or financial statements of the Company, financial information systems design and implementation, appraisal or valuation services, fairness opinions or contribution-in-kind reports, actuarial services, internal audit outsourcing services, management functions or human resources, broker-dealer, investment advisor or investment banking services, legal services and expert services unrelated to the audit, services provided for a contingent fee or commission and services related to planning, marketing or opining in favor of the tax treatment of a confidential transaction or an aggressive tax position transaction that was initially recommended, directly or indirectly, by the independent auditors. In addition, the Committee has determined that the independent auditors may not provide any services, including personal financial counseling and tax services, to any officer of the Company or member of the Audit and Oversight Committee or an immediate family member of these individuals, including spouses, spousal equivalents and dependents.

Fee Table. The following table shows the fees for professional audit services provided by Deloitte & Touche LLP for the audit of Wisconsin Electric's annual financial statements for fiscal years 2006 and 2005 and fees for other services rendered during those periods. No fees were paid to Deloitte & Touche LLP pursuant to the "de minimus" exception to the pre-approval policy permitted under the Securities and Exchange Act of 1934, as amended.

	2006	2005
Audit Fees [1]	$786,146	$729,158
Audit-Related Fees [2]	--	33,380
Tax Fees [3]	--	998
All Other Fees [4]	2,339	1,483
Total	$788,485	$765,019

(1) *Audit Fees* consist of fees for professional services rendered in connection with the audits of Wisconsin Electric's annual financial statements, reviews of financial statements included in Form 10-Q filings of the Company and services normally provided in connection with statutory and regulatory filings or engagements.

(2) *Audit-Related Fees* consist of fees for professional services that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported under "Audit Fees." These services primarily include consultations regarding implementation of accounting standards.

(3) *Tax Fees* consist of fees for professional services rendered with respect to federal and state tax compliance and tax advice. This includes preparation of tax returns, claims for refunds, payment planning and tax law interpretation. Deloitte & Touche LLP did not provide any tax strategy consulting in 2006 or 2005.

(4) *All Other Fees* consist of costs for certain employees to attend accounting/tax seminars hosted by Deloitte & Touche LLP in 2006 and 2005.

AUDIT AND OVERSIGHT COMMITTEE REPORT

The Audit and Oversight Committee, which is comprised solely of independent directors, oversees the integrity of the financial reporting process on behalf of the Board of Directors of Wisconsin Electric Power Company. In addition, the Committee oversees compliance with legal and regulatory requirements. The Committee operates under a written charter approved by the Board of Directors, which can be found in the "Governance" section of Wisconsin Energy Corporation's website at www.wisconsinenergy.com.

The Committee is also responsible for the appointment, compensation, retention and oversight of the Company's independent auditors, as well as the oversight of the Company's internal audit function. The Committee selected Deloitte & Touche LLP to remain as the Company's independent auditors for 2007, subject to ratification by Wisconsin Energy Corporation's stockholders.

Management is responsible for the Company's financial reporting process, the preparation of consolidated financial statements in accordance with generally accepted accounting principles and the system of internal controls and procedures designed to provide reasonable assurance regarding compliance with accounting standards and applicable laws and regulations. The Company's independent auditors are responsible for performing an independent audit of the Company's consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States) and issuing a report thereon.

The Committee held six meetings during 2006. Meetings are designed to facilitate and encourage open communication among the members of the Committee, management, the internal auditors and the Company's independent auditors, Deloitte & Touche LLP. During these meetings, we reviewed and discussed with management, among other items, the Company's unaudited quarterly and audited annual financial statements and the system of internal controls designed to provide reasonable assurance regarding compliance with accounting standards and applicable laws. We reviewed the financial statements and the system of internal controls with the Company's independent auditors, both with and without management present, and we discussed with Deloitte & Touche LLP matters required by Statement on Auditing Standards No. 61, as amended, as adopted by the Public Company Accounting Oversight Board in Rule 3200T, relating to communications with audit committees, including the quality of the Company's accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements.

In addition, we received the written disclosures and the letter relative to the auditors' independence from Deloitte & Touche LLP, as required by Independence Standards Board Standard No. 1, as adopted by the Public Company Accounting Oversight Board in Rule 3600T. The Committee discussed with Deloitte & Touche LLP its independence and also considered the compatibility of non-audit services provided by Deloitte & Touche LLP with maintaining its independence.

Based on these reviews and discussions, the Audit and Oversight Committee recommended to the Board of Directors that the audited financial statements be included in Wisconsin Electric Power Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2006 and filed with the Securities and Exchange Commission.

Respectfully submitted to Wisconsin Electric Power Company's stockholders by the Audit and Oversight Committee of the Board of Directors.

Thomas J. Fischer, Committee Chair
John F. Bergstrom
Barbara L. Bowles
Robert A. Cornog

COMPENSATION DISCUSSION AND ANALYSIS

General Overview. The primary objective of our executive compensation program is to provide a competitive, performance-based executive compensation program that enables the Company to attract and retain key individuals and to motivate them to achieve both the Company's long-term and short-term goals. Our program has been designed to provide a level of compensation that is strongly dependent upon the achievement of goals that are aligned with the interests of WEC's stockholders and our customers. As a result, a substantial portion of pay is at risk.

The Compensation Committee of the Company is comprised of the same individuals who are members of the Compensation Committee of the Board of Directors of Wisconsin Energy Corporation (the "WEC Compensation Committee" and, together with the Company's Compensation Committee, the "Compensation Committee"). The named executive officers of the Company are the same as the named executive officers of WEC, and the WEC Compensation Committee and the Company's Compensation Committee each have responsibility for making compensation decisions regarding these executive officers.

The following discussion provides an overview and analysis of our executive compensation program, including the role of the Compensation Committee, the elements of our executive compensation program, the purposes and objectives of these elements and the manner in which we established the compensation of our executive officers for fiscal year 2006.

References to "we", "us", "our" and the "Company" in this discussion and analysis mean Wisconsin Electric Power Company and its management, as applicable, and references to "WEC" mean Wisconsin Energy Corporation.

Compensation Committee. The Compensation Committee is responsible for making decisions regarding compensation for executive officers of WEC and its principal subsidiaries, including the Company, and for developing our executive compensation philosophy. The assessment of the Chief Executive Officer's performance and determination of the CEO's compensation are among the principal responsibilities of the Compensation Committee. The Compensation Committee also approves the compensation of each of our other executive officers and recommends the compensation of our Board of Directors for approval by the Board. In addition, the Compensation Committee administers our long-term incentive compensation programs, including the WEC 1993 Omnibus Stock Incentive Plan, as amended, and the WEC Performance Unit Plan, which are discussed further below.

The Compensation Committee is comprised solely of directors who are "independent directors" under WEC's corporate governance guidelines (which are also applicable to the Company) and the rules of the New York Stock Exchange. No member of the Compensation Committee is a current or former employee of WEC or its subsidiaries.

Elements of the Executive Compensation Program. The principal goal of the Compensation Committee is to provide an executive compensation program that is competitive with programs of comparable employers, aligns management's incentives with the short-term and long-term interests of WEC's stockholders and encourages the retention of top performers. To achieve this goal, we compensate executives through a mix of compensation elements that include:

- annual base salary;
- annual cash incentive compensation (based principally on earnings and cash flow performance);
- long-term incentive compensation through a mix of: (1) WEC stock options; (2) WEC performance units; and (3) dividends on the performance units;
- retirement programs; and
- other employee benefit programs, including executive perquisites.

In addition, under our compensation program, each executive officer is entitled to severance compensation if his or her employment is terminated in connection with a change in control of WEC.

A more detailed discussion of each of these elements is set forth below. Except as described in this Compensation Discussion and Analysis, we do not have any particular policies with respect to the allocation of cash versus non-cash compensation or short-term versus long-term incentive compensation.

Competitive Data. As a general matter, we believe the labor market for WEC executive officers is consistent with that of general industry. Although we recognize WEC's business has become less diversified and more focused on the energy services industry as WEC has divested non-core assets, our goal is to have an executive compensation program that will allow us to be competitive in recruiting the most qualified candidates to serve as executive officers of the Company, including individuals who may be employed outside of the energy services industry. Further, in order to retain top performing executive officers, we believe our compensation practices must be competitive with those of general industry.

In order to confirm that our annual executive compensation is competitive with the market, we consider market data obtained from Towers Perrin, a compensation consulting firm retained by management. Towers Perrin provides us with compensation data obtained from approximately 825 companies of varying sizes in a wide range of businesses throughout general industry, including information from approximately 100 companies within the "energy services" industry (i.e., companies with regulated and/or unregulated utility operations and independent power producers).

The extent to which we consider this market data in establishing individual elements of compensation is described in more detail below. For any named executive officer, except Mr. Kuester, the term "market median" means the median level for an executive officer serving in a comparable position in a comparably sized company to WEC (revenues of $3 billion to $6 billion) in general industry based on our analysis of the Towers Perrin survey data. With respect to Mr. Kuester, given the nature of his position as principal executive officer of WEC's electric utility generation operations, we consider the average of (1) the median level for an individual serving as the top generation officer of a company comparable in size to We Energies (revenues of $3 billion to $6 billion) in the energy services industry and (2) the median level for the chief executive officer in general industry in a business comparable in size to the generation operations of Wisconsin Energy.

Annual Base Salary. The annual base salary component of our executive compensation program provides each executive officer with a fixed level of annual cash compensation. We believe that providing a base level of annual cash compensation through a base salary is an established market practice and is a necessary component of a competitive overall executive compensation program.

In determining the annual base salaries to be paid to our named executive officers for 2006, we targeted base salaries to be within 10% of the market median for each named executive officer. Actual salary determinations were made taking into consideration factors such as the relative levels of individual experience, performance, responsibility and contribution to the results of both WEC's and the Company's operations.

With respect to Mr. Klappa, based on the factors described above and the results of the Board's annual CEO evaluation, the Compensation Committee approved an annual base salary of $1,005,000 for 2006, which represented an increase of approximately 4.5% from 2005. This annual base salary was within 10% of the market median for general industry.

With respect to each other named executive officer, Mr. Klappa recommended an annual base salary to the Compensation Committee based on a review of market compensation data and the factors described above. The Compensation Committee approved Mr. Klappa's recommendations, which represented an approximately 4.5% increase in base salary for each of the named executive officers (other than Mr. Fleming, who did not begin service until 2006) over 2005 levels. The annual base salaries of Messrs. Kuester and Fleming were within 10% of the appropriate market median. The annual base salaries for Messrs. Leverett and Salustro were more than 10% above the market median for general industry. We believe that the responsibilities of these officers vary widely from those of their counterparts within general industry, and thus, comparisons to individuals serving in comparable positions are not relied upon as heavily. In recognition of their respective significant responsibilities and contributions to the strategic direction of WEC and the Company beyond those of a typical principal financial officer or general counsel, the Compensation Committee approved higher levels of base salary for these executive officers.

Annual Cash Incentive Compensation. We provide annual cash incentive compensation through WEC's Short-Term Performance Plan (STPP). The STPP provides for annual cash awards to named executive officers based upon the achievement of pre-established WEC stockholder, customer and employee focused objectives. All payments under the plan are at risk. Payments are made only if performance goals are achieved, and awards may be less or greater than targeted amounts based on actual performance. Annual bonuses under the STPP are intended to award achievement of short-term goals that contribute to WEC stockholder value and to reward individual contributions to successful operations.

2006 Target Awards. Each year, the Compensation Committee approves a target level of compensation under the STPP for each of our named executive officers. This target level of compensation is expressed as a percentage of base salary. Each of Messrs. Klappa, Leverett and Kuester has an employment agreement with WEC that specifies a minimum target level of compensation under the STPP based on a percentage of such executive officer's annual base salary. Under the terms of these employment agreements, the target award may not be adjusted below these minimum levels unless the WEC Board of Directors takes action resulting in the lowering of target awards for the entire senior executive group. Mr. Fleming's employment agreement provided for a target level of compensation under the STPP equal to 70% of his annual base salary in 2006.

For 2006, the Compensation Committee approved the following target awards under the STPP for each named executive officer:

Executive Officer	Target STPP Award as a Percentage of Base Salary
Mr. Klappa	100%
Mr. Leverett	80%
Mr. Kuester	80%
Mr. Salustro	80%
Mr. Fleming	70%

For 2006, the possible payout for any named executive officer ranged from 0% of the target award to 210% of the target award, based on our performance.

2006 Performance Goals. The Compensation Committee adopted the 2006 STPP with a continued principal focus on financial results. In December 2005, the Compensation Committee approved the two primary performance measures to be used in 2006: (1) WEC earnings per share from ongoing operations (75% weight); and (2) WEC cash flow (25% weight). In January 2006, the Compensation Committee approved threshold level, target level, above target level and maximum payout level performance goals for each of these performance measures under the STPP. If the threshold level, target level, above target level or maximum payout level performance goal was achieved for both performance measures, officers participating in the STPP could receive 50%, 100%, 125% or 200%, respectively, of the target award.

In July 2006, the Compensation Committee increased the target range of earnings and cash flow after receipt of updated revenue information from management. The Compensation Committee increased the threshold level, target level, above target level and maximum payout level performance goals for WEC earnings per share from ongoing operations and WEC cash flow. The adjusted WEC earnings per share from ongoing operations goals for 2006 were a threshold level goal of $2.43 per share, a target level goal of $2.48 per share, an above target level goal of $2.50 and a maximum payout level goal of $2.56 per share. The performance goals for WEC cash flow, as adjusted in July 2006, were a threshold level goal of ($661.7) million, a target level goal of ($635.7) million, an above target level goal of ($622.7) million and a maximum payout level goal of ($583.8) million.

In January 2006, the Compensation Committee also approved operational goals under the annual incentive plan. Annual incentive awards could be increased or decreased by up to 10% of the target award based upon WEC's performance in the operational areas of customer satisfaction (5% weight), supplier and workforce diversity (2.5%) and safety (2.5%).

In addition to applying these financial and operational factors, the Compensation Committee retains the right to exercise discretion in adjusting awards under the STPP when it is deemed appropriate.

2006 Performance Under the STPP. In January 2007, the Compensation Committee reviewed WEC's actual performance for 2006 against the financial and operational performance goals established under the STPP, subject to final audit. In 2006WEC's financial performance substantially exceeded the target level goals and satisfied the maximum payout level goals established for both earnings per share from ongoing operations and cash flow. In 2006, WEC's earnings per share from ongoing operations were $2.58 per share and WEC's cash flow was ($317.6) million. To compute earnings per share from ongoing operations, WEC began with WEC earnings per share from continuing operations which were $2.64 in 2006, and WEC excluded a gain on the sale of its interest in the Guardian Pipeline of $0.01 per share and a gain from the reversal of certain state tax allowances of $0.05. WEC cash flow is measured by subtracting cash used in investing activities excluding asset sales proceeds from cash provided by operating activities. The same items excluded from the calculation of WEC's earnings per share from ongoing operations were excluded for the purposes of calculating WEC cash flow. WEC's earnings per share from ongoing operations and cash flow measures are not measures of financial performance under generally accepted accounting principles.

By satisfying the maximum payout level performance goals with respect to both earnings per share from ongoing operations and cash flow, officers participating in the STPP, including the named executive officers, earned 200% of the target award from the financial goal component of the STPP.

With respect to operational goals in 2006, the performance at WEC and its subsidiaries, including the Company, generated an additional 5% based on performance in customer satisfaction. The Compensation Committee measured customer satisfaction levels based on the results of surveys that an independent third party conducted of customers who had direct contact with WEC and its subsidiaries, including the Company, during the year, which measured (1) our customers' satisfaction with us in general and (2) our customers' satisfaction with respect to their particular contacts with us. In 2006, our performance significantly exceeded targeted

levels with respect to both measures. We also achieved target level performance with respect to supplier and workforce diversity and safety, but did not achieve the levels necessary to further increase the STPP award for 2006.

Based on the performance against the financial and operational goals established by the Compensation Committee, Mr. Klappa received annual incentive cash compensation under the STPP of $2,060,250 for 2006. This represented 205% of his annual base salary. Messrs. Leverett, Kuester and Fleming received annual cash incentive compensation for 2006 under the STPP equal to 164%, 164% and 143.5% of their respective annual base salaries, representing 205% of the target award for each officer. Based on the performance, Mr. Salustro would have received annual incentive compensation under the STPP of 164% of base salary, representing 205% of the target award. However, since Mr. Salustro did not serve in the role of General Counsel for the entire year, he agreed that 50% of his payment would be based on actual performance and 50% of his payment would be based on his target award. As a result, Mr. Salustro's annual cash incentive compensation for 2006 was 122% of his annual base salary, or 152.5% of his target award for the year.

In view of the discretionary component of the annual cash incentive plan, the Compensation Committee also considered other significant accomplishments of WEC and its subsidiaries, including the Company, in 2006. These accomplishments included:

- Strong financial performance
  - Record WEC earnings from continuing operations of $2.64 per share of WEC common stock.
  - WEC total stockholder return (stock price appreciation plus dividends) of 24.2% in 2006.
  - WEC debt to total capital ratio of 59.5% at year-end 2006, which was significantly better than our target of 61.5%.
- Significant achievements with respect to our Point Beach nuclear facility
  - Achieved highest-ever level of energy generation at Point Beach in 2006.
  - Point Beach was removed from Column 4 in the U.S. Nuclear Regulatory Commission's (NRC) performance matrix, which means that the red findings received in 2002 and 2003 will no longer be considered in the NRC's assessment process.
  - Entered into agreement to sell Point Beach for highest price per kilowatt of capacity ever achieved for the sale of a nuclear plant in the U.S.
- Continued progress in WEC's *Power the Future* strategic plan
  - Continued to progress on time and on budget with major construction projects at Oak Creek and Port Washington.
- Operational excellence
  - Named most reliable utility in the Midwest for the fourth time in the last five years by P.A. Consulting.
  - Major improvements in customer satisfaction based on customer surveys.
  - Received a national best practice award for the Company's We Care Call program.
  - Completed a run of 517 consecutive days at Pleasant Prairie Unit 1, which was by far the longest run in the plant's operating history of more than 20 years.
  - Improved employee safety in 2006, with a 20% reduction in lost-time accidents.
- Continued leadership and excellence in corporate governance as evidenced by continued receipt by WEC during 2006 of a rating of "10", the highest possible score, from GovernanceMetrics International (only one of three U.S. companies to consistently earn a "10" for governance practices).
- Community involvement and recognition
  - Named corporation of the year by The Business Council of the Metropolitan Milwaukee Association of Commerce for our efforts to advance supplier diversity.
  - Opened the Milwaukee 7 Resource Center to support economic development in Southeastern Wisconsin.

In view of the financial and operational accomplishments and the accomplishments listed above, the Compensation Committee determined that the awards under the STPP were appropriate in relation to our 2006 performance without any further adjustment.

Long-Term Incentive Compensation. The Compensation Committee administers WEC's 1993 Omnibus Stock Incentive Plan, as amended, which is a WEC stockholder approved, long-term incentive plan designed to link the interests of executives and other key

employees of WEC and its subsidiaries, including the Company, to creating long-term stockholder value. It allows for various types of awards tied to the performance of WEC's common stock, including stock options, stock appreciation rights, restricted stock and performance shares. In 2005, the Compensation Committee approved the Wisconsin Energy Corporation Performance Unit Plan, under which the Compensation Committee may award WEC performance units. Since 2004, the Compensation Committee has primarily used (1) WEC stock options and (2) WEC performance shares/performance units to deliver long-term incentive opportunities.

Each year, the Compensation Committee makes annual stock option grants as part of our long-term incentive program. These stock options have an exercise price equal to the fair market value of WEC's common stock on the date of grant and expire on the 10th anniversary of the grant date. Since management benefits from a stock option award only to the extent WEC's stock price appreciates above the exercise price of the stock option, stock options align the interests of management with those of WEC's stockholders in attaining long-term stock price appreciation.

In 2004, the Compensation Committee awarded "performance shares" under the WEC 1993 Omnibus Stock Incentive Plan and has since made annual grants of "performance units" under the WEC Performance Unit Plan. The performance shares/performance units are designed to provide an additional form of long-term incentive compensation that more closely aligns the interests of management with those of a typical utility stockholder who is focused not only on stock price appreciation but also on receiving dividend payments. Under the terms of the performance shares/performance units, payouts are based on WEC's level of "total stockholder return" (stock price appreciation plus dividends) in comparison to a peer group of companies over a three-year performance period. In addition, each holder of performance units receives a cash dividend when WEC declares a dividend on its common stock in an amount equal to the number of performance units granted to the holder at the target 100% rate multiplied by the amount of the dividend paid on a share of WEC's common stock. The performance shares and performance units are substantially similar, except that the performance units are settled in cash and the performance shares could have been settled in cash or shares of WEC's common stock at the election of the holder.

Aggregate 2006 Long-Term Incentive Awards. In establishing the target value of long-term incentive awards for each named executive officer in 2006, we analyzed the market compensation data included in the Towers Perrin survey. For Messrs. Klappa and Fleming we determined the ratio of (1) the market median value of long-term incentive compensation to (2) the market median level of annual base salary, and multiplied his annual base salary by the applicable market ratio to determine the value of long-term incentive awards to be granted. With respect to our Executive Vice Presidents who were continuing service from the prior year (Messrs. Leverett, Kuester and Salustro), we used the average of the results obtained for each to develop a uniform target level of long-term incentive compensation that applied to each officer. This target value of long-term incentive compensation for each named executive officer was presented to and approved by the Compensation Committee.

In 2006, the Compensation Committee approved a WEC stock option grant designed to represent approximately two-thirds of the value of the long-term incentive award and a WEC performance unit grant designed to represent approximately one-third of the value of the long-term incentive award. When the Compensation Committee initially implemented performance share awards in 2004, the Compensation Committee made 75% of the award option grants and 25% performance shares. As the market has moved away from stock options, we have increased the size of the performance units as a component of our long-term incentive awards and decreased the relative size of stock option awards.

2006 Stock Option Grants. In December 2005, the Compensation Committee approved the grant of WEC stock options to each of our named executive officers and established an overall pool of options that were granted to approximately 135 other employees. These option grants were made effective January 3, 2006, the first trading day of 2006. The options were granted with an exercise price equal to the average of the high and low prices reported on the New York Stock Exchange for shares of WEC common stock on the January 3, 2006 grant date. The options were granted in accordance with our standard practice of making annual stock option grants in January of each year and the timing of the grants was not tied to the timing of any release of material non-public information. These stock options have a term of 10 years and vest 100% on the third anniversary of the date of grant. The vesting of the stock options may be accelerated in connection with a change in control of WEC or an executive officer's termination of employment. See "Potential Payments upon Termination or Change in Control" under "Executive Officers' Compensation" for additional information.

For purposes of determining the appropriate number of options to grant to a particular named executive officer, the value of an option was determined based on the Black-Scholes option pricing model. We use the Black-Scholes option pricing model for purposes of the compensation valuation primarily because the market information we review from Towers Perrin calculates the value of option awards on this basis. The following table provides the number of WEC stock options granted to each named executive officer.

Executive Officer	Options Granted
Mr. Klappa	252,000
Mr. Leverett	95,000
Mr. Kuester	95,000
Mr. Salustro	95,000
Mr. Fleming	75,000

For financial reporting purposes under SFAS 123R, the stock options granted to the named executive officers in 2006 had a grant date fair value of $7.69 per option.

2006 Performance Units. In 2006, the Compensation Committee granted WEC performance units to each of our named executive officers and approved a pool of performance units that were granted to approximately 135 other employees. With respect to the 2006 performance units, the amount of the benefit that ultimately vests will be dependent upon WEC's total stockholder return over a three-year period ending December 31, 2008, as compared to the total stockholder return of a custom peer group of companies described below. Total stockholder return is the calculation of total WEC return (stock price appreciation plus reinvestment of dividends) based upon an initial investment of $100 and subsequent $100 investments at the end of each quarter during the three-year performance period. As described above, the Compensation Committee believes this measure closely aligns executive financial interests with those of WEC's typical stockholder.

Upon vesting, the performance units will be settled in cash in an amount determined by multiplying the number of performance units that have vested by the fair market value of WEC's common stock on the date of vesting.

The peer group used for purposes of the performance units is: Allegheny Energy, Inc.; Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; Avista Corporation; Consolidated Edison, Inc.; DTE Energy Company; Duke Energy Corp.; Energy East Corporation; Entergy Corporation; Exelon Corporation; FirstEnergy Corp.; FPL Group, Inc.; NiSource Inc.; Northeast Utilities; Nstar; OGE Energy Corp.; Pinnacle West Capital Corporation; Pepco Holdings, Inc.; Progress Energy Inc.; Public Service Enterprise Group Incorporated; Puget Energy, Inc.; SCANA Corporation; Sempra Energy; Sierra Pacific Resources; The Southern Company; Westar Energy, Inc.; Wisconsin Energy Corporation; WPS Resources Corporation (now known as Integrys Energy Group, Inc.); and Xcel Energy Inc. This peer group was chosen because we believe these companies are similar to WEC in terms of business model and long-term strategies.

The required performance percentile rank and the applicable vesting percentage are set forth in the chart below.

Performance Percentile Rank	Vesting Percent
< 25th Percentile	0%
25th Percentile	25%
Target (50th Percentile)	100%
75th Percentile	125%
90th Percentile	175%

If WEC's rank is between the benchmarks identified above, the vesting percentage will be determined by interpolating the appropriate vesting percentage. Unvested performance units generally are immediately forfeited upon a named executive officer's cessation of employment with WEC prior to completion of the three-year performance period. However, the performance units will vest immediately at the target 100% rate upon (1) the termination of the named executive officer's employment by reason of disability or death or (2) a change in control of WEC while the named executive officer is employed by WEC or its subsidiaries, including the Company. In addition, a prorated number of performance units (based upon the target 100% rate) will vest upon the termination of employment of the named executive officer by reason of retirement prior to the end of the three-year performance period.

For purposes of determining the appropriate number of performance units to grant to a particular named executive officer, the value of a unit was determined based on an assumed approximate value of $38.50 per unit. The assumed approximate value was based on trading prices for WEC's common stock in late November 2005, the time at which we were analyzing target compensation levels for 2006. The following table provides the number of units granted to each named executive officer at the 100% target level.

Executive Officer	Performance Units Granted
Mr. Klappa	29,600
Mr. Leverett	12,800
Mr. Kuester	12,800
Mr. Salustro	12,800
Mr. Fleming	7,900

For financial reporting purposes under SFAS 123R, the performance units granted to the named executive officers in 2006 had a grant date fair value of $39.90 per unit.

2006 Payouts Under Previously Granted Long-Term Incentive Awards. In 2004, the Compensation Committee granted WEC performance share awards to participants in the plan, including the named executive officers (other than Mr. Fleming who was not an officer of the Company at the time). The terms of the performance shares granted in 2004 were substantially similar to those of the performance units granted in 2006 described above, except that participants could elect to receive a payout in cash or WEC common stock at vesting. Payouts under the 2004 performance shares were based on WEC's total stockholder return for the three-year performance period ended December 31, 2006 against substantially the same group of peer companies used for the 2006 performance unit awards. The required performance percentile ranks and related vesting schedule were identical to that of the 2006 units described above.

For the three-year performance period ended December 31, 2006, WEC's total stockholder return was at approximately the 59th percentile of the peer group, resulting in the performance shares vesting at a level of 108.6%. The actual payouts were determined by multiplying the number of vested performance shares by the closing price of WEC's common stock ($46.52) on January 8, 2007, the date the Compensation Committee validated WEC's total stockholder return for the three-year performance period. The actual payout to each named executive officer is reflected in the "Option Exercises and Stock Vested for Fiscal Year 2006" table below. This table also reflects amounts realized by any named executive officer in connection with the exercise in 2006 of any vested stock options and the amounts realized by any named executive officer in connection with the vesting of previously granted restricted stock. For information on other outstanding equity awards held by our named executive officers at December 31, 2006, please refer to the table entitled "Outstanding Equity Awards at Fiscal Year-End 2006" below.

Stock Ownership Guidelines. The Compensation Committee believes that an important adjunct to the long-term incentive program is significant stock ownership by officers who participate in the program, including the named executive officers. Accordingly, the Compensation Committee has implemented stock ownership guidelines for officers of WEC and its subsidiaries, including the Company. These guidelines provide that each executive officer should, over time (generally within five years of appointment as an executive officer), acquire and hold WEC common stock having a minimum fair market value ranging from 150% to 300% of base salary. In addition to certificated shares, holdings of each of the following are included in determining compliance with the stock ownership guidelines: WEC restricted stock; WEC phantom stock units held in the Executive Deferred Compensation Plan; WEC stock held in the 401(k) plan; WEC performance shares and performance units at target; vested WEC stock options; WEC shares held in our dividend reinvestment plan; and WEC shares held by a brokerage account, jointly with an immediate family member or in a trust.

Policy Regarding Hedging the Economic Risk of Stock Ownership. Certain forms of hedging or monetization transactions, such as zero-cost collars and forward sale contracts, allow a director, officer or employee to lock in much of the value of his or her stock holdings, often in exchange for all or part of the potential for upside appreciation in the stock. These transactions allow the director, officer or employee to continue to own the covered securities, but without the full risks and rewards of ownership. When that occurs, the director, officer or employee may no longer have the same objectives as WEC's other stockholders. Therefore, we have a policy under which directors, officers and employees are prohibited from engaging in any such transactions.

Analysis of Aggregate Salary, Annual Incentive and Long-Term Incentive Compensation. The discussion above describes the manner in which we determined the (1) annual base salary, (2) target level annual cash incentive compensation and (3) long-term incentive compensation awards for each named executive officer. As we developed preliminary target compensation levels for each of these elements of total compensation, we compared the aggregate amount of these elements to the market compensation data. The purpose of this review is to confirm that the aggregate targeted compensation does not deviate significantly from market medians.

Retirement Programs. We also maintain four different retirement plans in which our named executive officers participate: a defined benefit pension plan of the cash balance type, two supplemental executive retirement plans and individual letter agreements with each of the named executive officers. We believe our retirement plans are a valuable benefit in the attraction and retention of our employees, including our executive officers. We believe the value of ensuring long-term financial security for our employees, beyond their employment with the Company, is a valuable component of our overall compensation program, which will inspire increased

loyalty and improved performance. For more information about our retirement plans, see "Pension Benefits at Fiscal Year-End 2006" and "Retirement Plans" later in this information statement.

Other Benefits, Including Perquisites. The Company provides its executive officers with employee benefits and perquisites. Except as specifically noted elsewhere in this information statement, the employee benefits programs in which executive officers participate (which provide benefits such as medical benefits coverage, retirement benefits and annual contributions to a qualified savings plan) are generally the same programs offered to substantially all of the Company's salaried employees.

The perquisites made available to executive officers include the availability of financial planning, payment of the cost of an annual physical exam and limited spousal travel. The Company also pays periodic dues and fees for certain club memberships for the named executive officers and other designated officers. In addition, executive officers receive tax gross-ups to reimburse the officer for certain tax liabilities. None of these perquisites exceeded the greater of $25,000 or 10% of the officer's total perquisites in 2006, except for certain relocation expenses paid to Mr. Fleming in the amount of $52,451. We believe this one-time payment of relocation expenses was appropriate to recruit an executive officer of Mr. Fleming's caliber and experience. For a more detailed discussion of perquisites made available to our named executive officers, please refer to the notes following the Summary Compensation Table below.

In addition, each of our executive officers participates in a death benefit only plan. Under the terms of the plan, upon an executive officer's death a benefit is paid to his or her designated beneficiary in an amount equal to the after-tax value of three times the officer's base salary if the officer is employed by us at the time of death or the after-tax value of one times final base salary if death occurs post-retirement.

Severance Benefits and Change in Control. Competitive practices dictate that companies should provide reasonable severance benefits to employees. In addition, we believe it is important to provide protections to our executive officers in connection with a change in control of WEC. Our belief is that the interests of WEC's stockholders will be best served if the interests of our executive officers are aligned with them, and providing change in control benefits should eliminate, or at least reduce, the reluctance of management to pursue potential change in control transactions that may be in the best interests of WEC's stockholders.

The Compensation Committee has approved severance programs that provide for severance benefits in the event of a change in control to designated executives and other key employees. Of our named executive officers, only Mr. Salustro participated in these general severance programs. Mr. Salustro retired effective February 28, 2007.

Each of Messrs. Klappa, Leverett, Kuester and Fleming has an employment agreement with WEC, which includes change in control and severance provisions. Under the terms of these agreements, the applicable named executive officer is entitled to certain benefits in the event of a termination of employment. In the event of a termination of employment (1) by WEC for any reason other than cause, death or disability in anticipation of or following a change in control, (2) by the applicable executive officer for good reason in connection with or in anticipation of a change in control or (3) by the applicable executive officer after completing one year of service following a change in control, each named executive officer is generally entitled to:

- A lump sum payment equal to three times: (1) the highest annual base salary in effect during the last three years and (2) the higher of the current year target bonus amount or the highest bonus paid in any of the last three years;
- A lump sum payment assuming three years of additional credited service under the qualified and non-qualified retirement plans based upon the highest annual base salary in effect during the last three fiscal years and highest bonus amount;
- A lump sum payment equal to the value of three additional years of WEC match in the 401(k) plan and the WEC Executive Deferred Compensation Plan;
- Continuation of health and certain other welfare benefit coverage for three years following termination of employment;
- Full vesting of WEC stock options, WEC restricted stock and WEC performance units;
- Financial planning services and other benefits; and
- A gross-up payment should any payments trigger federal excise taxes as a "parachute payment."

In the absence of a change in control, if we terminate the employment of the applicable executive officer for any reason other than cause, death or disability, or the applicable executive officer terminates his or her employment for good reason, the payments to the applicable named executive officer will be the same as those described above, except that with respect to Messrs. Leverett, Kuester and Fleming, (1) the multiple for the lump sum payment in the first bullet point will be reduced to two, (2) the number of additional years of credited service for qualified and non-qualified retirement plans will be two, (3) the number of additional years of matching in the 401(k) plan and the WEC Executive Deferred Compensation Plan will be two years, and (4) health and certain other welfare benefits will continue for two years following termination of employment.

In addition, our supplemental executive retirement plan provides that in the event of a change in control of WEC, each named executive officer will be entitled to a lump sum payment of amounts due under the plan without regard to whether such officer's employment has been terminated.

For a more detailed discussion of the benefits and tables that describe payouts under various termination scenarios, see "Potential Payments upon Termination or Change in Control" later in this information statement.

Impact of Prior Compensation. The Compensation Committee did not consider the amounts realized or realizable from prior incentive compensation awards in establishing the levels of short-term and long-term incentive compensation for 2006.

Section 162(m) of the Internal Revenue Code. Section 162(m) of the Internal Revenue Code limits the deductibility of certain executives' compensation that exceeds $1 million per year, unless the compensation is performance-based under Section 162(m) and is issued through a plan that has been approved by stockholders. While the Compensation Committee takes into consideration the provisions of Section 162(m), maintaining tax deductibility is but one consideration among many in the design of the executive compensation program.

With respect to 2006 compensation for the named executive officers, the annual stock option grants under WEC's 1993 Omnibus Stock Incentive Plan have been structured to qualify as performance-based compensation under Section 162(m). Annual cash incentive awards under the STPP and performance units under the WEC Performance Unit Plan do not qualify for tax deductibility under Section 162(m).

COMPENSATION COMMITTEE REPORT

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K with management and, based on such review and discussions, the Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this information statement.

The Compensation Committee

John F. Bergstrom, Committee Chair
John F. Ahearne
Ulice Payne, Jr.

EXECUTIVE OFFICERS' COMPENSATION

The following table summarizes total compensation awarded to, earned by or paid to the Company's Chief Executive Officer, Chief Financial Officer and each of the Company's other three most highly compensated executive officers (the "named executive officers") during 2006. The amounts shown in this and all subsequent tables in this information statement are WEC consolidated compensation data.

Summary Compensation Table

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Name and Principal Position	Year	Salary ($)	Bonus ($)	Stock Awards [2] ($)	Option Awards [2] ($)	Non-Equity Incentive Plan Compensation [3] ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings [4] ($)	All Other Compensation [10] [11] ($)	Total ($)
Gale E. Klappa Chairman of the Board, President and Chief Executive Officer of WEC, WE and WG	2006	1,005,000	--	1,392,112	1,422,493	2,060,250	1,838,928 [5]	209,828 [12]	7,928,611
Allen L. Leverett Executive Vice President and Chief Financial Officer of WEC, WE and WG	2006	538,200	--	767,686	520,850	882,648	-- [6]	79,542	2,788,926
Frederick D. Kuester Executive Vice President of WEC and WG; Executive Vice President and Chief Operating Officer of WE	2006	582,000	--	787,223	520,850	954,480	689,533 [7]	116,210	3,650,296
Larry Salustro Executive Vice President of WEC, WE and WG	2006	424,872	--	823,758	520,850	518,344	575,196 [8]	115,895	2,978,915
James C. Fleming Executive Vice President and General Counsel of WEC, WE and WG	2006	400,008	150,000 [1]	145,153	192,250	574,012	147,488 [9]	271,484	1,880,395

(1) Represents a one-time signing bonus paid to Mr. Fleming upon commencement of employment.

(2) The amounts reported reflect the amounts recognized for financial statement reporting purposes in WEC's 2006 consolidated financial statements in accordance with SFAS 123R for WEC stock option awards and WEC performance unit awards made in 2005 and 2006, WEC performance share awards made in 2004 and various WEC restricted stock grants that have not yet vested. The expenses related to WEC performance shares, performance units and restricted stock are reflected in column (e) above and the expenses related to WEC stock options are reflected in column (f) above. The actual value received by the executives from these awards may range from $0 to greater than the reported amounts recognized for financial statement reporting purposes, depending upon WEC performance and the executive's number of additional years of service with WEC or its subsidiaries. In accordance with Item 402 of Regulation S-K, the amounts reported in the table above do not reflect the amount of estimated forfeitures related to service-based vesting conditions used for financial reporting purposes. In accordance with SFAS 123R, certain assumptions were made in the valuation of the WEC stock options, the WEC performance units/shares and the WEC restricted stock for financial reporting purposes. See "Stock Options" in Note A -- Summary of Significant Accounting Policies and Note N -- Common Equity in the Notes to Consolidated Financial Statements in our 2006 Annual Report on Form 10-K for a description of these assumptions (which Notes are also included in the 2006 Annual Report to Stockholders attached as Appendix A). The assumptions made in connection with the valuation of the stock options are the same as described in Note A and Note N, except for the expected life of the options which is 6.5 years. The change in the expected life of the options to 6.5 years from 6.3 years, as set forth in Note A, results from none of the named executive officers being "retirement eligible" as of December 31, 2006 whereas the assumption described in Note A is a weighted average of all option holders, some of who are "retirement eligible."

The reported amounts for 2006 include expenses attributable to stock options and unvested stock awards granted in prior years, respectively, for each named executive officer as follows: Mr. Klappa - $776,533 and $923,840; Mr. Leverett - $277,333 and $565,190; Mr. Kuester - $277,333 and $584,727; Mr. Salustro - $277,333 and $621,262; and Mr. Fleming - $0 and $0. For additional information regarding the value of option awards and stock awards granted in 2006, see column (l) in "Grants of Plan-Based Awards for Fiscal Year 2006."

In December 2004, the Compensation Committee approved the acceleration of vesting of all unvested WEC options awarded, including those awarded to executive officers, in 2002, 2003 and 2004 in anticipation of the impact of adoption of SFAS 123R. Therefore, the reported amounts only reflect compensation expense for two years of option awards (2005 and 2006) and do not reflect any compensation expense for the options awarded to the named executive officers in 2004 as they were fully vested prior to 2006.

(3) Consists of amounts earned under Wisconsin Energy's Short-Term Performance Plan for 2006. See Note (2) under Grants of Plan-Based Awards for Fiscal Year 2006 for a description of the terms of these awards.

(4) The amounts reported reflect the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under all defined benefit plans from December 31, 2005 to December 31, 2006. Our employees, including the named executive officers, participate in WEC's defined benefit plans. The named executive officers did not receive any above-market or preferential earnings on deferred compensation in 2006. A change in the assumptions used to calculate the actuarial present values under Wisconsin Energy's defined benefit plans as a result of a change in the tax laws caused Mr. Leverett's reported amount to be negative. The tax laws no longer allow for an acceleration of nonqualified retirement benefits, and therefore our actuarial valuation now assumes a life annuity rather than a lump sum payment for the nonqualified benefits. The discount rate used to measure the actuarial present value under the nonqualified plans changed to 5.75% from 4.68%. The change affects all named executive officers, but only Mr. Leverett's balance was small enough to result in a negative change in present value. This change in assumptions does not constitute a plan change.

(5) Wisconsin Energy's pension benefit obligations to Mr. Klappa will be offset by pension benefits Mr. Klappa is entitled to receive from a prior employer for nearly 29 years of service. The amount reported for Mr. Klappa represents only WEC's obligation of the aggregate change in the actuarial present value of Mr. Klappa's accumulated benefit under all defined benefit plans. Based on information received from the prior employer, we have estimated the portion of Mr. Klappa's total accumulated pension benefit for which WEC will be responsible. The total aggregate change in the actuarial present value of Mr. Klappa's accumulated benefit is $1,970,360 - $131,432 of which we estimate the prior employer is obligated to pay. If Mr. Klappa's prior employer becomes unable to pay its portion of Mr. Klappa's accumulated pension benefit, WEC is obligated to pay the total amount.

(6) The aggregate change in the actuarial present value of Mr. Leverett's accumulated benefit under all defined benefit plans is ($109,950).

(7) Wisconsin Energy's pension benefit obligations to Mr. Kuester will be offset by pension benefits Mr. Kuester is entitled to receive from a prior employer for nearly 32 years of service. The amount reported for Mr. Kuester represents only WEC's obligation of the aggregate change in the actuarial present value of Mr. Kuester's accumulated benefit under all defined benefit plans. Based on information received from the prior employer, we have estimated the portion of Mr. Kuester's total accumulated pension benefit for which WEC will be responsible. The total aggregate change in the actuarial present value of Mr. Kuester's accumulated benefit is $802,868 – $113,335 of which we estimate the prior employer is obligated to pay. If Mr. Kuester's prior employer becomes unable to pay its portion of Mr. Kuester's accumulated pension benefit, WEC is obligated to pay the total amount.

(8) The amount reported for Mr. Salustro represents the total aggregate change in the actuarial present value of Mr. Salustro's accumulated benefit. Wisconsin Energy's pension benefit obligations to Mr. Salustro will be offset by pension benefits Mr. Salustro is entitled to receive from a prior employer. We are currently unable to determine the amount of this offset.

(9) In addition to Mr. Fleming's participation in WEC's qualified pension plan and supplemental executive retirement plan, the present value of the amount to be credited to a special supplemental pension account is $126,418, which will be paid upon termination of employment after age 65. See "Pension Benefits at Fiscal Year-End 2006" and "Retirement Plans" later in this information statement for additional details.

(10) Messrs. Klappa, Leverett, Kuester, Salustro and Fleming received perquisites in 2006 as indicated below.

Type of Perquisite	Named Executive Officer				
	Gale E. Klappa	Allen L. Leverett	Frederick D. Kuester	Larry Salustro	James C. Fleming
Club Dues	X	X	X		X
Financial Planning	X	X	X	X	X
Medical Physical	X	X	X	X	X
Relocation			X		X[a]
Spousal Travel	X[b]				

(a) Mr. Fleming received relocation benefits in the amount of $52,451, consisting of amounts paid to a third party relocation company and one month's base salary.

(b) Mr. Klappa's spouse will occasionally accompany him on certain business trips, flying on the airplane in which we own a partial interest. The amounts reported for Mr. Klappa do not reflect any incremental cost for this travel as the airplane cost is the same regardless of whether his spouse travels. The only cost to the Company related to Mr. Klappa's spouse's travel is the tax gross-up paid to Mr. Klappa to reimburse him for taxes paid on compensation imputed pursuant to the Internal Revenue Code, which amount is separately reflected in the Summary Compensation Table as described in Note (11) below.

(11) Wisconsin Energy maintains a Death Benefit Only Plan. Pursuant to the terms of the Plan, upon an officer's death a benefit is paid to his or her designated beneficiary in an amount equal to the after-tax value of three times the officer's base salary if the officer is employed at the time of death or the after-tax value of one times final base salary if death occurs post-retirement. We recognized an expense for the Death Benefit Only Plan as follows in 2006: Mr. Klappa ($65,725), Mr. Leverett ($13,821), Mr. Kuester ($41,124), Mr. Salustro ($53,909) and Mr. Fleming ($174,031). Much of the expense recognized for Mr. Fleming is a "catch-up" amount because he is over the age of 60 and 2006 was his first year of employment with WEC and its subsidiaries, including the Company.

In addition to the perquisites and amounts recognized under the Death Benefit Only Plan identified above, All Other Compensation for Messrs. Klappa, Leverett, Kuester, Salustro and Fleming consist of:

- Employer matching of contributions into the 401(k) plan in the amount of $6,600 for each named executive;
- "Make-whole" payments under WEC's Executive Deferred Compensation Plan that provide a match at the same level as the 401(k) plan (3% for up to 6% of wages) for all deferred salary and bonus not otherwise eligible for a match in the amounts of $81,435, $34,343, $37,680, $25,723 and $9,000, respectively; and
- Tax reimbursements or "gross-ups" for all applicable perquisites in the amounts of $18,696, $8,276, $7,022, $5,476 and $13,751, respectively.

(12) Includes $14,406 attributable to Wisconsin Energy's Directors' Charitable Awards Program in connection with Mr. Klappa's service on the Board of Directors. See "Director Compensation" for a description of the Directors' Charitable Awards Program.

Percentages of Total Compensation. For Messrs. Klappa, Leverett, Kuester, Salustro and Fleming, (1) salary (as reflected in column (c) above) represented approximately 13%, 19%, 16%, 14% and 21%, respectively, of total compensation (as shown in column (j) above) for 2006, (2) annual incentive compensation (as reflected in column (g) above) represented approximately 26%, 32%, 26%, 17% and 31%, respectively, of total compensation in 2006, and (3) salary and annual incentive compensation together represented approximately 39%, 51%, 42%, 32% and 52%, respectively, of total compensation in 2006.

Grants of Plan-Based Awards for Fiscal Year 2006

The following table shows additional data regarding incentive plan awards to the named executive officers in 2006.

(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)		(l)
			Estimated Possible Payouts Under Non-Equity Incentive Plan Awards[2]			Estimated Future Payouts Under Equity Incentive Plan Awards[3]			All Other Stock Awards: Number of Shares of Stock or Units	All Other Option Awards[4]			Grant Date Fair Value of Stock and Option Awards[7]
Name	Grant Date	Action Date[1]	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	(#)	Number of Securities Underlying Options (#)	Exercise or Base Price[5] ($/Sh)	Closing Market Price[6] ($/Sh)	($)
Gale E. Klappa	1/18/06	--	502,500	1,005,000	2,110,500	--	--	--	--	--	--	--	--
	1/03/06	12/12/05	--	--	--	7,400	29,600	51,800	--	--	--	--	1,181,040
	1/03/06	12/12/05	--	--	--	--	--	--	--	252,000	39.475	39.90	1,937,880
Allen L. Leverett	1/18/06	--	215,280	430,560	904,176	--	--	--	--	--	--	--	--
	1/03/06	12/12/05	--	--	--	3,200	12,800	22,400	--	--	--	--	510,720
	1/03/06	12/12/05	--	--	--	--	--	--	--	95,000	39.475	39.90	730,550
Frederick D. Kuester	1/18/06	--	232,800	465,600	977,760	--	--	--	--	--	--	--	--
	1/03/06	12/12/05	--	--	--	3,200	12,800	22,400	--	--	--	--	510,720
	1/03/06	12/12/05	--	--	--	--	--	--	--	95,000	39.475	39.90	730,550
Larry Salustro	1/18/06	--	169,949	339,898	713,786	--	--	--	--	--	--	--	--
	1/03/06	12/12/05	--	--	--	3,200	12,800	22,400	--	--	--	--	510,720
	1/03/06	12/12/05	--	--	--	--	--	--	--	95,000	39.475	39.90	730,550
James C. Fleming	1/18/06	--	140,003	280,006	588,013	--	--	--	--	--	--	--	--
	1/03/06	12/12/05	--	--	--	1,975	7,900	13,825	--	--	--	--	315,210
	1/06/06	11/23/05	--	--	--	--	--	--	2,500[8]	--	--	--	100,875
	1/03/06	12/12/05	--	--	--	--	--	--	--	75,000	39.475	39.90	576,750

(1) On December 12, 2005, the Compensation Committee awarded the 2006 option and performance unit grants effective the first trading day of 2006 (January 3, 2006).

(2) Non-equity incentive plan awards consist of awards under Wisconsin Energy's Short-Term Performance Plan. The target bonus levels established for each of Messrs. Klappa, Leverett, Kuester, Salustro and Fleming for 2006 were 100%, 80%, 80%, 80% and 70% of base salary, respectively. Pursuant to the terms of their respective employment agreements, the target bonus levels for each of Messrs. Klappa, Leverett and Kuester may not be adjusted downward except by an action of the Board or Compensation Committee which lowers the target bonus for the entire senior executive group. Based on certain financial and operational goals established by the Compensation Committee, actual payments to the named executive officers could have ranged from 0% of the target award to 210% of the target. Based on actual performance for 2006, each named executive officer (other than Mr. Salustro) earned 205% of the target award and these amounts are reported above in the Summary Compensation Table. For a more detailed description of the STPP and Mr. Salustro's payout, see the Compensation Discussion and Analysis above.

(3) Consists of performance units awarded under the Wisconsin Energy Corporation Performance Unit Plan. Upon vesting, the WEC performance units will be settled in cash in an amount determined by multiplying the number of performance units which have become vested by the fair market value of Wisconsin Energy's common stock on the date of vesting. The number of WEC performance units that ultimately will vest is dependent upon Wisconsin Energy's total stockholder return over a three-year period ending December 31, 2008 as compared to the total stockholder return of a Custom Peer Group consisting of 30 companies that Wisconsin Energy believes provides an accurate representation of its peers. These companies, similar to WEC in terms of business model and long-term strategies, are: Allegheny Energy, Inc.; Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; Avista Corporation; Consolidated Edison, Inc.; DTE Energy Company; Duke Energy Corp.; Energy East Corporation; Entergy Corporation; Exelon Corporation; FirstEnergy Corp.; FPL Group, Inc.; NiSource Inc.; Northeast Utilities; Nstar; OGE Energy Corp.; Pinnacle West Capital Corporation; Pepco Holdings, Inc.; Progress Energy Inc.; Public Service Enterprise Group Incorporated; Puget Energy, Inc.; SCANA Corporation; Sempra Energy; Sierra Pacific Resources; The Southern Company; Westar Energy, Inc.; Wisconsin Energy Corporation; WPS Resources Corporation (now known as Integrys Energy Group, Inc.); and Xcel Energy Inc. In 2006, Cinergy Corp. and Duke Energy Corp. merged. Cinergy Corp. was part of the Custom Peer Group, but was replaced by Duke Energy Corp. after the merger.

Total stockholder return is the calculation of total WEC return (stock price appreciation plus reinvested dividends) based upon an initial investment of $100 and subsequent $100 investments at the end of each quarter during the three-year performance period. The regular vesting schedule for the performance units is as follows:

Percentile Rank	Vesting Percent
< 25th Percentile	0%
25th Percentile	25%
Target (50th Percentile)	100%
75th Percentile	125%
90th Percentile	175%

If Wisconsin Energy's rank is between the benchmarks identified above, the vesting percentage will be determined by interpolating the appropriate vesting percentage. Except as discussed herein, unvested performance units are immediately forfeited upon cessation of employment with WEC or its subsidiaries prior to completion of the three-year performance period.

The performance units will vest immediately at the target 100% rate upon (1) the termination of the named executive officer's employment by reason of disability or death or (2) a change in control of Wisconsin Energy while employed by the Company. In addition, a prorated number of performance units (based upon the target 100% rate) will vest upon the termination of employment by reason of retirement prior to the end of the three-year performance period. Participants, including the named executive officers, will receive a cash dividend when Wisconsin Energy declares a dividend on its common stock in an amount equal to the number of WEC performance units granted to the named executive officer at the target 100% rate multiplied by the amount of the dividend paid on a share of WEC common stock. The performance units have no voting rights attached to them.

(4) Consists of non-qualified stock options to purchase shares of Wisconsin Energy common stock pursuant to the 1993 Omnibus Stock Incentive Plan, as amended. These options have exercise prices equal to the fair market value of Wisconsin Energy common stock on the date of grant. These options were granted for a term of ten years, subject to earlier termination in certain events related to termination of employment. The options fully vest and become exercisable three years from the date of grant. Notwithstanding the preceding sentence, the options become immediately exercisable upon the occurrence of a change in control of WEC or termination of employment by reason of retirement, disability or death. The exercise price may be paid by delivery of already-owned shares. Tax withholding obligations related to exercise may be satisfied by withholding shares otherwise deliverable upon exercise, subject to certain conditions. Subject to the limitations of WEC's 1993 Omnibus Stock Incentive Plan, as amended, the Compensation Committee has the power to amend the terms of any option (with the participant's consent).

(5) The exercise price of the option awards is equal to the fair market value of Wisconsin Energy's common stock on the date of grant, January 3, 2006. Fair market value is the average of the high and low prices of Wisconsin Energy common stock reported in the New York Stock Exchange Composite Transaction Report on the grant date.

(6) Reflects the closing market price of Wisconsin Energy common stock reported in the New York Stock Exchange Composite Transaction Report on the grant date.

(7) Grant date fair value of each award as determined in accordance with SFAS 123R, which includes the value of the right to receive dividends. The actual value received by the executives from these awards may range from $0 to greater than the reported amounts, depending upon WEC performance and the executive's number of additional years of service with WEC or its subsidiaries.

(8) Consists of WEC restricted stock granted to Mr. Fleming effective January 6, 2006, which vests at the rate of 20% for each year of service until 100% vesting occurs on January 6, 2011. Notwithstanding the preceding sentence, 100% vesting may occur upon death or disability while Mr. Fleming is employed by WEC or its subsidiaries, a change in control of WEC or by action of the Compensation Committee. Wisconsin Energy granted the restricted stock pursuant to the terms of the Letter Agreement between Wisconsin Energy and Mr. Fleming, dated November 23, 2005 and effective as of January 3, 2006.

Outstanding Equity Awards at Fiscal Year-End 2006

The following table reflects the number and value of exercisable and unexercisable WEC options as well as the number and value of other WEC stock awards held by the named executive officers at fiscal year-end 2006.

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options: Exercisable[1] (#)	Number of Securities Underlying Unexercised Options: Unexercisable[2] (#)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock that Have Not Vested (#)	Market Value of Shares or Units of Stock that Have Not Vested[3] ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights that Have Not Vested[3] ($)
Gale E. Klappa	250,000	--	--	25.3100	4/14/13	--	--	--	--
	200,000	--	--	33.4350	1/02/14	--	--	--	--
	--	280,000	--	34.2000	1/18/15	--	--	--	--
	--	252,000	--	39.4750	1/03/16	--	--	--	--
	--	--	--	--	--	30,171[4]	1,431,916	--	--
	--	--	--	--	--	--	--	35,875[9]	1,702,628[9]
	--	--	--	--	--	--	--	29,600[10]	1,404,816[10]
Allen L. Leverett	200,000	--	--	29.1300	7/01/13	--	--	--	--
	150,000	--	--	33.4350	1/02/14	--	--	--	--
	--	100,000	--	34.2000	1/18/15	--	--	--	--
	--	95,000	--	39.4750	1/03/16	--	--	--	--
	--	--	--	--	--	8,361[5]	396,813	--	--
	--	--	--	--	--	--	--	15,750[9]	747,495[9]
	--	--	--	--	--	--	--	12,800[10]	607,488[10]
Frederick D. Kuester	200,000	--	--	31.0700	10/13/13	--	--	--	--
	150,000	--	--	33.4350	1/02/14	--	--	--	--
	--	100,000	--	34.2000	1/18/15	--	--	--	--
	--	95,000	--	39.4750	1/03/16	--	--	--	--
	--	--	--	--	--	18,119[6]	859,928	--	--
	--	--	--	--	--	--	--	15,750[9]	747,495[9]
	--	--	--	--	--	--	--	12,800[10]	607,488[10]
Larry Salustro	40,000	--	--	27.6530	12/17/07	--	--	--	--
	10,000	--	--	29.3438	5/19/08	--	--	--	--
	10,000	--	--	27.3130	6/02/09	--	--	--	--
	50,000	--	--	19.9690	4/03/10	--	--	--	--
	75,000	--	--	20.3900	2/07/11	--	--	--	--
	75,000	--	--	22.6550	1/02/12	--	--	--	--
	125,000	--	--	25.4100	1/02/13	--	--	--	--
	150,000	--	--	33.4350	1/02/14	--	--	--	--
	--	100,000	--	34.2000	1/18/15	--	--	--	--
	--	95,000	--	39.4750	1/03/16	--	--	--	--
	--	--	--	--	--	28,802[7]	1,366,943	--	--
	--	--	--	--	--	--	--	15,750[9]	747,495[9]
	--	--	--	--	--	--	--	12,800[10]	607,488[10]
James C. Fleming	--	75,000	--	39.4750	1/03/16	--	--	--	--
	--	--	--	--	--	2,554[8]	121,213	--	--
	--	--	--	--	--	--	--	7,900[10]	374,934[10]

(1) All options reported in this column are fully vested and exercisable.

(2) All options reported in this column with an exercise price of $34.20 and an expiration date of January 18, 2015 fully vest and become exercisable on January 18, 2008. All options reported in this column with an exercise price of $39.475 and an expiration date of January 3, 2016, fully vest and become exercisable on January 3, 2009.

(3) Based on the closing price of Wisconsin Energy common stock reported in the New York Stock Exchange Composite Transaction Report on December 29, 2006, the last trading day of the year.

(4) Effective April 14, 2003, Mr. Klappa was granted a WEC restricted stock award of 39,510 shares which vests at the rate of 10% for each year of service until 100% vesting occurs on April 14, 2013. Earlier vesting may occur due to (1) a termination of employment by (a) death, (b) disability, (c) a change in control of WEC, (d) Mr. Klappa for good reason, or (e) WEC without cause, or (2) action by the Compensation Committee. The number of shares reported includes shares acquired pursuant to the reinvestment of dividends on the restricted stock.

(5) Effective July 1, 2003, Mr. Leverett was granted a WEC restricted stock award of 28,850 shares. Two-thirds of the shares vested on July 1, 2005 and the remaining one-third vest at the rate of 20% for each year of service after that date until 100% vesting occurs on July 1, 2010. Earlier vesting may occur due to (1) a termination of employment by (a) death, (b) disability, (c) a change in control of WEC, (d) Mr. Leverett for good reason, or (e) WEC without cause, or (2) action by the Compensation Committee. The number of shares reported includes shares acquired pursuant to the reinvestment of dividends on the restricted stock.

(6) Effective October 13, 2003, Mr. Kuester was granted a WEC restricted stock award of 24,140 shares, which vest at the rate of 10% for each year of service until 100% vesting occurs on October 13, 2013. Earlier vesting may occur due to (1) a termination of employment by (a) death, (b) disability, (c) a change in control of WEC, (d) Mr. Kuester for good reason, or (e) WEC without cause, or (2) action by the Compensation Committee. The number of shares reported includes shares acquired pursuant to the reinvestment of dividends on the restricted stock.

(7) Effective each of May 19, 1998, June 2, 1999, October 21, 2000 and February 7, 2001, Mr. Salustro was granted shares of WEC restricted stock that vest in full ten years from the respective grant date, subject to a performance accelerator. The performance accelerator is triggered by achieving certain WEC cumulative earnings per share targets measured from the respective grant date. Ten percent annually is available for accelerated vesting and the stock is subject to cumulative vesting. Earlier vesting may occur due to termination of employment by death, disability or a change in control of WEC or by action of the Compensation Committee. In addition, the stock vests upon retirement at or after attainment of age 60. Mr. Salustro retired effective February 28, 2007, at which time he had reached age 60.

In addition, effective April 29, 2003, Mr. Salustro was granted a WEC restricted stock award that vests upon retirement at or after attainment of age 60. The number of shares reported includes shares acquired pursuant to the reinvestment of dividends on the restricted stock.

(8) Effective January 6, 2006, Mr. Fleming was granted a WEC restricted stock award of 2,500 shares, which vest at the rate of 20% for each year of service until 100% vesting occurs on January 6, 2011. Earlier vesting may occur due to termination of employment by death, disability or a change in control of WEC or by action of the Compensation Committee. The number of shares reported includes shares acquired pursuant to the reinvestment of dividends on the restricted stock.

(9) The number of WEC performance units reported vest at the end of the three-year performance period ending December 31, 2007. The number of performance units reported and their corresponding value are based upon a payout at the maximum amount.

(10) The number of WEC performance units reported vest at the end of the three-year performance period ending December 31, 2008. The number of performance units reported and their corresponding value are based upon a payout at the target amount.

Option Exercises and Stock Vested for Fiscal Year 2006

This table shows the number and value of (1) WEC stock options that were exercised by the named executive officers, (2) WEC restricted stock awards that vested and (3) WEC performance shares that were earned in 2006.

(a)	(b)	(c)	(d)	(e)
	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)	Value Realized on Vesting ($)
Gale E. Klappa	-- --	-- --	4,379 (1) 21,177 (3)	167,869 (2) 985,154 (4)
Allen L. Leverett	-- --	-- --	2,069 (1) 17,919 (3)	83,358 (2) 833,592 (4)
Frederick D. Kuester	-- --	-- --	2,666 (1) 17,919 (3)	119,050 (2) 833,592 (4)
Larry Salustro	-- --	-- --	344 (1) 17,919 (3)	14,458 (2) 833,592 (4)
James C. Fleming	-- --	-- --	-- --	-- --

(1) Reflects the number of shares of WEC restricted stock that vested.

(2) Restricted stock value realized is determined by multiplying the number of shares of restricted stock that vested by the fair market value of Wisconsin Energy common stock on the date of vesting. We compute fair market value as the average of the high and low prices of Wisconsin Energy common stock reported in the New York Stock Exchange Composite Transaction Report on the vesting date.

(3) Reflects the number of WEC performance shares that were earned in 2006. Pursuant to the terms of the performance shares as amended by the Compensation Committee, each participant, including the named executive officers, was entitled to elect to receive shares of WEC's common stock or a cash payment based on the closing market price of shares of WEC common stock on the vesting date. Each named executive officer elected to receive a cash payment in lieu of shares of WEC common stock. Although the performance shares were earned as of December 31, 2006, the end of the applicable three-year performance period, the shares did not vest until the Compensation Committee took action on January 8, 2007.

(4) Performance shares value realized is determined by multiplying the number of performance shares that vested by the closing market price of Wisconsin Energy common stock on the date of vesting, January 8, 2007.

Pension Benefits at Fiscal Year-End 2006

The following table sets forth information for each named executive officer regarding their pension benefits at fiscal year-end 2006 under WEC's four different retirement plans discussed below.

(a)	(b)	(c)	(d)	(e)
Name	Plan Name	Number of Years Credited Service [1] (#)	Present Value of Accumulated Benefit [2][3] ($)	Payments During Last Fiscal Year ($)
Gale E. Klappa	WEC Plan	3.67	58,449	--
	SERP A	3.67	490,722	--
	Individual Letter Agreement	29.33	5,185,010	--
Allen L. Leverett	WEC Plan	3.50	47,599	--
	SERP A	3.50	314,547	--
	Individual Letter Agreement	18.00	708,537	--
Frederick D. Kuester	WEC Plan	3.17	46,191	--
	SERP A	3.17	200,970	--
	Individual Letter Agreement	34.33	3,133,137	--
Larry Salustro	WEC Plan	9.00	157,980	--
	SERP A	9.00	261,196	--
	SERP B	-- [4]	979,590	--
	Individual Letter Agreement	34.92	5,066,580	--
James C. Fleming	WEC Plan	1.00	11,588	--
	SERP A	1.00	9,481	--
	Individual Letter Agreement	1.00	126,418	--

(1) Years of service are computed as of December 31, 2006, the pension plan measurement date used for financial statement reporting purposes. Messrs. Klappa, Leverett, Kuester and Salustro have been credited with 25.66, 14.5, 31.16 and 25.92 years of service, respectively, pursuant to the terms of their Individual Letter Agreements (ILAs). The increase in the aggregate amount of each of Messrs. Klappa's, Leverett's, Kuester's and Salustro's accumulated benefit under all of Wisconsin Energy's retirement plans resulting from the additional years of credited service is the amount identified in connection with each respective ILA set forth in column (d).

(2) The key assumptions used in calculating the actuarial present values reflected in this column are:

- First projected unreduced retirement age based on current service:
  - For Messrs. Klappa, Leverett and Fleming, age 65.
  - For Messrs. Kuester and Salustro, age 62.
- Discount rate of 5.75%.
- Cash balance interest crediting rate of 7.375%.
- Form of payment:
  - WEC Plan: Lump sum.
  - SERP: Life annuity.
  - ILA: Life annuity, other than Mr. Fleming who we assume will receive a lump sum payment.
- Mortality Table, for life annuity:
  - Messrs. Klappa, Leverett, Kuester and Salustro - RP2000 with projection to 2010 - Male.
  - Mr. Fleming – N/A.

(3) Wisconsin Energy's pension benefit obligations to Messrs. Klappa and Kuester will be partially offset by pension benefits Messrs. Klappa and Kuester are entitled to receive from their former employers. The amounts reported for Messrs. Klappa and Kuester represent only WEC's obligation of the aggregate actuarial present value of each of their accumulated benefit under all of the plans. The total aggregate actuarial present value of each of Messrs. Klappa's and Kuester's accumulated benefit under all of the plans is $8,171,649 and $5,561,003, respectively, $2,437,468 and $2,180,705 of which we estimate the prior employer is obligated to pay. If either Mr. Klappa's or Mr. Kuester's former employer becomes unable to pay its portion of Mr. Klappa's or Mr. Kuester's accumulated pension benefit, WEC is obligated to pay the total amount.

The amount reported for Mr. Leverett represents the total aggregate present value of his accumulated benefit under all of the plans. Wisconsin Energy's pension benefit obligations to Mr. Leverett will be offset by pension benefits he is entitled to receive from a prior employer.

The amount reported for Mr. Salustro represents the total aggregate present value of his accumulated benefit under all of the plans. Wisconsin Energy's pension benefit obligations to Mr. Salustro will be offset by pension benefits he is entitled to receive from a prior employer. We are currently unable to determine the amount of this offset.

(4) Pursuant to the terms of SERP B, participants are not entitled to any payments until after they retire at or after age 60, regardless of how many years they have been employed with WEC or its subsidiaries. Therefore, there are no years of credited service associated with participation in SERP B.

Retirement Plans

Wisconsin Energy maintains four different plans providing for retirement payments and benefits: a defined benefit pension plan of the cash balance type (WEC Plan); two supplemental executive retirement plans (SERP A and SERP B); and Individual Letter Agreements with each of the named executive officers. The compensation currently considered for purposes of the retirement plans (other than the WEC Plan) for Messrs. Klappa, Leverett, Kuester and Salustro is $2,423,046, $1,248,942, $1,182,868 and $944,347, respectively. These amounts represent the average compensation (consisting of base salary and annual incentive compensation) for the 36 highest consecutive months. Under the terms of Mr. Fleming's employment agreement with WEC, the compensation considered for purposes of the retirement plans (other than the WEC Plan) is $400,008. This amount represents the cash compensation paid to Mr. Fleming in 2006. As of December 31, 2006, Messrs. Klappa, Leverett, Kuester, Salustro and Fleming currently have or are considered to have 29.33, 18.00, 34.33, 34.92 and 1.00 credited years of service, respectively, under the various supplemental plans described below. Messrs. Klappa, Kuester, Leverett and Salustro are not entitled to these supplemental benefits until they attain the age of 60. Mr. Fleming was not granted additional years of credited service.

The WEC Plan. Most regular full-time and part-time employees, including the named executive officers, participate in the WEC Plan. The WEC Plan bases a participant's defined benefit pension on the value of a hypothetical account balance. For individuals participating in the WEC Plan as of December 31, 1995, a starting account balance was created equal to the present value of the benefit accrued as of December 31, 1994, under the plan benefit formula prior to the change to a cash balance approach. That formula provided a retirement income based on years of credited service and average compensation (consisting of base salary) for the 36 highest consecutive months, with an adjustment to reflect the Social Security integrated benefit. In addition, individuals participating in the WEC Plan as of December 31, 1995, received a special one-time transition credit amount equal to a specified percentage varying with age multiplied by credited service and 1994 base pay.

The present value of the accrued benefit as of December 31, 1994, plus the transition credit, was also credited with interest at a stated rate. For 1996 and thereafter, a participant receives annual credits to the account equal to 5% of base pay (including 401(k) plan pre-tax deferrals and other items), plus an interest credit on all prior accruals equal to 4% plus 75% of the annual time-weighted trust investment return for the year in excess of 4%. Additionally, the WEC Plan provides that up to an additional 2% of base pay may be earned based upon achievement of earnings targets.

The life annuity payable under the WEC Plan is determined by converting the hypothetical account balance credits into annuity form.

Individuals who were participants in the WEC Plan on December 31, 1995 were "grandfathered" so that they will not receive any lower retirement benefit than would have been provided under the prior formula, had it continued. This amount will continue to increase until December 31, 2010, at which time it will be frozen. Upon retirement, participants will receive the greater of this amount or the cash balance.

For the named executive officers other than Mr. Fleming who does not participate in the prior plan formula, estimated benefits under the "grandfathered" formula are higher than under the cash balance plan formula. Although all of the named executive officers participate in the cash balance plan formula, pursuant to the agreements discussed below, Messrs. Klappa's, Leverett's, Kuester's and Salustro's total retirement benefits would currently be determined by the prior plan benefit formula if they were to retire at or after age 60. These benefits are payable under the Individual Letter Agreements, not the WEC Plan. The named executive officers would receive the cash balance in their accounts if they were to terminate employment prior to attaining the age of 60.

Under the WEC Plan, participants receive unreduced pension benefits upon reaching one of the following three thresholds: (1) age 65; (2) age 62 with 30 years of service; or (3) age 60 with 35 years of service.

Pursuant to the Internal Revenue Code, only $220,000 of pension eligible earnings (base pay) may be considered for purposes of the WEC Plan.

Supplemental Executive Retirement Plans and Individual Letter Agreements. Designated officers of Wisconsin Energy and Wisconsin Electric, including all of the named executive officers, participate in the Supplemental Executive Retirement Plan (SERP).

There are two components of the SERP (SERP A and SERP B). SERP A provides monthly supplemental pension benefits to participants, which will be paid out of unsecured corporate assets, or the grantor trust described below, in an amount equal to the difference between the actual pension benefit payable under the WEC Plan and what such pension benefit would be if calculated without regard to any limitation imposed by the Internal Revenue Code on pension benefits or covered compensation. In addition, pursuant to the terms of SERP B, Mr. Salustro also will receive a supplemental lifetime annuity, equal to 10% of the average compensation (consisting of base salary and annual incentive compensation) for the 36 highest consecutive months. Except for a "change in control" of Wisconsin Energy, as defined in the SERP, and pursuant to the terms of the Individual Letter Agreements discussed below, no payments are made until after the participant's retirement at or after age 60 or death. If a participant in the SERP dies prior to age 60, his or her beneficiary is entitled to receive retirement benefits under the SERP. SERP B is only provided to a grandfathered group of officers and was designed to provide an incentive to key employees to remain with WEC until retirement or death. The Compensation Committee determined to eliminate the SERP B benefit a number of years ago.

Wisconsin Energy has entered into an agreement with Mr. Salustro who cannot accumulate by normal retirement age the maximum number of years of credited service under the pension plan formula in effect immediately before the change to the cash balance formula. According to Mr. Salustro's agreement, Mr. Salustro at retirement will receive supplemental retirement payments which will make his total retirement benefits at age 60 or older substantially the same as those payable to employees who are age 60 or older, who are in the same compensation bracket and who became plan participants at the age of 25, offset by the value of any qualified or non-qualified defined benefit pension plans of prior employers. Mr. Salustro retired effective February 28, 2007, at which time he had reached the age of 60.

Wisconsin Energy has entered into agreements with Messrs. Klappa, Leverett and Kuester to provide them with supplemental retirement benefits upon retirement at or after age 60. The supplemental retirement payments are intended to make the total retirement benefits payable to the executive comparable to that which would have been received under the WEC Plan as in effect on December 31, 1995, had the defined benefit formula then in effect continued until the executive's retirement, calculated without regard to Internal Revenue Code limits, and as if the executive had started participation in the WEC Plan at age 27 for Mr. Klappa, on January 1, 1989 for Mr. Leverett, and at the age of 22 for Mr. Kuester. The retirement benefits payable to Messrs. Klappa, Leverett and Kuester will be offset by the value of any qualified or non-qualified defined benefit pension plans of prior employers.

Messrs. Klappa's, Leverett's and Kuester's agreements also provide for a pre-retirement spousal benefit to be paid to their spouses in the event of the executive's death while employed by WEC. The benefit payable is equal to the amount which would have been received by the executive's spouse under the WEC Plan as in effect on December 31, 1995, had the benefit formula then in effect continued until the executive's death, calculated without regard to Internal Revenue Code limits, and as if the executive had started at the ages or dates indicated above for each executive. The spousal benefit payable would be offset by one-half of the value of any qualified or non-qualified deferred benefit pension plans of Messrs. Klappa's, Leverett's and Kuester's prior employers.

Wisconsin Energy has entered into an agreement with Mr. Fleming to provide him a special supplemental pension to keep him whole for pension benefits he would have received from his prior employer. Wisconsin Energy will credit Mr. Fleming's account with a minimum of $80,000 annually, and will credit up to an additional $40,000 annually based on performance against corporate goals as determined by the Compensation Committee. The amounts credited to Mr. Fleming's account will earn interest as if it had been credited to the WEC Plan. The account balance vests at the earlier of 5 years from the date Mr. Fleming commenced employment (January 3, 2011) or age 65, and will be paid pursuant to the terms of the SERP. Mr. Fleming also participates in the WEC Plan and SERP A, without any additional years of credited service.

The purpose of these agreements is to ensure that Messrs. Klappa, Leverett, Kuester, Salustro and Fleming do not lose pension earnings by joining the executive management team at Wisconsin Energy and the Company they otherwise would have received from their former employers. Since retirement plans operate in a manner where accrued amounts increase substantially as a participant increases in age and years of service, these officers forego substantial pension benefits by coming to work for us. Without providing a means to retain these pension benefits, it would have been difficult for us to attract these officers.

The plans and agreements provide in the instance of a change in control of WEC and, absent a deferral election, mandatory lump sum payments without regard to whether the executive's employment has terminated. The Wisconsin Energy Amended Non-Qualified Trust, a grantor trust, was established to fund certain non-qualified benefits, including the SERP and the Individual Letter Agreements, as well as WEC's Executive Deferred Compensation Plan and WEC's Directors' Deferred Compensation Plan discussed later in this information statement. See "Potential Payments upon Termination or Change in Control" later in this information statement for additional information.

Nonqualified Deferred Compensation for Fiscal Year 2006

The following table reflects activity by the named executive officers during 2006 in WEC's Executive Deferred Compensation Plan discussed below.

(a)	(b)	(c)	(d)	(e)	(f)
Name	Executive Contributions in Last Fiscal Year[1] ($)	Registrant Contributions in Last Fiscal Year[1] ($)	Aggregate Earnings In Last Fiscal Year ($)	Aggregate Withdrawals / Distributions ($)	Aggregate Balance at Last Fiscal Year-End[2] ($)
Gale E. Klappa	166,021	81,435	75,358	--	1,090,307
Allen L. Leverett	117,123	34,343	167,367	--	1,460,043
Frederick D. Kuester	82,739	37,680	75,882	--	862,604
Larry Salustro	64,645	25,723	83,336	--	594,542
James C. Fleming	25,268	9,000	1,906	--	36,175

(1) All of the reported amounts are reported as compensation in the Summary Compensation Table of this information statement.

(2) $705,030, $922,602, $515,015 and $276,321 of the reported amounts were reported as compensation in the Summary Compensation Tables in prior information statements for Messrs. Klappa, Leverett, Kuester and Salustro, respectively.

Executive Deferred Compensation Plan

Executive officers and certain other highly compensated employees are eligible to participate in the WEC Executive Deferred Compensation Plan. Under the plan, a participant may defer up to 100% of his or her base salary, annual incentive compensation, long-term incentive compensation (including the value of any WEC stock option gains, vested awards of WEC restricted stock, WEC performance shares and units and dividends earned on unvested WEC performance shares and units), severance payments due under WEC's Executive Severance Policy or under any change in control agreement between WEC and a participant, and any "make whole" pension supplements.

Generally, deferral elections are made annually by each participant for the upcoming plan year. Wisconsin Energy maintains detailed records tracking each participant's "account balance." In addition to deferrals made by the participants, WEC may also credit each participant's account balance by matching a certain portion of each participant's deferral. Such deferral matching is determined by a formula taking into account the matching rate applicable under WEC's 401(k) plan, the percentage of compensation subject to such matching rate, the participant's gross compensation eligible for matching and the amount of base salary actually deferred. Also, WEC, in its discretion, may credit any other amounts, as appropriate, to each participant's account. Additionally, "make whole" payments may be made to participants who are not eligible to participate in the SERP and whose deferrals result in lesser payments under WEC's qualified pension plan.

Wisconsin Energy tracks each participant's account balance as though the balance was actually invested in one or more of several measurement funds. Measurement fund elections are not actual investments, but are elections chosen only for purposes of calculating market gain or loss on deferred amounts for the duration of the deferral period. Each participant may select the amount of deferred compensation to be allocated among any one or more of the available measurement funds. For 2006 and 2007 deferrals, participants may elect from among eight measurement funds that correspond to investment options in WEC's 401(k) plan in addition to the prime rate fund and WEC's stock measurement fund. Deferred amounts relating to the value of participants' WEC stock option gains, vested WEC restricted stock and WEC performance shares are always deemed invested in WEC's stock measurement fund and may not be transferred to any other measurement fund. Contributions and deductions may be made to each participant's account based on the performance of the measuring funds elected. The table below shows the funds available under the EDCP and their annual rate of return for the calendar year ended December 31, 2006:

Name of Fund	Rate of Return (%)	Name of Fund	Rate of Return (%)
Fidelity Balanced Fund	11.65	Fidelity U.S. Bond Index Fund	4.33
Fidelity Diversified International Fund	22.52	Prime Rate	8.28
Fidelity Equity – Income Fund	19.81	S&P 500 Fund	15.79
Fidelity Growth Company Fund	9.56	Vanguard Mid-Cap Index	13.60
Fidelity Low-Priced Stock Fund	17.76	WEC Common Stock Fund	24.15

Each participant's account balance is debited or credited periodically based on the performance of the measurement fund(s) elected by the participant. Subject to certain restrictions, participants may make changes to their measurement fund elections by notice to the committee administering the plan.

At the time of his or her deferral election, each participant may designate a prospective payout date for any or the entire amount deferred, plus any amounts debited or credited to the deferred amount as of the designated payout date. For amounts deferred prior to January 1, 2005, a participant may elect, at any time, to withdraw part (a minimum of $25,000) or all of his or her account balance, subject to a withdrawal penalty of 10%. Pursuant to the new IRS rules that became effective on January 1, 2005, amounts deferred after that date may not be withdrawn at the discretion of the participant. Payout amounts may be limited to the extent to which they are deductible under Section 162(m) of the Internal Revenue Code.

The balance of a participant's account is payable on his or her retirement in either a lump sum payout or in annual installments, at the election of the participant. Upon the death of a participant after retirement, payouts are made to the deceased participant's beneficiary in the same manner as though such payout would have been made to the participant had the participant survived. In the event of a participant's termination of employment, the participant may elect to receive a payout beginning the year after termination in the amount of his account balance as of the termination date either in a lump sum or in annual installments over a period of five years. Any participant who suffers from a continued disability will be entitled to the benefits of plan participation unless and until the committee administering the plan determines that the participant has been terminated for purposes of continued participation in the plan. Upon any such determination, the disabled participant is paid out as though the participant had retired. Except in certain limited circumstances, participants' account balances will be paid out in a lump sum (1) upon the occurrence of a change in control of WEC, as defined in the plan, or (2) for amounts deferred prior to January 1, 2005, upon any downgrade of WEC's senior debt obligations to less than "investment grade." The deferred amounts will be paid out of the general corporate assets or the assets of the WEC Amended Non-Qualified Trust.

Potential Payments upon Termination or Change in Control

The tables below reflect the amount of compensation payable to each of our named executive officers in the event of termination of each executive's employment. These amounts are in addition to each named executive officers' aggregate balance in the EDCP at fiscal year-end 2006, as reported in column (f) under "Nonqualified Deferred Compensation for Fiscal Year 2006." The amount of compensation payable to each named executive officer upon voluntary termination, normal retirement, for-cause termination, involuntary termination (by WEC for any reason other than cause, death or disability or by the executive for "good reason"), termination following a "change in control" of WEC, disability and death are set forth below. The amounts shown assume that such termination was effective as of December 31, 2006 and include amounts earned through that date, and are estimates of the amounts which would be paid out to the named executive officers upon termination. The amounts shown under "Normal Retirement" assume the named executive officers were retirement eligible with no reduction of retirement benefits. The amounts reported in the row "Retirement Plans" in each table below are not in addition to the amounts reflected under "Pension Benefits at Fiscal Year-End 2006." The actual amounts to be paid out can only be determined at the time of an officer's termination of employment.

Payments Made Upon Voluntary Termination or Termination for Cause, Death or Disability. In the event a named executive officer voluntarily terminates employment or is terminated for cause, death or disability, the officer will receive:

- accrued but unpaid base salary and, for termination by death or disability, pro-rated annual incentive compensation;
- 401(k) plan and EDCP account balances;
- the WEC Plan cash balance;
- in the case of death or disability, full vesting in all outstanding stock options, restricted stock and performance units (otherwise, the ability to exercise already vested options within three months of termination); and
- if termination occurs after age 60, vesting in the SERP and Individual Letter Agreements.

Named executive officers are also entitled to the value of unused vacation days, if any.

Payments Made Upon Normal Retirement. In the event of the retirement of a named executive officer, the officer will receive:

- full vesting in all outstanding stock options and restricted stock, and a prorated amount of performance units;
- full vesting in all retirement plans, including the WEC Plan, SERP and Individual Letter Agreements; and
- 401(k) plan and EDCP account balances.

Named executive officers are also entitled to the value of unused vacation days, if any.

Payments Made Upon a Change in Control or Involuntary Termination. Wisconsin Energy has entered into written employment agreements with each of Messrs. Klappa, Leverett, Kuester and Fleming that provide for certain severance benefits as described below.

Under the agreement with Mr. Klappa, severance benefits are provided if his employment is terminated:

- in anticipation of a change in control by WEC for any reason, other than cause, death or disability;
- by Mr. Klappa for good reason following a change in control of WEC;
- by Mr. Klappa within six months after completing one year of service following a change in control of WEC; or
- in the absence of a change in control of WEC, by Wisconsin Energy for any reason other than cause, death or disability or by Mr. Klappa for good reason.

Upon the occurrence of one of these events, Mr. Klappa's agreement provides for:

- a lump sum severance payment equal to three times the sum of Mr. Klappa's highest annual base salary in effect in the last three years and highest bonus amount;
- three years' continuation of health and certain other welfare benefit coverage and eligibility for retiree health coverage thereafter;
- a payment equal to the value of three additional years' of participation in the applicable qualified and non-qualified retirement plans;
- a payment equal to the value of three additional years of WEC match in the 401(k) plan and the EDCP;
- full vesting in all outstanding stock options, restricted stock and other equity awards;
- 401(k) plan and EDCP account balances;
- certain financial planning services and other benefits; and
- in the event of a change in control, a "gross-up" payment should any payments or benefits under the agreements trigger federal excise taxes under the "parachute payment" provisions of the tax law.

The highest bonus amount would be calculated as the largest of (1) the current target bonus for the fiscal year in which employment termination occurs, or (2) the highest bonus paid in any of the last three fiscal years prior to termination or the change in control of WEC. The agreement contains a one-year non-compete provision applicable on termination of employment.

Mr. Leverett's, Mr. Kuester's and Mr. Fleming's agreements are substantially similar to Mr. Klappa's, except that if their employment is terminated by WEC for any reason other than cause, death or disability or by them for good reason in the absence of a change in control:

- the special lump sum severance benefit is two times the sum of their highest annual base salary in effect for the three years preceding their termination and their highest bonus amount;
- health and certain other welfare benefits are provided for a two-year period;
- the special retirement plan lump sum is calculated as if their employment continued for a two-year period following termination of employment; and
- the payment for 401(k) plan and EDCP match is equal to two years of WEC match.

Mr. Leverett's and Mr. Kuester's agreements contain a one-year non-compete provision applicable on termination of employment.

Pursuant to the terms of the SERP and Individual Letter Agreements, retirement benefits are paid to the named executive officers upon a change in control of WEC, without regard to whether the executive's employment has been terminated. Participants in the SERP, including the named executive officers, are also eligible to receive a supplemental disability benefit in an amount equal to the difference between the actual amount of the benefit payable under the long-term disability plan applicable to all employees and what such disability benefit would have been if calculated without regard to any limitation imposed by the Internal Revenue Code on annual compensation recognized under the broad-based plan.

Generally, pursuant to the agreements, a change in control is deemed to occur:

(1) if any person acquires 20% or more of WEC's voting securities, other than securities acquired directly from WEC or any of its affiliates;
(2) if a majority of the Board of WEC as of the date of the agreement (or any new director whose appointment or election was approved or recommended by a vote of at least two-thirds of the Board who were either directors as of the date of the agreement or who were appointed or elected as set forth herein) are replaced;

(3) upon the consummation of a merger of WEC or any of its subsidiaries other than (a) a merger where the directors immediately prior to the merger continue to constitute at least a majority of the Board of Directors of WEC, the surviving entity or any parent thereof, or (b) a merger effected to implement a recapitalization of WEC in which no person is or becomes the beneficial owner of securities of WEC representing 20% or more of the combined voting power of WEC's then outstanding securities;
(4) upon a liquidation or dissolution of WEC or a sale of all or substantially all of WEC's assets, other than a sale of assets to a company, at least a majority of the Board of which were directors of WEC immediately prior to the sale; or
(5) if the Board of Directors determines that there has been a change in control of WEC.

Generally, pursuant to the agreements, good reason means:

(1) solely in the context of a change in control of WEC, a material reduction of the executive's duties and responsibilities;
(2) any failure by WEC to provide for the continuation of the executive's compensation at certain prescribed levels following a change in control;
(3) the relocation of the executive's principal place of employment after a change in control to a location more than 35 miles from the executive's principal place of employment immediately prior to the change in control;
(4) WEC requires the executive to travel on business to a materially greater extent than was required immediately prior to a change in control; or
(5) a material breach of the agreement by WEC.

Mr. Salustro's employment agreement with Wisconsin Energy did not provide for severance benefits, but he did participate in the Amended and Restated Wisconsin Energy Corporation Special Executive Severance Policy. Under this policy, Mr. Salustro would have been entitled to a lump sum severance payment equal to three times the sum of his current base salary and his highest bonus in the last three years (or his then current target bonus, if higher), a pension lump sum for the equivalent of three years' worth of additional service and three years' continuation of health and life insurance coverage. An overall limit would have been placed on benefits to avoid federal excise taxes under the "parachute payment" provisions of the tax law. Mr. Salustro was not entitled to these severance benefits upon his retirement, effective February 28, 2007. Upon his retirement, Mr. Salustro was entitled to (1) the retirement benefits set forth under "Pension Benefits at Fiscal Year-End 2006" and "Retirement Plans," (2) the aggregate balance in his EDCP account which was $594,542 as of December 31, 2006, (3) the aggregate balance in his 401(k) plan account, and (4) the value of any unused vacation days. In addition, on February 26, 2007, the Compensation Committee accelerated the vesting of all of Mr. Salustro's outstanding WEC stock options granted in 2005, 2006 and 2007. Mr. Salustro is eligible to participate in all retiree health and other welfare benefits.

The following table shows the potential payments upon termination or a change in control of WEC for Gale E. Klappa.

Executive Benefits and Payments Upon Separation	Voluntary Termination ($)	Normal Retirement ($)	For Cause Termination ($)	Involuntary Termination ($)	Termination Upon a Change in Control ($)	Disability ($)	Death ($)
Compensation:							
Cash Severance	--	--	--	8,803,545	8,803,545	--	--
Additional Pension Credited Service	--	--	--	3,574,938	3,574,938	--	--
Additional 401(k) and EDCP Match	--	--	--	264,106	264,106	--	--
Long-Term Incentive Compensation:							
Performance Units	--	116,892	--	2,377,746	2,377,746	2,377,746	2,377,746
Restricted Stock	--	1,431,916	--	1,431,916	1,431,916	1,431,916	1,431,916
Options	--	5,725,020	--	5,725,020	5,725,020	5,725,020	5,725,020
Benefits & Perquisites:							
Retirement Plans	58,449	5,734,180	58,449	6,801,479	6,801,479	5,734,180	2,875,777
Health and Welfare Benefits	--	--	--	36,959	36,959	--	--
Excise Tax Gross-Up	--	--	--	--	9,296,287	--	--
Financial Planning	--	--	--	45,000	45,000	--	--
Outplacement	--	--	--	30,000	30,000	--	--

The following table shows the potential payments upon termination or a change in control of WEC for Allen L. Leverett.

Executive Benefits and Payments Upon Separation	Voluntary Termination ($)	Normal Retirement ($)	For Cause Termination ($)	Involuntary Termination ($)	Termination Upon a Change in Control ($)	Disability ($)	Death ($)
Compensation:							
Cash Severance	--	--	--	2,960,488	4,440,732	--	--
Additional Pension Credited Service	--	--	--	486,642	658,421	--	--
Additional 401(k) and EDCP Match	--	--	--	88,815	133,222	--	--
Long-Term Incentive Compensation:							
Performance Units	--	487,256	--	1,034,628	1,034,628	1,034,628	1,034,628
Restricted Stock	--	396,813	--	396,813	396,813	396,813	396,813
Options	--	2,084,575	--	2,084,575	2,084,575	2,084,575	2,084,575
Benefits & Perquisites:							
Retirement Plans	47,599	877,127	47,599	904,497	904,497	877,127	554,572
Health and Welfare Benefits	--	--	--	24,639	36,959	--	--
Excise Tax Gross-Up	--	--	--	--	3,288,699	--	--
Financial Planning	--	--	--	45,000	45,000	--	--
Outplacement	--	--	--	30,000	30,000	--	--

The following table shows the potential payments upon termination or a change in control of WEC for Frederick D. Kuester.

Executive Benefits and Payments Upon Separation	Voluntary Termination ($)	Normal Retirement ($)	For Cause Termination ($)	Involuntary Termination ($)	Termination Upon a Change -in Control ($)	Disability ($)	Death ($)
Compensation:							
Cash Severance	--	--	--	2,951,982	4,427,973	--	--
Additional Pension Credited Service	--	--	--	1,605,152	2,060,600	--	--
Additional 401(k) and EDCP Match	--	--	--	88,559	132,839	--	--
Long-Term Incentive Compensation:							
Performance Units	--	487,256	--	1,034,628	1,034,628	1,034,628	1,034,628
Restricted Stock	--	859,975	--	859,975	859,975	859,975	859,975
Options	--	2,084,575	--	2,084,575	2,084,575	2,084,575	2,084,575
Benefits & Perquisites:							
Retirement Plans	46,191	3,380,297	46,191	2,773,762	2,873,708	3,380,297	1,265,448
Health and Welfare Benefits	--	--	--	24,639	36,959	--	--
Excise Tax Gross-Up	--	--	--	--	4,567,561	--	--
Financial Planning	--	--	--	45,000	45,000	--	--
Outplacement	--	--	--	30,000	30,000	--	--

The following table shows the potential payments upon termination or a change in control of WEC for James C. Fleming.

Executive Benefits and Payments Upon Separation	Voluntary Termination ($)	Normal Retirement ($)	For Cause Termination ($)	Involuntary Termination ($)	Termination Upon a Change in Control ($)	Disability ($)	Death ($)
Compensation:							
Cash Severance	--	--	--	1,360,012	2,040,018	--	--
Additional Pension Credited Service	--	--	--	280,000	420,000	--	--
Additional 401(k) and EDCP Match	--	--	--	40,800	61,201	--	--
Long-Term Incentive Compensation:							
Performance Units	--	127,978	--	374,934	374,934	374,934	374,934
Restricted Stock	--	121,213	--	121,213	121,213	121,213	121,213
Options	--	598,875	--	598,875	598,875	598,875	598,875
Benefits & Perquisites:							
Retirement Plans	11,588	147,487	11,588	144,336	146,554	147,487	140,000
Health and Welfare Benefits	--	--	--	24,639	36,959	--	--
Excise Tax Gross-Up	--	--	--	--	1,383,595	--	--
Financial Planning	--	--	--	45,000	45,000	--	--
Outplacement	--	--	--	30,000	30,000	--	--

DIRECTOR COMPENSATION

The following table summarizes total compensation awarded to, earned by or paid to each of the Company's non-employee directors during 2006. The amounts shown in this table are WEC consolidated compensation data.

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Name	Fees Earned or Paid In Cash ($)	Stock Awards [3][4][5] ($)	Option Awards [6] ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation [7] ($)	Total ($)
John F. Ahearne	75,850	65,000	--	--	--	23,374	164,224
John F. Bergstrom	68,350	65,000	--	--	--	18,533	151,883
Barbara L. Bowles	71,550	65,000	--	--	--	16,973	153,523
Patricia W. Chadwick [1]	29,800	10,833	--	--	--	19,843	60,476
Robert A. Cornog	60,300	65,000	--	--	--	37,747	163,047
Curt S. Culver	62,600	54,167	--	--	--	13,194	129,961
Thomas J. Fischer	59,550	32,500	--	--	--	22,717	114,767
Ulice Payne, Jr.	65,400	65,000	--	--	--	9,297	139,697
Frederick P. Stratton, Jr.	59,850	65,000	--	--	--	42,771	167,621
George E. Wardeberg [2]	40,500	130,000	--	--	--	20,608 [8]	191,108

(1) On June 26, 2006, the Board of Directors increased the number of directors constituting the whole Board from nine to ten and elected Patricia W. Chadwick to fill the vacancy on the Board.

(2) Mr. Wardeberg did not stand for re-election to the Board of Directors in May 2006. On May 4, 2006, the Compensation Committee approved the acceleration of all of Mr. Wardeberg's unvested WEC restricted stock, consisting of 5,692 shares of restricted stock. Mr. Wardeberg was the Vice Chairman of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas Boards of Directors from 2000 to 2002.

(3) Except as described in this note (3), the amounts reported reflect the amounts recognized for financial statement reporting purposes in WEC's 2006 consolidated financial statements in accordance with SFAS 123R for annual WEC restricted stock awards made to directors in 2004, 2005 and 2006. Each restricted stock award vests in full on the third anniversary of the grant date. We made certain assumptions in our valuation of the restricted stock awarded to the directors. See Note N -- Common Equity in the Notes to Consolidated Financial Statements in our 2006 Annual Report on Form 10-K for a description of these assumptions (which Note is also included in the 2006 Annual Report to Stockholders attached as Appendix A).

(4) The grant date fair value of each award made in 2006 determined in accordance with SFAS 123R is $65,000.

(5) Directors held the following number of shares of WEC restricted stock as of December 31, 2006: Dr. Ahearne (5,783), Mr. Bergstrom (5,783), Ms. Bowles (5,783), Ms. Chadwick (837), Mr. Cornog (5,783), Mr. Culver (4,767), Mr. Fischer (2,521), Mr. Payne (5,783) and Mr. Stratton (5,783).

(6) Directors held the following number of options to purchase Wisconsin Energy common stock as of December 31, 2006, all of which are exercisable: Dr. Ahearne (13,000), Mr. Bergstrom (26,000), Ms. Bowles (26,000), Mr. Cornog (26,000), Mr. Payne (10,000), Mr. Stratton (23,000) and Mr. Wardeberg (250,000).

(7) All amounts represent costs for the Directors' Charitable Awards Program.

(8) Mr. Wardeberg, in connection with his retirement as an officer of Wisconsin Energy and its subsidiaries in 2002, also received pension payments in the amount of $88,526 (constitutes five months of payments). In addition, during the first five months of 2006, Wisconsin Energy recognized an expense of $14,138 related to Mr. Wardeberg's participation in the Death Benefit Only Plan provided to officers.

Compensation of the Board of Directors

During 2006, each non-employee director received an annual retainer fee of $36,000. Non-employee chairs of Board committees received a quarterly retainer of $1,250. Non-employee directors received a fee of $1,500 for each Board or committee meeting attended. In addition, each non-employee director received a per diem fee of $1,250 for travel on Company business for each day on which a Board or committee meeting was not also held, and the Company reimbursed non-employee directors for all out-of-pocket travel expenses (which reimbursed amounts are not reflected in the table above). Non-employee directors were paid $300 for each signed written unanimous consent in lieu of a meeting. The lead nuclear director received a quarterly retainer of $1,250, an attendance fee of $1,500 for each business meeting/site visit and a per diem fee of $1,250 for travel on Company business for each day on which a business meeting/site visit was not also held. Each non-employee director also received on January 3, 2006, the 2006 annual stock compensation award in the form of WEC restricted stock equal to a value of $65,000, with all shares vesting three years from the grant date. Employee directors do not receive these fees. Insurance is also provided by the Company for director liability coverage, fiduciary and employee benefit liability coverage and travel accident coverage for director travel on Company business. The premiums paid for this insurance are not included in the amounts reported in the table above.

Non-employee directors may defer all or a portion of director fees pursuant to WEC's Directors' Deferred Compensation Plan. Deferred amounts can be credited to any of ten measurement funds, including a WEC phantom stock account. The value of these accounts will appreciate or depreciate based on market performance, as well as through the accumulation of reinvested dividends. Deferral amounts are credited to accounts in the name of each participating director on the books of WEC, are unsecured and are payable only in cash following termination of the director's service to WEC and its subsidiaries, including Wisconsin Electric. The deferred amounts will be paid out of the general corporate assets or the assets of the WEC Amended Non-Qualified Trust.

Although Wisconsin Electric directors also serve on the Wisconsin Energy and Wisconsin Gas boards and their committees, a single annual retainer fee was paid and only a single attendance fee was paid for meetings held on the same day. Fees were allocated among Wisconsin Electric, Wisconsin Energy and Wisconsin Gas based on services rendered.

A Directors' Charitable Awards Program has been established to help further WEC's philosophy of charitable giving. Under the program, WEC intends to contribute up to $100,000 per year for 10 years to one or more charitable organizations chosen by each director, including employee directors, upon the director's death. Directors are provided with one charitable award benefit for serving on the boards of WEC and its subsidiaries, including Wisconsin Electric. There is a vesting period of three years of service on the Board required for participation in this program. Charitable donations under the program will be paid out of general corporate assets. Directors derive no financial benefit from the program, and all income tax deductions accrue solely to WEC. The tax deductibility of these charitable donations mitigates the net cost to WEC.

Effective January 1, 2007, the Compensation Committee determined that the compensation components should be modified. In general, non-employee directors will no longer receive fees for attendance at Board and committee meetings or for signed written

unanimous consents in lieu of meetings or receive per diem fees for travel on Company business. In lieu of these fees, the retainer fees will be increased. For 2007, each non-employee director will receive an annual retainer fee of $75,000, payable in cash in one installment. Non-employee chairs of Board committees will continue to receive a quarterly retainer of $1,250, except the chair of the Audit and Oversight Committee and the lead nuclear director will each receive a quarterly retainer of $1,875. Each non-employee director will also receive an annual grant of WEC restricted stock equal to a value of $75,000. Each non-employee director received this grant on January 3, 2007. The Directors' Charitable Awards Program has been eliminated for any new directors elected after January 1, 2007; current participants are grandfathered.

STOCK OWNERSHIP OF DIRECTORS, NOMINEES AND EXECUTIVE OFFICERS

None of the WE directors, nominees or executive officers own any of WE's stock, but do beneficially own shares of its parent company, Wisconsin Energy Corporation. The following table lists the beneficial ownership of WEC common stock of each WE director, nominee, named executive officer and all of the directors and executive officers as a group as of February 15, 2007. In general, "beneficial ownership" includes those shares as to which the indicated persons have voting power or investment power and stock options that are exercisable currently or within 60 days of February 15, 2007. Included are shares owned by each individual's spouse, minor children or any other relative sharing the same residence, as well as shares held in a fiduciary capacity or held in WEC's Stock Plus Investment Plan and 401(k) plan. None of these persons beneficially owns more than 1% of the outstanding WEC common stock.

	Shares Beneficially Owned[1]		
Name	Shares Owned[2] [3] [4] [5]	Option Shares Exercisable Within 60 Days	Total
John F. Ahearne	13,587	13,000	26,587
John F. Bergstrom	8,267	26,000	34,267
Barbara L. Bowles	10,122	26,000	36,122
Patricia W. Chadwick	2,408	--	2,408
Robert A. Cornog	13,003	26,000	39,003
Curt S. Culver	6,338	--	6,338
Thomas J. Fischer	6,993	--	6,993
James C. Fleming	2,230	--	2,230
Gale E. Klappa	38,455	450,000	488,455
Frederick D. Kuester	22,194	350,000	372,194
Allen L. Leverett	9,444	350,000	359,444
Ulice Payne, Jr.	6,391	10,000	16,391
Larry Salustro	28,867	535,000	563,867
Frederick P. Stratton, Jr.	13,867	23,000	36,867
All directors and executive officers as a group (17 persons)	213,244	2,052,716[6]	2,265,960[7]

(1) Information on beneficially owned shares is based on data furnished by the specified persons and is determined in accordance with Rule 13d-3 under the Securities Exchange Act of 1934, as amended, as required for purposes of WEC's proxy statement. It is not necessarily to be construed as an admission of beneficial ownership for other purposes.

(2) Certain directors, named executive officers and other executive officers also hold share units in the WEC phantom common stock account under WEC's deferred compensation plans as indicated: Mr. Bergstrom (9,561), Mr. Cornog (15,329), Mr. Culver (4,889), Mr. Fleming (511), Mr. Kuester (2,605), Mr. Salustro (3,192), Mr. Stratton (11,426) and all directors and executive officers as a group (57,246). Share units are intended to reflect the performance of WEC common stock and are payable in cash. While these units do not represent a right to acquire WEC common stock, have no voting rights and are not included in the number of shares reflected in the "Shares Owned" column in the table above, the Company listed them in this footnote because they represent an additional economic interest of the directors, named executive officers and other executive officers tied to the performance of WEC common stock.

(3) Each individual has sole voting and investment power as to all shares listed for such individual, except the following individuals have shared voting and/or investment power (included in the table above) as indicated: Mr. Bergstrom (3,000), Mr. Cornog (5,007), Mr. Stratton (4,600), Mr. Wardeberg (23,899) and all directors and executive officers as a group (12,607).

(4) Certain directors and executive officers hold shares of WEC restricted stock (included in table above) over which the holders have sole voting but no investment power: Dr. Ahearne (5,267), Mr. Bergstrom (5,267), Ms. Bowles (5,267), Ms. Chadwick (2,408), Mr. Cornog (5,267), Mr. Culver (6,338), Mr. Fischer (4,092), Mr. Fleming (2,043), Mr. Klappa (30,171), Mr. Kuester (18,119), Mr. Leverett (8,361), Mr. Payne (5,267), Mr. Salustro (18,504), Mr. Stratton (5,267) and all directors and executive officers as a group (136,155).

(5) None of the shares beneficially owned by the directors, named executive officers and all directors and executive officers as a group are pledged as security.

(6) Option shares listed include options granted by WICOR, Inc. which were converted to WEC stock options on the effective date of WEC's acquisition of WICOR, Inc.

(7) Represents 1.9% of total WEC common stock outstanding on February 15, 2007.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires the Company's executive officers, directors and persons owning more than ten percent of a registered class of the Company's equity securities to file reports of ownership and changes in ownership of equity and derivative securities of WE with the Securities and Exchange Commission. To the Company's knowledge, based on information provided by the reporting persons, all applicable reporting requirements for fiscal year 2006 were complied with in a timely manner.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The Company provides to and receives from WEC, and other subsidiaries of WEC, services, property and other things of value (the "Items"). These transactions are made pursuant to either a master affiliated interest agreement or a service agreement, both of which have been approved by the Public Service Commission of Wisconsin. The master affiliated interest agreement provides that the Company receive payment equal to the higher of its cost or fair market value for the Items provided to Wisconsin Energy or its nonutility subsidiaries, and that the Company make payment equal to the lower of the provider's cost or fair market value for the Items which Wisconsin Energy Corporation or its nonutility subsidiaries provide to the Company. The service agreement provides that Items provided by the Company or Wisconsin Gas to each other shall be provided at cost. Modification or amendment to the master affiliated interest agreement or the service agreement requires the approval of the Public Service Commission of Wisconsin.

AVAILABILITY OF FORM 10-K

A copy (without exhibits) of Wisconsin Electric Power Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2006, as filed with the Securities and Exchange Commission, is available without charge to any stockholder of record or beneficial owner of WE preferred stock by writing to the Corporate Secretary, Anne K. Klisurich, at the Company's principal business office, 231 West Michigan Street, P. O. Box 2046, Milwaukee, Wisconsin 53201. The WE consolidated financial statements and certain other information found in the Form 10-K are included in the Wisconsin Electric Power Company 2006 Annual Report to Stockholders, attached hereto as Appendix A.

APPENDIX A

WISCONSIN ELECTRIC POWER COMPANY

2006 ANNUAL REPORT TO STOCKHOLDERS

2006 ANNUAL FINANCIAL STATEMENTS

And

REVIEW of OPERATIONS

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below.

Wisconsin Electric Subsidiary and Affiliates

Primary Subsidiary and Affiliates

Bostco	Bostco LLC
Edison Sault	Edison Sault Electric Company
We Power	W.E. Power, LLC
Wisconsin Gas	Wisconsin Gas LLC
Wisconsin Energy	Wisconsin Energy Corporation

Significant Assets

OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
Point Beach	Point Beach Nuclear Plant
PWGS	Port Washington Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2

Other Affiliates

ATC	American Transmission Company LLC
Guardian	Guardian Pipeline L.L.C
NMC	Nuclear Management Company, LLC

Federal and State Regulatory Agencies

DOA	Wisconsin Department of Administration
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPSC	Michigan Public Service Commission
NRC	United States Nuclear Regulatory Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources

Environmental Terms

Act 141	2005 Wisconsin Act 141
Air Permit	Air Pollution Control Construction Permit
BART	Best Available Retrofit Technology
BTA	Best Technology Available
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CO2	Carbon Dioxide
CWA	Clean Water Act
NAAQS	National Ambient Air Quality Standard
NOx	Nitrogen Oxide
PM 2.5	Fine Particulate Matter
RI/FS	Remedial Investigation and Feasibility Study

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below.

SO2	Sulfur Dioxide
WPDES	Wisconsin Pollution Discharge Elimination System

Other Terms and Abbreviations

Compensation Committee	Compensation Committee of the Wisconsin Energy Board of Directors
CPCN	Certificate of Public Convenience and Necessity
D&D Fund	Uranium Enrichment Decontamination and Decommissioning Fund
Energy Policy Act	Energy Policy Act of 2005
FPL	FPL Group, Inc.
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
GDP	Gross Domestic Product
LLC	Limited Liability Company
LMP	Locational Marginal Price
LSEs	Load Serving Entities
MAIN	Mid-America Interconnected Network, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Midwest Market	MISO bid-based energy market
Moody's	Moody's Investor Service
NEIL	Nuclear Electric Insurance Limited
PJM	PJM Interconnection, L.L.C.
PTF	Power the Future
PUHCA 1935	Public Utility Holding Company Act of 1935, as amended
PUHCA 2005	Public Utility Holding Company Act of 2005
RTO	Regional Transmission Organizations
S&P	Standard & Poors Corporation
Yellowcake	Uranium Concentrate

Measurements

Btu	British thermal unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
kW	Kilowatt(s) (One kW equals one thousand watts)
kWh	Kilowatt-hour(s)
MW	Megawatt(s) (One MW equals one million watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
APB	Accounting Principles Board
ARO	Asset Retirement Obligation
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits
SAB	Staff Accounting Bulletin
SFAS	Statement of Financial Accounting Standards

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below.

Accounting Pronouncements

FIN 46	Consolidation of Variable Interest Entities
FIN 46R	Consolidation of Variable Interest Entities (Revised 2003)
FIN 47	Accounting for Conditional Asset Retirement Obligations
FIN 48	Accounting for Uncertainty in Income Taxes
FSP SFAS 106-2	Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003
FSP FIN 46R-6	Determining the Variability to Be Considered in Applying FIN 46R
SAB 108	Process of Quantifying Financial Statement Misstatements
SFAS 71	Accounting for the Effects of Certain Types of Regulation
SFAS 87	Employers' Accounting for Pensions
SFAS 88	Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits
SFAS 106	Employers' Accounting for Postretirement Benefits Other Than Pensions
SFAS 109	Accounting for Income Taxes
SFAS 115	Accounting for Certain Investments in Debt and Equity Securities
SFAS 123	Accounting for Stock-Based Compensation
SFAS 123R	Share-Based Payment (Revised 2004)
SFAS 132R	Employers' Disclosures about Pensions and Other Postretirement Benefits (Revised 2003)
SFAS 133	Accounting for Derivative Instruments and Hedging Activities
SFAS 143	Accounting for Asset Retirement Obligations
SFAS 148	Accounting for Stock-Based Compensation - Transition and Disclosure
SFAS 149	Amendment of SFAS 133 on Derivative Instruments and Hedging Activities
SFAS 157	Fair Value Measurements
SFAS 158	Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report and other documents or oral presentations are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding completion of construction projects, regulatory matters, fuel costs, sources of electric energy supply, the proposed sale of Point Beach, coal and gas deliveries, remediation costs, environmental and other capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "intends," "may," "objectives," "plans," "possible," "potential," "projects" or similar terms or variations of these terms.

Actual results may differ materially from those set forth in forward-looking statements. In addition to the assumptions and other factors referred to specifically in connection with these statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statements or otherwise affect our future results of operations and financial condition include, among others, the following:

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related or terrorism-related damage; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, nuclear fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; nuclear or environmental incidents; resolution of used nuclear fuel storage and disposal issues; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; inflation rates; or demographic and economic factors affecting utility service territories or operating environment.

- Regulatory factors such as unanticipated changes in rate-setting policies or procedures; unanticipated changes in regulatory accounting policies and practices; industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; recovery of costs of previous investments made under traditional regulation; recovery of costs associated with adoption of changed accounting standards; required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities; required approvals for new construction; changes in the United States Nuclear Regulatory Commission's regulations related to Point Beach Nuclear Plant or a permanent repository for used nuclear fuel; changes in the regulations of the United States Environmental Protection Agency as well as the Wisconsin Department of Natural Resources, the Michigan Department of Natural Resources or the Michigan Department of Environmental Quality, including but not limited to regulations relating to the release of emissions from fossil-fueled power plants such as carbon dioxide, sulfur dioxide, nitrogen oxide, small particulates or mercury, water quality and lead paint; and regulations relating to the intake and discharge of water; the siting approval process for new generation and transmission facilities; recovery of costs associated with implementation of a bid-based energy market; or changes in the regulations from the Wisconsin Department of Natural Resources related to the siting approval process for new pipeline construction.

- The changing electric and gas utility environment as market-based forces replace strict industry regulation and other competitors enter the electric and gas markets resulting in increased wholesale and retail competition.

- Unanticipated operational and/or financial consequences related to implementation of the Midwest Independent Transmission System Operator, Inc. bid-based energy market that started in April 2005.

- Consolidation of the industry as a result of the combination and acquisition of utilities in the Midwest, nationally and globally as a result of the repeal of the Public Utility Holding Company Act of 1935 or otherwise.

- Factors related to the proposed sale of our Point Beach Nuclear Plant including receipt of the necessary approvals by various regulatory agencies, including the United States Nuclear Regulatory Commission, the Public Service Commission of Wisconsin, the Michigan Public Service Commission and the Federal Energy Regulatory Commission, for the transaction; and our ability to retain the assets for the benefit of customers in the non-qualified decommissioning trust.

- Factors which impede execution of Wisconsin Energy Corporation's *Power the Future* strategy, including receipt of necessary state and federal regulatory approvals, timely and successful resolution of legal challenges, local opposition to siting of new generating facilities, construction risks, including the adverse interpretation or enforcement of permit conditions by the permitting agencies, and obtaining the investment capital from outside sources necessary to implement the strategy.

- Changes in social attitudes regarding the utility and power industries.

- Customer business conditions including demand for their products or services and supply of labor and material used in creating their products and services.

- The cost and other effects of legal and administrative proceedings, settlements, investigations and claims and changes in those matters.

- Factors affecting the availability or cost of capital such as: changes in interest rates and other general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or our subsidiary; or security ratings.

- Federal, state or local legislative factors such as changes in tax laws or rates; changes in trade, monetary and fiscal policies, laws and regulations; electric and gas industry restructuring initiatives; changes in the Price-Anderson Act; changes in environmental laws and regulations; or changes in allocation of energy assistance, including state public benefits funds.

- Implementation of the Energy Policy Act of 2005 and the effect of state level proceedings and the development of regulations by federal and other agencies, including the Federal Energy Regulatory Commission.

- Authoritative generally accepted accounting principle or policy changes from such standard setting bodies as the Financial Accounting Standards Board, the Securities and Exchange Commission and the Public Company Accounting Oversight Board.

- Unanticipated technological developments that result in competitive disadvantages and create the potential for impairment of existing assets.

- Other business or investment considerations that may be disclosed from time to time in our Securities and Exchange Commission filings or in other publicly disseminated written documents.

We expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

Financial	2006	2005	2004	2003	2002
Year Ended December 31					
Earnings available for common stockholder (Millions)	$ 275.6	$ 283.6	$ 248.7	$ 255.5	$ 258.0
Operating revenues (Millions)					
Electric	$ 2,499.5	$ 2,320.9	$ 2,070.8	$ 1,986.4	$ 1,884.6
Gas	590.0	593.6	523.8	513.0	389.8
Steam	27.2	23.5	22.0	22.5	21.5
Total operating revenues	$ 3,116.7	$ 2,938.0	$ 2,616.6	$ 2,521.9	$ 2,295.9
At December 31 (Millions)					
Total assets	$ 8,257.8	$ 7,909.2	$ 7,050.3	$ 6,644.6	$ 6,285.1
Long-term debt and capital lease obligations (including current maturities)	$ 2,152.1	$ 2,058.5	$ 1,706.8	$ 1,599.5	$ 1,459.4

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

	(Millions of Dollars) (a)			
	March		June	
Three Months Ended	2006	2005	2006	2005
Total operating revenues	$ 872.7	$ 759.7	$ 685.8	$ 657.2
Operating income	$ 142.6	$ 121.6	$ 94.3	$ 92.0
Earnings available for common stockholder	$ 87.1	$ 70.4	$ 56.8	$ 51.4
	September		December	
Three Months Ended	2006	2005	2006	2005
Total operating revenues	$ 745.2	$ 711.5	$ 813.0	$ 809.6
Operating income	$ 126.1	$ 130.2	$ 92.9	$ 133.5
Earnings available for common stockholder	$ 77.7	$ 78.9	$ 54.0	$ 82.9

(a) Quarterly results of operations are not directly comparable because of seasonal and other factors. See Management's Discussion and Analysis of Financial Condition and Results of Operations.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS

INTRODUCTION

Wisconsin Electric Power Company, a wholly-owned subsidiary of Wisconsin Energy, is engaged primarily in the business of generating electricity and distributing electricity and natural gas in Wisconsin and the Upper Peninsula of Michigan. Unless qualified by their context, when used in this document the terms Wisconsin Electric, the Company, our, us or we refer to Wisconsin Electric Power Company and its subsidiary.

Wisconsin Energy is also the parent company of Wisconsin Gas, a natural gas distribution utility which serves customers throughout Wisconsin, Edison Sault, an electric utility which serves customers in the Upper Peninsula of Michigan, and We Power. We Power is principally engaged in the engineering, construction and development of electric generating power facilities for long-term lease to us. Wisconsin Electric and Wisconsin Gas have combined common functions and operate under the trade name of "We Energies".

CORPORATE STRATEGY

Business Opportunities

Wisconsin Energy's key corporate strategy is PTF, which was announced in September 2000. This strategy is designed to address Wisconsin's growing electric supply needs by increasing the electric generating capacity in the state while maintaining a fuel-diverse, reasonably priced electric supply. It is also designed to improve the delivery of energy within our distribution systems to meet increasing customer demands and to support our commitment to improved environmental performance. Wisconsin Energy's PTF strategy, which is discussed further below, is having and is expected to continue to have a significant impact on us. In July 2005, the first of four new electric generating units under the PTF strategy was placed into service. Construction on the remaining three units is underway.

Proposed Sale of Point Beach: In February 2006, we announced that we were undertaking a formal review regarding our options for the ownership and operation of Point Beach. These options included (1) continued operation by NMC, (2) having a third party other than NMC operate the plant, (3) a return to in-house operations by us, (4) sale of the plant and (5) a partial sale of the plant with us retaining a minority interest in the Plant. Under this fifth option, the new majority owner would operate the plant. After a thorough review of the various options, we concluded that a full sale of the plant was in our best interest and in the best interest of our customers.

In December 2006, we announced that we had signed a definitive agreement with an affiliate of FPL to sell Point Beach for approximately $998 million, subject to closing price adjustments. Under the terms of the sale, the buyer would assume the obligation to decommission the plant, and we would transfer assets in a qualified trust for decommissioning. We would retain assets in a non-qualified decommissioning trust. We also entered into a long-term power purchase agreement to purchase all of the existing capacity and energy of the plant. This long-term power purchase agreement will become effective upon the closing of the sale. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us), NMC would transfer Point Beach's operating licenses to FPL and our relationship with NMC would be terminated. The sale of the plant and the long-term power purchase agreement are subject to review and approval by various regulatory agencies including the NRC, PSCW, MPSC and FERC. We anticipate closing the sale during the third quarter of 2007.

We, along with FPL, have made a request to the IRS for a Private Letter Ruling (PLR) related to the transfer of the qualified decommissioning trust assets. We are requesting permission to withdraw excess funds from the qualified trust without receiving unfavorable tax treatment. If we receive a favorable PLR, we would use the excess funds for the direct benefit of our customers. If we do not receive a favorable PLR, then the purchase price would be adjusted upward by approximately $50 million based on information as of December 31, 2006. We are unable to predict how or even if the IRS may rule on our request for a PLR.

If the sale is approved, we expect to receive after-tax cash proceeds exceeding $1.0 billion from the sale and the liquidation of the decommissioning trust assets. The net sales proceeds are expected to exceed our cost in the nuclear plant, and, absent regulatory treatment, we would expect to record a gain on the sale. However, we have made a filing with PSCW to defer any gain (net of transaction related costs) as a regulatory liability that would be applied to the benefit of our customers in future rate proceedings. As such, we do not expect the sale of the plant, if approved, to have a material impact on our 2007 earnings.

Power the Future Strategy: In February 2001, Wisconsin Energy filed a petition with the PSCW that would allow Wisconsin Energy to begin implementing its 10-year PTF strategy to improve the supply and reliability of electricity in Wisconsin. PTF is intended to

meet a growing demand for electricity and ensure a diverse fuel mix while keeping electricity prices reasonable. Under PTF, Wisconsin Energy plans to add new coal-fired and natural gas-fired generating capacity to the state's power portfolio which would allow us to maintain approximately the same fuel mix as exists today. PWGS 1 and 2 and OC 1 and 2 have a total output of 2,320 MW, of which Wisconsin Energy expects to own 2,120 MW. As part of its PTF strategy, Wisconsin Energy plans to (1) invest approximately $2.6 billion in 2,120 MW of new natural gas-fired and coal-fired generating capacity at existing sites; (2) upgrade our existing electric generating facilities; and (3) invest in upgrades of our existing energy distribution system. The new generating capacity will be built by We Power.

Subsequent to Wisconsin Energy's February 2001 filing, the state legislature amended several laws, making changes which were critical to the implementation of PTF. In October 2001, the PSCW issued a declaratory ruling finding, among other things, that it was prudent to proceed with PTF and for Wisconsin Energy to incur the associated pre-certification expenses. However, individual expenses are subject to review by the PSCW in order to be recovered.

In November 2001, Wisconsin Energy created We Power to design, construct, own and lease the new generating capacity. We will lease each new generating facility from We Power as well as operate and maintain the new plants under 25- to 30-year lease agreements approved by the PSCW. Based upon the structure of the leases, Wisconsin Energy expects to recover the investments in We Power's new facilities over the initial lease term. At the end of the leases, we will have the right to acquire the plants outright at market value or to renew the leases. We expect that payments under the plant leases will be recoverable in rates under the provisions of the Wisconsin Leased Generation Law.

Under the PTF strategy, Wisconsin Energy expects to meet a significant portion of our future generation needs through We Power's construction of the PWGS units and the Oak Creek expansion.

As of December 31, 2006, Wisconsin Energy:

- Received approval from the PSCW to build two 545 MW natural gas-fired intermediate load units in Port Washington, Wisconsin (PWGS 1 and PWGS 2). PWGS 1 was placed into service in July 2005 and is fully operational. PWGS 1 was completed within the PSCW approved cost parameters.

- Completed site preparation for PWGS 2 in early 2006, and procured all of the major components for PWGS 2. Construction is underway and PWGS 2 is expected to be operational in 2008.

- Received approval from the PSCW to build two 615 MW coal-fired base load units (OC 1 and OC 2) adjacent to the site of our existing Oak Creek Power Plant in Oak Creek, Wisconsin (the Oak Creek expansion), with OC 1 expected to be in service in 2009 and OC 2 in 2010. The CPCN was granted contingent upon us obtaining the necessary environmental permits. We have received all permits necessary to commence construction. In June 2005, construction commenced at the site.

- Completed the planned sale of approximately a 17% ownership interest in the Oak Creek expansion to two co-owners in November 2005. We will lease We Power's approximate 515 MW interest in each unit.

- Received approval from the PSCW for various leases between us and We Power.

Primary risks under PTF are construction risks associated with the schedule and costs for both Wisconsin Energy's Oak Creek expansion and PWGS 2, continuing legal challenges to permits obtained and changes in applicable laws or regulations, adverse interpretation or enforcement of permit conditions, laws and regulations by the permitting agencies, the inability to obtain necessary operating permits in a timely manner, obtaining the investment capital from outside sources necessary to implement the strategy, governmental actions, and events in the global economy.

You can find additional information regarding risks associated with the PTF strategy, as well as the regulatory process, and specific regulatory approvals, in Factors Affecting Results, Liquidity and Capital Resources below.

Utility Operations: We are realizing operating efficiencies through the integration of our operations with those of Wisconsin Gas. These operating efficiencies are expected to increase customer satisfaction and reduce operating costs. In connection with Wisconsin Energy's PTF strategy, we are improving our existing energy distribution systems and upgrading existing electric generating assets.

Divestiture of Assets

During 2000, we agreed to join ATC by transferring our electric utility transmission system assets to ATC in exchange for an ownership interest in this new company. Transfer of these electric transmission assets became effective on January 1, 2001. As of December 31, 2006, we had an ownership interest of approximately 25.8% in ATC.

RESULTS OF OPERATIONS

EARNINGS

2006 vs. 2005: Earnings decreased to $275.6 million in 2006 compared with $283.6 million in 2005. Operating income decreased $21.4 million between the comparative periods. During 2006, we experienced mild weather, which reduced electric and gas sales. In addition, operation and maintenance expenses increased due to the timing of scheduled outages and maintenance projects at our coal units. However, these items were largely offset by improved recovery of fuel costs, only one scheduled refueling outage at Point Beach and increased gas margins.

2005 vs. 2004: Earnings increased to $283.6 million in 2005 compared with $248.7 million in 2004. Operating income increased $18.1 million between the comparative periods. During 2005, we experienced an increase in revenues due to favorable weather and pricing increases. Also, during 2004, we recorded severance costs under a voluntary severance program. The year to year increase in operating income was partially offset by an increase in our net under-recovered fuel position and higher operation and maintenance expenses during 2005. We had two scheduled refueling outages at our nuclear plant in 2005 in comparison to one scheduled refueling outage in 2004.

The following table summarizes our consolidated earnings during 2006, 2005 and 2004.

	2006	2005	2004
		(Millions of Dollars)	
Utility Gross Margin			
Electric (See below)	$1,710.1	$1,555.0	$1,492.2
Gas (See below)	158.4	147.3	146.9
Steam	18.6	15.6	15.2
Total Gross Margin	1,887.1	1,717.9	1,654.3
Other Operating Expenses			
Other operation and maintenance	1,074.5	880.5	844.7
Depreciation, decommissioning and amortization	270.9	281.8	274.1
Property and revenue taxes	85.8	78.3	76.3
Operating Income	455.9	477.3	459.2
Equity in Earnings of Transmission Affiliate	33.9	30.4	26.4
Other Income, net	42.9	28.4	7.1
Interest Expense	87.0	85.8	89.6
Income Before Income Taxes	445.7	450.3	403.1
Income Taxes	168.9	165.5	153.2
Preferred Stock Dividend Requirement	1.2	1.2	1.2
Earnings Available for Common Stockholder	$275.6	$283.6	$248.7

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2006 with similar information for 2005 and 2004, including a summary of electric operating revenues and electric sales by customer class.

Electric Utility Operations	Electric Revenues and Gross Margin			Electric MWh Sales		
	2006	2005	2004	2006	2005	2004
	(Millions of Dollars)			(Thousands, Except Degree Days)		
Customer Class						
Residential	$870.8	$815.5	$720.7	8,154.0	8,389.6	7,885.3
Small Commercial/Industrial	796.0	727.6	651.9	8,899.0	8,943.9	8,597.0
Large Commercial/Industrial	637.0	592.7	541.4	10,972.2	11,489.8	11,477.4
Other-Retail/Municipal	87.0	103.1	82.6	1,982.7	2,467.1	2,157.6
Resale-Utilities	73.5	42.5	39.9	1,436.2	682.8	1,045.1
Other Operating Revenues	35.2	39.5	34.3	-	-	-
Total Electric Operating Revenues	2,499.5	2,320.9	2,070.8	31,444.1	31,973.2	31,162.4
Fuel and Purchased Power						
Fuel	487.7	432.6	335.0			
Purchased Power	301.7	333.3	243.6			
Total Fuel and Purchased Power	789.4	765.9	578.6			
Total Electric Gross Margin	$1,710.1	$1,555.0	$1,492.2			
Weather -- Degree Days (a)						
Heating (6,663 Normal)				6,043	6,628	6,663
Cooling (716 Normal)				723	949	442

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a 20-year moving average.

Electric Utility Revenues and Sales

2006 vs. 2005: Our electric utility operating revenues increased by $178.6 million, or 7.7%, when compared to 2005. We estimate that revenues in 2006 were $213.3 million higher than 2005 due to pricing increases that we received in January 2006 and during 2005. The most significant pricing increases authorized by the PSCW related to the recovery of higher fuel costs, costs associated with the new plants under Wisconsin Energy's PTF strategy and increased transmission costs.

Our electric utility operating revenues are expected to increase in 2007 primarily due to the impact of a full year of the January 2006 Wisconsin retail pricing increase and the expected implementation of increased wholesale rates, as well as the impacts of our fuel adjustment clause that are tied to our fuel and purchase power costs. During 2006, we reserved approximately $38 million of revenues associated with favorable recoveries of fuel and purchased power. For more information on the pricing increases and the fuel cost adjustment clause, see Rates and Regulatory Matters in Factors Affecting Results, Liquidity and Capital Resources.

Our electric sales volumes decreased by 1.7% in 2006 as compared to 2005 due to mild weather and lower commercial and industrial sales, offset by an increase in sales for resale. Residential sales volumes decreased 2.8% due largely to weather. In 2006, heating degree days decreased approximately 8.8% compared to 2005, and cooling degree days decreased approximately 23.8%. We estimate that the weather had an unfavorable impact on operating revenues of approximately $46.5 million when compared to the prior year. Total sales volumes to commercial/industrial customers decreased 2.8% between the comparative periods. Sales volumes to commercial/industrial customers, excluding our largest customers, two iron ore mines, decreased 1.4%. Sales volumes in the Other Retail/Municipal class decreased approximately 19.6% compared to the prior year due, in part, to the expiration of a wholesale contract on December 31, 2005. The increase in sales volumes to other utilities is attributed to the availability of PWGS 1 for all of 2006, which provided additional generation capacity. PWGS 1 was not operational until the third quarter of 2005. Under the Wisconsin fuel rules, sales to other utilities reduce fuel costs charged to customers.

2005 vs. 2004: During 2005, our total electric utility operating revenues increased by $250.1 million or 12.1% when compared with 2004 primarily due to favorable weather during the summer of 2005 and pricing increases.

During 2005, we estimate that pricing increases contributed an additional $145.8 million of revenues than in 2004. The most significant impact to rates was a March 2005 interim order we received from the PSCW authorizing an annualized increase in electric rates of approximately $114.9 million due to the increased costs of fuel and purchased power. In November 2005, we received the

final rate order, which authorized an additional $7.7 million of annual revenues. Additional orders impacting rates in 2005 were the May 2004 and May 2005 orders we received from the PSCW authorizing annualized increases in electric rates of approximately $59.0 million and $59.7 million, respectively, primarily to cover construction costs associated with Wisconsin Energy's PTF strategy.

Total electric sales increased by 2.6% between 2005 and 2004. Residential sales volumes increased 6.4% due to the favorable summer weather in 2005. Total sales volumes to commercial/industrial customers increased 1.8% between comparative periods. Sales volumes to commercial/industrial customers, excluding our largest customers, two iron ore mines, increased 2.4% due to the favorable weather during the summer of 2005. We estimate that weather increased our electric revenues by approximately $68.8 million during 2005 as compared to the prior year. As measured by cooling degree days, 2005 was 114.7% warmer than in 2004.

Sales volumes in the Resale-Utilities class decreased 34.7% primarily due to the reduced availability of base-load capacity for sale at competitive prices as a result of limited fuel supplies and outages. Sales volumes to municipal utilities, the Other Retail/Municipal customer class, increased 14.3% between the periods due to higher off-peak demand from lower margin municipal wholesale power customers.

Electric Fuel and Purchased Power Expenses

2006 vs. 2005: Our fuel and purchased power expenses increased by $23.5 million, or approximately 3.1%, when compared to 2005. Our average cost of fuel and purchased power increased from $23.95 per MWh in 2005 to $25.10 per MWh in 2006. The largest factor for the higher cost per MWh was a 24.1% increase in the per MWh cost of coal-fired generation, which includes coal and related transportation costs, between the comparative periods. This increase was partially offset by increased generation from Point Beach and a decrease in the average costs of purchased power and fuel for our natural gas-fired units.

Our electric fuel and purchased power expenses in 2007 are expected to be impacted by the duration of the scheduled nuclear refueling outage in the first quarter of 2007; the timing and completion of the proposed sale of Point Beach; the price of purchased power; the increased cost of coal and related transportation; and changes in electric sales.

2005 vs. 2004: Gross fuel and purchased power costs for our electric utility increased by a total of $260.1 million during 2005 when compared with 2004. During 2005, we deferred $72.8 million of fuel and purchased power costs which resulted in a net increase of fuel and purchased power expense of $187.3 million or 32.4% during 2005 when compared to 2004. The increase in fuel and purchased power expense was driven by a 2.6% increase in MWh sales and an increase in our average cost of fuel and purchased power from $18.57 per MWh in 2004 to $23.95 per MWh in 2005, or 29.0% between the comparative periods.

The increase in our average cost of fuel and purchased power was due primarily to (1) the reduced availability of nuclear generation due to scheduled refueling outages, (2) higher natural gas prices that increased the cost of power supplied by natural gas, (3) the impact of the implementation of the MISO Midwest Market in April 2005 and (4) limitations on coal supplies due to transportation shortfalls.

During 2005, we had two scheduled refueling outages at our nuclear plant and in 2004 we had one scheduled refueling outage. As a result, we had approximately 1,145,000 fewer MWh of nuclear generation in 2005. Our average fuel cost for nuclear generation is approximately $5 per MWh, while the average energy cost for purchased power was approximately $55 per MWh. We estimate that the reduction in nuclear generation resulted in approximately $57 million of increased fuel and purchased power costs in 2005 as compared to 2004. During the 2005 outages we replaced both reactor vessel heads resulting in longer outages. This work, along with other planned maintenance, lasted longer than originally expected due to delays. For more information regarding the scheduled refueling outages, see Factors Affecting Results, Liquidity and Capital Resources -- Nuclear Operations.

In 2005, we experienced significant increases in the cost of natural gas used in our own generating assets and in the price of purchased energy which is highly influenced by the price of natural gas. This increase was most significant in the last six months of 2005 due to market related factors including the hurricanes in the Gulf of Mexico. The average combined cost per MWh of purchased energy and natural gas fired units in 2005 was 46.8% higher than in 2004, increasing total cost by approximately $72.5 million.

In April 2005, we began participating in the MISO Midwest Market which fundamentally changed the way we dispatch our generating units and obtain purchased energy. As part of this new market, we are subject to new types of charges which, among other things, recognize the cost of transmission congestion, MWh losses and other costs associated with operating the generating units in an uneconomic fashion to support the MISO Midwest Market service territory. The State of Wisconsin has a constrained transmission system and we believe these constraints result in higher costs for us than in other parts of the MISO Midwest Market service territory. The incremental costs associated with the MISO Midwest Market charges identified above were approximately $28 million in 2005. For more information regarding MISO and the MISO Midwest Market, see Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition -- Electric Transmission and Energy Markets.

Our 2005 operations were also adversely impacted by limitations on deliveries of coal supply due to the failure of our primary rail delivery supplier to deliver contracted quantities of coal to our units. The largest limitation was related to critical rail track maintenance in the Powder River basin. This, in turn, resulted in reduced coal deliveries of the coal which primarily serves our Oak Creek and Pleasant Prairie generating units from June through December 2005. In response to the reduced deliveries, we reduced generating output of these units during off-peak periods when replacement power prices were lower, purchased more expensive replacement power and took measures to purchase and transport higher cost coal in place of contracted supplies when it made economic sense to do so. We estimate that this increased our costs by approximately $52 million in 2005. For additional information on the decreased coal deliveries, see Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks -- Commodity Prices.

Under the State of Wisconsin fuel rules, we are allowed to request recovery in fuel revenues if our projected fuel and purchased power costs exceed bands established by the PSCW. In March 2005, we received a rate order that allowed us to increase our annual revenues by $114.9 million (final order received in November 2005 for an annual increase of $122.6 million) due to increased fuel and purchased power costs. As provided under the Wisconsin rules, we are also allowed to request deferral for the costs associated with adverse events which materially impact fuel and purchased power costs which were not anticipated, or for which costs could not be reasonably estimated at the time of the fuel recovery request for consideration in future rate proceedings. During 2005, we deferred approximately $72.8 million of fuel and purchased power costs due to the extended outage at Point Beach Unit 2, the coal delivery problems and increased costs associated with the MISO Midwest Market. During 2005, we estimate that we under-recovered fuel and purchased power costs by $108.4 million before these deferred items. Adjusted for the allowed deferrals, our net under-recovered fuel and purchased power costs were approximately $35.6 million.

Gas Utility Revenues, Gross Margin and Therm Deliveries

The following table compares our total gas utility operating revenues and gross margin (total gas utility operating revenues less cost of gas sold) during 2006, 2005 and 2004.

Gas Utility Operations	2006	2005	2004
	(Millions of Dollars)		
Operating Revenues	$590.0	$593.6	$523.8
Cost of Gas Sold	431.6	446.3	376.9
Gross Margin	$158.4	$147.3	$146.9

We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under our GCRM. The following table compares our gas utility gross margin and therm deliveries by customer class during 2006, 2005 and 2004.

	Gross Margin			Therm Deliveries		
Gas Utility Operations	2006	2005	2004	2006	2005	2004
	(Millions of Dollars)			(Millions, Except Degree Days)		
Customer Class						
Residential	$104.8	$96.4	$95.7	313.2	340.5	342.3
Commercial/Industrial	35.5	33.0	32.9	190.3	199.9	200.4
Interruptible	0.6	0.5	0.5	6.0	6.2	6.4
Total Gas Sold	140.9	129.9	129.1	509.5	546.6	549.1
Transported Gas	15.4	15.6	15.9	303.1	355.8	286.0
Other Operating	2.1	1.8	1.9	-	-	-
Total	$158.4	$147.3	$146.9	812.6	902.4	835.1
Weather -- Degree Days (a)						
Heating (6,663 Normal)				6,043	6,628	6,663

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a 20-year moving average.

2006 vs. 2005: Gas utility gross margin increased by $11.1 million or 7.5% between the comparative periods. The increase in gross margin is due, in part, to a pricing increase that was granted by the PSCW and implemented in January 2006. The gas pricing increase was primarily granted to recover higher operating costs, including bad debt expenses. We estimate that our gross margin increased between the comparative periods by approximately $19.1 million due to this pricing increase.

The pricing increase was partially offset by a decline in gas sales volumes that was driven by mild winter weather and by lower customer usage. Temperatures (as measured by heating degree days) were approximately 8.8% warmer in 2006 as compared to 2005. The mild winter weather reduced customer demand for heating. We estimate that the weather decreased our gross margin by approximately $8.3 million between the comparative periods. We continue to see a reduction in normalized use of gas per customer which we believe is caused by high natural gas prices and the continued improvements in energy efficient appliances. During 2006, we estimate this reduction in normalized use decreased our gross margin by approximately $2.0 million. The decrease in volume of transport gas sales was due in part to fuel switching during months where gas commodity prices were high during 2006. Residential therm deliveries decreased 8.0% as compared to 2005, due to warmer weather and a decrease in use per customer that was driven in part by high commodity prices.

Our gas utility's gross margin is expected to increase in 2007 primarily due to the impact of a full year of the January 2006 pricing increase. In addition, 2007 gross margins will be impacted by weather and customer demand. For more information on the pricing increases, see Rates and Regulatory Matters in Factors Affecting Results, Liquidity and Capital Resources.

2005 vs. 2004: Gas utility gross margin was relatively flat in 2005, increasing by only $0.4 million or 0.3%. Total therm deliveries were 8.1% higher during 2005, primarily due to increased transport gas deliveries of 69.8 million therms. Transport volumes increased between the comparative periods due to a higher amount of electric generation from natural gas within our service territory. Our margins on transport gas volumes are significantly lower than our margins for retail gas sales, which is the primary reason why gross margin remained flat even with an increase in therm deliveries.

Other Operation and Maintenance Expenses

2006 vs. 2005: Our other operation and maintenance expenses increased by $194.0 million, or 22.0%, when compared to 2005. As discussed above, we received a pricing increase in January 2006 to cover increased costs. The increases in other operation and maintenance expenses that relate to the pricing increase include higher PTF lease costs of $85.4 million, increased transmission expenses of $62.7 million, increased renewable energy and energy efficiency program expenses of $9.1 million and increased bad debt expenses of $2.8 million. Other operation and maintenance expenses increased approximately $34.8 million due to PWGS 1 operating costs and the timing of scheduled outages and maintenance projects at our coal plants. In 2005, we received approximately $10.0 million as a settlement to resolve a vender dispute, reducing other operation and maintenance expense in 2005. These increases were partially offset by decreased nuclear operating and maintenance expense. In 2006, we had only one scheduled nuclear refueling outage as compared to two scheduled refueling outages in 2005, which resulted in approximately a $10.9 million decrease in nuclear operation and maintenance expenses between the comparative periods. In addition, the elimination of seams elimination transmission charges, effective March 31, 2006, resulted in reduced costs of approximately $9.5 million for 2006. For further information on seams elimination charges, see Electric Transmission in Factors Affecting Results, Liquidity and Capital Resources below.

Our operation and maintenance expenses are expected to increase in 2007 as a result of increased amortizations related to the impact of the 2006 pricing increase. In addition, operation and maintenance expenses are influenced by wage inflation, employee benefit costs and the length of plant outages.

2005 vs. 2004: Other operation and maintenance expenses increased by $35.8 million or 4.2% during 2005 compared with 2004. The most significant changes in our operation and maintenance expense related to increased lease costs and increased nuclear outage costs. Partially offsetting these increases was a charge in 2004 for severance costs related to the voluntary severance program and lower employee costs in 2005 due to fewer employees.

The largest operations and maintenance increase was due to $50.0 million of additional costs related to lease agreements between us and We Power in connection with the PTF strategy.

In addition to the increased lease costs, our nuclear operating and maintenance expense increased approximately $11.0 million due to two scheduled refueling outages in 2005 where we also replaced the reactor vessel heads. In 2004, we had one scheduled refueling outage. This increase was partially offset by a $10.0 million settlement we received to resolve a vendor dispute.

Additionally, in 2004 we recognized $22.3 million of severance related costs due to the voluntary severance program that was implemented in the second half of 2004. In 2005, we had approximately 138 fewer employees, which reduced operation and maintenance costs by $11.1 million.

Benefit costs increased $12.2 million between the comparative periods due to increased pension and medical costs. In October 2005, we announced that we were offering to our retirees a Medicare Advantage program as an option within our existing post-retirement medical and drug plans.

Depreciation, Decommissioning and Amortization Expense

2006 vs. 2005: Depreciation, decommissioning and amortization expenses decreased by $10.9 million or 3.9% when compared to 2005. In January 2006, we implemented new depreciation rates approved by the PSCW which reduced annual depreciation expenses. We estimate that the new rates reduced annual depreciation expense by approximately $15 million, which was offset, in part, by net plant additions in 2006. We expect depreciation, decommissioning and amortization expenses in 2007 to increase as a result of an overall increase in plant assets in service.

2005 vs. 2004: Depreciation, decommissioning and amortization expense increased by $7.7 million in 2005 as compared to 2004. This increase was primarily due to increased depreciable plant balances.

Other Income, net

The following table identifies the components of consolidated other income, net during 2006, 2005 and 2004.

Other Income, net	2006	2005	2004
		(Millions of Dollars)	
Capitalized Carrying Costs	$25.0	$20.4	$12.7
AFUDC-Equity	14.5	9.2	1.7
Donations and Contributions	(6.0)	(6.7)	(5.6)
Gross Receipts Tax Recovery	4.0	2.6	1.5
Other, net	5.4	2.9	(3.2)
Total Other Income, net	$42.9	$28.4	$7.1

2006 vs. 2005: Other income, net increased by $14.5 million when compared to 2005. The largest increases relate to increased AFUDC - Equity of $5.3 million and capitalized carrying costs of $4.6 million. In 2007, we expect a reduction in AFUDC - Equity as we placed in service the new scrubber at our Pleasant Prairie Power Plant in the fourth quarter of 2006. The scrubber was installed as part of our EPA consent decree spending. For further information on the consent decree with the EPA, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

2005 vs. 2004: Other income, net increased by $21.3 million in 2005 compared to 2004. Significant items included an increase of $7.7 million in the recognition of capitalized carrying costs, and a $7.5 million increase in AFUDC - Equity due to a higher average balance of AFUDC qualifying utility construction projects in 2005.

Interest Expense

2006 vs. 2005: Interest expense increased by $1.2 million in 2006 when compared with 2005. This increase was due to higher interest rates on short-term debt, increased average balances of commercial paper outstanding and a net increase in long-term debt outstanding. These increases were partially offset by the items that follow. We expensed approximately $6.2 million in 2005 related to the amortization of costs associated with prior debt redemptions. These costs were fully amortized as of July 2005; therefore, there was no similar expense in 2006. In addition, there was increased capitalized interest in 2006 due to a higher average balance of construction projects in 2006.

We expect total interest expense in 2007 to increase reflecting a full year of interest on the $300 million of 5.70% Debentures that we issued in November 2006.

2005 vs. 2004: Total interest expense decreased by $3.8 million in 2005 compared with 2004. The major components of this decrease included a reduction in the amortization of debt premiums and increased capitalized interest in 2005 due to a higher average balance of construction projects in 2005. These items were partially offset by increases in interest expense due mainly to higher interest rates on our short-term debt. Additionally, in November 2004 we sold $250 million of unsecured 3.50% Debentures due December 1, 2007, the proceeds of which were used to repay outstanding commercial paper, including commercial paper which funded the August 2004 retirement of our $140 million of 7-1/4% First Mortgage Bonds.

Income Taxes

2006 vs. 2005: Our effective income tax rate was 38.0% in 2006 compared with 36.9% in 2005.

2005 vs. 2004: Our effective income tax rate was 36.9 % in 2005 compared with 38.0% in 2004. This decrease in the effective income tax rate reflected higher AFUDC - Equity.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2006, 2005 and 2004:

Wisconsin Electric	2006	2005	2004
		(Millions of Dollars)	
Cash Provided by (Used in)			
Operating Activities	$498.5	$481.3	$630.8
Investing Activities	($473.8)	($482.1)	($423.9)
Financing Activities	($29.7)	($2.1)	($200.8)

Operating Activities

Cash provided by operating activities for 2006 totaled $498.5 million, which is a $17.2 million improvement over 2005. There were two primary areas that drove this improvement in operating cash flows. During 2006, we estimate that our collections of fuel costs improved by nearly $95 million as we had favorable collections in 2006 and unfavorable recoveries and fuel cost deferrals in 2005. The other primary area related to the working capital requirements related to gas in storage. During 2006, we entered into certain contracts that reduced our need to inject gas in storage. In addition, lower gas commodity prices, offset in part by less withdrawals due to weather, have lowered working capital requirements between the comparative periods. We estimate that these items reduced our cash needs for gas in storage by approximately $25.0 million. Partially offsetting these items was an increase of cash taxes of approximately $58.6 million due to higher taxable earnings.

Cash provided by operating activities decreased to $481.3 million during 2005 compared with $630.8 million during 2004. This decline reflected increased working capital needs, an increase in deferred costs, and an increase in cash taxes paid. During 2005, we experienced significant increases in natural gas costs which increased our working capital requirements for natural gas in storage. The increased natural gas costs also led to an increase in accounts receivable as the cost of gas is recovered dollar for dollar in our natural gas revenues. During 2005, we also experienced increased deferred costs related to transmission costs and deferred fuel.

Investing Activities

During 2006, net cash outflows from investing activities were $473.8 million compared with $482.1 million in 2005. The decrease primarily reflects lower capital expenditures of $10.5 million, partially offset by an increase in capital contributions to ATC of $3.6 million.

During 2005, we made net investments totaling $482.1 million compared to $423.9 during 2004. Capital expenditures increased by $50.3 million to $409.2 million and were primarily related to facilitating compliance with the consent decree entered into with the EPA (See Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements). In addition, expenditures associated with nuclear fuel purchases were higher by $19.7 million during 2005. These increases were partially offset by a reduction in capital contributions to ATC of $14.0 million during 2005.

In 2007, if we are able to close on the sale of Point Beach, we expect to receive an additional $1 billion of after-tax cash proceeds.

Financing Activities

The following table summarizes our cash flows from financing activities:

	2006	2005	2004
		(Millions of Dollars)	
Dividends to Wisconsin Energy	($179.6)	($179.6)	($179.6)
Capital Contribution from Wisconsin Energy	100.0	-	-
Increase (Reduction) in Total Debt	50.0	178.7	(19.5)
Other	(0.1)	(1.2)	(1.7)
Cash Used in Financing	($29.7)	($2.1)	($200.8)

During 2006, we used $29.7 million for net financing activities compared with $2.1 million during 2005. In November 2006, we issued $300 million of 5.70% Debentures due December 1, 2036. The net proceeds from the sale were used to retire our $200 million of 6-5/8% Debentures due November 15, 2006 at their scheduled maturity and to repay outstanding commercial paper incurred for working capital requirements. During 2006, short-term debt decreased approximately $48.5 million.

In November 2004, we issued $250 million of unsecured 3.50% debentures due December 1, 2007, the proceeds of which were used to pay down outstanding commercial paper. In August 2004, we retired $140 million of 7-1/4% First Mortgage Bonds at their scheduled maturity.

For additional information concerning changes in our long-term debt, see Note G -- Long-Term Debt in the Notes to Consolidated Financial Statements.

CAPITAL RESOURCES AND REQUIREMENTS

In December 2006, we announced that we had reached an agreement to sell Point Beach to an affiliate of FPL. If the sale is completed, we expect to receive over $1 billion of after-tax cash proceeds from the sale and liquidation of decommissioning trust assets. In the short-term, these proceeds would be used to reduce outstanding debt or temporarily invested in short-term securities. However, as discussed in Corporate Developments - Corporate Strategy, we have filed an application with the PSCW that outlines our intention to use the gain (net of transaction related costs) on the sale for the benefit of our customers as decided by our regulators in future rate proceedings. As such, if the Point Beach sale is approved, we believe that the cash proceeds, after transaction costs and return of invested capital that will result from the sale will replace revenues that we would have received in future rate proceedings.

Capital Resources

We anticipate meeting our capital requirements during 2007 and the next several years primarily through internally generated funds and short-term borrowings, supplemented from time to time, depending on market conditions and other factors, by the issuance of intermediate or long-term debt securities and equity contributions from our parent.

We have access to capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We believe that we have adequate capacity to fund our operations for the foreseeable future through our borrowing arrangements and internally generated cash.

In March 2004, the Governor of Wisconsin signed into law a measure that gives utilities the ability to securitize the portion of customer bills that recovers the cost of certain investments intended to improve the environment. We evaluated the possible issuance of environmental trust bonds for some time. However, after extensive evaluation and analysis, we will not be pursuing an issuance of environmental trust bonds.

We have a credit agreement that provides liquidity support for our obligations with respect to commercial paper and for general corporate purposes.

As of December 31, 2006, we had approximately $485.9 million of available unused lines under our bank back-up credit facility and $304.2 million of total consolidated short-term debt outstanding.

We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. The following table summarizes our facility at December 31, 2006:

Total Facility	Letters of Credit	Credit Available	Facility Expiration	Facility Term
(Millions of Dollars)				
$500.0	$14.1	$485.9	March 2011	5 year

On March 30, 2006, we entered into an unsecured five year $500 million bank back-up credit facility to replace a $250 million three year credit facility with an expiration date of June 2007 and a $125 million three year credit facility with an expiration date of November 2007. This new facility will expire in March 2011. This facility has a renewal provision for two one-year extensions, subject to lender approval.

The following table shows our consolidated capitalization structure at December 31:

Capitalization Structure	2006		2005	
	(Millions of Dollars)			
Common Equity	$2,528.6	50.4%	$2,310.9	48.6%
Preferred Stock	30.4	0.6%	30.4	0.6%
Long-Term Debt (a)	1,587.2	31.6%	1,493.0	31.5%
Capital Lease Obligations (a)	564.9	11.3%	565.5	11.9%
Short-Term Debt	304.2	6.1%	352.7	7.4%
Total	$5,015.3	100.0%	$4,752.5	100.0%

(a) Includes current maturities

We recorded a $335.5 million capital lease in July 2005 in connection with the in-service date of PWGS 1. For additional information, see Note G -- Long-Term Debt in the Notes to Consolidated Financial Statements.

Access to capital markets at a reasonable cost is determined in large part by credit quality. The following table summarizes the ratings of our debt securities and preferred stock by S&P, Moody's and Fitch as of December 31, 2006.

	S&P	Moody's	Fitch
Commercial Paper	A-2	P-1	F1
Senior Secured Debt	A-	Aa3	AA-
Unsecured Debt	A-	A1	A+
Preferred Stock	BBB	A3	A

On June 15, 2006, Fitch affirmed our security ratings. Our security ratings outlook assigned by Fitch is stable.

On June 8, 2006, S&P affirmed our security ratings and ratings outlook. Our security ratings outlook assigned by S&P is negative.

Our security ratings outlook assigned by Moody's is stable.

We believe these security ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agencies only. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities, but rather an indication of creditworthiness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Capital Requirements

Total capital expenditures, excluding the purchase of nuclear fuel, are currently estimated to be approximately $600 million during 2007. Due to changing environmental and other regulations such as air quality standards and electric reliability initiatives that impact us, future long-term capital requirements may vary from recent capital requirements. We currently expect these capital expenditures to be between $500 million and $600 million per year during the next three years.

In June 2005, we purchased the development rights to two wind farm projects from Navitas Energy Inc. We plan to develop the wind sites and construct wind turbines with a combined generating capability between 130 and 200 MW. We estimate that the capital cost of the project, excluding AFUDC, will be up to $360 million. We anticipate the cost to build the wind farm projects would be recovered in our rates. We expect the turbines to be placed in service in 2008, dependent upon the availability of wind turbines and the receipt of necessary regulatory approvals. For additional information on Wind Generation see Rates and Regulatory Matters - Wind Generation below.

Investments in Outside Trusts: We have funded our pension obligations, certain other post-retirement obligations and future nuclear obligations in outside trusts. Collectively, these trusts had investments that exceeded $1.7 billion as of December 31, 2006. These trusts hold investments that are subject to the volatility of the stock market and interest rates. For further information, see Note F -- Nuclear Operations and Note L -- Benefits in the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements: We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit which support commodity contracts and other payment obligations. We believe that these agreements do not have, and are not reasonably likely to have, a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For further information, see Note M -- Guarantees in the Notes to Consolidated Financial Statements.

We have identified three tolling and purchased power agreements with third parties but have been unable to determine if we are the primary beneficiary of any of these three variable interest entities as defined by FIN 46. As a result, we do not consolidate these entities. Instead, we account for one of these contracts as a capital lease and for the other two contracts as operating leases as reflected in the table below. We have included our contractual obligations under all three of these contracts in our Contractual Obligations/Commercial Commitments disclosure that follows. For additional information, see Note D -- Variable Interest Entities in the Notes to Consolidated Financial Statements.

Contractual Obligations/Commercial Commitments: We have the following contractual obligations and other commercial commitments as of December 31, 2006:

	Payments Due by Period				
Contractual Obligations (a)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
		(Millions of Dollars)			
Long-Term Debt Obligations (b)	$3,630.2	$332.0	$144.2	$144.2	$3,009.8
Capital Lease Obligations (c)	1,677.7	109.6	204.4	178.6	1,185.1
Operating Lease Obligations (d)	183.9	51.6	58.2	41.2	32.9
Purchase Obligations (e)	1,376.1	347.8	596.4	156.9	275.0
Other Long-Term Liabilities (f)	74.9	72.7	1.4	0.8	-
Total Contractual Obligations	$6,942.8	$913.7	$1,004.6	$521.7	$4,502.8

(a) The amounts included in the table are calculated using current market prices, forward curves and other estimates. Contracts with multiple unknown variables have been omitted from the analysis. This table excludes the long-term power purchase commitment which is contingent upon the sale of Point Beach.

(b) Principal and interest payments on our Long-Term Debt and the Long-Term Debt of our affiliates (excluding capital lease obligations).

(c) Capital Lease Obligations for nuclear fuel lease, PWGS 1 and purchase power commitments.

(d) Operating Lease Obligations for purchase power commitments and vehicle and rail car leases.

(e) Purchase Obligations under various contracts for the procurement of fuel, power, gas supply and associated transportation and for information technology and other services for utility operations.

(f) Other Long-Term Liabilities include the expected 2007 supplemental executive retirement plan obligation and the 2007 non-discretionary pension contribution. For additional information on employer contributions to our benefit plans see Note L - Benefits in the Notes to Consolidated Financial Statements.

Our obligations for utility operations have historically been included as part of the rate making process and therefore are generally recoverable from customers.

FACTORS AFFECTING RESULTS, LIQUIDITY AND CAPITAL RESOURCES

MARKET RISKS AND OTHER SIGNIFICANT RISKS

We are exposed to market and other significant risks as a result of the nature of our businesses and the environment in which those businesses operate. These risks, described in further detail below, include but are not limited to:

Regulatory Recovery: Our electric operations burn natural gas in our leased power plants, in several of our peaking power plants and as a supplemental fuel at several coal-fired plants. In addition, the cost of purchased power is generally tied to the cost of natural gas. We bear regulatory risk for the recovery of these fuel and purchased power costs when these costs are higher than the base rate established in our rate structure. For further information on the recovery of fuel and purchase power costs see Commodity Prices.

We account for our regulated operations in accordance with SFAS 71. Our rates are determined by regulatory authorities. Our primary regulator is the PSCW. SFAS 71 allows regulated entities to defer certain costs that would otherwise be charged to expense, if the regulated entity believes the recovery of these costs is probable. We record regulatory assets pursuant to specific orders or by a generic order issued by our regulators, and recovery of these deferred costs in future rates is subject to the review and approval of those regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of these costs is not approved by our regulators, the costs are charged to income in the current period. We expect to recover our outstanding regulatory assets in rates over a period of no longer than 20 years. Regulators can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. Under SFAS 71, we record these items as regulatory liabilities.

Commodity Prices: In the normal course of providing energy, we are subject to market fluctuations of the costs of coal, natural gas and the cost of purchased power. We manage our fuel and gas supply costs through a portfolio of short- and long-term procurement contracts with various suppliers for the purchase of coal, uranium, natural gas and fuel oil. In addition, we manage the risk of price volatility by utilizing gas hedging programs.

Wisconsin's retail electric fuel cost adjustment procedure mitigates some of our risk of electric fuel cost fluctuation. If cumulative fuel and purchased power costs for electric utility operations deviate from a prescribed range when compared to the costs projected in the most recent retail rate proceeding, retail electric rates may be adjusted prospectively. For 2007, we will operate under a traditional fuel cost adjustment clause in the Wisconsin retail jurisdiction whereby fuel revenues may be adjusted prospectively if fuel and purchased power costs fall outside a pre-established annual band of plus or minus 2%. For information regarding the 2006 fuel rules, see Rates and Regulatory Matters.

The PSCW has authorized dollar for dollar recovery for the majority of natural gas costs for our gas utility operations through a gas cost recovery mechanism, which mitigates most of the risk of gas cost variations. For information concerning the electric utility fuel cost adjustment procedure and our natural gas utility's GCRM, see Rates and Regulatory Matters.

Natural Gas Costs: Significant increases in the cost of natural gas affect our electric and gas utility operations. Natural gas costs have increased significantly because the supply of natural gas in recent years has not kept pace with the demand for natural gas. We expect that demand for natural gas will remain high into the foreseeable future and that significant price relief will not occur until additional natural gas is added to the nation's energy supply mix.

Higher natural gas costs increase our working capital requirements and result in higher gross receipts taxes in the State of Wisconsin. Higher natural gas costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. Because federal and state energy assistance dollars have not kept pace with rising natural gas costs over the recent year, our risks related to bad debt expenses have increased.

In February 2005, the PSCW authorized the use of the escrow method of accounting for bad debt costs allowing for deferral of Wisconsin residential bad debt expense that exceed amounts allowed in rates. In 2004 and 2003, we had approval from the PSCW to defer residential bad debt net write-offs that exceed amounts allowed in rates.

As a result of our GCRM, our gas distribution operations receive dollar for dollar recovery on the cost of natural gas. However, increased natural gas costs increase the risk that customers will switch to alternative fuel sources, which could reduce future gas margins.

Weather: Our Wisconsin utility rates are set by the PSCW based upon estimated temperatures which approximate 20-year averages. Our electric revenues are unfavorably sensitive to below normal temperatures during the summer cooling season, and to some extent, to above normal temperatures during the winter heating season. Our gas revenues are unfavorably sensitive to above normal temperatures during the winter heating season. A summary of actual weather information in our service territory during 2006, 2005 and 2004, as measured by degree-days, may be found above in Results of Operations.

Interest Rate: We have various short-term borrowing arrangements to provide working capital and general corporate funds. We also have variable rate long-term debt outstanding at December 31, 2006. Borrowing levels under these arrangements vary from period to period depending upon capital investments and other factors. Future short-term interest expense and payments will reflect both future short-term interest rates and borrowing levels.

We performed an interest rate sensitivity analysis at December 31, 2006 of our outstanding portfolio of $304.2 million of short-term debt with a weighted average interest rate of 5.47% and $164.4 million of variable-rate long-term debt with a weighted average interest rate of 3.83%. A one-percentage point change in interest rates would cause our annual interest expense to increase or decrease by approximately $3.0 million before taxes from short-term borrowings and by $1.6 million before taxes from variable rate long-term debt outstanding.

Marketable Securities Return: We fund our pension, OPEB and nuclear decommissioning obligations through various trust funds, which in turn invest in debt and equity securities. Changes in the market prices of these assets can affect future pension, other post-retirement benefit and nuclear decommissioning expenses. Additionally, future contributions can also be affected by changes in the market price of trust fund assets. We expect that the risk of expense and contribution variations as a result of changes in the market price of trust fund assets would be mitigated in part through future rate actions by our various utility regulators. Through December 31, 2005, we were operating under a PSCW-ordered, qualified five-year rate restriction period. For further information about the rate restriction, see Rates and Regulatory Matters.

At December 31, 2006, we held, or Wisconsin Energy held on our behalf, the following total trust fund assets at fair value, primarily consisting of publicly traded debt and equity security investments.

Wisconsin Electric Power Company	Millions of Dollars
Pension trust funds	$777.2
Nuclear decommissioning trust funds	$881.6
Other post-retirement benefits trust funds	$119.7

Fiduciary oversight of the pension and other post-retirement plan trust fund investments is the responsibility of an Investment Trust Policy Committee. Qualified external investment managers are engaged to manage the investments. Asset/liability studies are periodically conducted with the assistance of an outside investment advisor. The current study for the pension fund projects long-term, annualized returns of approximately 8.5%.

Fiduciary oversight for the nuclear decommissioning trust fund investments is also the responsibility of the Investment Trust Policy Committee. Qualified external investment managers are also engaged to manage these investments. Asset/liability studies are periodically conducted with the assistance of an outside investment advisor, subject to additional constraints established by the PSCW. The current study projects long-term, annualized returns of approximately 9%. Current PSCW constraints allow a maximum allocation of 65% in equities.

We insure various property and outage risks through NEIL. Annually, NEIL reviews its underwriting and investment results and determines the feasibility of granting a distribution to policyholders. Adverse loss experience, rising reinsurance costs or impaired investment results at NEIL could result in increased costs or decreased distributions to us.

Credit Ratings: We do not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. We do have certain agreements in the form of commodity and energy services contracts and employee benefit plans that could require, in the event of a credit ratings change to below investment grade, a termination payment if collateral is not provided or an accelerated payment. At December 31, 2006, we estimate that the potential payments under these agreements that could result from credit rating downgrades totaled approximately $46.1 million.

Economic Conditions: We are exposed to market risks in the regional midwest economy.

Inflation: We continue to monitor the impact of inflation, especially with respect to the rising costs of medical plans, in order to minimize its effects in future years through pricing strategies, productivity improvements and cost reductions. Except for continuance of an increasing trend in the inflation of medical costs and the impacts on our medical and post-retirement benefit plans, we have expectations of low-to-moderate inflation. We do not believe the impact of general inflation will have a material effect on our future results of operations.

For additional information concerning risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information at the beginning of this report.

POWER THE FUTURE

Under Wisconsin Energy's PTF strategy, we expect to meet a significant portion of our future generation needs through the construction of the PWGS and the Oak Creek expansion by We Power. We Power will lease the new plants to us under long-term leases, and we expect to recover the lease payments in our electric rates. Our lease payments are based on the cash costs authorized by our primary regulator to We Power.

The PTF units include PWGS 1, PWGS 2, OC 1 and OC 2. The following table identifies certain key items related to the units:

Unit Name	Expected In Service	Authorized Cash Costs (a)
PWGS 1	July 2005 (Actual)	$ 333 million (Actual)
PWGS 2	Summer 2008	$ 329 million
OC 1	Summer 2009	$ 1,300 million
OC 2	Summer 2010	$ 640 million

(a) Authorized cash costs represent the PSCW approved costs and the increases for factors such as inflation as identified in the PSCW approved lease terms for PWGS 2, and adjusted for Wisconsin Energy's ownership percentages in the case of OC 1 and OC 2.

Power the Future - Port Washington

Background: In December 2002, the PSCW issued a written order (the Port Order) granting Wisconsin Energy, us and We Power a CPCN to commence construction of the PWGS consisting of two 545 MW natural gas-fired combined cycle generating units on the site of our existing Port Washington Power Plant. The Port Order also authorized Wisconsin Gas to proceed with the construction of a connecting natural gas lateral, which was completed in December 2004, and it authorized ATC to construct transmission system upgrades to serve PWGS 1 and PWGS 2. PWGS 1 was completed in July 2005 and placed into service at that time. PWGS 1 was completed within the PSCW approved cost parameters. In October 2003, we received approval from FERC to transfer by long-term lease certain associated FERC jurisdictional transmission related assets from We Power to us. Construction of PWGS 2 is well underway. Site preparation, including removal of the old coal units at the site, was completed in early 2006, and all of the major components have been procured. The unit is expected to begin commercial operation in time for the peak summer season in 2008.

Lease Terms: The PSCW approved the lease agreements and related documents under which we will staff, operate and maintain PWGS 1 and PWGS 2. Key terms of the leased generation contracts include:

- Initial lease term of 25 years with the potential for subsequent renewals at reduced rates;
- Cost recovery over a 25 year period on a mortgage basis amortization schedule;
- Imputed capital structure of 53% equity, 47% debt;
- Authorized rate of return of 12.7% after tax on equity;
- Fixed construction cost of PWGS 1 and PWGS 2 at $309.6 million and $280.3 million (2001 dollars) subject to escalation at the GDP inflation rate;
- Recovery of carrying costs during construction; and
- Ongoing PSCW supervisory authority over those lease terms and conditions specifically identified in the Port Order, which do not include the key financial terms.

In January 2003, we filed a request with the PSCW to defer costs for recovery in future rates. The PSCW approved the request in an open meeting in April 2003. We Power began collecting certain costs from us in the third quarter of 2003 as provided for in lease generation contracts that were signed in May 2003. We defer the lease costs on our balance sheet, and we amortize the costs to expense as we recover the costs in rates.

Legal and Regulatory Matters: There are currently no legal challenges to the construction of PWGS and all construction permits have been received for PWGS 1 and PWGS 2. As a result of the enactment of the Energy Policy Act, FERC, through an amendment to Section 203 of the Federal Power Act, has been given jurisdiction over the acquisition of generation (which includes leasing generation), an activity that previously was not subject to FERC's jurisdiction. Under FERC's rules implementing the Energy Policy Act, Wisconsin Energy, We Power and us filed a joint application for FERC authorization to transfer the generating assets and limited interconnection facilities of PWGS 2 through a lease arrangement between We Power and us. Approval was received from FERC for this asset transfer in December 2006.

***Power the Future* - Oak Creek Expansion**

Background: In November 2003, the PSCW issued an order (the Oak Creek Order) granting us, along with Wisconsin Energy and We Power, a CPCN to commence construction of two 615 MW coal-fired units (the Oak Creek expansion) to be located adjacent to the site of our existing Oak Creek Power Plant. We anticipate OC 1 will be operational in 2009 and OC 2 will be operational in 2010. The Oak Creek Order concluded, among other things, that there was a need for additional electric generation for Southeastern Wisconsin and that a diversity of fuel sources best serves the interests of the State. The total cost for the two units was set at $2.191 billion, and the order provided for recovery of excess costs of up to 5% of the total project, subject to a prudence review by the PSCW. The CPCN was granted contingent upon us obtaining the necessary environmental permits. All necessary permits have been received at this time. In June 2005, construction commenced at the site.

In November 2005, We Power completed the sale of approximately a 17% interest in the project to two unaffiliated entities, who will share ratably in the construction costs.

Lease Terms: In October 2004, the PSCW approved the lease generation contracts between us and We Power for the Oak Creek expansion. Key terms of the leased generation contracts include:

- Initial lease term of 30 years with the potential for subsequent renewals at reduced rates;
- Cost recovery over a 30 year period on a mortgage basis amortization schedule with the potential for subsequent renewals at reduced rates;
- Imputed capital structure of 55% equity, 45% debt;
- Authorized rate of return of 12.7% after tax on equity;
- Recovery of carrying costs during construction; and
- Ongoing PSCW supervisory authority over those lease terms and conditions specifically identified in the Oak Creek Order, which do not include the key financial terms.

Legal and Regulatory Matters: The CPCN granted for the construction of the Oak Creek expansion was the subject of a number of legal challenges by third parties; these legal challenges were resolved in June 2005. We have received all permits necessary to commence construction. Certain of these permits continue to be contested, but remain in effect unless and until overturned by a reviewing court or administrative law judge. The major permits are discussed below.

The WDNR issued a Chapter 30 permit for wetlands and waterways alterations and construction on the bed of Lake Michigan for the construction of the Oak Creek expansion. The permit has been the subject of appeals since 2003. The final appeal was resolved by the Wisconsin Court of Appeals in February 2006, and the period for appeal of that decision to the Wisconsin Supreme Court has expired.

We applied to the WDNR to modify the existing WPDES permit that is required for operation of the water intake and discharge system for the planned Oak Creek expansion and existing Oak Creek generating units. In March 2005, the WDNR determined that the proposed cooling water intake structure and water discharge system meets regulatory requirements and reissued the WPDES permit with specific limitations and conditions. The opponents filed a petition for judicial review in Dane County Circuit Court and a request for a contested case proceeding with the WDNR. In September 2005, the judicial review petition was dismissed by agreement of the parties. The WDNR granted a contested case hearing that was held in March 2006. The administrative law judge upheld the issuance of the permit in a decision issued in July 2006. In August 2006, the opponents filed for judicial review of the administrative law judge's decision upholding the issuance of the permit. Briefing was completed in December 2006. However, based on the federal court decision discussed below, the opponents filed a motion on January 26, 2007 requesting supplemental briefing. In a telephone conference on February 2, 2007, the Court said that additional briefing was not necessary, but that it might request oral argument before issuing its decision regarding review of the permit. We anticipate a decision in the case in 2007.

On January 26, 2007, the Federal Court of Appeals for the Second Circuit issued a decision in Riverkeeper, Inc. v. EPA, Nos. 04-6692-ag(L) et al. (2d Cir. 2007) relating to the 316(b) rules for cooling water intake systems for existing large utility plants. The Second Circuit Court found certain portions of the rule impermissible and remanded several parts of the rule to the EPA for further consideration or potential additional rule-making. The WPDES permit for our Oak Creek expansion and existing Oak Creek generating units is a state permit, issued by WDNR with concurrence of EPA. Based on our review of the Second Circuit decision, we do not believe the decision invalidates the WPDES permit for Oak Creek. However, we cannot predict what, if any, impact the decision may have on the court's decision in the Dane County Circuit Court case.

In May 2005, we received the Army Corps of Engineers federal permit necessary for the construction of the Oak Creek expansion. Opponents may appeal the permit in federal court.

In addition, as a result of the enactment of the Energy Policy Act, FERC, through an amendment to Section 203 of the Federal Power Act, has been given jurisdiction over the acquisition of generation (which includes leasing generation), an activity that previously was not subject to FERC's jurisdiction. Under FERC's rules implementing the Energy Policy Act, Wisconsin Energy, us and We Power

filed a joint application for FERC authorization to transfer the generating assets and limited interconnection facilities of OC 1 and OC 2 through a lease arrangement between We Power and us. Approval was received from FERC for these leases in December 2006.

RATES AND REGULATORY MATTERS

The PSCW regulates our retail electric, natural gas and steam rates in the State of Wisconsin, while FERC regulates our wholesale power, electric transmission and interstate gas transportation service rates. The MPSC regulates our retail electric rates in the State of Michigan. We estimate that approximately 89% of our electric revenues are regulated by the PSCW, 5% are regulated by the MPSC and the balance of our electric revenues is regulated by FERC. All of our natural gas revenues are regulated by the PSCW. Orders from the PSCW can be viewed at http://psc.wi.gov/ and orders from the MPSC can be viewed at www.michigan.gov/mpsc/.

Overview: For the period from March 2000 until December 31, 2005, our rates were governed by an order from the PSCW in connection with the approval of Wisconsin Energy's acquisition of WICOR. Under this order, we were restricted from increasing Wisconsin rates for a five year period ending December 31, 2005, with certain limited exceptions.

The table below summarizes the anticipated annualized revenue impact of recent rate changes.

Service - Wisconsin Electric	Incremental Annualized Revenue Increase (Millions)	Percent Change in Rates (%)	Effective Date
Fuel Electric, Michigan	$3.4	7.5%	January 1, 2007
Retail electric, Wisconsin	$222.0	10.6%	January 26, 2006
Retail gas, Wisconsin	$21.4	2.9%	January 26, 2006
Retail steam, Wisconsin (a)	$7.8	31.5%	January 26, 2006
Fuel electric, Michigan	$2.7	5.9%	January 1, 2006
Fuel electric, Wisconsin (b)	$7.7	0.3%	November 24, 2005
Fuel electric, Michigan	$2.5	5.8%	November 1, 2005
Retail electric, Wisconsin	$59.7	3.1%	May 19, 2005
Retail steam, Wisconsin	$0.5	3.6%	May 19, 2005
Fuel electric, Wisconsin (b)	$114.9	5.9%	March 18, 2005
Fuel electric, Michigan	$3.4	8.0%	January 1, 2005
Fuel electric, Michigan	$1.3	3.1%	October 1, 2004
Retail steam, Wisconsin	$0.5	3.4%	May 5, 2004
Retail electric, Wisconsin (c)	$59.0	3.3%	May 5, 2004
Fuel electric, Michigan	$3.3	7.6%	January 1, 2004

(a) In January 2006, the PSCW issued a final order authorizing an increase in steam rates of $7.8 million over the two year period of 2006 and 2007.

(b) In November 2005, the PSCW issued a final order authorizing a fuel surcharge for $7.7 million of additional fuel costs. In March 2005, the PSCW issued an interim order authorizing a fuel surcharge for $114.9 million that was effective until the November 2005 final order was issued by the PSCW. The final November 2005 order for $122.6 million superseded the March 2005 interim order.

(c) In May 2004, the PSCW issued a final order authorizing an increase in electric rates for costs associated with the PWGS under construction and increased costs associated with low-income energy assistance.

2006 Pricing: In January 2006, we received an order from the PSCW that allowed us to increase annual electric revenues by approximately $222.0 million or 10.6% to recover increased costs associated with investments in Wisconsin Energy's PTF units, transmission services and fuel and purchased power, as well as costs associated with additional sources of renewable energy. The rate increase was based on an authorized return on equity of 11.2%. The order also required us to refund to customers, with interest, any fuel revenues that we receive that are in excess of fuel and purchased power costs that we incur, as defined by the Wisconsin fuel rules. The original order stipulated that any refund would also include interest at short-term rates. This refund provision does not extend past December 31, 2006.

During 2006, we experienced lower than expected fuel and purchased power costs. In September 2006, we requested and received approval from the PSCW to refund favorable fuel recoveries including accrued interest at a short-term rate. In addition, in September 2006 the PSCW determined that if the total recoveries for 2006 exceeded $36 million, interest on the amount in excess of $36 million

would be paid at the rate of 11.2%, our authorized return on equity rather than at short-term rates as originally set forth in the order. During October 2006, we refunded $28.7 million, including interest, to Wisconsin retail customers as a credit on their bill and we received approval from the PSCW to refund an additional $10 million, including interest, in the first quarter of 2007.

For 2007, we expect to operate under a traditional fuel cost adjustment clause in the Wisconsin retail jurisdiction whereby fuel revenues may be adjusted prospectively if fuel and purchased power costs fall outside a pre-established annual band of plus or minus 2%.

Our gas operations went through a traditional rate proceeding whereby the revenues were set to recover projected costs and to provide a return on rate base. The January 2006 order provided for an increase in gas revenues totaling $21.4 million or 2.9%. The rate increase was based on an authorized return on equity of 11.2%.

The steam rate proceeding was a traditional rate proceeding. The January 2006 order provided for an increase in steam rates of $7.8 million or 31.5% to be phased in over a two year period beginning in 2006. The rate increase was based on an authorized return on equity of 11.2%.

2008 Pricing: We anticipate filing a rate case in May 2007 for new rates effective in January 2008.

Limited Rate Adjustment Requests

2005 Fuel Recovery Filing: In February 2005, we filed an application with the PSCW for an increase in electric rates in the amount of $114.9 million due to the increased costs of fuel and purchased power as a result of customer growth and the increase in the reliance upon natural gas as a fuel source. We received approval for the increase in fuel recoveries on an interim basis in March 2005. In November 2005, we received the final rate order, which authorized an additional $7.7 million in rate increases, for a total increase of $122.6 million (6.2%). In December 2005, two parties filed suit against the PSCW in Dane County Circuit Court challenging the PSCW's decision to allow fuel cost recovery, while allowing us to keep the savings that resulted from Wisconsin Energy's acquisition of WICOR. As a condition of the PSCW approval of Wisconsin Energy's WICOR acquisition, we were restricted from increasing Wisconsin rates for a five year period ending December 31, 2005, with certain limited exceptions, but we were allowed to keep the savings generated from the merger. In July 2006, the Dane County Circuit Court affirmed the PSCW's decision. In August 2006, the opponents appealed this decision to the Wisconsin Court of Appeals. We anticipate a decision from the Wisconsin Court of Appeals in 2007.

2005 Revenue Deficiencies: In May 2004, we filed an application with the PSCW for an increase in electric and steam rates for anticipated 2005 revenue deficiencies associated with (1) costs for the new PWGS and the Oak Creek expansion being constructed as part of Wisconsin Energy's PTF strategy, (2) costs associated with our energy efficiency procurement plan and (3) costs associated with making changes to our steam utility systems as part of the reconstruction of the Marquette Interchange highway project in downtown Milwaukee, Wisconsin. The filing identified anticipated revenue deficiencies in 2005 attributable to Wisconsin in the amount of $84.8 million (4.5%) for our electric operations and $0.5 million (3.6%) for our steam operations. In January 2005, as a result of the litigation involving the Oak Creek expansion, we amended this filing to reduce the total revenue request to $52.4 million. In May 2005, the PSCW issued its final written order implementing an annualized increase in electric rates of $59.7 million (3.1%) and an increase of $0.5 million (3.6%) in steam rates.

Other Utility Rate Matters

Electric Transmission Cost Recovery: We divested our transmission assets with the formation of ATC in January 2001. We now procure transmission service from ATC at FERC approved tariff rates. In connection with the formation of ATC, our transmission costs have escalated due to the socialization of costs within ATC and increased transmission infrastructure requirements in the state. In 2002, in connection with the increased costs experienced by our customers, the PSCW issued an order which allowed the deferral of transmission costs in excess of amounts imbedded in rates. We are allowed to earn a return on the unrecovered transmission costs at our weighted average cost of capital. As of December 31, 2006, we have deferred $192.2 million of unrecovered transmission costs. In January 2006, our rates were increased by approximately $67.5 million annually to recover transmission costs that were not currently in rates. We will continue to accrue carrying costs on the unrecovered balances.

Fuel Cost Adjustment Procedure: Within the State of Wisconsin, we operate under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity and purchase power contracts. Imbedded within our base rates is an amount to recover fuel costs. Under the current fuel rules, no adjustments are made to rates as long as fuel and purchased power costs are expected to be within a band of the costs imbedded in current rates for the twelve month period ending December 31. If, however, annual fuel costs are expected to fall outside of the band, and actual costs fall outside of established fuel bands, then we may file for a change in fuel recoveries on a prospective basis. For 2006, the upper band was 2%. As discussed above, during 2006, we experienced lower than expected fuel and purchased power costs. In September 2006, we requested and

received approval from the PSCW to refund favorable fuel recoveries including accrued interest at short-term rates. Approximately $28.7 million, including interest, in refunds were issued as a credit on customer bills in October 2006. We had favorable fuel recoveries of approximately $37.4 million, excluding interest, for 2006. We received approval from the PSCW to refund an additional $10 million, including interest, during the first quarter of 2007. In September 2006, the PSCW determined that if the total favorable recoveries for 2006 exceeded $36 million, interest on the favorable recoveries in excess of $36 million will be paid at the rate of 11.2%, our authorized return on equity, rather than at short-term rates as originally set forth in the order. For 2007, the band is plus or minus 2%.

In June 2006, the PSCW opened a docket (01-AC-224) in which it was looking into revising the current fuel rules (Chapter PSC 116). In February 2007, five Wisconsin utilities regulated by the fuel rules including us, filed a joint proposal to modify the existing rules in this docket. The proposal recommends modifying the rules to allow for escrow accounting for fuel costs outside a plus or minus 1% annual band width of fuel costs allowed in rates. It further recommends that the escrow balance be trued-up annually following the end of each calendar year. We are unable to predict if or when the PSCW will make any changes to the existing fuel rules.

Our electric operations in Michigan operate under a Power Supply Cost Recovery mechanism which generally allows for the recovery of fuel and purchase power costs on a dollar for dollar basis.

Gas Cost Recovery Mechanism: Our natural gas operations operate under a GCRM as approved by the PSCW. Generally, the GCRM allows for a dollar for dollar recovery of gas costs. There is an incentive mechanism under the GCRM which allows for increased revenues if we acquire gas lower than benchmarks approved by the PSCW. During 2006 and 2005, no additional revenues were earned under the incentive portion of the GCRM and $0.2 million of additional revenues were earned in 2004 under the GCRM.

Bad Debt Costs: In 2004, due to a combination of unusually high natural gas prices, a soft economy within our utility service territories, and limited governmental assistance available to low-income customers, we saw a significant increase in residential uncollectible accounts receivable. These factors led us to request and receive letters from the PSCW which allowed us to defer the costs of residential bad debts to the extent that the costs exceeded the amounts allowed in rates. As a result of these letters from the PSCW, we deferred approximately $11.7 million in 2004 related to bad debt costs.

In January 2006, the PSCW issued an order approving the amortization over the next five years of the bad debts deferred in 2004 for our gas operations. The bad debts deferred in 2004 related to electric operations will be considered for recovery in future rates, subject to audit and approval of the PSCW.

In December 2004, we filed with the PSCW a request to implement a pilot program, which, among other things, is designed to better match our collection efforts with the ability of low income customers to pay their bills. Included in this filing was a request to implement escrow accounting for all residential bad debt costs. In February 2005, the PSCW approved our pilot program and our request for the use of escrow accounting. The final decision was received in March 2005. The escrow method of accounting for bad debt costs allows for deferral of Wisconsin residential bad debt expense that exceed amounts allowed in rates. As a result of this approval from the PSCW, we escrowed approximately $6.0 million in 2006 and $9.7 million in 2005 related to bad debt costs. These amounts were not addressed in the January 2006 rate order, and will therefore be considered for recovery in future rates, subject to audit and approval of the PSCW. We will continue following the escrow method of accounting for bad debts as approved in the March 2005 PSCW order.

MISO Midwest Market: In January 2005, we requested deferral accounting treatment from the PSCW for certain incremental costs or benefits that may occur due to the implementation on April 1, 2005 of the MISO Midwest Market. We received approval for this accounting treatment in March 2005. Additionally, in March 2005 we submitted a joint proposal to the PSCW with other utilities requesting escrow accounting treatment for the MISO Midwest Market costs until each utility's first rate case following April 1, 2008. The purpose of the March 2005 request for escrow accounting was to provide clarification on costs not included in the March 2005 approval for deferral accounting treatment. The PSCW approved deferral treatment for these costs in June 2006. For additional information see Industry Restructuring and Competition -- Electric Transmission and Energy Markets -- MISO.

Wholesale Electric Rates: On August 1, 2006, we filed a wholesale rate case with FERC. The filing requests an annual increase in rates of approximately $16.7 million applicable to four existing wholesale electric customers. In November 2006, FERC accepted the rate filing subject to refund with interest; however, the rates have not yet been approved. Three of the existing customer's rates are effective January 1, 2007 and the remaining $16.5 million for the largest wholesale customers' rates will be effective May 1, 2007. The rates are subject to refund and hearing and settlement procedures.

Depreciation Rates: In January 2005, along with Wisconsin Gas, we filed a joint application with the PSCW for certification of depreciation rates for specific classes of utility plant assets. In November 2005, we received notice from the PSCW that the proposed estimated lives, net salvage values and depreciation rates were approved and became effective January 1, 2006. For more information, see Note A -- Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements.

Nuclear Refueling Outages - 2005: In May 2005, we requested and received approval from the PSCW to defer replacement power costs incurred after May 30, 2005 due to the longer-than-expected outage at Point Beach Unit 2. We deferred $22.1 million of incremental purchased power costs related to the extended outage.

Renewables, Efficiency and Conservation: In March 2006, Wisconsin enacted new public benefits legislation, Act 141. This legislation changes the renewable energy requirements for utilities. Act 141 requires Wisconsin utilities to provide 2% more of their total retail energy from renewable resources than their current levels by 2010, and 6% more renewable energy than their current levels by 2015. Act 141 establishes a statewide goal that 10% of all electricity in Wisconsin be generated by renewable resources by December 31, 2015. Assuming the bulk of additional renewables is wind turbines, we must obtain approximately 210 MW of additional renewable capacity by 2010 and another approximately 610 MW of additional renewable capacity by 2015 to meet the retail energy delivered requirements. We have already started development of additional sources of renewable energy to comply with commitments made as part of Wisconsin Energy's PTF initiative which will assist us in complying with Act 141. See Wind Generation discussion below.

Act 141 allows the PSCW to delay a utility's implementation of the renewable portfolio standard if it finds that achieving the renewable requirement would be too expensive or would lessen reliability, or that new renewable projects could not be permitted on a timely basis or could not be served by adequate transmission facilities. The previous law did not include similar provisions. Act 141 provides that if a utility is in compliance with the renewable energy and energy efficiency requirements as determined by the PSCW, then the utility is considered in compliance with the Energy Priorities law. Prior to Act 141, there had been no agreement on how to determine compliance with the Energy Priorities law, which provides that it is the policy of the PSCW, to the extent it is cost-effective and technically feasible, to consider the following options in the listed order when reviewing energy-related applications: (1) energy conservation and efficiency, (2) noncombustible renewable energy resources, (3) combustible renewable energy resources, (4) natural gas, (5) oil or low sulfur coal and (6) high sulfur coal and other carbon-based fuels.

We are evaluating the requirements of Act 141. Additionally, the details of the new requirements are subject to administrative rulemaking that could take until March 2007 to complete.

Act 141 also redirects the administration of energy efficiency, conservation and renewable programs from the DOA back to the utilities and/or contracted third parties. In addition, the law requires that 1.2% of utilities' operating revenues be set aside for these programs. We do not expect the impact of this action to be material as the 1.2% approximates the amounts currently in our rates for these matters. The effective date of this action is July 1, 2007. The PSCW is expected to develop implementation plans over the upcoming months.

Wind Generation: In June 2005, we purchased the development rights to two wind farm projects (Blue Sky Green Field) from Navitas Energy Inc. We plan to develop the wind sites and construct wind turbines with a combined generating capacity of between approximately 130 and 200 MW. We filed for approval of a CPCN with the PSCW in March 2006. A prehearing conference was held in September 2006. In addition, our direct testimony was filed in September 2006. Staff and intervenor testimony was filed in October 2006 and rebuttal testimony by all parties was filed in November 2006. Hearings were held at the end of November 2006. In February 2007, the PSCW issued a written notice approving the CPCN. In addition to the CPCN approval, we are working to secure any additional permits necessary to commence construction. In early 2006, the United States Congress directed the Department of Defense and the Department of Homeland Security to investigate possible conflicts between military radar and wind turbine installations. In November 2006, we received confirmation that Blue Sky Green Field poses no such conflict, and to date the FAA has issued all requested permits for Blue Sky Green Field.

We estimate that the capital cost of the project, excluding AFUDC, will be up to $360 million. The demand for wind turbine equipment has been strong, pushing off equipment deliveries to dates later than originally anticipated. We currently expect the turbines to be placed in service by the end of 2008, dependent upon the availability of wind turbines and the receipt of necessary regulatory approvals.

ELECTRIC SYSTEM RELIABILITY

In response to customer demand for higher quality power required by modern equipment, we are evaluating and updating our electric distribution system. We are taking steps to reduce the likelihood of outages by upgrading substations and rebuilding lines to upgrade voltages and reliability. These improvements, along with better technology for analysis of our existing system, better resource management to speed restoration and improved customer communication, are near-term efforts to enhance our current electric distribution infrastructure. For the long-term, we have developed a distribution system asset management strategy that requires increased levels of automation of both substations and line equipment to consistently provide the level of reliability needed for a digital economy.

We had adequate capacity to meet all of our firm electric load obligations during 2006. All of our generating plants performed well during the warmest periods of the summer and all power purchase commitments under firm contract were received. During this

period, public appeals for conservation were not required; however, pursuant to MISO's orders we did interrupt or curtail service to non-firm customers who participate in load management programs in exchange for discounted rates.

We expect to have adequate capacity to meet all of our firm load obligations during 2007. However, extremely hot weather, unexpected equipment failure or unavailability could require us to call upon load management procedures during 2007 as we have in past years.

ENVIRONMENTAL MATTERS

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation challenges related to current and past operations. Specific environmental issues affecting our utility and non-utility energy segments include but are not limited to (1) air emissions such as CO_2, SO_2, NO_x, small particulates and mercury, (2) disposal of combustion by-products such as fly ash, (3) remediation of former manufactured gas plant sites, (4) disposal of used nuclear fuel and (5) the eventual decommissioning of Point Beach.

We are currently pursuing a proactive strategy to manage our environmental issues including (1) substituting new and cleaner generating facilities for older facilities as part of Wisconsin Energy's PTF strategy, (2) developing additional sources of renewable electric energy supply, (3) water quality matters such as discharge limits and cooling water requirements, (4) adding emission control equipment to existing facilities to comply with new ambient air quality standards and federal clean air rules, (5) entering into agreements with the WDNR and EPA to reduce emissions of SO_2 and NO_x by more than 65% and mercury by 50% by 2013 from our coal-fired power plants in Wisconsin and Michigan, (6) evaluating and implementing improvements to our cooling water intake systems, (7) recycling of ash from coal-fired generating units and (8) the clean-up of former manufactured gas plant sites. The capital cost of implementing the EPA consent decree is estimated to be approximately $1 billion over the 10 years ending 2013. These costs are principally associated with the installation of air quality controls on Pleasant Prairie Units 1 and 2 and Oak Creek Units 5-8. Through December 31, 2006, we have spent approximately $355.0 million associated with implementing the EPA agreement. For further information concerning the consent decree, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements. For further information concerning disposal of used nuclear fuel and nuclear power plant decommissioning, see Nuclear Operations below and Note F -- Nuclear Operations in the Notes to Consolidated Financial Statements, respectively.

National Ambient Air Quality Standards: In 2000 and 2001, Michigan and Wisconsin finalized state rules implementing phased emission reductions required to meet the NAAQS for 1-hour ozone. In 2004, the EPA began implementing NAAQS for 8-hour ozone and $PM_{2.5}$. The states are currently developing rules to implement the new standards. Although specific emission control requirements are not yet defined, we believe that the revised standards will likely require significant reductions in SO_2 and NO_x emissions from coal-fired generating facilities. We expect that reductions needed to achieve compliance with the 8-hour ozone attainment standard will be implemented in stages. Reductions associated with the fine particulate matter standards are expected to be implemented in stages after the year 2010 and extending to the year 2017. We are currently unable to predict the impact that the revised air quality standards might have on the operations of our existing coal-fired generating facilities until the states develop rules and submit State Implementation Plans (SIP) to the EPA to demonstrate how they intend to comply with the 8-hour ozone and fine particulate matter NAAQS.

> ***8-hour Ozone Standard:*** In April 2004, the EPA designated 10 counties in Southeastern Wisconsin as nonattainment areas for the 8-hour ozone NAAQS. States are required to develop and submit SIPs to the EPA by June 2007 to demonstrate how they intend to comply with the 8-hour ozone NAAQS. We expect that reductions needed to achieve compliance with the 8-hour ozone attainment standard will be implemented in stages, and that some or all of these reductions will be accomplished through implementation of the CAIR. See below for further information regarding CAIR. We believe that compliance with the NO_x emission reductions requirements under the agreements with the WDNR and EPA will substantially mitigate costs to comply with the EPA's 8-hour ozone NAAQS. However, the timing of the requirements may be impacted by requiring earlier installation of NO_x controls at some units, depending on how the states implement the rules.
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> ***$PM_{2.5}$ Standard:*** In December 2004, the EPA designated $PM_{2.5}$ nonattainment areas in the country. All counties in the State of Wisconsin and all counties in the Upper Peninsula of Michigan were designated as in attainment with the standard. It is unknown at this time whether Wisconsin or Michigan will require additional emission reductions as part of state or regional implementation of the $PM_{2.5}$ standard and what impact those requirements would have on operation of our existing coal-fired generation facilities.

Clean Air Interstate Rule: The EPA issued the final CAIR regulation in March 2005 to facilitate the states in meeting the 8-hour ozone and $PM_{2.5}$ standards by addressing the regional transport of SO_2 and NO_x. CAIR requires NO_x and SO_2 emission reductions in two phases from electric generating units located in a 28-state region within the eastern United States. Wisconsin and Michigan are affected states under CAIR. The phase 1 compliance deadline is January 1, 2009 for NO_x and January 1, 2010 for SO_2, and the phase 2 compliance deadline is January 1, 2015 for both NO_x and SO_2. Overall, the CAIR is expected to result in a 70% reduction in SO_2 emissions and a 65% reduction in NO_x emissions from 2002 emission levels. The states are required to develop and submit

implementation plans by no later than March 2007. In Wisconsin, a final CAIR rule has been approved by the WDNR and is proceeding through the administrative process. Although the impacts are uncertain until the states' implementation plans are in place, we believe that compliance with the NO_x and SO_2 emission reductions requirements under the agreements with the WDNR and EPA will substantially mitigate costs to comply with the CAIR rule.

Clean Air Mercury Rule: The EPA issued the final CAMR in March 2005 following the agency's 2000 regulatory determination that utility mercury emissions should be regulated. CAMR limits mercury emissions from new and existing coal-fired power plants, and caps utility mercury emission in two phases, applicable in 2010 and 2018. The caps limit emissions at approximately 20% and ultimately 70% below today's utility mercury levels. The states were required to develop and submit implementation plans by November 2006, but neither state has finalized its plan yet. Until those plans are in place, it is not possible to estimate the final impact of the CAMR, but additional expenditures are anticipated in order to meet both phases of the federal rule. Because the technology is under development, it is difficult to estimate the cost. We believe the range of possible expenditures could be approximately $50 million to $200 million. The construction air permit issued for the Oak Creek expansion is not impacted by the new rule.

The federal rule is being challenged by a number of states including Wisconsin and Michigan. Depending on the litigation, the timing for compliance may be affected.

The WDNR independently developed mercury emission control rules that affect electric utilities in Wisconsin and issued state-only mercury control rules in October 2004. The rules explicitly recognize an underlying state statutory restriction that state regulations cannot be more stringent than those included in any federal program. The rules state that the WDNR must adopt state rule changes within 18 months of publication of any federal rules. State rules are to be changed to be consistent with, and no more restrictive than, any federal rules. It is not possible to determine if there will be requirements in addition to CAMR until a rule is in place or the existing rule is set aside. Because the 18 month deadline has passed, we are reviewing our options.

Clean Air Visibility Rule: The EPA issued the CAVR in June 2005 to address regional haze, or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines BART requirements for electric generating units and how BART will be addressed in the 28 states subject to EPA's CAIR. Under CAVR, states are required to identify certain industrial facilities and power plants that affect visibility in the nation's 156 Class I protected areas. States then determine the types of emission controls that those facilities must use to control their emissions. The pollutants from power plants that reduce visibility include particulate matter or compounds that contribute to fine particulate formation, NO_x, SO_2 and ammonia. States must submit plans to implement CAVR to the EPA by December 2007. The reductions associated with the state plans are scheduled to begin to take effect in 2014 with full implementation before 2018. We are currently unable to predict the impact that CAVR might have on the operations of our existing coal-fired generating facilities until the states develop rules and submit implementation plans to the EPA.

Clean Water Act: Section 316(b) of the CWA requires that the location, design, construction and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact. This law dates back to 1972; however, prior to September 2004, there were no federal rules that defined precisely how states and EPA regions determined that an existing intake met BTA requirements. This rule established, for the first time, national performance standards and compliance alternatives for existing facilities that are designed to minimize the potential adverse environmental impacts to aquatic organisms associated with water withdrawals from cooling water intakes. Costs associated with implementation of the rule for our Oak Creek Power Plant, We Power's Oak Creek expansion and PWGS have been included in project costs. Studies to determine what costs, if any, that may be associated with our other existing facilities are expected to take place over the next two years.

On January 26, 2007, the Federal Court of Appeals for the Second Circuit issued a decision concerning the 316(b) rule for existing facilities (Riverkeeper, Inc. v. EPA, Nos. 04-6692-ag(L) (2d Cir. 2007)). The Second Circuit Court found certain portions of the rule impermissible and remanded several parts of the rule to the EPA for further consideration or potential additional rulemaking. Until such time as the EPA completes those actions, we cannot predict what impact the changes, if any, to the rule may have on our facilities.

Manufactured Gas Plant Sites: We are voluntarily reviewing and addressing environmental conditions at a number of former manufactured gas plant sites. For further information, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Ash Landfill Sites: We aggressively seek environmentally acceptable, beneficial uses for our combustion byproducts. For further information, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

EPA - Proposed Consent Decree: We entered into a proposed consent decree with the EPA to address all matters relating to information requests received from the EPA pursuant to Section 114(a) of the Clean Air Act. For further information, see Note Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Greenhouse Gases: There have been international efforts seeking legally binding reductions in emissions of greenhouse gases, principally CO_2, including the United Nations Framework Convention on Climate Change held in Kyoto, Japan. While the Bush

Administration has not supported U.S. ratification of the Kyoto Protocol or other legislation requiring reductions in CO_2, in 2002, the Bush Administration announced a goal of reducing the greenhouse gas intensity of the U.S. economy by 18% by 2012. In addition, in December 2004, the DOE announced the Climate VISION program in furtherance of reduced greenhouse gas emissions. We continue to take voluntary measures to reduce our emissions of greenhouse gases. However, legislative proposals that would impose mandatory restrictions on CO_2 continue to be considered in Congress. The impact of any future legislation that would require reductions in greenhouse gases cannot be assessed at this time.

We continue to support flexible, market-based strategies to curb greenhouse gas emissions. These strategies include emissions trading, joint implementation projects and credit for early actions. We also support a voluntary approach that encourages technology development and transfer and includes all sectors of the economy and all significant global emitters.

Our emissions in future years will continue to be influenced by several actions completed, planned or underway as part of Wisconsin Energy's PTF strategy, including:

- Repowering the Port Washington Power Plant from coal to natural gas combined cycle units.
- Adding coal-fired units using state-of-the-art technology as part of the Oak Creek expansion.
- Increasing investment in energy efficiency and conservation.
- Maintaining and increasing non-emitting generation by potentially adding approximately 130 to 200 MW of wind capacity and increasing customer participation in the Energy for Tomorrow® renewable energy program.
- Successful renewal of the Point Beach units' operating licenses.

LEGAL MATTERS

Arbitration Proceedings: Our largest electric customers, two iron ore mines, operate in the Upper Peninsula of Michigan. The mines represent approximately 6% to 7% of our annual electric sales; however, the earnings are insignificant to us. The mines have special negotiated contracts that expire in December 2007. The contracts have price caps for approximately 80% of the energy sales. We do not recognize revenue on amounts billed that exceed the price caps.

The incremental power costs in the Upper Peninsula of Michigan are now determined by MISO. In April 2005, we began to bill the mines the incremental power costs as quantified by the MISO Midwest Market. The mines have notified us that they are disputing these billings and a portion of these disputed amounts have been deposited in escrow. In September 2005, the mines notified us that they filed for formal arbitration related to the contracts. We have notified the mines that we believe that they have failed to comply with certain notification provisions related to annual production as specified within the contracts. The arbitration hearings previously scheduled for October 2006 have been postponed and rescheduled for the third quarter of 2007, and we anticipate a decision in the fourth quarter of 2007. As of December 31, 2006, the mines have placed $29.3 million in escrow. As of December 31, 2005, the mines had placed $70.6 million in escrow. The decrease in the escrow balance relates to amounts that we refunded without interest for the amounts billed in 2005 that exceeded the price caps. At this time, we are unable to predict the outcome of the formal arbitration process, but we believe that it will not have a material adverse impact on our financial condition or results of operations.

Although it is currently uncertain, we anticipate that we will provide power to the mines under the terms of one or more regulated tariffs to be approved by the MPSC beginning January 1, 2008.

Stray Voltage: On July 11, 1996, the PSCW issued a final order regarding the stray voltage policies of Wisconsin's investor-owned utilities. The order clarified the definition of stray voltage, affirmed the level at which utility action is required, and placed some of the responsibility for this issue in the hands of the customer. Additionally, the order established a uniform stray voltage tariff which delineates utility responsibility and provides for the recovery of costs associated with unnecessary customer demanded services.

In recent years, dairy farmers have commenced actions or made claims against us for loss of milk production and other damages to livestock allegedly caused by stray voltage, and more recently, ground currents resulting from the operation of its electrical system, even though that electrical system has been operated within the parameters of the PSCW's order. In 2003, the Wisconsin Supreme Court upheld a Court of Appeals' affirmance of a jury verdict against us, awarding $1.2 million to the plaintiffs in a stray voltage lawsuit. The Supreme Court rejected the argument that if a utility company's measurement of stray voltage is below the PSCW "level of concern," that utility could not be found negligent in stray voltage cases. Additionally, the Court held that the PSCW regulations regarding stray voltage were only minimum standards to be considered by a jury in stray voltage litigation.

As a result of this case, claims by dairy farmers for livestock damage have been based upon ground currents with levels measuring less than the PSCW level of concern. Even though the claims which have been made against us with respect to stray voltage and ground currents are not expected to have a material adverse effect on our financial statements, we continue to evaluate various options and strategies to mitigate this risk.

NUCLEAR OPERATIONS

Point Beach Nuclear Plant: We own two 518 MW electric generating units (Unit 1 and Unit 2) at Point Beach in Two Rivers, Wisconsin. Point Beach is operated by NMC, a joint venture of the Company and affiliates of other unaffiliated utilities. During 2006, 2005 and 2004, Point Beach provided approximately 25.7%, 20.3% and 24.4%, respectively, of our net electric energy supply.

Each unit at Point Beach has a scheduled refueling outage approximately every 18 months. A refueling outage is scheduled for Unit 1 during the first quarter of 2007. In the fourth quarter of 2006, Unit 2 had a scheduled refueling outage. In 2005, Unit 2 had a scheduled refueling outage over the second and third quarters and Unit 1 had a scheduled refueling outage over the third and fourth quarters. During the 2005 scheduled refueling outages we replaced the reactor vessel heads at each unit. As expected, this work, along with other planned maintenance, resulted in longer than normal outages. During scheduled refueling outages, we incur significant operations and maintenance costs for work performed during the outages and we incur costs associated with replacement power. See Results of Operations for further discussion regarding the costs associated with nuclear outages. In 2004, Unit 1 had a scheduled refueling outage in the second quarter.

In December 2005, the NRC approved the request of NMC and us for license renewal. The new operating licenses expire in October 2030 for Unit 1 and March 2033 for Unit 2.

In February 2006, we announced that we were undertaking a formal review during 2006 regarding our options for the ownership and operation of Point Beach. At December 31, 2006, NMC operated six nuclear generating units. In addition, another owner has announced the planned sale of its unit. This sale would further reduce the size of the fleet operated by NMC. Given these changes, we believed it was prudent to evaluate a range of options for Point Beach. The options that we evaluated included: (1) continued operation by NMC, (2) continued operation by a third party operator other than NMC, (3) a return to in-house operation of the plant by us, (4) a sale of the Point Beach facility and (5) a partial sale of the plant with us retaining a minority interest in the plant. Under this fifth option, the new majority owner would operate the plant. As part of our continuing review, we invited qualified third parties to tour Point Beach and review the data necessary to submit a bid to operate the plant or purchase all or part of the plant and operate it. We evaluated the bids received in comparison to continued operation of Point Beach by NMC or us. In December 2006, we announced that we had reached a definitive agreement to sell Point Beach to an affiliate of FPL. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us), NMC would transfer Point Beach's operating licenses to the buyer and we would withdraw from NMC and our relationship with NMC would be terminated. We would be required to pay a termination fee of approximately $12 million to withdraw from NMC. In addition, Wisconsin Energy would be required to write-off its investment in NMC, which is approximately $5 million at December 31, 2006. We also entered into a long-term power purchase agreement to purchase all of the existing capacity and energy of the plant, which will become effective upon the closing of the sale. We will have the unilateral option, subject to PSCW direction, to select a term for the power purchase agreement of either (i) an estimated 23 years for Unit 1 and 26 years for Unit 2, or (ii) 16 years for Unit 1 and 17 years for Unit 2. The sale of the plant and the long-term power purchase agreement are subject to review and approval by various regulatory agencies including the NRC, PSCW, MPSC and FERC. We have submitted a request to the PSCW to defer any gain (net of transaction related costs) as a regulatory liability that would be applied to the benefit of our customers in future rate proceedings.

In July 2000, our senior management authorized the commencement of initial design work for the power uprate of both units at Point Beach. Subject to approval by the PSCW, the project could add approximately 90 MW of electrical output to Point Beach. In February 2003, Point Beach completed an equipment upgrade which resulted in a capacity increase of 7 MW per generating unit. If the proposed sale of Point Beach is completed, the uprate will be the responsibility of the new owner, FPL. In light of this, both companies are currently evaluating the timing for implementation of the power uprate project.

During 2002 and 2003, the NRC issued Final Significance Determination letters for two red (high safety significance) inspection findings regarding problems identified by Point Beach with the performance of the auxiliary feedwater system recirculation lines. During 2003, the NRC conducted a three-phase supplemental inspection of Point Beach in accordance with NRC Inspection Procedure 95003 to review corrective actions for the findings as well as the effectiveness of the corrective action, emergency preparedness and engineering programs.

The inspection results were presented at a public meeting in December 2003, and documented in a February 2004 NRC letter to NMC. The NRC determined that the plant is being operated in a manner that ensures public safety but also identified several performance issues in the areas of problem identification and resolution, emergency preparedness, electrical design basis calculation control and engineering-operations communication.

NMC responded to the supplemental inspection in February 2004 with specific commitments to address the NRC concerns, including revision of the Point Beach Excellence Plan. We were assessed a fine of $60,000 related to issues identified with our emergency preparedness. NRC reviewed the adequacy of the revised Excellence Plan and its implementation, and NMC received a confirmatory action letter in April 2004. Since then, the NRC has conducted numerous inspections and completed reviews of activities and meetings, noting the overall results were satisfactory. As a result, in the fourth quarter of 2006, the NRC closed the confirmatory

action letter and concluded that the red findings received in 2002 and 2003 will no longer be considered in the NRC's assessment process. Point Beach will now receive routine baseline inspection by the NRC.

As a result of the September 11, 2001 terrorist attacks, NRC and the industry have been strengthening security at nuclear power plants. Security at Point Beach remains at a high level, with limited access to the site continuing. Point Beach has responded to NRC's February 2002 Order for interim safeguards and security compensatory measures. Point Beach has also responded to NRC orders regarding security of independent spent fuel storage installations, design basis threat and security officer training and work hours.

Used Nuclear Fuel Storage and Disposal: We are authorized by the PSCW to load and store sufficient dry fuel storage containers to allow Point Beach Units 1 and 2 to operate to the end of their original operating licenses, but not to exceed the original 48-canister capacity of the dry fuel storage facility. The original operating licenses were set to expire in October 2010 for Unit 1 and in March 2013 for Unit 2 before they were renewed by the NRC in December 2005.

Temporary storage alternatives at Point Beach are necessary until the DOE takes ownership of and permanently removes the used fuel as mandated by the Nuclear Waste Policy Act of 1982, as amended in 1987. The Nuclear Waste Policy Act established the Nuclear Waste Fund which is composed of payments made by the generators and owners of such waste and fuel. Effective January 31, 1998, the DOE failed to meet its contractual obligation to begin removing used fuel from Point Beach, a responsibility for which we have paid a total of $215.2 million into the Nuclear Waste Fund over the life of Point Beach.

On August 13, 2000, the United States Court of Appeals for the Federal Circuit ruled in a lawsuit brought by Maine Yankee and Northern States Power Company that the DOE's failure to begin performance by January 31, 1998 constituted a breach of the Standard Contract, providing clear grounds for filing complaints in the Court of Federal Claims. Consequently, we filed a complaint on November 16, 2000 against the DOE in the Court of Federal Claims. In October 2004, the Court of Federal Claims granted our motion for summary judgment on liability. The Court has subsequently scheduled a trial to determine damages for September 2007. We have incurred substantial damages to date and damages continue to accrue. We are seeking recovery of our damages in this lawsuit and we expect that any recoveries would be considered in setting future rates.

In July 2002, the President signed a resolution which allowed the DOE to begin preparation of the application to the NRC for a license to design and build a spent fuel repository in Yucca Mountain, Nevada. In July 2006, the DOE announced plans to submit a license application to the NRC for a nuclear waste repository at Yucca Mountain no later than June 30, 2008. The DOE also announced if the requested legislative changes are enacted, the repository would be able to accept spent nuclear fuel starting in early 2017. It is not possible, at this time, to predict with certainty when the DOE will actually begin accepting used nuclear fuel.

INDUSTRY RESTRUCTURING AND COMPETITION

Electric Utility Industry

The regulated energy industry continues to experience significant changes. FERC continues to support large RTOs, which will affect the structure of the wholesale market. To this end, the MISO implemented a bid-based market, the MISO Midwest Market, including the use of LMP to value electric transmission congestion and losses. The MISO Midwest Market commenced operation on April 1, 2005. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us. It is uncertain when retail access might be implemented in Wisconsin; however, Michigan has adopted retail choice which potentially affects our Michigan operations. In August 2005, President Bush signed into law the Energy Policy Act, which impacts the electric utility industry. (See Other Matters below for additional information on the Energy Policy Act). In addition, major issues in industry restructuring, implementation of RTO markets and market power mitigation received substantial attention in 2006 and prior years. We continue to focus on infrastructure issues through Wisconsin Energy's PTF growth strategy.

Restructuring in Wisconsin: Electric utility revenues in Wisconsin are regulated by the PSCW. Due to many factors, including relatively competitive electric rates charged by the state's electric utilities, the PSCW has been focused in recent years on electric reliability infrastructure issues for the State of Wisconsin. These issues include:

- Addition of new generating capacity in the state;
- Modifications to the regulatory process to facilitate development of merchant generating plants;
- Development of a regional independent electric transmission system operator;
- Improvements to existing and addition of new electric transmission lines in the state; and
- Addition of renewable generation.

The PSCW continues to maintain the position that the question of whether to implement electric retail competition in Wisconsin should ultimately be decided by the Wisconsin legislature. No such legislation has been introduced in Wisconsin to date.

Restructuring in Michigan: Electric utility revenues are regulated by the MPSC. In June 2000, the Governor of Michigan signed the "Customer Choice and Electric Reliability Act" into law empowering the MPSC to implement electric retail access in Michigan. The new law provides that as of January 1, 2002, all Michigan retail customers of investor-owned utilities have the ability to choose their electric power producer.

As of January 1, 2002, our Michigan retail customers were allowed to remain with their regulated utility at regulated rates or choose an alternative electric supplier to provide power supply service. We have maintained our generation capacity and distribution assets and provide regulated service as we have in the past. We continue providing distribution and customer service functions regardless of the customer's power supplier.

Competition and customer switching to alternative suppliers in our service territory in Michigan has been limited. With the exception of two general inquiries, no alternate supplier activity has occurred in our service territory in Michigan, reflecting the small market area, our competitive regulated power supply prices and a lack of interest in general in the Upper Peninsula of Michigan as a market for alternative electric suppliers.

Restructuring in Illinois: In 1999, the State of Illinois passed legislation that introduced retail electric choice for large customers and introduced choice for all retail customers in May 2002. This legislation has not had, and is not expected to have a material impact on our business. We had one wholesale customer in Illinois, the City of Geneva, whose contract expired on December 31, 2005.

Electric Transmission and Energy Markets

ATC: ATC is regulated by FERC for all rate terms and conditions of service and is a transmission-owning member of MISO. As of February 1, 2002, operational control of ATC's transmission system was transferred to MISO, and we became a non-transmission owning member and customer of MISO.

MISO: In connection with its status as a FERC approved RTO, MISO implemented a bid-based energy market, the MISO Midwest Market, which commenced operations on April 1, 2005. As part of this energy market, the MISO developed a market-based platform for valuing transmission congestion and losses premised upon the LMP system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through the use of FTRs. FTRs are allocated to market participants by MISO. A new allocation of FTRs was completed for the period of June 1, 2006 through May 31, 2007. We were granted substantially all of the FTRs that we were permitted to request during the allocation process. Previously, our unhedged congestion costs had not been explicitly identified and were embedded in our fuel and purchased power expenses. Due to certain changes in the units that MISO is dispatching, our unhedged congestion costs increased in 2006. These incremental congestion charges are deferred as approved by the PSCW, and we expect to recover these costs in future rates, subject to review and approval by the PSCW.

MISO deferred the costs to develop and start-up its energy market (new software systems and personnel). Now that the market is operational, the development and start-up costs are charged to MISO market participants, including us.

To mitigate the risks of this new bid-based energy market, we requested deferral accounting treatment from the PSCW in January 2005 for certain incremental costs or benefits that may occur due to the implementation of the MISO Midwest Market. Our request excluded LMP energy costs because these costs are subject to recovery under the Wisconsin Fuel Cost Adjustment Procedure. In March 2005, the PSCW accepted our request. We submitted another joint proposal with other utilities in March 2005, requesting escrow accounting treatment for MISO Midwest Market costs until each utility's first rate case following April 1, 2008. The purpose of the March 2005 request for escrow accounting was to provide clarification on costs not included in the March 2005 approval for deferral accounting treatment. The PSCW approved deferral treatment for these costs in June 2006.

In MISO, base transmission costs are currently being paid by LSE's located in the service territories of each MISO transmission owner. The current license plate transmission rate design is scheduled to be replaced on February 1, 2008. A filing delineating a new rate design, or substantiation for maintaining the existing rate design is due at FERC by August 1, 2007. At this time, we are not able to determine the impact of this rate design change on our transmission costs. FERC also ordered a seams elimination charge to be paid by MISO LSE's from December 1, 2004 until March 31, 2006, to compensate transmission owners for the loss of revenues resulting from the joining of a RTO and/or FERC's elimination of through and out transmission charges between the MISO and PJM. FERC ordered that certain existing transmission transactions continue to pay for through and out service from December 1, 2004 until March 31, 2006. The details of the seams elimination charge and the quantification of the existing transaction charge are the subject of a hearing process initiated by FERC in a February 2005 order. In January 2006, along with certain other parties to the proceeding, we submitted an offer of settlement to the presiding administrative law judge that resolved all issues set for hearing that impact us with regard to the continued payment of through and out transmission charges as well as the seams elimination charge. The administrative law judge certified the settlement to FERC, and FERC approved the settlement in April 2006.

In April 2006, FERC issued an order determining that MISO had not applied its energy markets tariff correctly in the assessment of Revenue Sufficiency Guarantee charges. FERC ordered MISO to resettle all affected transactions retroactive to April 1, 2005. In October 2006, we received a ruling from FERC. Since the ruling, FERC's order has been challenged by MISO and numerous other market participants. Any resettlement associated with the order is expected in 2007 and early 2008. Due to the complexity of the order, we are unable to precisely determine the overall financial implication to us. However, we do not believe that the result will have a material impact on our results of operations.

MISO is in the process of developing a market for two ancillary services, regulation reserves and contingency reserves. The MISO ancillary services market is currently proposed to begin in 2008. We currently self-provide both regulation reserves and contingency reserves. In the MISO ancillary services market, we expect that we will buy/sell regulation and contingency reserves from/to the market. The MISO ancillary services market is expected to reduce overall ancillary services costs in the MISO footprint. We anticipate achieving a net reduction in fuel costs, but are unable to determine the amount of savings we will realize at this time. The MISO ancillary services market is expected to also enable MISO to assume significant balancing area responsibilities such as frequency control and disturbance control.

Natural Gas Utility Industry

Restructuring in Wisconsin: The PSCW previously instituted generic proceedings to consider how its regulation of gas distribution utilities should change to reflect the changing competitive environment in the natural gas industry. To date, the PSCW has made a policy decision to deregulate the sale of natural gas in customer segments with workably competitive market choices and has adopted standards for transactions between a utility and its gas marketing affiliates. However, work on deregulation of the gas distribution industry by the PSCW is presently on hold. Currently, we are unable to predict the impact of potential future deregulation on our results of operations or financial position.

OTHER MATTERS

Energy Policy Act: In August 2005, President Bush signed into law the Energy Policy Act. Among other things, the Energy Policy Act includes tax subsidies for electric utilities and the repeal of PUHCA 1935. The Energy Policy Act also amends federal energy laws and provides FERC with new oversight responsibilities for the electric utility industry. Implementation of the Energy Policy Act requires the development of regulations by federal agencies, including FERC. As noted above, the Energy Policy Act and corresponding rules required us to seek FERC authorization to allow us to lease from We Power the three PTF units that are currently being constructed by We Power. We received approval of these leases from FERC in December 2006. Additionally, the Energy Policy Act repealed PUHCA 1935 and enacted PUHCA 2005, transferring jurisdiction over holding companies from the SEC to FERC. We were an exempt holding company under PUHCA 1935, and, accordingly, were exempt from that law's provisions other than with respect to certain acquisitions of securities of a public utility. In March 2006, we filed with FERC notification of our status as a holding company as required under FERC regulations implementing PUHCA 2005 and a request for exempt status similar to that held under PUHCA 1935. In June 2006, we received notice from FERC confirming our status as a holding company as required under FERC regulations implementing PUHCA 2005 and granting exempt status similar to that held under PUHCA 1935. As federal agencies continue to develop new rules to implement the Energy Policy Act, we expect additional impacts on us in the future.

Pension Reform: In August 2006, President Bush signed the Pension Protection Act of 2006. We are currently evaluating the Pension Protection Act of 2006, but we do not anticipate it will have a material impact on our results of operations or cash flows from operating activities.

ACCOUNTING DEVELOPMENTS

New Pronouncements: See Note B -- Recent Accounting Pronouncements in the Notes to Consolidated Financial Statements for information on new accounting pronouncements.

CRITICAL ACCOUNTING ESTIMATES

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions. In addition, the financial and operating environment also may have a significant effect, not only on the operation of our business, but on our results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed.

The following is a list of accounting policies that are most significant to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective or complex judgments.

Regulatory Accounting: We operate under rates established by state and federal regulatory commissions which are designed to recover the cost of service and provide a reasonable return to investors. Under SFAS 71, the actions of our regulators may allow us to defer costs that non-regulated companies would expense. The actions of our regulators may also require us to accrue liabilities that non-regulated entities would not. As of December 31, 2006, we had $859.5 million in regulatory assets and $1,142.3 million in regulatory liabilities. In the future, if we move to market based rates or if the actions of our regulators change we may conclude that we are unable to follow SFAS 71. In this situation, continued deferral of certain regulatory asset and liability amounts on our books, as allowed under SFAS 71, may no longer be appropriate and the unamortized regulatory assets net of the regulatory liabilities would be recorded as an extraordinary after-tax non-cash charge to earnings. We continually review the applicability of SFAS 71 and have determined that it is currently appropriate to continue following SFAS 71. In addition, each quarter we perform a review of our regulatory assets and our regulatory environment and we evaluate whether we believe that it is probable that we will recover the regulatory assets in future rates. See Note C -- Regulatory Assets and Liabilities in the Notes to Consolidated Financial Statements for additional information.

Pension and Other Post-retirement Benefits: Our reported costs of providing non-contributory defined pension benefits (described in Note L -- Benefits in the Notes to Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension costs are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions made to plans and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

In accordance with SFAS 87 and SFAS 158, changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants.

The following chart reflects pension plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant.

Pension Plans Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate	$6.5
0.5% decrease in expected rate of return on plan assets	$3.5

In addition to pension plans, we maintain OPEB plans which provide health and life insurance benefits for retired employees (described in Note L -- Benefits in the Notes to Consolidated Financial Statements). We account for these plans in accordance with SFAS 106. Our reported costs of providing these post-retirement benefits are dependent upon numerous factors resulting from actual plan experience including employee demographics (age and compensation levels), our contributions to the plans, earnings on plan assets and health care cost trends. Changes made to the provisions of the plans may also impact current and future post-retirement benefit costs. OPEB costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the post-retirement benefit obligation and post-retirement costs. Our OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns, as well as changes in general interest rates, may result in increased or decreased other post-retirement costs in future periods. Similar to accounting for pension plans, our regulators have adopted SFAS 106 for rate making purposes.

The following chart reflects OPEB plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant.

OPEB Plans Actuarial Assumption	Impact on Reported Annual Cost (Millions of Dollars)
0.5% decrease in discount rate	$2.0
0.5% decrease in health care cost trend rate	($2.7)
0.5% decrease in expected rate of return on plan assets	$0.5

Unbilled Revenues: We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses and applicable customer rates. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total operating revenues during 2006 of $3,116.7 million included accrued revenues of $189.3 million as of December 31, 2006.

Asset Retirement Obligations: We account for legal liabilities for asset retirements at fair value in the period in which they are incurred according to the provisions of SFAS 143 and FIN 47. SFAS 143 applies primarily to decommissioning costs for Point Beach. Using a discounted future cash flow methodology, our estimated nuclear ARO was approximately $325.6 million at December 31, 2006. As it relates to our operations, FIN 47 applies primarily to asbestos removal costs. At December 31, 2006, we recorded an obligation of $39.6 million related to asbestos.

Calculation of the nuclear decommissioning ARO is based upon projected decommissioning costs calculated by an independent decommissioning consulting firm, as well as several significant assumptions including the timing of future cash flows, future inflation rates and the discount rate applied to future cash flows. Assuming the following changes in key assumptions and holding all other assumptions constant, we estimate that our nuclear ARO at December 31, 2006 would have changed by the following amounts:

Change in Assumption	Change in Liability (Millions of Dollars)
1% increase in inflation rate	$106.7
1% decrease in inflation rate	($79.8)

We were unable to identify a viable market for or third party who would be willing to assume this liability. Accordingly, we have used a market-risk premium of zero when measuring our nuclear ARO. We estimate that for each 1% increment that would be included as a market-risk premium, our nuclear ARO would increase by approximately $3.3 million.

For additional information concerning SFAS 143 and our estimated nuclear ARO, see Note F -- Nuclear Operations and Note I -- Asset Retirement Obligations in the Notes to Consolidated Financial Statements.

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED INCOME STATEMENTS
Year Ended December 31

	2006	2005	2004
		(Millions of Dollars)	
Operating Revenues	$ 3,116.7	$ 2,938.0	$ 2,616.6
Operating Expenses			
Fuel and purchased power	798.0	773.8	585.4
Cost of gas sold	431.6	446.3	376.9
Other operation and maintenance	1,074.5	880.5	844.7
Depreciation, decommissioning and amortization	270.9	281.8	274.1
Property and revenue taxes	85.8	78.3	76.3
Total Operating Expenses	2,660.8	2,460.7	2,157.4
Operating Income	455.9	477.3	459.2
Equity in Earnings of Transmission Affiliate	33.9	30.4	26.4
Other Income, net	42.9	28.4	7.1
Interest Expense	87.0	85.8	89.6
Income Before Income Taxes	445.7	450.3	403.1
Income Taxes	168.9	165.5	153.2
Net Income	276.8	284.8	249.9
Preferred Stock Dividend Requirement	1.2	1.2	1.2
Earnings Available for Common Stockholder	$ 275.6	$ 283.6	$ 248.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
Year Ended December 31

	2006	2005	2004
		(Millions of Dollars)	
Operating Activities			
Net income	$ 276.8	$ 284.8	$ 249.9
Reconciliation to cash			
Depreciation, decommissioning and amortization	280.5	297.0	294.9
Nuclear fuel expense amortization	28.7	23.0	24.0
Equity in earnings of transmission affiliate	(33.9)	(30.4)	(26.4)
Distributions from transmission affiliate	26.7	23.7	20.4
Deferred income taxes and investment tax credits, net	(59.3)	19.9	136.8
Change in - Accounts receivable and accrued revenues	(2.0)	(66.7)	(28.7)
Inventories	(15.5)	(23.7)	2.4
Other current assets	(19.4)	(2.9)	(6.5)
Accounts payable	(2.0)	44.1	57.1
Accrued income taxes, net	49.5	31.5	(64.4)
Deferred costs, net	(40.7)	(140.3)	(34.3)
Other current liabilities	(15.8)	1.1	5.0
Other	24.9	20.2	0.6
Cash Provided by Operating Activities	498.5	481.3	630.8
Investing Activities			
Capital expenditures	(398.7)	(409.2)	(358.9)
Investment in transmission affiliate	(12.8)	(9.2)	(23.2)
Nuclear fuel	(47.7)	(49.7)	(30.0)
Nuclear decommissioning funding	(17.6)	(17.6)	(17.6)
Proceeds from investments within nuclear decommissioning trust	530.7	435.7	327.2
Purchases of investments within nuclear decommissioning trust	(530.7)	(435.7)	(327.2)
Other	3.0	3.6	5.8
Cash Used in Investing Activities	(473.8)	(482.1)	(423.9)
Financing Activities			
Dividends paid on common stock	(179.6)	(179.6)	(179.6)
Dividends paid on preferred stock	(1.2)	(1.2)	(1.2)
Issuance of long-term debt	327.9	40.8	397.0
Retirement of long-term debt	(229.4)	(25.3)	(290.1)
Change in short-term debt	(48.5)	163.2	(126.4)
Capital contribution from parent	100.0	-	-
Other, net	1.1	-	(0.5)
Cash Used in Financing Activities	(29.7)	(2.1)	(200.8)
Change in Cash and Cash Equivalents	(5.0)	(2.9)	6.1
Cash and Cash Equivalents at Beginning of Year	23.2	26.1	20.0
Cash and Cash Equivalents at End of Year	$ 18.2	$ 23.2	$ 26.1
Supplemental Information - Cash Paid For			
Interest (net of amount capitalized)	$ 84.9	$ 78.4	$ 80.0
Income taxes (net of refunds)	$ 172.7	$ 114.1	$ 53.6

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
December 31

ASSETS

	2006	2005
	(Millions of Dollars)	
Property, Plant and Equipment		
Electric	$ 6,421.1	$ 6,024.1
Gas	741.6	712.8
Steam	82.0	78.5
Common	263.4	278.1
Other	62.3	58.9
	7,570.4	7,152.4
Accumulated depreciation	(2,914.0)	(2,805.0)
	4,656.4	4,347.4
Construction work in progress	99.7	232.0
Leased facilities, net	404.0	422.6
Nuclear fuel, net	130.9	112.0
Net Property, Plant and Equipment	5,291.0	5,114.0
Investments		
Nuclear decommissioning trust fund	881.6	782.1
Equity investment in transmission affiliate	201.2	181.2
Other	0.4	0.4
Total Investments	1,083.2	963.7
Current Assets		
Cash and cash equivalents	18.2	23.2
Accounts receivable, net of allowance for doubtful accounts of $20.2 and $20.2	297.2	308.9
Accrued revenues	189.3	175.6
Materials, supplies and inventories	313.0	297.5
Prepayments	93.9	90.0
Other	16.8	1.3
Total Current Assets	928.4	896.5
Deferred Charges and Other Assets		
Regulatory assets	859.5	822.5
Other	95.7	112.5
Total Deferred Charges and Other Assets	955.2	935.0
Total Assets	$ 8,257.8	$ 7,909.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED BALANCE SHEETS
December 31

CAPITALIZATION AND LIABILITIES

	2006	2005
	(Millions of Dollars)	
Capitalization		
Common equity	$ 2,528.6	$ 2,310.9
Preferred stock	30.4	30.4
Long-term debt	1,337.1	1,290.1
Capital lease obligations	534.5	536.0
Total Capitalization	4,430.6	4,167.4
Current Liabilities		
Long-term debt and capital lease obligations due currently	280.5	232.4
Short-term debt	304.2	352.7
Accounts payable	287.2	293.9
Payroll and vacation accrued	71.0	67.4
Accrued taxes	121.4	71.0
Accrued interest	9.5	8.6
Deferred income taxes - current	23.9	22.4
Other	62.9	84.1
Total Current Liabilities	1,160.6	1,132.5
Deferred Credits and Other Liabilities		
Regulatory liabilities	1,142.3	1,051.9
Deferred income taxes - long-term	510.1	553.2
Asset retirement obligations	371.1	354.9
Pension liability	294.6	347.2
Accumulated deferred investment tax credits	48.8	52.6
Other long-term liabilities	299.7	249.5
Total Deferred Credits and Other Liabilities	2,666.6	2,609.3
Commitments and Contingencies (Note Q)	-	-
Total Capitalization and Liabilities	$ 8,257.8	$ 7,909.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31

		2006	2005
		(Millions of Dollars)	
Common Equity (See Consolidated Statements of Common Equity)			
Common stock - $10 par value; authorized			
65,000,000 shares; outstanding - 33,289,327 shares		$ 332.9	$ 332.9
Other paid in capital		655.8	542.6
Retained earnings		1,539.9	1,443.9
Accumulated other comprehensive (loss)		-	(8.5)
Total Common Equity		2,528.6	2,310.9
Preferred Stock			
Six Per Cent. Preferred Stock - $100 par value;			
authorized 45,000 shares; outstanding - 44,498 shares		4.4	4.4
Serial preferred stock -			
$100 par value; authorized 2,286,500 shares; 3.60% Series			
redeemable at $101 per share; outstanding - 260,000 shares		26.0	26.0
$25 par value; authorized 5,000,000 shares; none outstanding		-	-
Total Preferred Stock		30.4	30.4
Long-Term Debt			
Debentures (unsecured)	6-5/8% due 2006	-	200.0
	9.47% due 2006	-	0.7
	3.50% due 2007	250.0	250.0
	4.50% due 2013	300.0	300.0
	6-1/2% due 2028	150.0	150.0
	5.625% due 2033	335.0	335.0
	5.70% due 2036	300.0	-
	6-7/8% due 2095	100.0	100.0
Notes (secured, nonrecourse)	2% stated rate due 2011	0.2	1.2
	4.81% effective rate due 2030	2.0	2.0
Notes (unsecured)	6.36% effective rate due 2006	-	1.2
	3.55% variable rate due 2006 (b)	-	1.0
	4.08% variable rate due 2015 (a)	17.4	17.4
	3.80% variable rate due 2016 (a)	67.0	67.0
	3.80% variable rate due 2030 (a)	80.0	80.0
Obligations under capital leases		564.9	565.5
Unamortized discount, net		(14.4)	(12.5)
Long-term debt and capital lease obligations due currently		(280.5)	(232.4)
Total Long-Term Debt		1,871.6	1,826.1
Total Capitalization		$ 4,430.6	$ 4,167.4

(a) Variable interest rate as of December 31, 2006.
(b) Variable interest rate as of December 31, 2005.

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock	Other Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
	(Millions of Dollars)				
Balance - December 31, 2003	$ 332.9	$ 532.4	$ 1,270.8	$ (4.2)	$ 2,131.9
Net income			249.9		249.9
Other comprehensive income					
Minimum pension liability				(2.9)	(2.9)
Hedging, net				0.2	0.2
Comprehensive income	-	-	249.9	(2.7)	247.2
Cash dividends					
Common stock			(179.6)		(179.6)
Preferred stock			(1.2)		(1.2)
Tax benefit of exercised stock options allocated from Parent		5.9			5.9
Balance - December 31, 2004	332.9	538.3	1,339.9	(6.9)	2,204.2
Net income			284.8		284.8
Other comprehensive income					
Minimum pension liability				(1.4)	(1.4)
Hedging, net				(0.2)	(0.2)
Comprehensive Income	-	-	284.8	(1.6)	283.2
Cash dividends					
Common stock			(179.6)		(179.6)
Preferred stock			(1.2)		(1.2)
Tax benefit of exercised stock options allocated from Parent		4.3			4.3
Balance - December 31, 2005	332.9	542.6	1,443.9	(8.5)	2,310.9
Net income			276.8		276.8
Other comprehensive income					
Pension liability				2.2	2.2
Comprehensive Income	-	-	276.8	2.2	279.0
Cash dividends					
Common stock			(179.6)		(179.6)
Preferred stock			(1.2)		(1.2)
Cash contribution from Parent		100.0			100.0
Stock-based compensation		6.8			6.8
Tax benefit of exercised stock options allocated from Parent		6.4			6.4
Adoption of SFAS 158				6.3	6.3
Balance - December 31, 2006	$ 332.9	$ 655.8	$ 1,539.9	$ -	$ 2,528.6

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

A – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General: Wisconsin Electric Power Company (Wisconsin Electric, the Company, our, us or we), a wholly-owned subsidiary of Wisconsin Energy, is an electric, gas and steam utility which services electric customers in Wisconsin and the Upper Peninsula of Michigan, gas customers in Wisconsin and steam customers in metro Milwaukee, Wisconsin. We consolidate our wholly owned subsidiary Bostco. Bostco owns real estate properties that are eligible for historical rehabilitation tax credits. Bostco had total assets of $39.5 million as of December 31, 2006.

All significant intercompany transactions and balances have been eliminated from the consolidated financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications: We have reclassified certain prior year financial statement amounts to conform to their current year presentation. These reclassifications had no effect on total assets or net income.

Revenues: We recognize energy revenues on the accrual basis and include estimated amounts for services rendered but not billed.

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchase power costs. The electric fuel rules in Wisconsin allow us to request rate increases if fuel and purchased power costs exceed bands established by the PSCW. In a rate order issued in January 2006, the PSCW approved a plan to refund any over-collected fuel on an annual basis for 2006. For 2007, the band is plus or minus 2%.

Our retail gas rates include monthly adjustments which permit the recovery or refund of actual purchased gas costs. We defer any difference between actual gas costs incurred (adjusted for a sharing mechanism) and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year.

Accounting for MISO Energy Transactions: MISO implemented the MISO Midwest Market on April 1, 2005. The MISO Midwest Market operates under both day-ahead and real-time markets. We record energy transactions in the MISO on a net basis for each hour.

Other Income, net: We recorded the following items in Other Income, net for the years ended December 31:

Other Income, net	2006	2005	2004
		(Millions of Dollars)	
Capitalized Carrying Costs	$25.0	$20.4	$12.7
AFUDC – Equity	14.5	9.2	1.7
Donations and Contributions	(6.0)	(6.7)	(5.6)
Gross Receipts Tax Recovery	4.0	2.6	1.5
Other, net	5.4	2.9	(3.2)
Total Other Income, net	$42.9	$28.4	$7.1

Property and Depreciation: We record property, plant and equipment at cost. Cost includes material, labor, overheads and capitalized interest. Utility property also includes AFUDC - Equity. Additions to and significant replacements of property are charged to property, plant and equipment at cost; minor items are charged to maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We include capitalized software costs associated with our regulated operations under the caption "Property, Plant and Equipment" on the Consolidated Balance Sheets. As of December 31, 2006 and 2005, the net book value of our capitalized software totaled $17.7 million and $21.8 million, respectively. The estimated useful life of our capitalized software is five years.

Our utility depreciation rates are certified by the state regulatory commissions and include estimates for salvage value and removal costs. Depreciation as a percent of average depreciable utility plant was 3.7% in 2006, 3.9% in 2005, and 4.0% in 2004. Nuclear plant decommissioning costs are accrued and included in depreciation expense (see Note F). The decline in depreciation as a percent of average depreciable utility plant was due to new depreciation rates approved by the PSCW, which became effective January 1, 2006.

For assets other than our regulated assets and leased equipment, we accrue depreciation expense at straight-line rates over the estimated useful lives of the assets, or over the non-cancellable lease term for leased equipment.

We collect in our rates amounts representing future removal costs for many assets that do not have an associated ARO. We record a regulatory liability on our balance sheet for the estimated amounts we have collected in rates for future removal costs less amounts we have spent in removal activities. This regulatory liability was $430.5 million as of December 31, 2006 and $414.1 million as of December 31, 2005.

Allowance For Funds Used During Construction: AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC - Debt) used during plant construction and a return on stockholders' capital (AFUDC - Equity) used for construction purposes. AFUDC - Debt is recorded as a reduction of interest expense and AFUDC - Equity is recorded in Other Income, net.

During 2006, we accrued AFUDC at a rate of 8.94%, as authorized by the PSCW. During 2005 and 2004, the authorized rate was 10.18%. We accrue AFUDC on all electric utility NO_x, SO_2 and particulates remediation projects. Our rates were set to provide a full return on electric safety and reliability projects so AFUDC is not accrued on these projects. We accrued AFUDC on 50% of the remaining electric, gas and steam projects in CWIP and rates were set assuming that 50% of the CWIP balances were included in rate base.

We recorded the following AFUDC for the years ended December 31:

	2006	2005	2004
	(Millions of Dollars)		
AFUDC – Debt	$5.1	$4.6	$0.9
AFUDC – Equity	$14.5	$9.2	$1.7

Materials, Supplies and Inventories: Our inventory at December 31 consists of:

Materials, Supplies and Inventories	2006	2005
	(Millions of Dollars)	
Fossil Fuel	$119.7	$90.4
Materials and Supplies	100.6	89.3
Natural Gas in Storage	92.7	117.8
Total	$313.0	$297.5

Substantially all fossil fuel, materials and supplies and natural gas in storage inventories are recorded using the weighted-average method of accounting.

Regulatory Accounting: We account for our regulated operations in accordance with SFAS 71. This statement sets forth the application of GAAP to those companies whose rates are determined by an independent third-party regulator. The economic effects of regulation can result in regulated companies recording costs that have been or are expected to be allowed in the rate making process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses in the periods when those same amounts are reflected in rates. We defer all of our regulatory assets pursuant to specific orders or by a generic order issued by our primary regulator. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities). We expect to recover our outstanding regulatory assets in rates over a period of no longer than 20 years. For further information, see Note C.

Derivative Financial Instruments: We have derivative physical and financial instruments as defined by SFAS 133 which we report at fair value. However, our use of financial instruments is limited. For further information, see Note J.

Cash and Cash Equivalents: Cash and cash equivalents include marketable debt securities acquired three months or less from maturity.

We have nuclear decommissioning trusts that hold investments in debt and equity securities. All assets within the nuclear decommissioning trusts are restricted to nuclear decommissioning activities as set forth by regulations promulgated by the IRS and by the PSCW. The accompanying Consolidated Statements of Cash Flows include proceeds from investments within the nuclear decommissioning trusts and purchases of investments within the nuclear decommissioning trusts.

Margin Accounts: Cash deposited in brokerage accounts for margin requirements is recorded in Other Current Assets on our Consolidated Balance Sheets.

Restrictions: Various financing arrangements and regulatory requirements impose certain restrictions on our ability to transfer funds to Wisconsin Energy in the form of cash dividends, loans or advances. In addition, under Wisconsin law, we are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. We do not believe that these restrictions will materially affect our operations. For further information, see Note N.

Asset Retirement Obligations: We adopted SFAS 143 effective January 1, 2003. We adopted FIN 47 effective December 31, 2005. FIN 47 defines the term conditional ARO as used in SFAS 143. As defined in FIN 47, a conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Consistent with SFAS 143, we record a liability at fair value for a legal ARO in the period in which it is incurred. When a new legal obligation is recorded, we capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. At the end of the asset's useful life, we settle the obligation for its recorded amount or incur a gain or loss. As it relates to our regulated operations, we apply SFAS 71 and recognize regulatory assets or liabilities for the timing differences between when we recover legal AROs in rates and when we would recognize these costs under SFAS 143. For further information, see Note I.

Investments: We account for investments in other affiliated companies in which we do not maintain control using the equity method. As of December 31, 2006 and 2005, we had a total ownership interest of approximately 25.8% and 29.4%, in ATC. We are represented by one out of ten ATC board members, each of whom has one vote. Due to the voting requirements, no individual member has more than 10% of the voting control. For further information regarding such investments, see Note P.

Nuclear Fuel Amortization: We lease our nuclear fuel and amortize the fuel inventory to fuel expense as the power is generated, generally over a period of 60 months.

Income Taxes: We follow the liability method in accounting for income taxes as prescribed by SFAS 109. SFAS 109 requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized.

Tax credits associated with regulated operations are deferred and amortized over the life of the assets. We are included in Wisconsin Energy's consolidated Federal income tax return. Wisconsin Energy allocates Federal tax expense or credits to us based on our separate tax computation.

Investment tax credits related to regulated utility assets are recorded as a deferred credit on the balance sheet and amortized to income over the applicable service lives of related properties in accordance with regulatory treatment. Historical rehabilitation credits are reported in income in the year claimed.

Wisconsin Energy allocates the tax benefit of stock options exercised to us to the extent the option holder's payroll cost was incurred by us. We record the allocated tax benefit as an addition to paid in capital.

We recognize interest and penalties accrued related to unrecognized tax benefits in Income Taxes in our Consolidated Income Statements, as well as Regulatory Assets or Regulatory Liabilities in our Consolidated Balance Sheets.

We collect sales and use taxes from our customers and remit these taxes to governmental authorities. These taxes are recorded in our Consolidated Income Statements on a net basis.

Stock Options: Employees of Wisconsin Electric participate in the Wisconsin Energy stock-based compensation plan. The amounts reported represent the allocated costs related to options held by our employees. For more information on the plan, see Note N.

Effective January 1, 2006, Wisconsin Energy adopted SFAS 123R, using the modified prospective method. Wisconsin Energy uses a binomial pricing model to estimate the fair value of stock options granted subsequent to December 31, 2005. Prior to January 1, 2006, Wisconsin Energy accounted for share based compensation under APB 25, Accounting for Stock Issued to Employees, and we disclosed the pro forma impact of share based compensation expense under SFAS 123. Historically, all stock options have been granted with an exercise price equal to the fair market value of the common stock on the date of grant and expire no later than ten

years from the grant date. Accordingly, no compensation expense was recognized in connection with option grants. All options granted subsequent to December 31, 2004 vest on a cliff-basis after a three year period. Prior to January 1, 2006, we reported benefits of tax deductions in excess of recognized compensation costs as operating cash flows. SFAS 123R requires that excess tax benefits be reported as a financing cash inflow rather than as an operating cash inflow. For further discussion of this new standard and the impacts to our Consolidated Financial Statements, see Note N.

Wisconsin Energy previously adopted the disclosure provisions of SFAS 123 as amended by SFAS 148. The fair value of each Wisconsin Energy option at date of grant for 2006 was calculated using a binomial option pricing model. For 2005 and 2004, the fair value of options at the date of grant was estimated using the Black-Scholes option-pricing model with the following weighted average assumptions:

	Binomial	Black-Scholes	
	2006	2005	2004
Risk free interest rate	4.3% - 4.4%	4.4%	4.6%
Dividend yield	2.4%	2.5%	2.5%
Expected volatility	17.0% - 20.0%	19.0%	23.1%
Expected life (years)	6.3	10.0	10.0
Pro forma weighted average fair value of our stock options granted	$7.55	$8.32	$9.45

As described more fully in the following table, had we expensed the 2005 and 2004 grants for stock-based compensation plans under SFAS 123, our net income would have been reduced to the pro forma amounts set forth in the table below. In 2004, the pro forma expense increased, in part, due to the effect of accelerating the vesting of Wisconsin Energy stock options held by our employees. For further information regarding equity based compensation see Note N.

	2005	2004
	(Millions of Dollars)	
Net Income - as reported	$283.6	$248.7
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	1.7	2.0
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	3.0	20.2
Net Income - Pro forma	$282.3	$230.5

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Share Based Compensation: In December 2004, the FASB issued SFAS 123R, which amended SFAS 123. In March 2005, the SEC issued SAB 107 regarding the SEC's interpretation of SFAS 123R and the valuation of share-based payment for public companies. This statement requires that the compensation costs relating to such transactions be recognized in the consolidated income statement. Wisconsin Energy adopted SFAS 123R and SAB 107 effective January 1, 2006 using the modified prospective method. For additional information, see Note N.

Implicit Variable Interests: In April 2006, the FASB issued FSP FIN 46R-6. FSP FIN 46R-6 addresses the requirement to determine the variability to be considered in applying FIN 46R-6 based on an analysis of the design of the entity. As required, we adopted FSP FIN 46R-6 effective July 1, 2006 for any new arrangements entered into after the effective date. For further information, see Note D.

Uncertainty in Income Taxes: In July 2006, the FASB issued FIN 48, an interpretation of SFAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the enterprise's financial statements in accordance with SFAS 109. We adopted FIN 48 effective January 1, 2007. For further information, see Note E.

Fair Value Measurements: In September 2006, the FASB issued SFAS 157. SFAS 157 provides guidance for using fair value to measure assets and liabilities. SFAS 157 defines fair value, provides a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently evaluating the provisions of SFAS 157 and we expect to adopt SFAS 157 on January 1, 2008.

Pension and Other Post-retirement Plans: In September 2006, the FASB issued SFAS 158, an amendment of SFAS 87, 88, 106 and 132R. SFAS 158 requires recognition of the overfunded or underfunded status of a defined benefit post-retirement plan as an asset or liability on the balance sheet and recognition of changes in that funded status in the year in which the changes occur through comprehensive income. SFAS 158 also requires an employer to measure the funded status of a plan as of the date of its year end balance sheet. We adopted SFAS 158 as of December 31, 2006. For further information, see Note L.

Financial Statement Errors: In September 2006, the SEC staff issued SAB 108. SAB 108 addresses the diversity in practice by registrants when quantifying the effect of an error on the financial statements. SAB 108 provides guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements. We adopted the provisions of SAB 108 effective December 31, 2006. The adoption of SAB 108 did not have any financial impact on our consolidated financial statements.

C – REGULATORY ASSETS AND LIABILITIES

We account for our regulated operations in accordance with SFAS 71.

Our primary regulator considers our regulatory assets and liabilities in two categories, escrowed and deferred. In escrow accounting we expense amounts that are included in rates. If actual costs exceed, or are less than the amounts that are allowed in rates, the difference in cost is escrowed on the balance sheet as a regulatory asset or regulatory liability and the escrowed balance is considered in setting future rates. Under deferred cost accounting, we defer amounts to our balance sheet based upon specific orders or correspondence with our primary regulator. These deferred costs will be considered in future rate setting proceedings. As of December 31, 2006, we had approximately $30.0 million of net regulatory assets that were not earning a return.

Our regulatory assets and liabilities as of December 31 consist of:

	2006	2005
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs (see Note L)	$236.3	$240.7
Escrowed electric transmission costs	192.2	169.4
Deferred income tax related	95.2	93.5
Deferred plant related -- capital leases (see Note G)	88.9	72.4
Deferred fuel related costs	79.1	72.8
Deferred environmental costs	42.4	43.9
Escrowed unrecovered plant costs	31.6	56.5
Other, net	93.8	73.3
Total long-term regulatory assets	$859.5	$822.5
Regulatory Liabilities		
Deferred asset retirement obligations (see Notes F and I)	$537.1	$475.3
Deferred cost of removal obligations (see Notes F and I)	430.5	414.1
Deferred income tax related	85.6	91.6
Other, net	89.1	70.9
Total long-term regulatory liabilities	$1,142.3	$1,051.9
Net long-term regulatory liabilities	$282.8	$229.4

As of December 31, 2005, we recorded a minimum pension liability to reflect the funded status of our pension plans (see Note L). Under SFAS 158, which Wisconsin Energy adopted effective December 31, 2006, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of the pension and OPEB plans qualify as a regulatory asset.

We record deferred regulatory assets and liabilities representing the future expected impact of deferred taxes on utility revenues (see Note A).

In October 2002, the PSCW issued an order authorizing us to implement a surcharge for recovery of annual electric transmission costs projected through 2005. In addition, the PSCW order authorized escrow accounting treatment for transmission costs.

As of December 31, 2006, we have deferred $79.1 million of fuel related costs. The majority of these deferred costs were incurred in 2005 as a result of an extended outage at Point Beach, increased costs associated with reduced coal deliveries due to a railroad transportation problem and increased costs associated with the MISO Midwest Market.

Consistent with a generic order from and past rate-making practices of the PSCW, we defer as a regulatory asset costs associated with the remediation of former manufactured gas plant sites. As of December 31, 2006, we have recorded $42.4 million of environmental

costs associated with manufactured gas plant sites as a regulatory asset, including $26.9 million of deferrals for actual remediation costs incurred and a $15.5 million accrual for estimated future site remediation (See Note Q). In addition, we have deferred $8.1 million of insurance recoveries associated with the environmental costs as regulatory liabilities. We included total actual remediation costs incurred net of the related insurance recoveries in our 2006 rate case. We began amortizing these costs upon receiving PSCW approval in January 2006. The amortization period for these costs is five years.

As part of Wisconsin Energy's PTF strategy, the PSCW approved the retirement and removal of the Port Washington Power Plant coal units to make way for construction of gas-fired facilities. In a September 27, 2003 order, the PSCW authorized transferring the undepreciated costs and related removal amounts to a regulatory asset account. The escrowed unrecovered plant costs totaled $31.6 million at December 31, 2006.

D – VARIABLE INTEREST ENTITIES

Under FIN 46 and FIN 46R, the primary beneficiary of a variable interest entity must consolidate the related assets and liabilities.

We continue to evaluate our tolling and purchased power agreements with third parties on a quarterly basis. After making an exhaustive effort, we concluded that for three of these agreements, we are unable to obtain the information necessary to determine whether these entities are variable interest entities. Pursuant to the terms of two of the three agreements, we deliver fuel to the entity's facilities and receive electric power. We pay the entity a "toll" to convert our fuel into the electric energy. The output of the facility is available for us to dispatch during the term of the respective agreement. In the other agreement, we have rights to the firm capacity of the entity's facility. We have approximately $603.0 million of required payments over the remaining term of these three agreements, which expire over the next 16 years. We believe the required payments will continue to be recoverable in rates. We account for one of these agreements as a capital lease.

In April 2006, the FASB issued FSP FIN 46R-6. As required, we adopted FSP FIN 46R-6 effective July 1, 2006 for any new arrangements entered into after the effective date. Although the adoption of FSP FIN 46R-6 did not have a material financial impact in the current period, we currently are unable to determine the potential impact in future periods.

E -- INCOME TAXES

The following table is a summary of income tax expense for each of the years ended December 31:

Income Taxes	2006	2005	2004
	(Millions of Dollars)		
Current tax expense	$228.2	$145.6	$16.4
Deferred income taxes, net	(55.4)	24.1	141.2
Investment tax credit, net	(3.9)	(4.2)	(4.4)
Total Income Tax Expense	$168.9	$165.5	$153.2

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable U.S. statutory federal income tax rate to income before income taxes and preferred dividend as a result of the following:

	2006		2005		2004	
Income Tax Expense	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
			(Millions of Dollars)			
Expected tax at statutory federal tax rates	$155.6	35.0%	$157.2	35.0%	$141.1	35.0%
State income taxes net of federal tax benefit	22.6	5.1%	20.9	4.7%	19.0	4.7%
Investment tax credit restored	(3.9)	(0.9%)	(4.2)	(0.9%)	(4.4)	(1.1%)
Other, net	(5.4)	(1.2%)	(8.4)	(1.9%)	(2.5)	(0.6%)
Total Income Tax Expense	$168.9	38.0%	$165.5	36.9%	$153.2	38.0%

The components of SFAS 109 deferred income taxes classified as net current liabilities and net long-term liabilities at December 31 are as follows:

	2006	2005
	(Millions of Dollars)	
Deferred Tax Assets		
Current		
Employee benefits and compensation	$10.7	$10.2
Recoverable gas costs	7.5	1.3
Other	2.1	5.7
Total Current Deferred Tax Assets	$20.3	$17.2
Non-current		
Decommissioning trust	98.1	85.8
Employee benefits and compensation	95.8	99.7
Construction advances	84.8	71.6
Deferred revenues	84.2	28.3
Emission allowances	19.0	18.4
Property-related	7.2	7.2
Other	9.2	15.2
Total Non-current Deferred Tax Assets	398.3	326.2
Total Deferred Tax Assets	$418.6	$343.4
Deferred Tax Liabilities		
Current		
Prepaid items	$35.1	$32.3
Uncollectible account expense	9.1	7.3
Total Current Deferred Tax Liabilities	$44.2	$39.6
Non-current		
Property-related	760.6	746.3
Deferred transmission costs	76.5	64.6
Investment in transmission affiliate	38.9	35.4
Other	32.4	33.1
Total Non-current Deferred Tax Liabilities	908.4	879.4
Total Deferred Tax Liabilities	$952.6	$919.0

Consolidated Balance Sheet Presentation	2006	2005
Current Deferred Tax Asset (Liability)	($23.9)	($22.4)
Non-current Deferred Tax Asset (Liability)	($510.1)	($553.2)

Consistent with ratemaking treatment, deferred taxes are offset in the above table for temporary differences which have related regulatory assets or liabilities.

In July 2006, the FASB issued FIN 48, an interpretation of SFAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the enterprise's financial statements in accordance with SFAS 109. FIN 48 provides clarification on the accounting for income taxes by setting forth a minimum recognition threshold an uncertain tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on de-recognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. We adopted FIN 48 effective January 1, 2007. As a result of the adoption of FIN 48, we estimate that the cumulative effect on retained earnings is immaterial.

F -- NUCLEAR OPERATIONS

Point Beach Nuclear Plant: We own two 518 MW electric generating units at Point Beach in Two Rivers, Wisconsin. NMC operates the units on our behalf. The units were placed in service in the early 1970's and the original operating licenses were effective

through 2010 and 2013. In December 2005, the NRC renewed the operating licenses through October 2030 for Unit 1 and March 2033 for Unit 2.

Proposed Sale of Point Beach: In December 2006, we announced that we signed a definitive agreement with an affiliate of FPL to sell Point Beach for approximately $998 million, subject to closing price adjustments. Under the terms of the sale, the buyer would assume the obligation to decommission the plant, and we would transfer assets in a qualified trust for decommissioning. We would retain assets in a non-qualified decommissioning trust. We also entered into a long-term power purchase agreement to purchase all of the existing capacity and energy of the plant, which will become effective upon closing of the sale. We will have the unilateral option, subject to PSCW direction, to select a term for the power purchase agreement of either (i) an estimated 23 years for Unit 1 and 26 years for Unit 2, or (ii) 16 years for Unit 1 and 17 years for Unit 2. The sale of the plant and the long-term power purchase agreement are subject to review and approval by various regulatory agencies including the NRC, PSCW, MPSC and FERC. We anticipate closing the sale during the third quarter of 2007. We have submitted a request to the PSCW to defer any gain (net of transaction related costs) as a regulatory liability that would be applied to the benefit of our customers in future rate proceedings.

Nuclear Insurance: The Price-Anderson Act currently limits the total public liability for damages arising from a nuclear incident at a nuclear power plant to approximately $10.8 billion, of which $300 million is covered by liability insurance purchased from private sources. The remaining $10.5 billion is covered by an industry retrospective loss sharing plan whereby, in the event of a nuclear incident resulting in damages exceeding the private insurance coverage, each owner of a nuclear plant would be assessed a deferred premium of up to $100.6 million per reactor with a limit of $15 million per reactor within one calendar year. We have two reactors. We are obligated to pay our proportionate share of any such assessment as long as we own Point Beach.

Through our membership in NEIL, we carry decontamination, property damage and decommissioning shortfall insurance covering losses of up to $2.1 billion at Point Beach. Under policies issued by NEIL, the insured member may be liable for a retrospective premium in the event of catastrophic losses exceeding the full financial resources of NEIL. Our maximum retrospective liability under the above policies is $17.8 million.

We also maintain insurance with NEIL through which we can recover up to $3.5 million per week, subject to a total limit of $490 million, during any prolonged outage at Point Beach caused by accidental property damage. Our maximum retrospective liability under this policy is $9.8 million.

It should not be assumed that, in the event of a major nuclear incident, any insurance or statutory limitation of liability would protect us from material adverse impact.

Nuclear Decommissioning: We record decommissioning expense in amounts equal to the amounts collected in rates and funded to the external trusts. Nuclear decommissioning costs are accrued over the expected service lives of the nuclear generating units and are included in electric rates. Decommissioning funding was $17.6 million for each of the years ended 2006, 2005 and 2004. As of December 31, 2006, our non-qualified investments were $303.7 million and our qualified investments were $577.9 million. We had the following investments in nuclear decommissioning trusts, stated at fair value as of December 31, 2006 and 2005.

	2006	2005
	(Millions of Dollars)	
Funding and Realized Earnings	$607.2	$566.6
Net Unrealized Gains	274.4	215.5
Total Investments	$881.6	$782.1

As of December 31, 2006, approximately 66.5% of the trust funds were invested in equity securities and 33.5% were invested in debt securities. In accordance with SFAS 115, our debt and equity security investments in the trusts are classified as available for sale. Gains and losses on the fund are determined on the basis of specific identification; net unrealized gains on the fund are recorded as part of the fund. Our investments in the trusts are recorded at fair value and we are allowed regulatory treatment for the fair value adjustment. Realized gains and losses for the years ended December 31, 2006 and 2005 were as follows:

	2006	2005
	(Millions of Dollars)	
Realized Gains	$21.2	$19.1
Realized (Losses)	(10.6)	(9.1)
Net Realized Gain	$10.6	$10.0

Total gains and total losses by security type for the years ended December 31, 2006 and 2005 were as follows:

December 31, 2006	Total Gains	Total (Losses)	Net Gain (Loss)
Debt	$1.4	($5.2)	($3.8)
Equity	296.5	(7.7)	288.8
Total	$297.9	($12.9)	$285.0

December 31, 2005	Total Gains	Total (Losses)	Net Gain (Loss)
Debt	$2.1	($5.0)	($2.9)
Equity	236.5	(8.1)	228.4
Total	$238.6	($13.1)	$225.5

The contractual maturities of debt securities at December 31, 2006 are as follows: $14.8 million in 2007; $52.0 million in 2008-2011; $97.9 million in 2012-2016; and $125.2 million thereafter.

The PSCW requires us to perform periodic Decommissioning Cost Studies to evaluate the funded status of our nuclear decommissioning trusts as compared with the estimated costs to perform the decommissioning work. In June 2005, we filed a new Decommissioning Cost Study with the PSCW. The study was performed by an outside consultant and it included several assumptions as to the timing and scope of the decommissioning work. This study estimated that the cost to decommission the plant would be $712.5 million in 2004 dollars. A prior study had estimated the cost to be $1.1 billion in 2003 dollars. The reduction in the estimated costs to decommission the plant was driven by several factors including the timing and the scope of the work to be performed.

The June 2005 Decommissioning Cost Study was also used to estimate our ARO for nuclear decommissioning. We record an ARO for future decommissioning costs based upon the net present value of the expected cash flows associated with our legal obligation to decommission our plants. Under SFAS 143, certain costs included in the June 2005 Decommissioning Cost Study that related to fuel management and non-nuclear demolition were excluded from the ARO calculation. Using the June 2005 study, our estimated costs for decommissioning, following SFAS 143, were $473.2 million. Our ARO for nuclear decommissioning as of December 31, 2006 was $325.6 million.

We recover decommissioning costs in our regulated rates. We have established a regulatory liability to reflect the difference between nuclear decommissioning costs recovered in rates and cumulative investment gains (our nuclear decommissioning trust investments) in comparison to the ARO for nuclear decommissioning that is calculated under SFAS 143. For further information on AROs, see Note I.

The ultimate timing and amount of future cash flows associated with nuclear decommissioning is dependent upon many significant variables including the scope of work involved, the ability to relicense the plants in the future, future inflation rates and discount rates. Because of our announced agreement to sell Point Beach to an affiliate of FPL, we do not expect to remain obligated to decommission Point Beach if the sale is consummated. However, if that sale is not completed, based on the license renewal received by the NRC in December 2005, we do not expect to make any significant nuclear decommissioning expenditures before the year 2030.

Decontamination and Decommissioning Fund: The Energy Policy Act of 1992 established a D&D Fund for the DOE's nuclear fuel enrichment facilities. Deposits to the D&D Fund are derived in part from special assessments on utilities using enrichment services. In October 2006, a final payment was made to the DOE. As a result, a liability no longer exists for this fund. The deferred regulatory asset will be amortized to nuclear fuel expense and included in utility rates through September 2007.

G -- LONG-TERM DEBT

Debentures and Notes: As of December 31, 2006, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2007	$250.0
2008	-
2009	0.1
2010	0.1
2011	-
Thereafter	1,351.4
Total	$1,601.6

We amortize debt premiums, discounts and debt issuance costs over the lives of the debt and we include the costs in interest expense.

In November 2006, we issued $300 million of 5.70% Debentures due December 1, 2036. The securities were issued under an existing $665 million shelf registration statement filed with the SEC. The net proceeds from the sale were used to retire our $200 million of 6-5/8% Debentures due November 15, 2006 at their scheduled maturity and to repay outstanding commercial paper incurred for working capital requirements.

Capital Leases: In 1997, we entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MW of firm capacity from a gas-fired cogeneration facility, includes no minimum energy requirements. When the contract expires in 2022, we may, at our option and with proper notice, renew for another ten years or purchase the generating facility at fair value or allow the contract to expire. We account for this contract as a capital lease and recorded the leased facility and corresponding obligation under the capital lease at the estimated fair value of the plant's electric generating facilities. We are amortizing the leased facility on a straight-line basis over the original 25-year term of the contract.

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as purchased power expense on the Consolidated Income Statements. We paid a total of $26.1 million, $25.2 million and $24.3 million in minimum lease payments during 2006, 2005, and 2004, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting as a deferred regulatory asset on our Consolidated Balance Sheets (see Regulatory Assets - Deferred plant related - capital leases in Note C). Due to the timing and the amounts of the minimum lease payments, we expect the regulatory asset to increase to approximately $78.5 million by the year 2009 at which time the regulatory asset will be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $159.4 million at December 31, 2006 and will decrease to zero over the remaining life of the contract.

In July 2005, the first 545-MW natural gas-fired generation unit was placed in service at the PWGS. We are leasing this unit from We Power under a PSCW approved lease. Pursuant to SFAS 13, Accounting for Leases, we are accounting for this lease as a capital lease and have recorded the leased plant and corresponding obligation under the capital lease at the estimated fair value of $335.5 million. We are amortizing the leased plant on a straight-line basis over the original 25-year term of the lease.

This lease is treated as an operating lease for rate-making purposes. We record the lease payments as rent expense in other operation and maintenance in the Consolidated Income Statement. The lease payments are expected to be recovered through our rates. The recoverability of the lease payments is supported by the 2001 lease generation law. We paid a total of $47.8 million and $21.9 million in minimum lease payments during 2006 and 2005, respectively. We are recording a deferred regulatory asset for the difference between the lease payments and the sum of imputed interest cost and amortization costs calculated under capital lease accounting (see Regulatory Assets - Deferred plant related - capital leases in Note C). Due to the timing and the amounts of the minimum lease payments, we expect the regulatory asset to increase to approximately $125.1 million in the year 2021 at which time the regulatory asset will be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $333.5 million at December 31, 2006 and will decrease to zero over the remaining life of the contract.

We also have a nuclear fuel leasing arrangement with Wisconsin Electric Fuel Trust (Trust) which is treated as a capital lease. We lease and amortize the nuclear fuel to fuel expense as power is generated, generally over a period of 60 months. Lease payments include charges for the cost of fuel burned, financing costs and management fees. In the event that we or the Trust terminates the lease, the Trust would recover its unamortized cost of nuclear fuel from us. Under the lease terms, we are in effect the ultimate guarantor of the Trust's commercial paper and line of credit borrowings that finance the investment in nuclear fuel. We recorded $4.2 million, $1.7 million and $1.4 million of interest expense on the nuclear fuel lease in fuel expense during 2006, 2005 and 2004, respectively.

Following is a summary of our capitalized leased facilities and nuclear fuel at December 31.

Capital Lease Assets	2006	2005
	(Millions of Dollars)	
Leased Facilities		
Long-term purchase power commitment	$140.3	$140.3
Accumulated amortization	(52.8)	(47.1)
Total Leased Facilities	$87.5	$93.2
PWGS Unit 1		
Under capital lease	$336.0	$335.5
Accumulated amortization	(19.5)	(6.1)
Total PWGS Unit 1	$316.5	$329.4
Nuclear Fuel		
Under capital lease	$136.0	$125.6
Accumulated amortization	(70.4)	(60.2)
In process/stock	65.3	46.6
Total Nuclear Fuel	$130.9	$112.0

Future minimum lease payments under our capital leases and the present value of our net minimum lease payments as of December 31, 2006 are as follows:

Capital Lease Obligations	Purchase Power Commitment	PWGS 1	Nuclear Fuel Lease	Total
	(Millions of Dollars)			
2007	$32.4	$48.0	$29.2	$109.6
2008	33.6	48.0	24.6	106.2
2009	34.9	48.0	15.4	98.3
2010	36.2	48.0	5.9	90.1
2011	37.5	48.0	2.9	88.4
Thereafter	295.3	889.8	-	1,185.1
Total Minimum Lease Payments	469.9	1,129.8	78.0	1,677.7
Less: Estimated Executory Costs	(103.8)	-	-	(103.8)
Net Minimum Lease Payments	366.1	1,129.8	78.0	1,573.9
Less: Interest	(206.7)	(796.3)	(6.0)	(1,009.0)
Present Value of Net Minimum Lease Payments	159.4	333.5	72.0	564.9
Less: Due Currently	(2.0)	(2.0)	(26.4)	(30.4)
	$157.4	$331.5	$45.6	$534.5

H -- SHORT-TERM DEBT

Short-term notes payable balances and their corresponding weighted-average interest rates as of December 31 consist of:

Short-Term Debt	2006 Balance	2006 Interest Rate	2005 Balance	2005 Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial Paper	$274.1	5.37%	$322.2	4.39%
Other	30.1	6.36%	30.5	6.66%
Total Short-Term Debt	$304.2	5.47%	$352.7	4.59%

On December 31, 2006, we had approximately $485.9 million of available unused lines under our bank back-up credit facility. Our bank back-up credit facility expires in March 2011.

The following information relates to commercial paper outstanding for the years ended December 31, 2006 and 2005:

	2006	2005
	(Millions of Dollars, except for percentages)	
Maximum Commercial Paper Outstanding	$369.9	$324.9
Average Commercial Paper Outstanding	$174.2	$117.8
Weighted Average Interest Rate	5.02%	3.26%

We have entered into a bank back-up credit agreement to maintain short-term credit liquidity which, among other terms, requires us to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 65%.

Our bank back-up credit agreement contains customary covenants, including certain limitations on our ability to sell assets. The credit agreement also contains customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, ERISA defaults and change of control.

At December 31, 2006, we were in compliance with all covenants.

I -- ASSET RETIREMENT OBLIGATIONS

The following table presents the change in our AROs during 2006.

	Balance at December 31, 2005	Liabilities Incurred	Liabilities Settled	Accretion	Balance at December 31, 2006
			(Millions of Dollars)		
Asset Retirement Obligations	$354.9	$ -	($2.1)	$18.3	$371.1

SFAS 143 primarily applies to the future decommissioning costs for Point Beach. Prior to January 2003, we recorded a long-term liability for accrued nuclear decommissioning costs. See Note F for further information about the nuclear decommissioning of Point Beach, including our investments in nuclear decommissioning trusts that are restricted to nuclear decommissioning.

In March 2005, the FASB issued FIN 47. FIN 47 defines a conditional ARO as a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. We adopted FIN 47 effective December 31, 2005. At adoption, we recorded additional AROs related to asbestos removal costs.

The adoption of FIN 47 had no impact on our net income in 2006 or 2005. As it relates to our regulated operations, we apply SFAS 71 and recognize regulatory assets or liabilities for the timing differences between when we recover legal AROs in rates and when we would recognize these costs under FIN 47. This treatment is consistent with the adoption of SFAS 143 for our regulated operations.

J -- DERIVATIVE INSTRUMENTS

We follow SFAS 133 as amended by SFAS 149, which requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives under SFAS 133, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. As of December 31, 2006, we recognized $18.5 million in regulatory assets related to derivatives in comparison to $2.2 million at December 31, 2005.

We had a limited number of financial contracts that are defined as derivatives under SFAS 133 and qualify for cash flow hedge accounting. These contracts were utilized to manage the cost of gas for utility operations. Changes in the fair market values of these

instruments were recorded in Accumulated Other Comprehensive Income. At the date the underlying transaction occurs, the amounts in Accumulated Other Comprehensive Income were reported in earnings.

For the year ended December 31, 2005 the amount of hedge ineffectiveness was immaterial. We did not exclude any components of derivative gains or losses from the assessment of hedge effectiveness.

K -- FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amount and estimated fair value of certain of our recorded financial instruments at December 31 are as follows:

	2006		2005	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Nuclear decommissioning assets	$881.6	$881.6	$782.1	$782.1
Preferred stock, no redemption required	$30.4	$22.6	$30.4	$22.6
Long-term debt including current portion	$1,601.6	$1,588.9	$1,505.5	$1,526.1

The carrying value of cash and cash equivalents, net accounts receivable, accounts payable and short-term borrowings approximates fair value due to the short-term nature of these instruments. The nuclear decommissioning assets are carried at fair value as reported by the trustee (see Note F). The fair value of our preferred stock is estimated based upon the quoted market value for the same or similar issues. The fair value of our long-term debt, including the current portion of long-term debt but excluding capitalized leases, is estimated based upon quoted market value for the same or similar issues or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. The fair values of derivative financial instruments and associated margin accounts are equal to their carrying values as of December 31, 2006.

L -- BENEFITS

Pensions and Other Post-retirement Benefits: We participate in Wisconsin Energy's noncontributory defined benefit pension plans that cover substantially all of our employees. The plans provide defined benefits based upon years of service and final average salary. In October 2006, Wisconsin Energy announced that it was making a change to pension benefits for new management employees hired subsequent to October 2006 and for those represented employees whose unions have adopted this plan. The retirement benefit for new employees is an enhanced 401(k) plan. Existing employee's pension benefits are unchanged. Our 2007 combined pension and savings plan costs are not expected to be materially affected as a result of this change to the plan.

We also participate in Wisconsin Energy's OPEB plans that cover substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually; the life insurance plans are noncontributory. The accounting for the health care plans anticipates future cost-sharing changes to the written plans that are consistent with our expressed intent to maintain the current cost sharing levels. The post-retirement health care plans include a limit on our share of costs for recent and future retirees. Wisconsin Energy uses a year end measurement date for all of the pension and OPEB plans.

The assets, obligations and the components of our pension costs are allocated by Wisconsin Energy's actuary to each of the participating companies as if each participating company had its own plan. The disclosures below are based on an allocation to us of the amounts for Wisconsin Energy's pension plan.

In September 2006, the FASB issued SFAS 158, which requires employers to recognize all obligations related to their pension and OPEB plans and to quantify the funded status of the pension and OPEB plans as an asset or liability on their statement of financial position. In addition, SFAS 158 requires employers to measure the funded status of their plans as of the date of their year-end statement of financial position.

Wisconsin Energy adopted SFAS 158 prospectively on December 31, 2006. Wisconsin Energy has historically and will continue to use a year end measurement date for all of the benefit plans. Prior to the issuance of SFAS 158, we recorded a minimum pension liability to reflect the funded status of the pension plan. Due to the regulatory nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of the pension and OPEB plans qualify as a regulatory asset.

The following table shows the incremental effect of applying SFAS 158 on individual line items in our year-end statement of financial position and compares prior year-end balances:

	December 31, 2006			December 31, 2005
	Before SFAS 158	Impact	As Reported	
	(Millions of Dollars)			(Millions of Dollars)
Regulatory Asset - Pension	$166.0	$ 70.3	$236.3	$240.7
Regulatory Asset - OPEB	$ -	$ 29.2	$ 29.2	$ -
Other Deferred Charges - Pension	$ 29.2	($29.2)	$ -	$ 31.6
Other Deferred Charges - OPEB	$ -	$ -	$ -	$ 0.1
Pension Liability	$264.1	$ 30.5	$294.6	$347.2
OPEB Liability	$112.5	$ 29.2	$141.7	$112.8
Other Comprehensive Income	($10.6)	$ 10.6	$ -	($14.3)

The following table presents additional details about the pension and OPEB plans.

	Pension		OPEB	
Status of Benefit Plans	2006	2005	2006	2005
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	$1,109.1	$1,019.5	$261.6	$313.1
Service cost	30.6	30.0	11.8	13.0
Interest cost	59.6	59.4	14.1	16.8
Plan amendments	3.0	2.8	-	(76.0)
Actuarial loss (gain)	(40.8)	77.3	(19.2)	6.6
Benefits paid	(89.7)	(79.9)	(8.1)	(11.9)
Federal Subsidy on benefits paid	N/A	N/A	1.0	N/A
Benefit Obligation at December 31	$1,071.8	$1,109.1	$261.2	$261.6
Change in Plan Assets				
Fair Value at January 1	$719.6	$748.0	$108.1	$107.4
Actual earnings on plan assets	89.1	48.6	7.2	3.5
Employer contributions	58.2	2.9	12.5	9.1
Benefits paid	(89.7)	(79.9)	(8.1)	(11.9)
Fair Value at December 31	$777.2	$719.6	$119.7	$108.1
Funded Status of Plans				
Funded status at December 31	($294.6)	($389.5)	($141.5)	($153.5)
Unrecognized (1)				
Net actuarial loss	N/A	297.5	N/A	102.3
Prior service cost	N/A	31.4	N/A	(63.9)
Net transition (asset) obligation	N/A	-	N/A	2.4
Accrued Benefit Cost	($294.6)	($60.6)	($141.5)	($112.7)

(1) After adoption of SFAS 158 on December 31, 2006, these amounts are recorded and this reconciliation is no longer needed.

The accumulated benefit obligation for all the defined benefit plans was $1,041.5 million and $1,067.2 million at December 31, 2006 and 2005, respectively.

Information for the pension plan, which has an accumulated benefit obligation in excess of the fair value of its assets, is as follows:

	2006	2005
	(Millions of Dollars)	
Projected benefit obligation	$1,071.8	$1,109.1
Accumulated benefit obligation	$1,041.5	$1,067.2
Fair value of plan assets	$777.2	$719.6

The components of net periodic pension and OPEB costs are:

	Pension			OPEB		
Benefit Plan Cost Components	2006	2005	2004	2006	2005	2004
			(Millions of Dollars)			
Net Periodic Benefit Cost						
Service cost	$30.6	$30.0	$26.9	$11.8	$13.0	$11.4
Interest cost	59.6	59.4	58.4	14.1	16.8	17.1
Expected return on plan assets	(59.8)	(64.4)	(62.6)	(8.7)	(8.9)	(7.9)
Amortization of:						
Transition (asset) obligation	-	(0.1)	(2.2)	0.3	1.2	1.5
Prior service cost	5.4	5.2	4.8	(13.3)	(3.3)	-
Actuarial loss	20.2	17.9	13.2	7.0	6.0	5.1
Net Periodic Benefit Cost	$56.0	$48.0	$38.5	$11.2	$24.8	$27.2
Weighted-Average assumptions used to determine benefit obligations at Dec 31						
Discount rate	5.75%	5.50%	5.75%	5.75%	5.50%	5.75%
Rate of compensation increase	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0
Weighted-Average assumptions used to determine net cost for year ended Dec 31						
Discount rate	5.50%	5.75%	6.25%	5.50%	5.75%	6.25%
Expected return on plan assets	8.5	9.0	9.0	8.5	9.0	9.0
Rate of compensation increase	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0
Assumed health care cost trend rates at Dec 31						
Health care cost trend rate assumed for next year (Pre 65 / Post 65)				9/11	10	10
Rate that the cost trend rate gradually adjusts to				5	5	5
Year that the rate reaches the rate it is assumed to remain at				2011	2011	2010

The expected long-term rate of return on plan assets was 8.5% in 2006 and 9% in 2005 and 2004. This return expectation on plan assets was determined by reviewing actual pension historical returns as well as calculating expected total trust returns using the weighted average of long-term market returns for each of the asset categories utilized in the pension fund.

Other Post-retirement Benefits Plans: We use various Employees' Benefit Trusts to fund a major portion of OPEB. The majority of the trusts' assets are mutual funds or commingled indexed funds.

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(Millions of Dollars)	
Effect on		
Post-retirement benefit obligation	$25.2	($21.1)
Total of service and interest cost components	$3.7	($3.0)

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) was signed into law. The Act introduced a prescription drug benefit program under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans. In 2004, the FASB issued FSP SFAS 106-2.

In 2004, in accordance with FSP SFAS 106-2, we chose to recognize the effects of the Act retroactively effective January 1, 2004. Calculated actuarially, the Act resulted in a reduction of $20.6 million in our benefit obligation. In addition, we recorded a reduction to SFAS 106 expense of $4.2 million in 2004. In January 2005, the Centers for Medicare & Medicaid Services released final regulations to implement the new prescription drug benefit under Part D of Medicare. It was determined that our employer sponsored plans met these regulations and that the previously determined actuarial measurements do not need to be revised.

In October 2005, we announced that we were offering to our retirees a Medicare Advantage program as an option within our existing post-retirement medical and drug plans. The Medicare Advantage program is part of the Act, and offers post-65 medical and drug benefits through private insurance carriers. The Medicare Advantage program is expected to reduce the cost of post-65 medical and drug costs for our retirees and the Company. Due to this change, we remeasured the fair value of our OPEB plans in the fourth quarter of 2005 in accordance with SFAS 106. In 2005, the impact of this remeasurement and the FSP SFAS 106-2 benefit was approximately a $4.1 million reduction to SFAS 106 expense.

Plan Assets: In our opinion, current pension trust assets and amounts which are expected to be contributed to the trusts in the future will be adequate to meet pension payment obligations to current and future retirees. The pension plans asset allocation at December 31, 2006 and 2005, and the target allocation for 2007, by asset category, are as follows:

Asset Category	Target Allocation 2007	Actual Allocation 2006	Actual Allocation 2005
Equity Securities	65%	61%	65%
Debt Securities	35%	39%	35%
Total	100%	100%	100%

Our OPEB plans asset allocation at December 31, 2006 and 2005, and our target allocation for 2007, by asset category, are as follows:

Asset Category	Target Allocation 2007	Actual Allocation 2006	Actual Allocation 2005
Equity Securities	54%	32%	32%
Debt Securities	46%	68%	67%
Other	- %	- %	1%
Total	100%	100%	100%

Wisconsin Energy's common stock is not included in equity securities. Investment managers are specifically prohibited from investing in our securities or any affiliate of ours except if part of a commingled fund or index fund.

The target asset allocations were established by an Investment Trust Policy Committee, which oversees investment matters related to all of our funded benefit plans. The asset allocations are monitored by the Investment Trust Policy Committee.

Cashflows:

Employer Contributions	Pension	OPEB
	(Millions of Dollars)	
2004	$72.4	$15.7
2005	$2.9	$9.1
2006	$58.2	$12.5

Based on our PSCW approved funding policy and current IRS funding requirements, we expect to contribute $36.5 million to fund pension benefits and $11.2 million to fund OPEB plans in 2007. Of the $36.5 million expected to be contributed to fund pension benefits in 2007, we estimate $32.4 million will be for our qualified pension plans. We contributed $54.0 million to our qualified pension plans during 2006. We did not make a contribution to our qualified pension plan during 2005.

The entire contribution to the OPEB plans during 2006 was discretionary as the plans are not subject to any minimum regulatory funding requirements.

The following table identifies our expected benefit payments over the next 10 years:

Year	Pension	Gross OPEB	Expected Medicare Part D Subsidy
		(Millions of Dollars)	
2007	$72.0	$13.8	($1.0)
2008	$77.7	$14.2	($0.8)
2009	$80.4	$13.0	-
2010	$81.2	$14.3	-
2011	$92.3	$15.6	-
2012-2016	$453.9	$96.8	-

Savings Plans: We sponsor savings plans which allow employees to contribute a portion of their pre-tax and or after-tax income in accordance with plan-specified guidelines. Under these plans, we expensed matching contributions of $9.3 million, $9.5 million and $9.1 million during 2006, 2005 and 2004, respectively.

Severance Plans: In 2004, we incurred $22.3 million ($13.4 million after-tax) of severance costs. The majority of the severance costs related to an enhanced severance package offered to selected management employees of Wisconsin Energy and its subsidiaries who voluntarily resigned in the fourth quarter of 2004. The program was enacted to help reduce the upward pressure on operating expenses.

Approximately 150 employees received severance benefits during 2004. At December 31, 2004, we accrued $6.6 million for severance benefits. As of December 31, 2006, all of the severance related benefits were paid.

M -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties. As of December 31, 2006, we had the following guarantees:

	Maximum Potential Future Payments	Outstanding at Dec 31, 2006	Liability Recorded at Dec 31, 2006
		(Millions of Dollars)	
Guarantees	$235.2	$0.1	$ -

We guarantee the potential retrospective premiums that could be assessed under our nuclear insurance program (See Note F).

Postemployment benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability, excluding severance benefits, for such benefits was $9.0 million as of December 31, 2006.

N -- COMMON EQUITY

Share-Based Compensation Plans: Employees of Wisconsin Electric participate in a plan approved by Wisconsin Energy stockholders that provides a long-term incentive through equity interests in Wisconsin Energy, to outside directors, selected officers and key employees of Wisconsin Energy and its subsidiaries. The plan provides for the granting of Wisconsin Energy stock options, stock appreciation rights, restricted stock awards and performance shares. Awards may be paid in Wisconsin Energy common stock, cash or a combination thereof.

The following is a summary of Wisconsin Energy stock options held by our employees and issued through December 31, 2006:

	2006		2005		2004	
Stock Options	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price
Outstanding at January 1	5,985,653	$28.99	5,656,042	$27.16	5,669,386	$23.96
Granted	1,169,907	$39.51	1,136,150	$34.25	1,653,065	$33.44
Exercised	(856,942)	$25.03	(801,026)	$23.43	(1,614,022)	$22.33
Forfeited	(26,931)	$36.79	(5,513)	$32.27	(52,387)	$28.15
Outstanding at December 31	6,271,687	$31.46	5,985,653	$28.99	5,656,042	$27.16
Exercisable at December 31	3,996,938	$28.38	4,834,833	$27.78	5,439,877	$27.30

The following table summarizes information about Wisconsin Energy stock options held by our employees and outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable		
		Weighted Average			Weighted Average	
Range of Exercise Prices	Number	Exercise Price	Remaining Contractual Life (years)	Number	Exercise Price	Remaining Contractual Life (years)
$11.58 to $23.05	860,770	$21.54	4.4	860,770	$21.54	4.4
$25.31 to $31.07	1,561,819	$27.02	5.6	1,556,869	$27.02	5.6
$33.44 to $42.56	3,849,098	$35.48	7.9	1,579,299	$33.46	7.0
	6,271,687	$31.46	6.9	3,996,938	$28.38	5.9

Aggregate Intrinsic Value (Millions)	Options Outstanding	Options Exercisable
December 31, 2006	$100.3	$76.3

In January 2007, the Compensation Committee awarded 1,247,760 non-qualified Wisconsin Energy stock options at the average market price of $47.76 to our officers and key employees under its normal schedule of awarding long-term incentive compensation.

We utilize the straight-line attribution method for recognizing stock-based compensation expense under SFAS 123R. We recorded compensation expense, net of tax, for stock option awards made to our officers and other key employees of $4.1 million for the twelve months ended December 31, 2006.

The aggregate intrinsic value of stock options exercised during the twelve months ended December 31, 2006 was approximately $16.0 million. Tax benefits associated with our stock option awards for the twelve months ended December 31, 2006 were $6.4 million.

The exercise price of a Wisconsin Energy stock option under the plan is to be no less than 100% of the common stock's fair market value on the grant date and options may not be exercised within six months of the grant date except in the event of a change in control. In December 2004, the Compensation Committee approved the acceleration of vesting of all unvested options awarded to our officers and other key employees in 2002, 2003 and 2004. In addition, the Compensation Committee determined that future option grants would be non-qualified stock options and they would vest on a cliff-basis after a three year period. The stock options that were granted prior to 2005 generally vest on a straight line basis over a four year period. Generally, options expire no later than ten years from the date of grant. For further information regarding the accounting changes related to stock based compensation, see Note A and Note B.

On December 31, 2005, the value of our non-vested Wisconsin Energy stock options outstanding was $9.6 million, or $8.32 per share on a weighted average grant date fair value basis. On December 31, 2006, the value of our Wisconsin Energy non-vested stock options outstanding was $18.0 million or $7.93 per share on a weighted average grant date fair value basis. During the year, 19,047 stock options vested and 26,931 stock options were forfeited on a weighted average grant date fair value of $7.71 and $7.94, respectively.

As of December 31, 2006, total compensation costs related to non-vested stock options not yet recognized was approximately $8.0 million, which is expected to be recognized over the next 19 months on a weighted-average basis.

The Compensation Committee has also approved Wisconsin Energy restricted stock grants to certain of our key employees and directors. The following restricted stock activity related to our employees occurred during 2006, 2005 and 2004:

	2006		2005		2004	
Restricted Shares	Number of Shares	Weighted-Average Market Price	Number of Shares	Weighted-Average Market Price	Number of Shares	Weighted-Average Market Price
Outstanding at January 1	150,772		180,614		243,017	
Granted	2,500	$40.35	-	$ -	-	$ -
Released / Forfeited	(21,327)	$26.91	(29,842)	$28.77	(62,403)	$24.25
Outstanding at December 31	131,945		150,772		180,614	

Recipients of the Wisconsin Energy restricted shares, who have the right to vote the shares and to receive dividends, are not required to provide consideration to us other than rendering service. Forfeiture provisions on the restricted stock generally expire 10 years after award grant subject to an accelerated expiration schedule for some of the shares based on the achievement of certain financial performance goals.

We record the market value of the restricted stock awards on the date of grant and then we charge their value to expense over the vesting period of the awards. We also adjust expense for acceleration of vesting due to achievement of performance goals. We recorded compensation expense, net of tax, for restricted stock awards made to our employees and directors of $0.2 million for the twelve months ended December 31, 2006. Tax benefits realized for our restricted stock awards were $0.3 million for the twelve months ended December 31, 2006. As of December 31, 2006, total compensation cost related to non-vested restricted stock awards not yet recognized was approximately $1.6 million, which is expected to be recognized over the next 62 months on a weighted-average basis.

In January 2004, the Compensation Committee granted 139,793 Wisconsin Energy performance shares to our officers and other key employees. In January 2007, 2006 and 2005, the Compensation Committee granted 124,160, 134,818 and 90,739 Wisconsin Energy performance units to our officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units which will be awarded is dependent upon the achievement of certain financial performance of Wisconsin Energy's common stock over a three year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance award. We are accruing compensation costs over the three year period based on an estimate of the final expected value of the award. In July 2006, the Compensation Committee amended the terms of the performance shares to allow the recipients of 2004 grants to receive cash or common stock upon settlement. The 2005, 2006 and 2007 grants will be settled in cash. We recorded compensation expense, net of tax, for performance awards made to our employees of $3.6 million for the twelve months ended December 31, 2006. We have not realized any tax benefits associated with our performance awards during the twelve months ended December 31, 2006. As of December 31, 2006, total compensation cost related to non-vested performance awards not yet recognized was approximately $5.5 million, which is expected to be recognized over the next 21 months on a weighted-average basis. Our portion of the consolidated final value of the 2004 performance share award was approximately $6.5 million, which was paid to our officers and key employees in January 2007.

Equity Contribution: Our capitalization reflects the impact of an equity contribution from Wisconsin Energy. An equity contribution of $100.0 million was made during the second quarter of 2006.

Restrictions: Our January 2006 rate order from the PSCW requires us to maintain a capital structure (i.e., the percentage by which each of common stock, preferred stock and debt constitute the total capital invested in the utility), which has a common equity ratio range of between 48.5% and 53.5% (including certain off-balance sheet obligations and capitalized leases, but excluding the PWGS 1 capitalized lease). As of December 31, 2006, our restricted net assets were approximately $2.2 billion. Previously in a June 2004 decision, the PSCW determined that we must obtain specific approval to pay dividends that exceed normal levels as long as any tax issue or appeals related to the sale of Wisconsin Energy's manufacturing business and/or the conversion of Wisconsin Gas to a limited liability company remain outstanding. The PSCW may modify such provisions by a future order.

We may not pay common dividends to Wisconsin Energy under our Restated Articles of Incorporation if any dividends on our outstanding preferred stock have not been paid. In addition, pursuant to the terms of our 3.60% Serial Preferred Stock, our ability to declare common dividends would be limited to 75% or 50% of net income during a twelve month period if our common stock equity to total capitalization, as defined, is less than 25% and 20%, respectively.

See Note H for discussion of certain financial covenants related to our bank back-up credit agreements.

We do not believe that these restrictions will materially affect our operations or limit any normal dividend payments in the foreseeable future.

O -- SEGMENT REPORTING

We are a wholly-owned subsidiary of Wisconsin Energy and have organized our operating segments according to how we are currently regulated. Our reportable operating segments include electric, natural gas and steam utility segments. The accounting policies of the reportable operating segments are the same as those described in Note A.

Our electric utility engages in the generation, distribution and sale of electric energy in southeastern (including metropolitan Milwaukee), east central and northern Wisconsin and in the Upper Peninsula of Michigan. Our natural gas utility is engaged in the purchase, distribution and sale of natural gas to retail customers and the transportation of customer-owned natural gas in three service areas in southeastern, east central and northern Wisconsin. Our steam utility produces, distributes and sells steam to space heating and processing customers in the Milwaukee, Wisconsin area.

Summarized financial information concerning our reportable operating segments for each of the years ended December 31, 2006, 2005 and 2004, is shown in the following table.

	Reporting Operating Segments				
Year Ended	Electric	Gas	Steam	Other (a)	Total
	(Millions of Dollars)				
December 31, 2006					
Operating Revenues (b)	$2,499.5	$590.0	$27.2	$ -	$3,116.7
Depreciation, Decommissioning and Amortization	$234.8	$32.4	$3.7	$ -	$270.9
Operating Income (c)	$407.2	$47.7	$1.0	$ -	$455.9
Equity in Earnings of Transmission Affiliate	$33.9	$ -	$ -	$ -	$33.9
Capital Expenditures	$362.4	$33.6	$2.6	$0.1	$398.7
Total Assets (d)	$7,416.6	$666.2	$59.2	$115.8	$8,257.8
December 31, 2005					
Operating Revenues (b)	$2,320.9	$593.6	$23.5	$ -	$2,938.0
Depreciation, Decommissioning and Amortization	$242.7	$35.8	$3.3	$ -	$281.8
Operating Income (Loss) (c)	$437.5	$41.5	($1.7)	$ -	$477.3
Equity in Earnings of Transmission Affiliate	$30.4	$ -	$ -	$ -	$30.4
Capital Expenditures	$374.2	$28.4	$4.6	$2.0	$409.2
Total Assets (d)	$7,020.2	$709.0	$58.9	$121.1	$7,909.2

Year Ended	Reporting Operating Segments				
	Electric	Gas	Steam	Other (a)	Total
	(Millions of Dollars)				
December 31, 2004					
Operating Revenues (b)	$2,070.8	$523.8	$22.0	$ -	$2,616.6
Depreciation, Decommissioning and Amortization	$234.9	$36.1	$3.1	$ -	$274.1
Operating Income (Loss) (c)	$427.2	$33.1	($1.1)	$ -	$459.2
Equity in Earnings of Transmission Affiliate	$26.4	$ -	$ -	$ -	$26.4
Capital Expenditures	$313.7	$33.2	$6.7	$5.3	$358.9
Total Assets (d)	$6,153.0	$667.1	$54.0	$176.2	$7,050.3

(a) Other includes primarily non-utility property and investments, materials and supplies, deferred charges and other corporate items.

(b) We account for intersegment revenues at a tariff rate established by the PSCW. Intersegment revenues are not material.

(c) We evaluate operating income to manage our utility business. Equity in Earnings of Transmission Affiliate, Interest Expense and Income Taxes are not included in segment operating income.

(d) Common utility plant is allocated to electric, gas and steam utility operations to determine segment assets (see Note A).

P -- RELATED PARTIES

We provide to and receive from certain of our Wisconsin Energy affiliates managerial, financial, accounting, legal, data processing and other services in accordance with service agreements approved by the PSCW. In addition, we make lease payments to We Power for PWGS 1 and the other generating facilities being constructed under Wisconsin Energy's PTF strategy, and we sell electric energy to an affiliated utility, Edison Sault. We also receive and/or provide certain services to other associated companies in which we have, or Wisconsin Energy has, an equity investment.

ATC: As of December 31, 2006, we have a 25.8% interest in ATC. We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance and project management work for ATC, which are reimbursed to us by ATC. Under Wisconsin Energy's PTF plan, we are required to pay the cost of needed transmission infrastructure upgrades. ATC will reimburse us for these costs when the units are placed into service. At December 31, 2006 and 2005, we had a receivable of $27.2 million and $19.4 million, respectively, for these items.

NMC: At December 31, 2006, NMC, which operates Point Beach, was owned by Wisconsin Energy's affiliate, WEC Nuclear Corporation, and the affiliates of two other unaffiliated investor-owned utilities in the region. We pay NMC a plant operating charge. In December 2006, we announced our intention to sell Point Beach to an affiliate of FPL. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us), the operating licenses for Point Beach will transfer from NMC to the buyer and our relationship with NMC will be terminated.

Guardian: In April 2006, Wisconsin Energy sold its one third ownership interest in Guardian. As such, the tables below reflect activity through April 2006 with respect to Guardian. Wisconsin Gas has committed to purchase 650,000 Dth per day of capacity under the terms of a 10 year transportation agreement expiring December 2022. Under a PSCW-approved agreement, we have purchased some of this capacity from Wisconsin Gas when they have excess, and we expect to continue to do so.

We provided and received services from the following associated companies during 2006, 2005 and 2004:

Company	2006	2005	2004
	(Millions of Dollars)		
Wisconsin Electric Affiliate			
Net Services Provided			
-We Power (excluding lease payments)	$3.2	$3.8	$3.3
-Wisconsin Gas	$44.4	$48.8	$50.4
-Edison Sault (including electric energy sold)	$22.6	$21.5	$15.6
-Minergy	$3.6	$8.1	$7.3
-Other	$1.5	$1.5	$1.9
Net Services Received			
-We Power (lease payments)	$135.3	$79.8	$59.0
-Wisconsin Energy	$9.1	$6.6	$2.9
Equity Investee			
Services Provided			
-ATC	$15.8	$20.0	$20.7
Services Received			
-ATC	$145.7	$126.8	$112.5
-NMC	$65.2	$61.2	$58.1
-Guardian	$3.9	$12.0	$11.4

At December 31, 2006 and 2005, our consolidated balance sheets included receivable and payable balances with the following equity investee companies:

Company	2006	2005
	(Millions of Dollars)	
Equity Investee		
Accounts Receivable		
-ATC	$1.2	$1.2
Accounts Payable		
-ATC	$12.1	$10.3
-NMC	$5.7	$2.5
-Guardian	$ -	$1.0

Q -- COMMITMENTS AND CONTINGENCIES

Capital Expenditures: We have made certain commitments in connection with 2007 capital expenditures. During 2007, we estimate that total capital expenditures will be approximately $600 million, excluding the purchase of nuclear fuel.

Operating Leases: We enter into long-term purchase power contracts to meet a portion of our anticipated increase in future electric energy supply needs. These contracts expire at various times through 2013. Certain of these contracts were deemed to qualify as operating leases. In addition, we have various other operating leases, including leases for vehicles and coal cars.

Future minimum payments for the next five years and thereafter for our operating lease contracts are as follows:

	(Millions of Dollars)
2007	$51.6
2008	35.7
2009	22.5
2010	20.5
2011	20.7
Thereafter	32.9
Total	$183.9

Environmental Matters: We periodically review our exposure for environmental remediation costs as evidence becomes available indicating that our liability has changed. Given current information, including the following, we believe that future costs in excess of the amounts accrued and/or disclosed on all presently known and quantifiable environmental contingencies will not be material to our financial position or results of operations.

We have a program of comprehensive environmental remediation planning for former manufactured gas plant sites and coal-ash disposal sites. We perform ongoing assessments of our manufactured gas plant sites and related disposal sites, as well as coal ash disposal/landfill sites. We are working with the WDNR in our investigation and remediation planning. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

Manufactured Gas Plant Sites: We have identified several sites at which we or a predecessor company historically owned or operated a manufactured gas plant. We have substantially completed planned remediation activities at some of those sites and certain other sites are subject to ongoing monitoring. Remediation at additional sites is currently being performed, and other sites are being investigated or monitored. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon ongoing analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from $13 to $30 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of December 31, 2006, we have established reserves of $15.5 million related to future remediation costs.

The PSCW has allowed Wisconsin utilities, including us, to defer the costs spent on the remediation of manufactured gas plant sites, and has allowed for these costs to be recovered in rates over five years. Accordingly, we have recorded a regulatory asset for remediation costs.

Ash Landfill Sites: We aggressively seek environmentally acceptable, beneficial uses for our coal combustion by-products. However, these coal-ash by-products have been, and to a small degree, continue to be disposed in company-owned, licensed landfills. Some early designed and constructed landfills may allow the release of low levels of constituents resulting in the need for various levels of monitoring or adjusting. Where we have become aware of these conditions, efforts have been expended to define the nature and extent of any release, and work has been performed to address these conditions. The costs of these efforts are recovered under our fuel clause and are expensed as incurred. During 2006, 2005 and 2004, we incurred $0.5 million, $0.1 million and $1.8 million, respectively, in coal-ash remediation expenses. As of December 31, 2006 we have no reserves established related to ash landfill sites.

EPA - Proposed Consent Decree: In April 2003, we and the EPA announced that a consent decree had been reached that resolved all issues related to a request for information that had been issued by the EPA. Under the consent decree, we agreed to significantly reduce our air emissions from our coal-fired generating facilities. The reductions are expected to be achieved by 2013 through a combination of installing new pollution control equipment, upgrading existing equipment and retiring certain older units. Through December 31, 2006, we have spent approximately $355.0 million associated with implementing the EPA agreement and the ultimate capital cost of implementing this agreement is estimated to be $1 billion through the year 2013.

The consent decree, amended to include the State of Michigan, has been filed with a federal court for approval. Various intervenor groups have commented on the consent decree and we believe that the briefings and subsequent discovery is complete. At this time, we are unable to predict the timing or the ultimate resolution of the federal court's consideration; however, we do not believe that the ultimate resolution of this matter will have a material impact on our financial position or results of operations.

Deloitte.

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Milwaukee, WI 53202-3824
USA

Tel: 414-271-3000
Fax: 414-347-6200
www.deloitte.com

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Electric Power Company:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Wisconsin Electric Power Company and subsidiary (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, common equity and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Wisconsin Electric Power Company and subsidiary at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

February 22, 2007

Member of
Deloitte Touche Tohmatsu

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Dividends declared on our common stock during the two most recent fiscal years are set forth below. Dividends were paid entirely in cash. Dividends were paid to our sole common stockholder, Wisconsin Energy Corporation. There is no established public trading market for our common stock.

Quarter	2006	2005
	(Millions of Dollars)	
First	$44.9	$44.9
Second	44.9	44.9
Third	-	44.9
Fourth	89.8	44.9
Total	$179.6	$179.6

Subject to any regulatory restriction or other limitations on the payment of dividends, future dividends will be at the discretion of the board of directors and will depend upon, among other factors, earnings, financial condition and other requirements.

Various financing arrangements and regulatory requirements impose certain restrictions on our ability to transfer funds to Wisconsin Energy in the form of cash dividends, loans or advances. Under Wisconsin law, we are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. For additional information regarding restrictions on our ability to pay dividends, see Note N -- Common Equity in the Notes to Consolidated Financial Statements.

BUSINESS OF THE COMPANY

We are an electric, gas and steam utility which was incorporated in the State of Wisconsin in 1896. Our operations are conducted in the following three segments.

Electric Operations: We are the largest electric utility in the State of Wisconsin. We generate and distribute electric energy to approximately 1,102,200 customers in southeastern (including the metropolitan Milwaukee area), east central and northern Wisconsin and in the Upper Peninsula of Michigan.

Gas Operations: We purchase, distribute and sell natural gas to retail customers; we also transport customer-owned gas. We have approximately 452,600 customers in three distinct service areas: west and south of the City of Milwaukee, the Appleton area and areas within Iron and Vilas Counties, Wisconsin. We began doing business with Wisconsin Gas, an affiliated gas utility, under the trade name "We Energies" in April 2002.

Steam Operations: We generate, distribute and sell steam supplied by our Valley and Milwaukee County Power Plants. Steam is used by approximately 460 customers in the metropolitan Milwaukee area for processing, space heating, domestic hot water and humidification.

For additional financial information about our operating segments, see "Note O -- Segment Reporting" in the Notes to Consolidated Financial Statements.

DIRECTORS AND EXECUTIVE OFFICERS

DIRECTORS

The information under "Information About Nominees for Election to the Board of Directors for Terms Expiring in 2008" in Wisconsin Electric Power Company's definitive Information Statement dated March 29, 2007, attached hereto, is incorporated herein by reference.

EXECUTIVE OFFICERS

Gale E. Klappa – Chairman of the Board, President and Chief Executive Officer

James C. Fleming – Executive Vice President and General Counsel

Frederick D. Kuester – Executive Vice President and Chief Operating Officer

Allen L. Leverett – Executive Vice President and Chief Financial Officer

Larry Salustro[1] – Executive Vice President

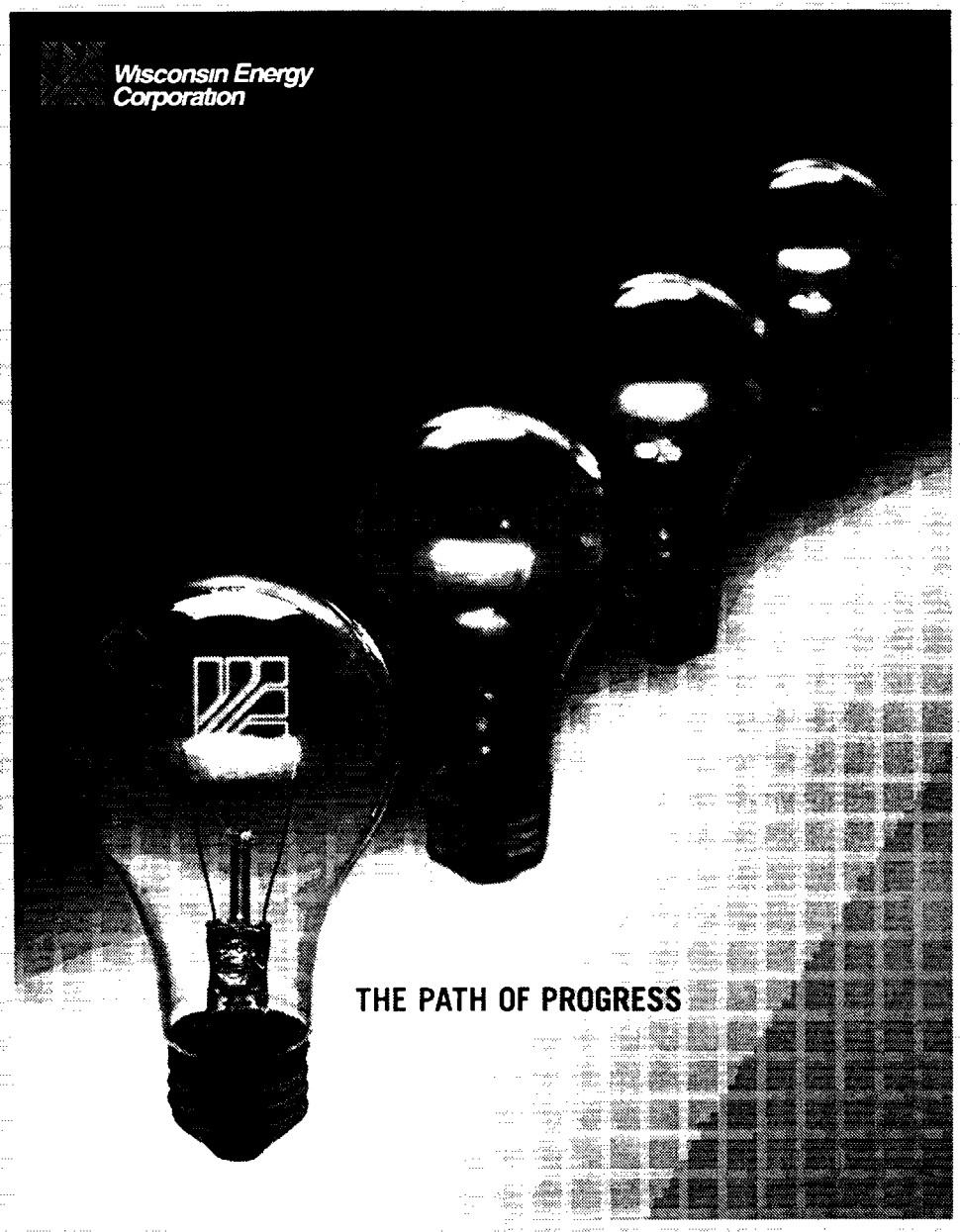
Charles R. Cole – Senior Vice President

Kristine A. Rappé – Senior Vice President and Chief Administrative Officer

Stephen P. Dickson – Vice President and Controller

[1] Mr. Salustro retired from Wisconsin Electric Power Company effective February 28, 2007.

Wisconsin Energy Corporation



THE PATH OF PROGRESS

2006 Annual Report • Notice of 2007 Annual Meeting and Proxy Statement

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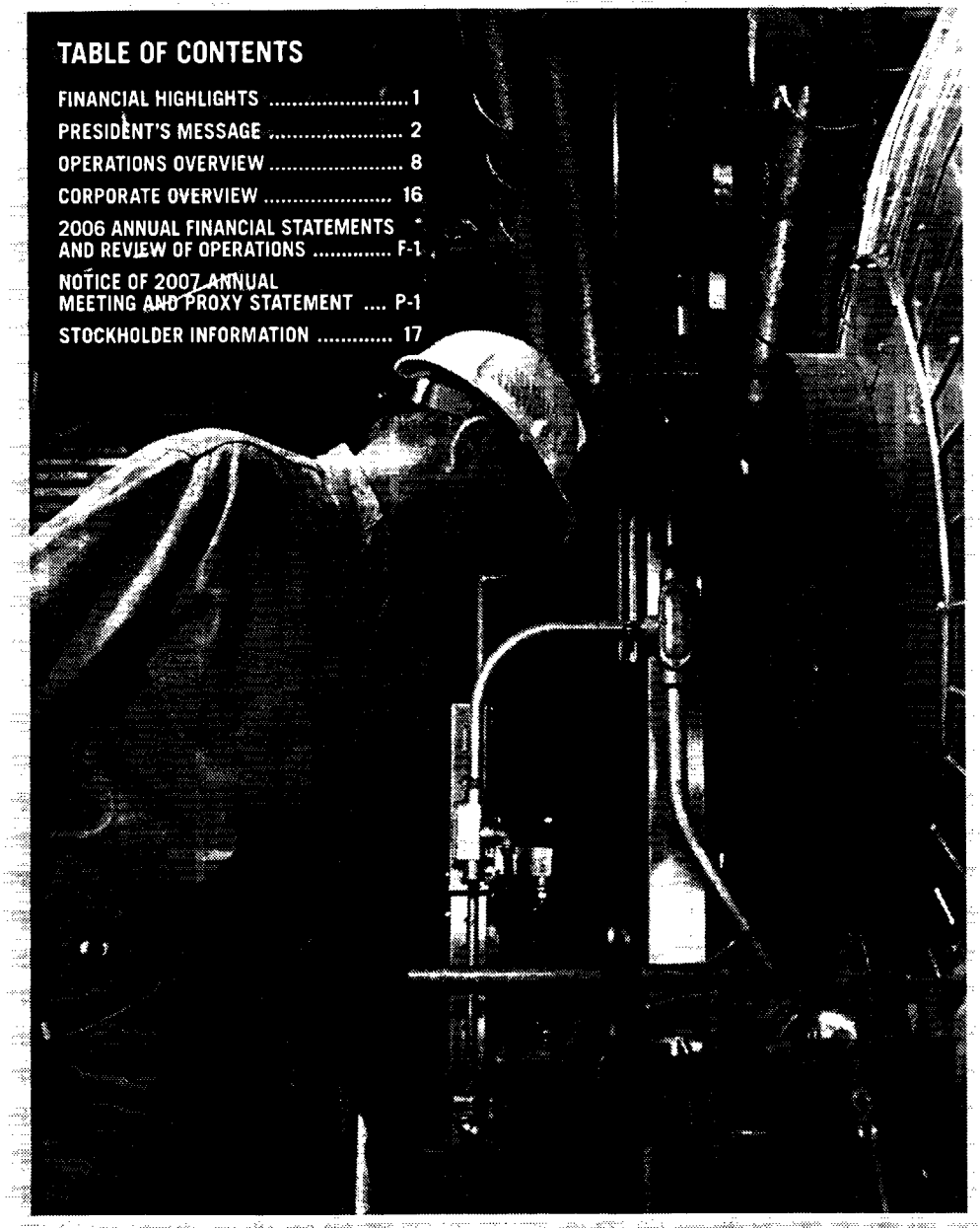
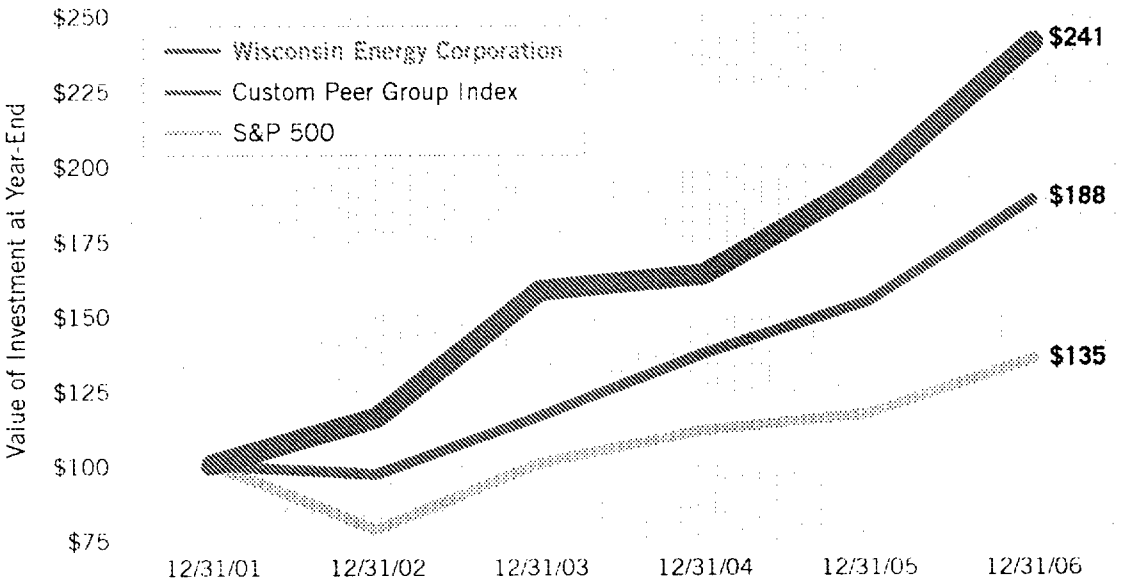


FIVE-YEAR PERFORMANCE CHART

If you had invested $100 in Wisconsin Energy stock on the last trading day of 2001 and reinvested the dividends, your $100 investment would have grown to $241 by the end of 2006. That exceeds by a significant amount what you would have earned by investing $100 in the S&P 500 or in our peer group of U.S. utilities.

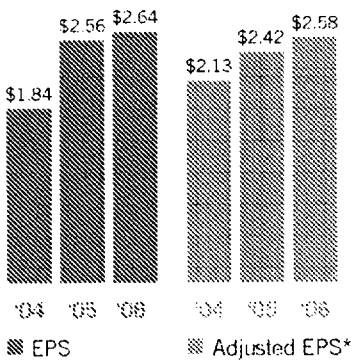
WISCONSIN ENERGY CORPORATION FIVE-YEAR PERFORMANCE CHART
Annual Cumulative Returns with $100 Invested at 12/31/01*



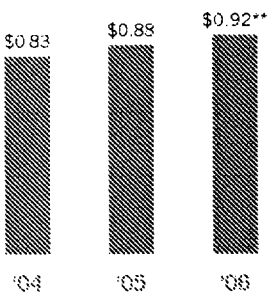
* Includes reinvested dividends.

For additional information on this performance chart, please refer to page F-87 of this Annual Report.

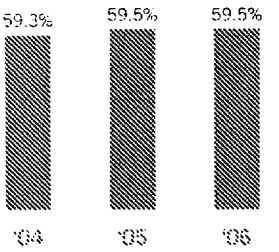
EARNINGS PER SHARE – CONTINUING OPERATIONS
(in dollars)



DIVIDENDS PER SHARE
(in dollars)

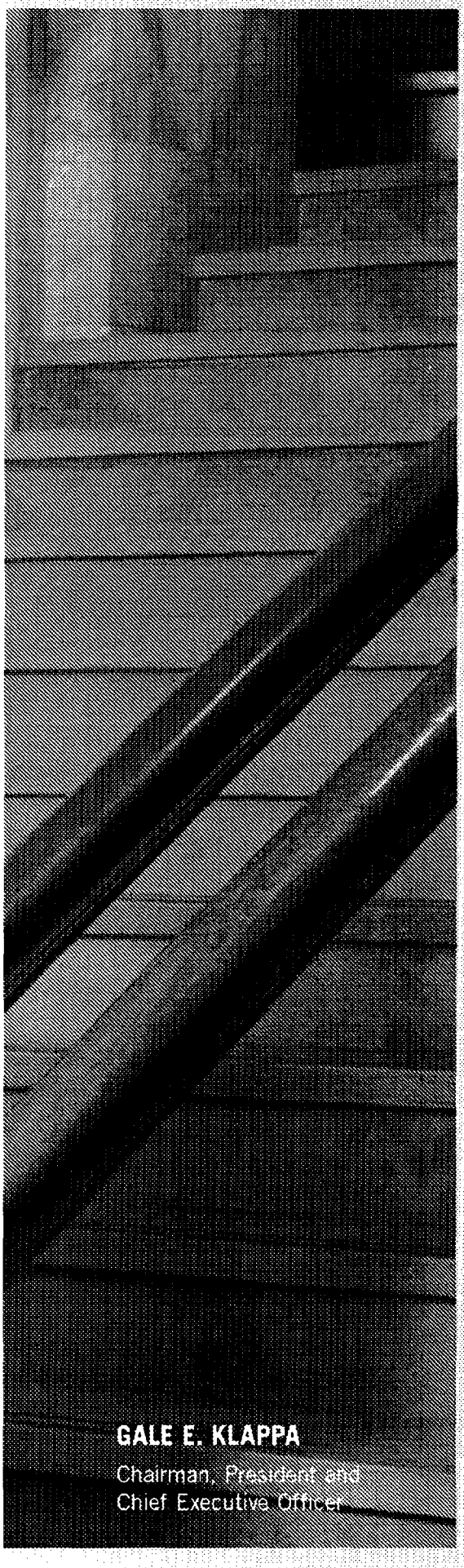


DEBT TO TOTAL CAPITAL
(in percent)



* Excludes nonoperating items totaling 6 cents per share in 2006, 14 cents per share in 2005 and (29 cents) per share in 2004. For additional information on our adjusted earnings per share, please refer to page F-88 of this Annual Report.

** The quarterly dividend rate was increased from 23 cents per share to 25 cents per share in the first quarter of 2007.



GALE E. KLAPPA
Chairman, President and
Chief Executive Officer

TO OUR STOCKHOLDERS,

To paraphrase the lyrics from an old Frank Sinatra song...
2006 was a very good year.

In fact, on nearly every meaningful measure—from customer satisfaction to earnings and cash flow, from operational performance to progress on our construction plan—this was the best year in the 110-year history of the company.

RECORD FINANCIAL RESULTS

Earnings from continuing operations rose to a record $312 million or $2.64 a share in 2006. Excluding gains and nonoperating items, adjusted earnings for the year were $2.58 per share. This is an increase of 6.6 percent as compared with earnings on the same basis in 2005.

ON NEARLY EVERY MEANINGFUL MEASURE THIS WAS THE BEST YEAR IN THE 110-YEAR HISTORY OF THE COMPANY.

Key factors driving this increase included a full year of operation of our new Port Washington Generating Station, stronger margins in our natural gas distribution business and full recovery of our fuel costs.

I'm also pleased to report that the financial markets responded positively to our progress and to the prospects of our long-term business plan. Wisconsin Energy stock hit 34 new all-time closing highs during the year. We ended 2006 at $47.46 a share—up 21.5 percent from year-end 2005. And our stock outperformed virtually every relevant market index including the Dow Jones Industrial Average, the S&P 500, the Russell 2000, the S&P Electric Index and the Philadelphia Utility Index.

As the performance chart shows on page one, our total shareholder return over the past five years has also been strong—materially outpacing the S&P 500 and our peer group of 30 utilities across the United States.

Our ratio of debt to total capital in the business remained essentially unchanged at 59.5 percent as we closed 2006. This is a significant

accomplishment in light of the fact that we invested nearly $930 million during the year to improve the energy infrastructure in Wisconsin and Michigan's Upper Peninsula.

As we turned the page on the new year, our board of directors voted to raise the dividend on our common stock to a new quarterly rate of 25 cents a share—an increase of 8.7 percent. This marks the fourth consecutive year that we've raised our dividend.

A FOCUS ON CUSTOMER SATISFACTION

The long-term success of our franchise rests in our ability to satisfy customers with reliable service and responsive care. And I'm pleased to report that we continued to make significant progress last year in raising the level of customer satisfaction with our company and with the manner in which every customer transaction was handled.

THE MARKETS RESPONDED POSITIVELY TO OUR PROGRESS AND TO THE PROSPECTS OF OUR LONG-TERM BUSINESS PLAN. THE STOCK CLOSED THE YEAR AT $47.46 A SHARE—UP 21.5 PERCENT FROM YEAR-END 2005.

Independent surveys show an increase of nearly 8 percentage points in the number of customers who were 'very satisfied' during the fourth quarter of 2006 compared with the fourth quarter of 2005.

One way that we work to ensure customer satisfaction is our We Care Call program. More than 500 employees from across the company make We Care calls—following up with customers after there's been an outage at their home or business to determine that the service restoration was completed to the customer's satisfaction. We Care calls are also made each day to customers who've received other types of service from the company, such as forestry work or meter changes.

In all, we made more than 365,000 We Care calls during 2006. And we were honored by Chartwell, a research organization that studies best practices in the utility industry, as the winner of the 2006 national award for customer service.

OPERATIONAL EXCELLENCE

Of course, our We Care calls would be of little value if we didn't have a reliable network and a fleet of power plants that runs well. Last year, for the fourth time in the past

five years, we were named the most reliable utility in the Midwest by an independent firm that analyzes outage data from utilities across the United States.

In addition, we set production records at two of our largest power plants. Unit 1 at Pleasant Prairie, one of our major workhorse plants, set a new site record with 517 days of continuous operation—by far the longest run in the plant's 20-plus-year history. And our Point Beach Nuclear Plant produced more energy during 2006 than during any other calendar year in its more than 30-year history.

GROWING DEMAND FOR ENERGY

As temperatures neared the 100-degree mark on the last day of July, our customers set another all-time demand record for electricity. At 6,505 megawatts, the new peak demand was approximately 5 percent higher than the previous record set in the summer of 2003—underscoring the decision to build additional power plant capacity in Wisconsin.

In our natural gas business, more records were set in February 2007 as arctic air gripped the region. We delivered more natural gas to our customers on February 4 and again on February 5 than during any other 24-hour periods in our history. The new delivery record is 6.8 percent above the previous one-day mark set in 2004.

BUILDING FOR THE FUTURE

As many of you know, we're engaged in the largest construction program in our company's history—as we work to improve and expand the energy infrastructure of the region. The plan, which was approved by the Public Service Commission of Wisconsin, calls for the completion of four major new generating units between the years 2005 and 2010—with a total investment of nearly $2.6 billion.

The first new unit at our Port Washington site was placed into service in July of 2005—on time and on budget. With 545 megawatts of capacity, this new gas-fired unit certainly helped us keep the power flowing during the days of high demand last summer.

Construction of the second unit at Port Washington is moving along very well. At year end, the project was about 30 percent complete—tracking on schedule and on budget.

WE CONTINUED TO MAKE SIGNIFICANT PROGRESS IN RAISING THE LEVEL OF CUSTOMER SATISFACTION WITH OUR COMPANY.

At our Oak Creek site, south of Milwaukee, we're building two new coal-fired units. Activity at the site began on June 29, 2005, following a favorable ruling by the Wisconsin Supreme Court. Since that time, we've moved forward with engineering, procurement, site excavation, foundations, structural steel, air quality control equipment, the coal handling facilities and the cooling water tunnel.

At the end of 2006, the project stood at almost 25 percent complete. And we continue to be very satisfied with the progress at the site.

We have received all the permits needed to build the facilities at Oak Creek. One of these permits, which will allow us to operate the water intake and discharge system, is being challenged by an environmental group.

On March 5, the parties received a decision from the Circuit Court in Dane County. The judge reaffirmed—in several important respects—the decision by the state

Department of Natural Resources (DNR) to issue our water permit.

However, the judge remanded certain elements of the permit for further review and asked that they be made to "...comport with all aspects of Riverkeeper II." Riverkeeper II is a case involving the federal Environmental Protection Agency that could affect power plants nationwide.

We will work with the DNR on this additional review of the permit. And in the meantime, construction continues at Oak Creek.

Our plan remains to have the first unit at Oak Creek in service in the summer of 2009. The second unit is scheduled to follow—one year later—in 2010.

WE'LL RECEIVE THE HIGHEST PRICE EVER PAID PER UNIT OF NUCLEAR CAPACITY IN THE UNITED STATES AND PRESERVE THE BENEFITS OF POINT BEACH FOR OUR CUSTOMERS FOR YEARS TO COME.

AN EXPANDED ROLE FOR WIND POWER

I'm also pleased to report that we recently received Public Service Commission approval to build the largest wind farm in Wisconsin. We call it our Blue Sky Green Field wind project, and we expect construction to begin this year. The wind farm will have a generating capacity of up to 200 megawatts. This is a key step in helping us meet the requirements of a new Wisconsin law that calls for nearly 5 percent of our retail electricity sales to come from renewable sources by the year 2010.

SELLING POINT BEACH

Throughout the past year, we also conducted a formal review of our options for the ownership and operation of our Point Beach Nuclear Plant. Point Beach is one of our most valuable assets. It has served our customers well for more than three decades and has years of productive capacity ahead.

We initiated this review in light of changing circumstances across the nuclear power industry. Companies that operate fleets of nuclear power plants clearly have a cost and talent advantage compared to companies that operate at only a single site.

After a thorough analysis and an extensive market test, we announced in December an agreement to sell Point Beach to FPL Energy, a subsidiary of FPL Group in Florida. FPL will purchase the plant, equipment and inventories for $998 million, subject to normal adjustments at closing. We've also agreed to purchase all the energy produced at Point Beach for the remaining life of the units—at a price comparable to our projected cost of power had we continued to own and operate the plant.

I believe this is a very positive transaction for the company. Not only will we receive the highest price ever paid per unit of nuclear capacity in the United States, but we've also been able to preserve the benefits of the plant for our customers for years to come.

We hope to receive all federal and state approvals and close this transaction by the end of August 2007.

SUPPORTING WISCONSIN'S ECONOMIC GROWTH

In last year's report, I mentioned that a number of business and government leaders were working together to craft an economic development initiative for southeastern Wisconsin. In part, this effort was designed to give our region some of the fundamental tools needed to attract and support economic growth.

One of those tools was launched in late November—a ChooseMilwaukee.com web site and a high-tech resource center that will give any business or industrial firm instant information on site availability, demographics, job training, taxes—all the fundamental data a company might need to decide whether it wants to expand or locate here.

I'm pleased that the Wisconsin Energy headquarters building was chosen as the home for the new resource center. This is just one more way we're helping to grow the economy, expand the opportunity for jobs and sustain the quality of life that we enjoy in this region.

A LOOK TO THE FUTURE

The path of progress was marked with achievement in 2006. Our business plan is sound. Our prospects are bright. And, we'll continue to focus on growing the value of this enterprise for our customers and stockholders.

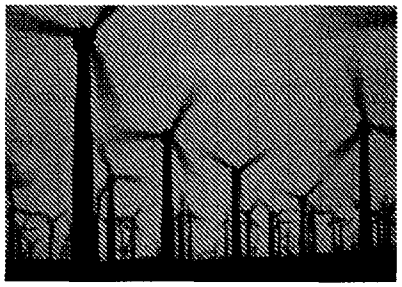
Our management team truly appreciates your confidence and support.

Sincerely,

Gale E. Klappa
Chairman, President and Chief Executive Officer
March 14, 2007

Generation and construction worked side-by-side in Port Washington in 2006. The initial Port Washington generating unit, placed in service in July 2005, logged its first full year of operation. At the same time, construction continued on the second 545-megawatt unit, which is expected to reach commercial operation in May 2008.

BLUE SKY GREEN FIELD WILL HAVE A GENERATING CAPACITY OF 130 TO 200 MEGAWATTS.



Work on the second unit at the Port Washington Generating Station transitioned from the demolition phase to the construction phase in March 2006. By year's end, construction on the second unit was about 30 percent complete. Engineering was essentially finished, most concrete foundation work had been completed and the erection of structural steel was proceeding on schedule.

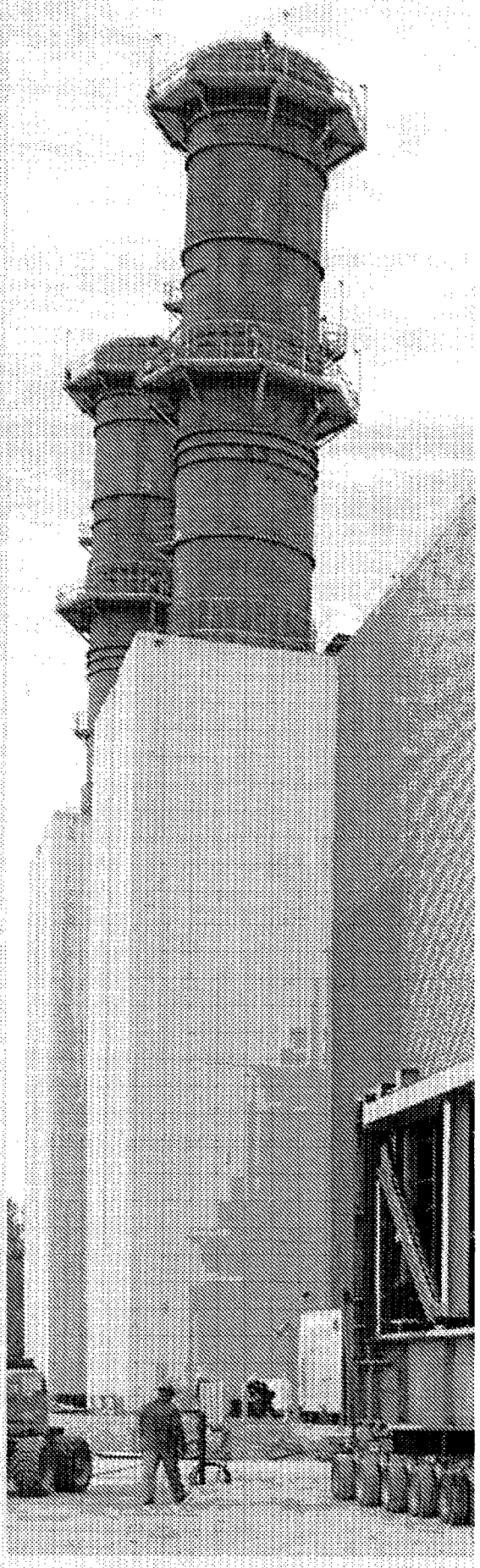
The heat recovery steam generator modules for the second unit were delivered in September and have been set in place. The gas and steam turbines also were delivered in September. Construction work to tie the new construction into the existing water intake and discharge tunnels was completed in the fall.

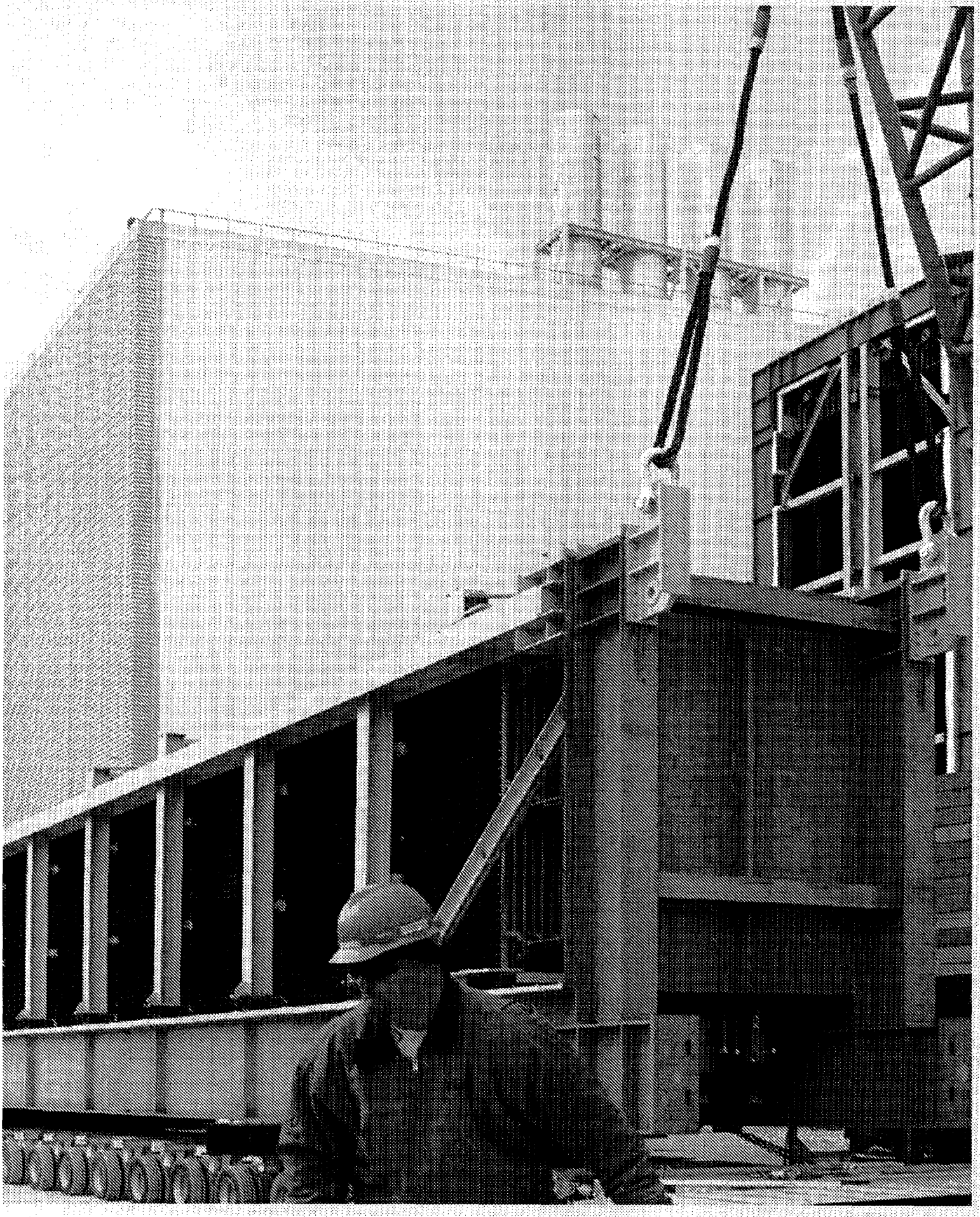
When complete, the Port Washington Generating Station will supply approximately 1,100 megawatts of electricity.

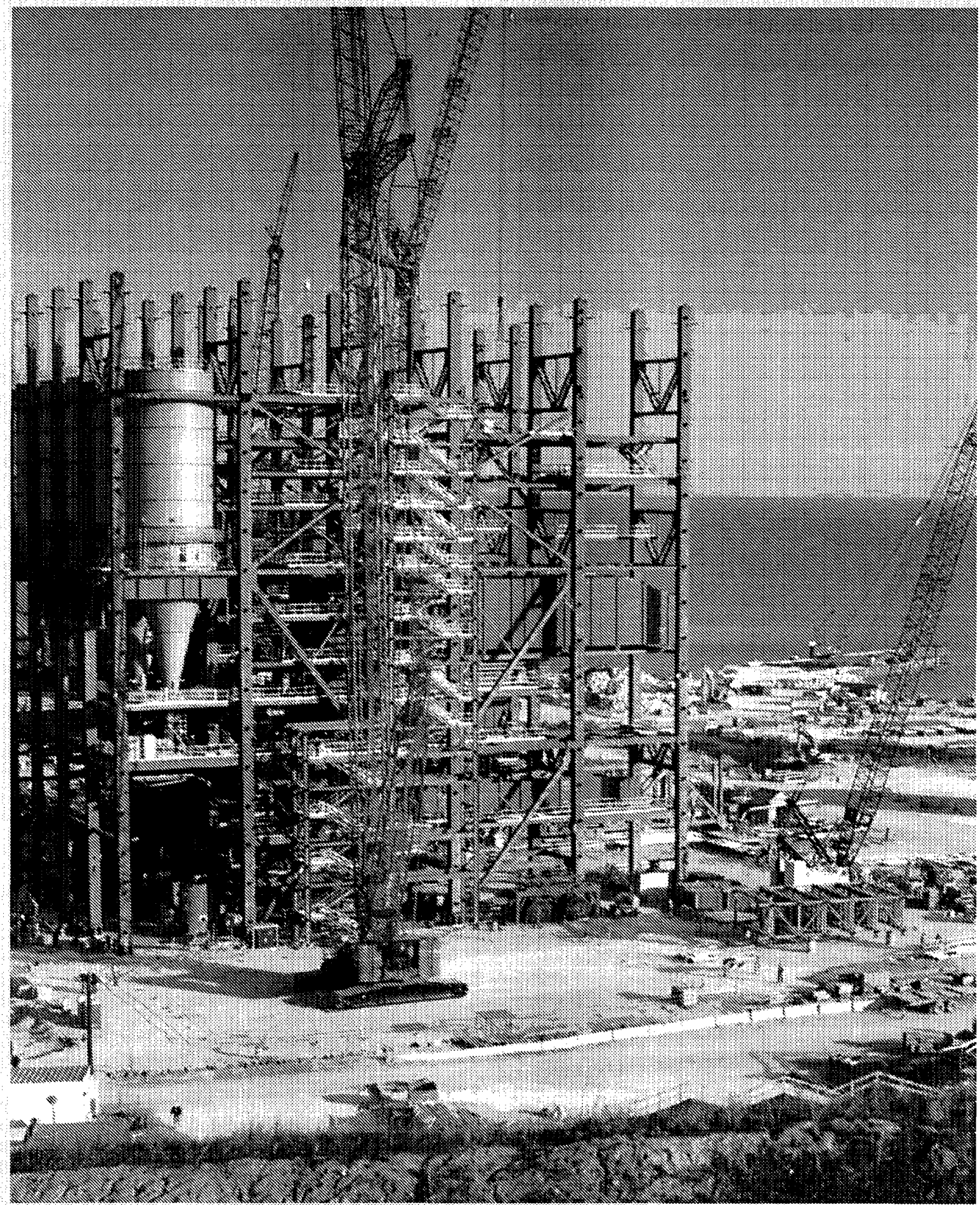
BLUE SKY GREEN FIELD WIND PROJECT

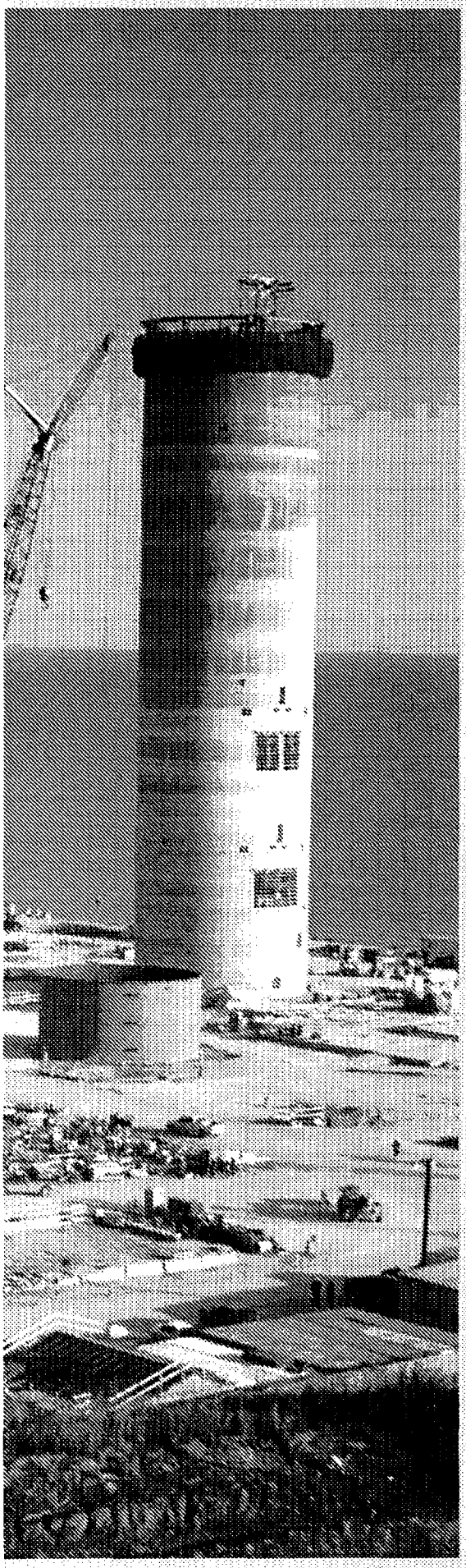
On February 1, 2007, the Public Service Commission of Wisconsin issued an order approving construction of our Blue Sky Green Field wind project in Fond du Lac County.

When complete, there will be up to 88 wind turbines on the 10,600-acre site with a total generating capacity of 130 to 200 megawatts—depending on the size of the turbines. We're evaluating turbines ranging in capacity from 1.5 to 2.3 megawatts. Construction of the Blue Sky Green Field wind project is expected to begin late this year and is scheduled to be in service by the end of 2008 at an anticipated cost of $300 million to $400 million.



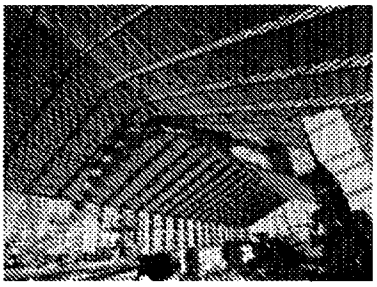






Progress was steady and according to plan in 2006 at our Oak Creek expansion project.

We finished moving approximately 6 million cubic yards of material to create the platform for the plant's main power block. The boiler foundations for Unit 1 were completed and we began erecting structural steel for the unit. In all, more than 28,000 tons of structural steel will be needed to complete the project.



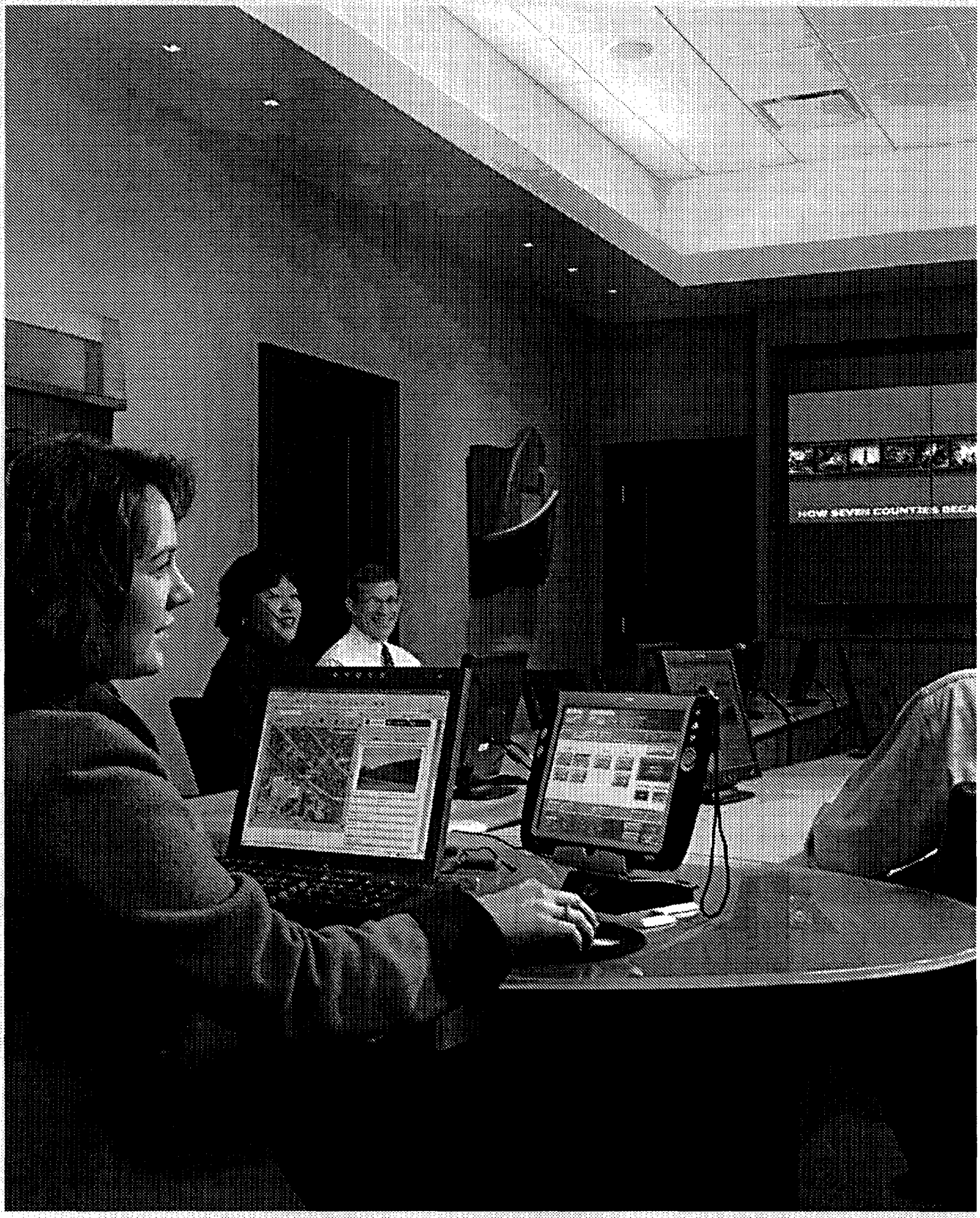
PROGRESS WAS STEADY AND ACCORDING TO PLAN AT OUR OAK CREEK EXPANSION PROJECT.

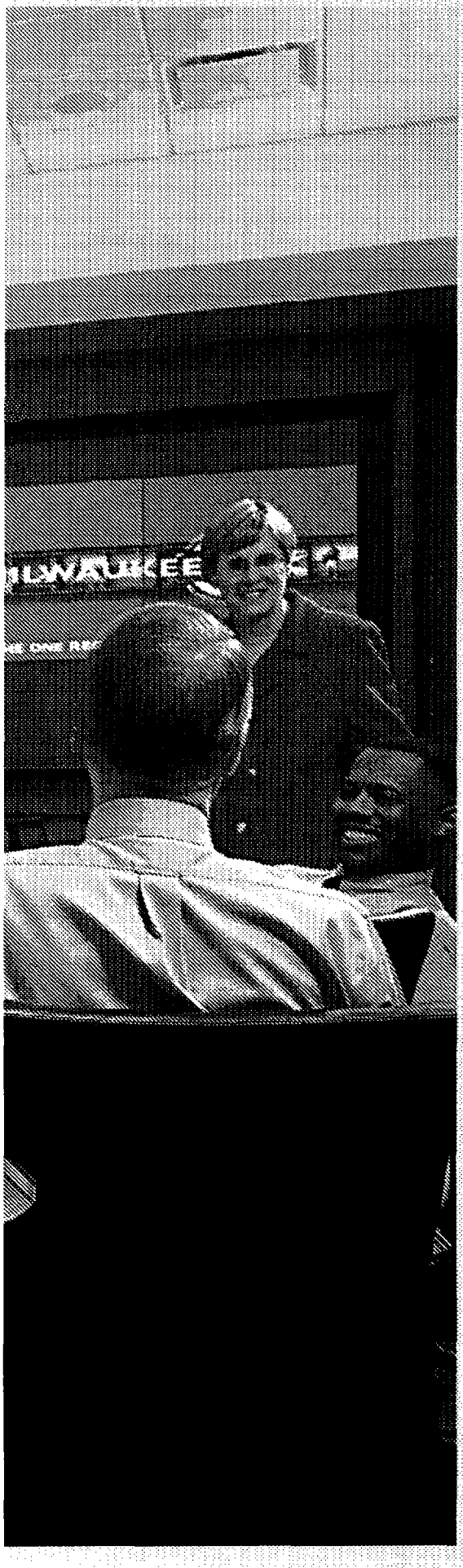
We've also been installing the boiler air ducts, coal silos and coal piping in the main power block. Foundations for the Unit 2 boiler and the turbine/generator pedestal were well along by year's end, and the main underground cooling water system is finished. The chimney shell is complete, and we've laid the foundations for the air quality control equipment we expect to install in 2007.

Construction of the water intake system also is progressing well. Drilling for the water intake tunnel—which is 9,226 feet long—started in September 2006 and was completed in February 2007. All four downshafts in the lake have been drilled and sleeved with 12-foot steel casings. We've installed manifolds on two of the shafts and the remaining two manifolds are expected to be completed in the first quarter of 2007.

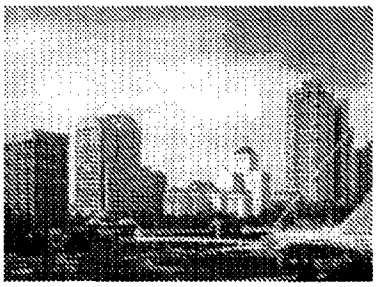
Major upgrades to the existing rail infrastructure and coal handling system also are on schedule. We expect these facilities to be ready in the summer of 2007—as planned—to support coal supply to the existing units at the site.

At year-end 2006, engineering for the Oak Creek expansion was more than 80 percent complete. Procurement of engineered equipment and supplies was 96 percent complete. Overall, at the end of December, the project was approximately 25 percent complete.





The economic growth of southeastern Wisconsin is vital to Wisconsin Energy's future. A healthy economy encourages business investment, creates jobs and helps attract and retain a talented, diverse work force.



THE MILWAUKEE 7 RESOURCE CENTER PROVIDES EASY ACCESS TO REGIONAL INFORMATION.

Wisconsin Energy has been a leader in a key economic development initiative called the Milwaukee 7. Formed in 2005 to create a regional economic development platform for seven counties in southeastern Wisconsin, the Milwaukee 7's mission is to attract, retain and grow world class businesses and talent.

During 2006, the Milwaukee 7 developed several essential tools needed to accomplish its mission—including a web site, a business call program and a resource center located inside Wisconsin Energy's headquarters in downtown Milwaukee.

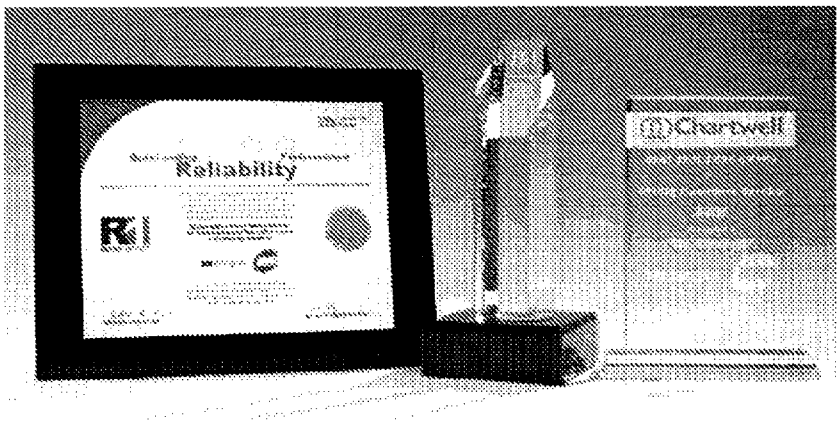
MILWAUKEE 7 RESOURCE CENTER

The Milwaukee 7 Resource Center provides interested parties with armchair access to an array of information about prospective site locations, work force demographics and the region's cultural and leisure assets. Key features of the Resource Center include:

- An interactive database with real-time information that can be customized to a user's specific search criteria.
- Dozens of video clips highlighting the quality of life in the Milwaukee 7 region.
- State-of-the-art audio and video conferencing.
- Wireless Internet connectivity.

Opened in November 2006, the Milwaukee 7 Resource Center already is enhancing the region's ability to attract and retain business in southeastern Wisconsin.

Exceptional customer service goes hand in hand with customer satisfaction. We Energies employees devote a lot of energy to deliver consistently high levels of customer care—and their efforts are generating results. Not only did we achieve the highest levels of customer satisfaction in company history in 2006, but we also were honored with two prestigious awards.



For the fourth time in five years, We Energies was named the most reliable utility in the Midwest by PA Consulting Group, the energy industry's largest management consulting firm. Based on a review of 2005 data on outage performance for utilities across the country, We Energies was rated the best in the Midwest for keeping the lights on.

We Energies also received the 2006 National Best Practices Award for its We Care Call program from Chartwell, Inc., an information services and best practices research organization for the utility industry.

Approximately 600,000 We Care calls have been made since the program was started in 2004 as an initiative to improve customer satisfaction. Every customer who reports an outage to our Customer Contact Center receives a We Care call. And if an outage lasts more than two hours, every customer gets a follow-up call. We Care calls have had such a positive impact on customer satisfaction that we've expanded the program to include follow-up calls regarding contact center inquiries, field appointments, gas emergencies, new service installations and forestry.

The We Care Call program helps employees focus on customer satisfaction, enhances accountability and empowers employees to take personal responsibility to resolve customer problems or concerns.

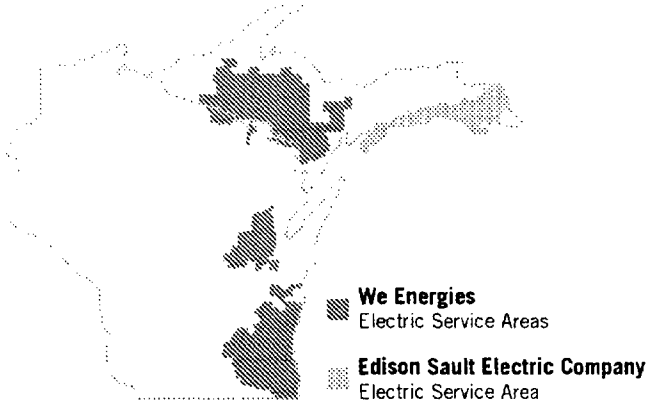
WISCONSIN ENERGY CORPORATION (NYSE:WEC) is one of the nation's premier energy companies with more than $11 billion of assets and a diversified portfolio of businesses engaged in electric generation; electric, natural gas, steam and water distribution; and certain nonutility businesses.

Its principal utilities are We Energies (the trade name for Wisconsin Electric Power Company and Wisconsin Gas LLC) and Edison Sault Electric Company. These companies serve more than 1.1 million electric customers in Wisconsin and Michigan's Upper Peninsula, and more than one million natural gas customers in Wisconsin.

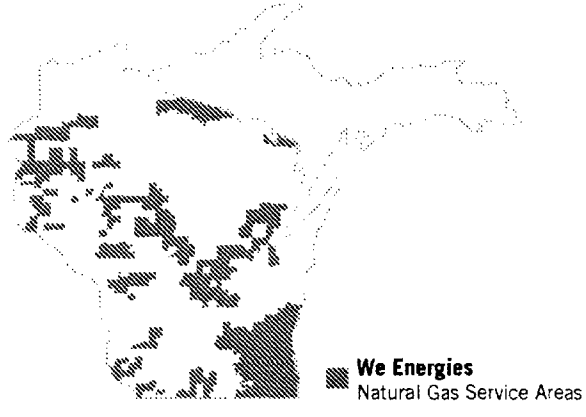
Through its nonutility subsidiaries—W.E. Power, LLC, Wispark LLC, Minergy Corp. and Wisvest Corporation—the company is involved in renewable energy technology and real estate development.

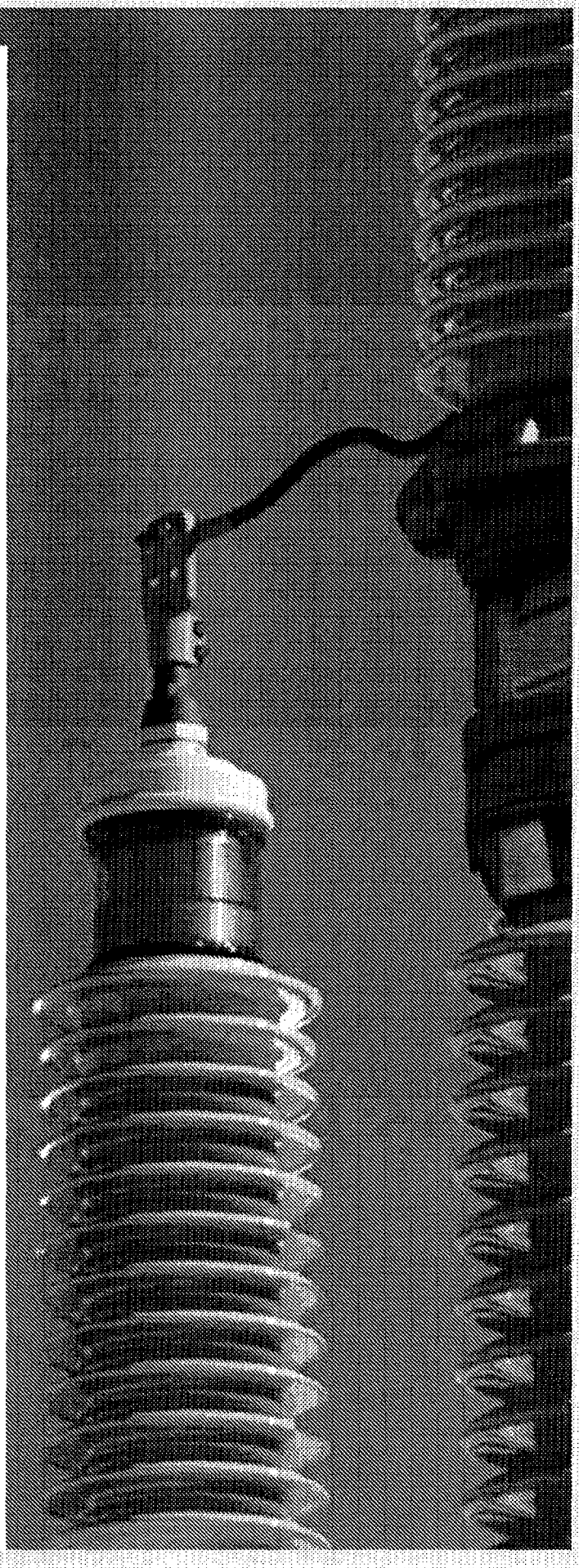
Headquartered in Milwaukee, Wisconsin Energy has more than 5,200 employees and approximately 54,000 stockholders of record.

ELECTRIC CUSTOMERS AS OF DEC. 31, 2006: 1,125,185



NATURAL GAS CUSTOMERS AS OF DEC. 31, 2006: 1,041,364





STOCKHOLDER INFORMATION

ACCOUNT INFORMATION

- Visit www.stockbny.com. Wisconsin Energy's transfer agent, The Bank of New York, provides registered stockholders secure account access. Stockholders can access share balances, market value, tax documents and account statements, request electronic delivery of documents, review answers to frequently asked questions and perform many transactions at www.stockbny.com.
- Write to:

  Wisconsin Energy Corporation
  c/o The Bank of New York
  Church Street Station
  P.O. Box 11258
  New York, NY 10286-1258
- Call The Bank of New York at **800-558-9663**. Service representatives are available from 7 a.m. to 7 p.m. Central time on business days. An automated voice-response system also provides information 24 hours a day, seven days a week.

Securities analysts and institutional investors may contact our Investor Relations Line at 414-221-2592. Stockholders who hold Wisconsin Energy stock in brokerage accounts should contact their brokerage firm.

STOCK PURCHASE PLAN

Wisconsin Energy's Stock Plus Investment Plan provides a convenient way to purchase WEC common stock and reinvest dividends. To review the Prospectus and download an enrollment form, go to www.wisconsinenergy.com and select the Investor Relations tab. You also may contact The Bank of New York at 800-558-9663 to request an enrollment package. This is not an offer to sell, or a solicitation of an offer to buy, any securities. Any stock offering will be made only by Prospectus.

DIVIDENDS

Dividends, as declared by the board of directors, typically are payable on the first day of March, June, September and December. Stockholders may have their dividends deposited directly into their bank accounts. Contact The Bank of New York to request an authorization form. For more information on dividends, see page F-89 of this Annual Report.

INTERNET ACCESS HELPS REDUCE COSTS

To obtain the latest information about Wisconsin Energy Corporation, please access www.wisconsinenergy.com. The site provides access to financial, corporate governance and other information, including Securities and Exchange Commission reports.

DUPLICATE MAILINGS

To combine accounts or to discontinue multiple mailings of the proxy statement and annual report to your address, contact The Bank of New York.

ANNUAL CERTIFICATIONS

Wisconsin Energy has filed the required certifications of its Chief Executive Officer and Chief Financial Officer under Section 302 of the Sarbanes-Oxley Act of 2002 regarding the quality of its public disclosures as Exhibits 31.1 and 31.2 to its Annual Report on Form 10-K for the year ended Dec. 31, 2006. The certification of Wisconsin Energy's Chief Executive Officer regarding compliance with the New York Stock Exchange corporate governance listing standards required by NYSE Rule 303A.12 will be filed with the NYSE following the 2007 Annual Meeting of Stockholders. Last year, we filed this certification with the NYSE on May 24, 2006.

CORPORATE GOVERNANCE

Wisconsin Energy has consistently received a perfect 10—the highest possible score—from GovernanceMetrics International (GMI), a corporate governance research and ratings agency. In 2006, out of more than 3,800 companies worldwide evaluated by GMI, Wisconsin Energy was recognized again with a perfect 10. Historically, Wisconsin Energy has been one of only six companies worldwide, and one of only three U.S. companies, that has consistently received GMI's highest rating.

Wisconsin Energy Corporation

Wisconsin Energy Corporation

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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below.

Wisconsin Energy Subsidiaries and Affiliates

Primary Subsidiaries

Edison Sault	Edison Sault Electric Company
We Power	W.E. Power, LLC
Wisconsin Electric	Wisconsin Electric Power Company
Wisconsin Gas	Wisconsin Gas LLC

Significant Assets

OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
Point Beach	Point Beach Nuclear Plant
PWGS	Port Washington Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2

Other Affiliates

ATC	American Transmission Company LLC
Calumet	Calumet Energy
Guardian	Guardian Pipeline L.L.C.
Minergy	Minergy Corp.
Minergy Neenah	Minergy Neenah, LLC
NMC	Nuclear Management Company, LLC
WECC	Wisconsin Energy Capital Corporation
WICOR	Wicor, Inc.
Wispark	Wispark LLC
Wisvest	Wisvest Corporation

Federal and State Regulatory Agencies

DOA	Wisconsin Department of Administration
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPSC	Michigan Public Service Commission
NRC	United States Nuclear Regulatory Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources

Environmental Terms

Act 141	2005 Wisconsin Act 141
Air Permit	Air Pollution Control Construction Permit
BART	Best Available Retrofit Technology
BTA	Best Technology Available
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CO_2	Carbon Dioxide
CWA	Clean Water Act

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below.

NAAQS	National Ambient Air Quality Standard
NO_x	Nitrogen Oxide
$PM_{2.5}$	Fine Particulate Matter
RI/FS	Remedial Investigation and Feasibility Study
SO_2	Sulfur Dioxide
WPDES	Wisconsin Pollution Discharge Elimination System

Other Terms and Abbreviations

Compensation Committee	Compensation Committee of the Board of Directors
CPCN	Certificate of Public Convenience and Necessity
D&D Fund	Uranium Enrichment Decontamination and Decommissioning Fund
Energy Policy Act	Energy Policy Act of 2005
FPL	FPL Group, Inc.
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
GDP	Gross Domestic Product
LLC	Limited Liability Company
LMP	Locational Marginal Price
LSEs	Load Serving Entities
MAIN	Mid-America Interconnected Network, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Midwest Market	MISO bid-based energy market
Moody's	Moody's Investor Service
NEIL	Nuclear Electric Insurance Limited
PJM	PJM Interconnection, L.L.C.
PTF	*Power the Future*
PUHCA 1935	Public Utility Holding Company Act of 1935, as amended
PUHCA 2005	Public Utility Holding Company Act of 2005
RTO	Regional Transmission Organizations
S&P	Standard & Poors Corporation
Yellowcake	Uranium Concentrate

Measurements

Btu	British thermal unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
kW	Kilowatt(s) (One kW equals one thousand watts)
kWh	Kilowatt-hour(s)
MW	Megawatt(s) (One MW equals one million watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
APB	Accounting Principles Board
ARO	Asset Retirement Obligation
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
NOLs	Net Operating Loss Carryforwards
OPEB	Other Post-Retirement Employee Benefits

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below.

PCAOB	Public Company Accounting Oversight Board
SAB	Staff Accounting Bulletin
SFAS	Statement of Financial Accounting Standards

Accounting Pronouncements

FIN 46	Consolidation of Variable Interest Entities
FIN 46R	Consolidation of Variable Interest Entities (Revised 2003)
FIN 47	Accounting for Conditional Asset Retirement Obligations
FIN 48	Accounting for Uncertainty in Income Taxes
FSP SFAS 106-2	Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003
FSP FIN 46R-6	Determining the Variability to Be Considered in Applying FIN 46R
SAB 108	Process of Quantifying Financial Statement Misstatements
SFAS 34	Capitalization of Interest Cost
SFAS 71	Accounting for the Effects of Certain Types of Regulation
SFAS 87	Employers' Accounting for Pensions
SFAS 88	Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits
SFAS 106	Employers' Accounting for Postretirement Benefits Other Than Pensions
SFAS 109	Accounting for Income Taxes
SFAS 115	Accounting for Certain Investments in Debt and Equity Securities
SFAS 123	Accounting for Stock-Based Compensation
SFAS 123R	Share-Based Payment (Revised 2004)
SFAS 132R	Employers' Disclosures about Pensions and Other Postretirement Benefits (Revised 2003)
SFAS 133	Accounting for Derivative Instruments and Hedging Activities
SFAS 142	Goodwill and Other Intangible Assets
SFAS 143	Accounting for Asset Retirement Obligations
SFAS 144	Accounting for the Impairment or Disposal of Long-Lived Assets
SFAS 148	Accounting for Stock-Based Compensation - Transition and Disclosure
SFAS 149	Amendment of SFAS 133 on Derivative Instruments and Hedging Activities
SFAS 157	Fair Value Measurements
SFAS 158	Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report and other documents or oral presentations are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding completion of construction projects, regulatory matters, fuel costs, sources of electric energy supply, the proposed sale of Point Beach, coal and gas deliveries, remediation costs, environmental and other capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "intends," "may," "objectives," "plans," "possible," "potential," "projects" or similar terms or variations of these terms.

Actual results may differ materially from those set forth in forward-looking statements. In addition to the assumptions and other factors referred to specifically in connection with these statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statements or otherwise affect our future results of operations and financial condition include, among others, the following:

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related or terrorism-related damage; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, nuclear fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; nuclear or environmental incidents; resolution of used nuclear fuel storage and disposal issues; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; inflation rates; or demographic and economic factors affecting utility service territories or operating environment.

- Regulatory factors such as unanticipated changes in rate-setting policies or procedures; unanticipated changes in regulatory accounting policies and practices; industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; recovery of costs of previous investments made under traditional regulation; recovery of costs associated with adoption of changed accounting standards; required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities; required approvals for new construction; changes in the United States Nuclear Regulatory Commission's regulations related to Point Beach Nuclear Plant or a permanent repository for used nuclear fuel; changes in the regulations of the United States Environmental Protection Agency as well as the Wisconsin Department of Natural Resources, the Michigan Department of Natural Resources or the Michigan Department of Environmental Quality, including but not limited to regulations relating to the release of emissions from fossil-fueled power plants such as carbon dioxide, sulfur dioxide, nitrogen oxide, small particulates or mercury, water quality and lead paint; and regulations relating to the intake and discharge of water; the siting approval process for new generation and transmission facilities; recovery of costs associated with implementation of a bid-based energy market; or changes in the regulations from the Wisconsin Department of Natural Resources related to the siting approval process for new pipeline construction.

- The changing electric and gas utility environment as market-based forces replace strict industry regulation and other competitors enter the electric and gas markets resulting in increased wholesale and retail competition.

- Unanticipated operational and/or financial consequences related to implementation of the Midwest Independent Transmission System Operator, Inc. bid-based energy market that started in April 2005.

- Consolidation of the industry as a result of the combination and acquisition of utilities in the Midwest, nationally and globally as a result of the repeal of the Public Utility Holding Company Act of 1935 or otherwise.

- Factors related to the proposed sale of our Point Beach Nuclear Plant including receipt of the necessary approvals by various regulatory agencies, including the United States Nuclear Regulatory Commission, the Public Service Commission of Wisconsin, the Michigan Public Service Commission and the Federal Energy Regulatory Commission, for the transaction; and our ability to retain the assets for the benefit of customers in the non-qualified decommissioning trust.

- Factors which impede execution of our *Power the Future* strategy, including receipt of necessary state and federal regulatory approvals, timely and successful resolution of legal challenges, local opposition to siting of new generating facilities, construction risks, including the adverse interpretation or enforcement of permit conditions by the permitting agencies, and obtaining the investment capital from outside sources necessary to implement the strategy.

- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances.

- Changes in social attitudes regarding the utility and power industries.

- Customer business conditions including demand for their products or services and supply of labor and material used in creating their products and services.

- The cost and other effects of legal and administrative proceedings, settlements, investigations and claims and changes in those matters.

- Factors affecting the availability or cost of capital such as: changes in interest rates and other general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or any of our subsidiaries; or security ratings.

- Federal, state or local legislative factors such as changes in tax laws or rates; changes in trade, monetary and fiscal policies, laws and regulations; electric and gas industry restructuring initiatives; changes in the Price-Anderson Act; changes in environmental laws and regulations; or changes in allocation of energy assistance, including state public benefits funds.

- Implementation of the Energy Policy Act of 2005 and the effect of state level proceedings and the development of regulations by federal and other agencies, including the Federal Energy Regulatory Commission.

- Authoritative generally accepted accounting principle or policy changes from such standard setting bodies as the Financial Accounting Standards Board, the Securities and Exchange Commission and the Public Company Accounting Oversight Board.

- Unanticipated technological developments that result in competitive disadvantages and create the potential for impairment of existing assets.

- Possible risks associated with non-utility operations and investments, such as: general economic conditions; competition; operating risks; dependence upon certain suppliers and customers; the cyclical nature of property values that could affect real estate investments; unanticipated changes in environmental or energy regulations; and risks associated with minority investments, where there is a limited ability to control the development, management or operation of the project.

- Legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law.

- Other business or investment considerations that may be disclosed from time to time in our Securities and Exchange Commission filings or in other publicly disseminated written documents.

We expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

BUSINESS OF THE COMPANY

Wisconsin Energy Corporation was incorporated in the State of Wisconsin in 1981 and became a diversified holding company in 1986. We maintain our principal executive offices in Milwaukee, Wisconsin. We conduct our operations primarily in two operating segments: a utility energy segment and a non-utility energy segment. Our primary subsidiaries are Wisconsin Electric, Wisconsin Gas and We Power.

Utility Energy Segment: Our utility energy segment consists of: Wisconsin Electric, Wisconsin Gas and Edison Sault. We serve approximately 1,125,200 electric customers in Wisconsin and the Upper Peninsula of Michigan. We have approximately 1,041,400 gas customers in Wisconsin, 460 steam customers in metro Milwaukee, Wisconsin, and 3,000 water customers in suburban Milwaukee, Wisconsin. Wisconsin Electric and Wisconsin Gas operate under the trade name of "We Energies".

Non-Utility Energy Segment: Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our PTF strategy. See Management's Discussion and Analysis of Financial Condition and Results of Operations for more information on PTF.

Discontinued Operations: Effective September 27, 2006, we sold 100% of our membership interests in Minergy Neenah. Previously Minergy Neenah operations were included in Corporate and Other. We sold our Calumet facility, which was part of our non-utility energy segment, effective May 31, 2005. Effective July 31, 2004, we sold our manufacturing segment.

PTF Strategy: In September 2000, we announced our PTF strategy to improve the supply and reliability of electricity in Wisconsin. As part of our PTF strategy, we are: (1) investing in new natural gas-fired and coal-fired electric generating facilities, (2) upgrading Wisconsin Electric's existing electric generating facilities and (3) investing in upgrades of our existing energy distribution system. Also, as part of this strategy, we announced and began implementing plans to divest non-core assets and operations in our non-utility energy segment and to reduce our real estate operations. Additional information concerning PTF may be found in Management's Discussion and Analysis of Financial Condition and Results of Operations.

For further financial information about our business segments, see Results of Operations in Management's Discussion and Analysis of Financial Condition and Results of Operations and Note Q -- Segment Reporting in the Notes to Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS

INTRODUCTION

Wisconsin Energy Corporation is a diversified holding company with subsidiaries primarily in a utility energy segment and a non-utility energy segment. Unless qualified by their context, when used in this document the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of our subsidiaries.

Our utility energy segment, consisting of Wisconsin Electric and Wisconsin Gas, both doing business under the trade name of "We Energies", and Edison Sault, is engaged primarily in the business of generating electricity and distributing electricity and natural gas in Wisconsin and the Upper Peninsula of Michigan. Our non-utility energy segment primarily consists of We Power. We Power is principally engaged in the engineering, construction and development of electric power generating facilities for long-term lease to Wisconsin Electric.

CORPORATE STRATEGY

Business Opportunities

We seek to increase stockholder value by leveraging on our core competencies. Our key corporate strategy, announced in September 2000, is PTF. This strategy is designed to address Wisconsin's growing electric supply needs by increasing the electric generating capacity in the state while maintaining a fuel-diverse, reasonably priced electric supply. It is also designed to improve the delivery of energy within our distribution systems to meet increasing customer demands and to support our commitment to improved environmental performance. Our PTF strategy, which is discussed further below, is having and is expected to continue to have a significant impact on our utility and non-utility energy segments. In July 2005, the first of four new electric generating units under our PTF strategy was placed into service. Construction on the remaining three units is underway. Since 2000, we have been selling our non-core assets to direct more attention to the utility business and to finance PTF while reducing our debt leverage.

Proposed Sale of Point Beach: In February 2006, we announced that we were undertaking a formal review regarding our options for the ownership and operation of Point Beach. These options included (1) continued operation by NMC, (2) having a third party other than NMC operate the plant, (3) a return to in-house operations by Wisconsin Electric, (4) sale of the plant and (5) a partial sale of the plant with us retaining a minority interest in the Plant. Under this fifth option, the new majority owner would operate the plant. After a thorough review of the various options, we concluded that a full sale of the plant was in our best interest and in the best interest of our customers.

In December 2006, we announced that Wisconsin Electric had signed a definitive agreement with an affiliate of FPL to sell Point Beach for approximately $998 million, subject to closing price adjustments. Under the terms of the sale, the buyer would assume the obligation to decommission the plant, and we would transfer assets in a qualified trust for decommissioning. We would retain assets in a non-qualified decommissioning trust. Wisconsin Electric also entered into a long-term power purchase agreement to purchase all of the existing capacity and energy of the plant. This long-term power purchase agreement will become effective upon the closing of the sale. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us), NMC would transfer Point Beach's operating licenses to FPL and our relationship with NMC would be terminated. The sale of the plant and the long-term power purchase agreement are subject to review and approval by various regulatory agencies including the NRC, PSCW, MPSC and FERC. We anticipate closing the sale during the third quarter of 2007.

We, along with FPL, have made a request to the IRS for a Private Letter Ruling (PLR) related to the transfer of the qualified decommissioning trust assets. We are requesting permission to withdraw excess funds from the qualified trust without receiving unfavorable tax treatment. If we receive a favorable PLR, we would use the excess funds for the direct benefit of our customers. If we do not receive a favorable PLR, then the purchase price would be adjusted upward by approximately $50 million based on information as of December 31, 2006. We are unable to predict how or even if the IRS may rule on our request for a PLR.

If the sale is approved, we expect to receive after-tax cash proceeds exceeding $1.0 billion from the sale and the liquidation of the decommissioning trust assets. The net sales proceeds are expected to exceed our cost in the nuclear plant, and, absent regulatory treatment, we would expect to record a gain on the sale. However, we have made a filing with PSCW to defer any gain (net of transaction related costs) as a regulatory liability that would be applied to the benefit of our customers in future rate proceedings. As such, we do not expect the sale of the plant, if approved, to have a material impact on our 2007 earnings.

Utility Energy Segment: Our utility energy segment strives to provide reasonably priced energy delivered at high levels of customer service and reliability. We expect our prices to be established by our regulatory bodies under traditional rate based, cost of service methodologies. We continue to gain efficiencies and improve the effectiveness of our service deliveries through the combined support operations of our electric and gas businesses. We work to obtain a reliable, reasonably-priced supply of electricity through plants that we operate and various long-term supply contracts.

Non-Utility Energy Segment: Our primary focus in this segment is to improve the supply of electric generation in Wisconsin. We Power was formed to design, construct, own and lease new generation assets under the PTF strategy.

Power the Future Strategy: In February 2001, we filed a petition with the PSCW that would allow us to begin implementing our 10-year PTF strategy to improve the supply and reliability of electricity in Wisconsin. PTF is intended to meet a growing demand for electricity and ensure a diverse fuel mix while keeping electricity prices reasonable. Under PTF, we plan to add new coal-fired and natural gas-fired generating capacity to the state's power portfolio which would allow us to maintain approximately the same fuel mix as exists today. PWGS 1 and 2 and OC 1 and 2 have a total output of 2,320 MW, of which we expect to own 2,120 MW. As part of our PTF strategy, we plan to (1) invest approximately $2.6 billion in 2,120 MW of new natural gas-fired and coal-fired generating capacity at existing sites; (2) upgrade our existing electric generating facilities; and (3) invest in upgrades of our existing energy distribution system.

Subsequent to our February 2001 filing, the state legislature amended several laws, making changes which were critical to the implementation of PTF. In October 2001, the PSCW issued a declaratory ruling finding, among other things, that it was prudent to proceed with PTF and for us to incur the associated pre-certification expenses. However, individual expenses are subject to review by the PSCW in order to be recovered.

In November 2001, we created We Power to design, construct, own and lease the new generating capacity. Wisconsin Electric will lease each new generating facility from We Power as well as operate and maintain the new plants under 25- to 30-year lease agreements approved by the PSCW. Based upon the structure of the leases, we expect to recover the investments in We Power's new facilities over the initial lease term. At the end of the leases, Wisconsin Electric will have the right to acquire the plants outright at market value or to renew the leases. Wisconsin Electric expects that payments under the plant leases will be recoverable in rates under the provisions of the Wisconsin Leased Generation Law.

Under our PTF strategy, we expect to meet a significant portion of our future generation needs through We Power's construction of the PWGS units and the Oak Creek expansion.

As of December 31, 2006, we:

- Received approval from the PSCW to build two 545 MW natural gas-fired intermediate load units in Port Washington, Wisconsin (PWGS 1 and PWGS 2). PWGS 1 was placed into service in July 2005 and is fully operational. PWGS 1 was completed within the PSCW approved cost parameters.

- Completed site preparation for PWGS 2 in early 2006, and procured all of the major components for PWGS 2. Construction is underway and PWGS 2 is expected to be operational in 2008.

- Received approval from the PSCW to build two 615 MW coal-fired base load units (OC 1 and OC 2) adjacent to the site of our existing Oak Creek Power Plant in Oak Creek, Wisconsin (the Oak Creek expansion), with OC 1 expected to be in service in 2009 and OC 2 in 2010. The CPCN was granted contingent upon our obtaining the necessary environmental permits. We have received all permits necessary to commence construction. In June 2005, construction commenced at the site.

- Completed the planned sale of approximately a 17% ownership interest in the Oak Creek expansion to two co-owners in November 2005.

- Received approval from the PSCW for various leases between We Power and Wisconsin Electric.

We expect to finance the majority of our PTF strategy with internally generated cash and debt financings. We expect our debt to total capital ratio, as measured by the debt rating agencies will not exceed 61.5% through our PTF construction period. We currently do not plan to issue any new common equity as part of our PTF program.

Our primary risks under PTF are construction risks associated with the schedule and costs for both our Oak Creek expansion and PWGS 2; continuing legal challenges to permits obtained and changes in applicable laws or regulations; adverse interpretation or enforcement of permit conditions, laws and regulations by the permitting agencies; the inability to obtain necessary operating permits in a timely manner; obtaining the investment capital from outside sources necessary to implement the strategy; governmental actions; and events in the global economy.

For further information concerning PTF capital requirements, see Liquidity and Capital Resources below. You can find additional information regarding risks associated with the PTF strategy, as well as the regulatory process and specific regulatory approvals, in Factors Affecting Results, Liquidity and Capital Resources below.

Divestiture of Assets

Our PTF strategy led to a decision to divest non-core businesses. These non-core businesses primarily included non-utility generation assets located outside of Wisconsin and a substantial amount of Wispark's real estate portfolio, as well as our manufacturing business. In addition, in 2001 we contributed our transmission assets to ATC and received cash proceeds of $119.8 million and an economic interest in ATC. Since 2000, we have received total proceeds of approximately $2.2 billion from the divestiture of assets as follows:

Proceeds from divestitures:	2000 -2006
(Millions of Dollars)	
Manufacturing	$857.0
Non-Utility Energy	616.8
Real Estate	462.2
Transmission	119.8
Guardian	38.5
Other	77.3
Total	$2,171.6

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income for 2006, 2005 and 2004.

Wisconsin Energy Corporation	2006	2005	2004
	(Millions of Dollars)		
Utility Energy	$532.8	$542.4	$528.6
Non-Utility Energy	43.1	19.5	4.6
Corporate and Other	(7.4)	1.0	(3.2)
Total Operating Income	568.5	562.9	530.0
Equity in Earnings of Transmission Affiliate	38.6	34.6	30.1
Other Income and Deductions, net	53.1	28.7	(14.3)
Interest Expense	172.7	173.4	193.4
Income From Continuing Operations Before Income Taxes	487.5	452.8	352.4
Income Taxes	175.0	149.2	132.8
Income From Continuing Operations	312.5	303.6	219.6
Income From Discontinued Operations, Net of Tax (a)	3.9	5.1	86.8
Net Income	$316.4	$308.7	$306.4
Diluted Earnings Per Share			
Continuing Operation	$2.64	$2.56	$1.84
Discontinued Operations	0.03	0.05	0.73
Total Diluted Earnings Per Share	$2.67	$2.61	$2.57

(a) Income from Discontinued Operations, Net of Tax includes: (1) Minergy Neenah, which we sold effective September 27, 2006, (2) the manufacturing segment, which we sold effective July 31, 2004 and (3) Calumet which we sold effective May 31, 2005. All periods reported in this table reflect these items as discontinued operations.

The following table identifies significant items that are included in our Diluted Earnings per Share from Continuing Operations.

	(Expense) Benefit		
	2006	2005	2004
Reduction of Tax Valuation Allowances	$0.05	$0.14	$ -
Voluntary Severance Program	$ -	$ -	($0.16)
Debt Redemption Costs	$ -	$ -	($0.13)

An analysis of contributions to operating income by segment and a more detailed analysis of results in 2006, 2005, and 2004 follow.

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

2006 vs. 2005: Our utility energy segment contributed $532.8 million of operating income during 2006 compared with $542.4 million of operating income during 2005. During 2006, we experienced mild weather, which reduced electric and gas sales. In addition, operation and maintenance expenses increased due to the timing of scheduled outages and maintenance projects at our coal units. However, these items were largely offset by improved recovery of fuel costs, only one scheduled refueling outage at Point Beach and increased gas margins.

2005 vs. 2004: Our utility energy segment contributed $542.4 million of operating income during 2005 compared with $528.6 million of operating income during 2004. This increase primarily reflects favorable weather during the summer of 2005 and increased gas margins. Also, during 2004 we recorded severance costs under a voluntary severance program. The year to year increase in operating income was partially offset by an increase in our net under-recovered fuel position and higher operation and maintenance expenses during 2005. We had two scheduled refueling outages at our nuclear plant in 2005 in comparison to one scheduled refueling outage in 2004.

The following table summarizes our utility energy segment's operating income during 2006, 2005 and 2004.

Utility Energy Segment	2006	2005	2004
	(Millions of Dollars)		
Operating Revenues			
Electric	$2,529.4	$2,349.7	$2,099.0
Gas	1,419.9	1,417.5	1,252.4
Other	29.7	25.8	24.0
Total Operating Revenues	3,979.0	3,793.0	3,375.4
Fuel and Purchased Power	806.2	780.8	591.7
Cost of Gas Sold	1,018.3	1,047.3	890.9
Gross Margin	2,154.5	1,964.9	1,892.8
Other Operating Expenses			
Other Operation and Maintenance	1,211.1	1,010.4	963.0
Depreciation, Decommissioning and Amortization	314.0	324.1	315.5
Property and Revenue Taxes	96.6	88.0	85.7
Operating Income	$532.8	$542.4	$528.6

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2006 with similar information for 2005 and 2004, including a summary of electric operating revenues and electric sales by customer class.

	Electric Revenues and Gross Margin			Electric MWh Sales		
Electric Utility Operations	2006	2005	2004	2006	2005	2004
	(Millions of Dollars)			(Thousands, Except Degree Days)		
Customer Class						
Residential	$883.2	$827.6	$731.3	8,322.7	8,562.7	8,053.9
Small Commercial/Industrial	814.8	746.1	668.0	9,142.2	9,192.7	8,840.4
Large Commercial/Industrial	647.5	602.4	549.9	11,173.1	11,687.5	11,686.4
Other-Retail/Municipal	97.3	112.6	90.7	2,227.5	2,713.6	2,405.5
Resale-Utilities	51.2	21.3	24.6	1,025.7	313.7	662.2
Other Operating Revenues	35.4	39.7	34.5	-	-	-
Total Electric Operating Revenues	$2,529.4	$2,349.7	$2,099.0	31,891.2	32,470.2	31,648.4
Fuel and Purchased Power						
Fuel	487.9	432.7	334.7			
Purchased Power	309.8	340.3	250.3			
Total Fuel and Purchased Power	797.7	773.0	585.0			
Total Electric Gross Margin	$1,731.7	$1,576.7	$1,514.0			
Weather -- Degree Days (a)						
Heating (6,663 Normal)				6,043	6,628	6,663
Cooling (716 Normal)				723	949	442

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a twenty-year moving average.

Electric Utility Revenues and Sales

2006 vs. 2005: Our electric utility operating revenues increased by $179.7 million, or 7.6%, when compared to 2005. We estimate that revenues in 2006 were $213.3 million higher than 2005 due to pricing increases that we received in January 2006 and during 2005. The most significant pricing increases authorized by the PSCW related to the recovery of higher fuel costs, costs associated with the new plants under our PTF strategy and increased transmission costs.

Our electric utility operating revenues are expected to increase in 2007 primarily due to the impact of a full year of the January 2006 Wisconsin retail pricing increase and the expected implementation of increased wholesale rates, as well as the impacts of our fuel adjustment clause that are tied to our fuel and purchase power costs. During 2006, we reserved approximately $38 million of revenues associated with favorable recoveries of fuel and purchase power. For more information on the pricing increases and the fuel cost adjustment clause, see Utility Rates and Regulatory Matters in Factors Affecting Results, Liquidity and Capital Resources.

Our electric sales volumes decreased by 1.8% in 2006 as compared to 2005 due to mild weather and lower commercial and industrial sales, offset by an increase in sales for resale. Residential sales volumes decreased 2.8% due largely to weather. In 2006, heating degree days decreased approximately 8.8% compared to 2005, and cooling degree days decreased approximately 23.8%. We estimate that the weather had an unfavorable impact on operating revenues of approximately $46.5 million when compared to the prior year. Total sales volumes to commercial/industrial customers decreased 2.7% between the comparative periods. Sales volumes to commercial/industrial customers, excluding our largest customers, two iron ore mines, decreased 1.4%. Sales volumes in the Other Retail/Municipal class decreased approximately 18% compared to the prior year due, in part, to the expiration of a wholesale contract on December 31, 2005. The increase in sales volumes to other utilities is attributed to the availability of PWGS 1 for all of 2006, which provided additional generation capacity. PWGS 1 was not operational until the third quarter of 2005. Under the Wisconsin fuel rules, sales to other utilities reduce fuel costs charged to customers.

2005 vs. 2004: During 2005, our total electric utility operating revenues increased by $250.7 million or 11.9% when compared with 2004 primarily due to favorable weather during the summer of 2005 and pricing increases.

During 2005, we estimate that pricing increases contributed an additional $145.8 million of revenues than in 2004. The most significant impact to rates was a March 2005 interim order received by Wisconsin Electric from the PSCW authorizing an annualized increase in electric rates of approximately $114.9 million due to the increased costs of fuel and purchased power. In November 2005, Wisconsin Electric received the final rate order, which authorized an additional $7.7 million of annual revenues. Additional orders impacting rates in 2005 were the May 2004 and May 2005 orders received by Wisconsin Electric from the PSCW authorizing annualized increases in electric rates of approximately $59.0 million and $59.7 million, respectively, primarily to cover construction costs associated with our PTF strategy.

Total electric sales increased by 2.6% between 2005 and 2004. Residential sales volumes increased 6.3% due to the favorable summer weather in 2005. Total sales volumes to commercial/industrial customers increased 1.7% between comparative periods. Sales volumes to commercial/industrial customers, excluding our largest customers, two iron ore mines, increased 2.3% due to the favorable weather during the summer of 2005. We estimate that weather increased our electric revenues by approximately $68.8 million during 2005 as compared to the prior year. As measured by cooling degree days, 2005 was 114.7% warmer than in 2004.

Sales volumes in the Resale-Utilities class decreased 52.6% primarily due to the reduced availability of base-load capacity for sale at competitive prices as a result of limited fuel supplies and outages. Sales volumes to municipal utilities, the Other Retail/Municipal customer class, increased 12.8% between the periods due to higher off-peak demand from lower margin municipal wholesale power customers.

Electric Fuel and Purchased Power Expenses

2006 vs. 2005: Our fuel and purchased power expenses increased by $24.7 million, or approximately 3.2%, when compared to 2005. Our average cost of fuel and purchased power increased from $23.80 per MWh in 2005 to $25.01 per MWh in 2006. The largest factor for the higher cost per MWh was a 24.2% increase in the per MWh cost of coal-fired generation, which includes coal and related transportation costs, between the comparative periods. This increase was partially offset by increased generation from Point Beach and a decrease in the average costs of purchased power and fuel for our natural gas-fired units.

Our electric fuel and purchased power expenses in 2007 are expected to be impacted by the duration of the scheduled nuclear refueling outage in the first quarter of 2007; the timing and completion of the proposed sale of Point Beach; the price of purchased power; the increased cost of coal and related transportation; and changes in electric sales.

2005 vs. 2004: Gross fuel and purchased power costs for our electric utilities increased by a total of $260.8 million during 2005 when compared with 2004. During 2005, we deferred $72.8 million of fuel and purchased power costs which resulted in a net increase of fuel and purchased power expense of $188.0 million or 32.1% during 2005 when compared to 2004. The increase in fuel and purchased power expense was driven by a 2.6% increase in MWh sales and an increase in our average cost of fuel and purchased power from $18.48 per MWh in 2004 to $23.80 per MWh in 2005, or 28.8% between the comparative periods.

The increase in our average cost of fuel and purchased power was due primarily to (1) the reduced availability of nuclear generation due to scheduled refueling outages, (2) higher natural gas prices that increased the cost of power supplied by natural gas, (3) the impact of the implementation of the MISO Midwest Market in April 2005 and (4) limitations on coal supplies due to transportation shortfalls.

During 2005, we had two scheduled refueling outages at our nuclear plant and in 2004 we had one scheduled refueling outage. As a result, we had approximately 1,145,000 fewer MWh of nuclear generation in 2005. Our average fuel cost for nuclear generation is approximately $5 per MWh, while the average energy cost for purchased power was approximately $55 per MWh. We estimate that the reduction in nuclear generation resulted in approximately $57 million of increased fuel and purchased power costs in 2005 as compared to 2004. During the 2005 outages we replaced both reactor vessel heads resulting in longer outages. This work, along with other planned maintenance, lasted longer than originally expected due to delays. For more information regarding the scheduled refueling outages, see Factors Affecting Results, Liquidity and Capital Resources -- Nuclear Operations.

In 2005, we experienced significant increases in the cost of natural gas used in our own generating assets and in the price of purchased energy which is highly influenced by the price of natural gas. This increase was most significant in the last six months of 2005 due to market related factors including the hurricanes in the Gulf of Mexico. The average combined cost per MWh of purchased energy and natural gas fired units in 2005 was 47.7% higher than in 2004, increasing total cost by approximately $77.2 million.

In April 2005, we began participating in the MISO Midwest Market which fundamentally changed the way we dispatch our generating units and obtain purchased energy. As part of this new market, we are subject to new types of charges which, among other things, recognize the cost of transmission congestion, MWh losses and other costs associated with operating the generating units in an uneconomic fashion to support the MISO Midwest Market service territory. The State of Wisconsin has a constrained transmission system and we believe these constraints result in higher costs for us than in other parts of the MISO Midwest Market service territory. The incremental costs associated with the MISO Midwest Market charges identified above were approximately $28 million in 2005. For more information regarding MISO and the MISO Midwest Market, see Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition -- Electric Transmission and Energy Markets.

Our 2005 operations were also adversely impacted by limitations on deliveries of coal supply due to the failure of our primary rail delivery supplier to deliver contracted quantities of coal to our units. The largest limitation was related to critical rail track maintenance in the Powder River basin. This, in turn, resulted in reduced coal deliveries of the coal which primarily serves our Oak Creek and Pleasant Prairie generating units from June through December 2005. In response to the reduced deliveries, we reduced generating output of these units during off-peak periods when replacement power prices were lower, purchased more expensive replacement power and took measures to purchase and transport higher cost coal in place of contracted supplies when it made economic sense to do so. We estimate that this increased our costs by approximately $52 million in 2005. For additional information on the decreased coal deliveries, see Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks -- Commodity Prices.

Under the State of Wisconsin fuel rules, we are allowed to request recovery in fuel revenues if our projected fuel and purchased power costs exceed bands established by the PSCW. In March 2005, we received a rate order that allowed us to increase our annual revenues by $114.9 million (final order received in November 2005 for an annual increase of $122.6 million) due to increased fuel and purchased power costs. As provided under the Wisconsin rules, we are also allowed to request deferral for the costs associated with adverse events which materially impact fuel and purchased power costs which were not anticipated, or for which costs could not be reasonably estimated at the time of the fuel recovery request for consideration in future rate proceedings. During 2005, we deferred approximately $72.8 million of fuel and purchased power costs due to the extended outage at Point Beach Unit 2, the coal delivery problems and increased costs associated with the MISO Midwest Market. During 2005, we estimate that we under-recovered fuel and purchased power costs by $108.4 million before these deferred items. Adjusted for the allowed deferrals, our net under-recovered fuel and purchased power costs were approximately $35.6 million.

Gas Utility Revenues, Gross Margin and Therm Deliveries

The following table compares our total gas utility operating revenues and gross margin (total gas utility operating revenues less cost of gas sold) during 2006, 2005 and 2004.

Gas Utility Operations	2006	2005	2004
	(Millions of Dollars)		
Operating Revenues	$1,419.9	$1,417.5	$1,252.4
Cost of Gas Sold	1,018.3	1,047.3	890.9
Gross Margin	$401.6	$370.2	$361.5

We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under GCRMs. The following table compares our gas utility gross margin and therm deliveries by customer class during 2006, 2005 and 2004.

	Gross Margin			Therm Deliveries		
Gas Utility Operations	2006	2005	2004	2006	2005	2004
	(Millions of Dollars)			(Millions, Except Degree Days)		
Customer Class						
Residential	$255.0	$240.5	$238.0	727.9	791.0	809.9
Commercial/Industrial	86.0	72.9	71.9	435.9	460.7	464.0
Interruptible	2.0	1.8	1.8	21.3	23.4	24.7
Total Gas Sold	343.0	315.2	311.7	1,185.1	1,275.1	1,298.6
Transported Gas	51.3	48.5	43.8	843.8	893.7	769.5
Other Operating	7.3	6.5	6.0	-	-	-
Total	$401.6	$370.2	$361.5	2,028.9	2,168.8	2,068.1
Weather - Degree Days (a)						
Heating (6,663 Normal)				6,043	6,628	6,663

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a twenty-year moving average.

2006 vs. 2005: Gas utility gross margin increased by $31.4 million or 8.5% between the comparative periods. The increase in gross margin is due, in part, to pricing increases that were granted by the PSCW and implemented in January 2006. The gas pricing increases were primarily granted to recover higher operating costs, including bad debt expenses. We estimate that our gross margin increased between the comparative periods by approximately $53.4 million due to these pricing increases.

The pricing increases were partially offset by a decline in gas sales volumes that was driven by mild winter weather and by lower customer usage. Temperatures (as measured by heating degree days) were approximately 8.8% warmer in 2006 as compared to 2005. The mild winter weather reduced customer demand for heating. We estimate that the weather decreased our gross margin by approximately $21.0 million between the comparative periods. We continue to see a reduction in normalized use of gas per customer which we believe is caused by high natural gas prices and the continued improvements in energy efficient appliances. During 2006, we estimate this reduction in normalized use decreased our gross margin by approximately $4.9 million. The decrease in volume of transport gas sales was due in part to fuel switching during months where gas commodity prices were high during 2006. Residential therm deliveries decreased 8.0% as compared to 2005, due to warmer weather and a decrease in use per customer that was driven in part by high commodity prices.

The gas utility gross margins are expected to increase in 2007 primarily due to the impact of a full year of the January 2006 pricing increases. In addition, 2007 gross margins will be impacted by weather and customer demand. For more information on the pricing increases, see Utility Rates and Regulatory Matters in Factors Affecting Results, Liquidity and Capital Resources below.

2005 vs. 2004: Gas utility gross margin increased by $8.7 million or 2.4% between the comparative periods. This increase reflects $6.5 million of price increases which reflects the full year's impact of a $25.9 million annual rate increase, which became effective in March 2004. Total therm deliveries were 4.9% higher during 2005 primarily due to increased transport gas deliveries of 124.2 million therms. Transport volumes increased between the comparative periods due to a higher amount of electric generation from natural gas within our service territory. A portion of these sales are eliminated in consolidation. Our margins on these transport gas volumes are

significantly lower than our margins for retail gas sales. The price increases and increased transport volumes were offset, in part, by a decrease in residential therm deliveries. Residential therm deliveries decreased 2.3% as compared to 2004, due to slightly warmer weather and a decrease in use per customer that was driven in part by higher commodity prices. As measured by heating degree days, 2005 was less than 1% warmer than 2004.

Other Operation and Maintenance Expenses

2006 vs. 2005: Our other operation and maintenance expenses increased by $200.7 million, or 19.9%, when compared to 2005. As discussed above, we received pricing increases in January 2006 to cover increased costs. The increases in other operation and maintenance expenses that relate to the pricing increases include higher PTF lease costs of $85.4 million, increased transmission expenses of $62.7 million, increased renewable energy and energy efficiency program expenses of $10.6 million and increased bad debt expenses of $13.7 million. Other operation and maintenance expenses increased approximately $34.7 million due to PWGS 1 operating costs and the timing of scheduled outages and maintenance projects at our coal plants. In 2005, we received approximately $10.0 million as a settlement to resolve a vender dispute, reducing other operation and maintenance expense in 2005. These increases were partially offset by decreased nuclear operating and maintenance expense. In 2006, we had only one scheduled nuclear refueling outage as compared to two scheduled refueling outages in 2005, which resulted in approximately a $10.9 million decrease in nuclear operation and maintenance expenses between the comparative periods. In addition, the elimination of seams elimination transmission charges, effective March 31, 2006, resulted in reduced costs of approximately $9.5 million for 2006. For further information on seams elimination charges, see Electric Transmission in Factors Affecting Results, Liquidity and Capital Resources below.

Our utility operation and maintenance expenses are expected to increase in 2007 as a result of increased amortizations related to the impact of the 2006 pricing increases. In addition, operation and maintenance expenses are influenced by wage inflation, employee benefit costs and the length of plant outages.

2005 vs. 2004: Other operation and maintenance expenses increased by $47.4 million or 4.9% during 2005 compared with 2004. The most significant changes in our operation and maintenance expense related to increased lease costs and increased nuclear outage costs. Partially offsetting these increases was a charge in 2004 for severance costs related to the voluntary severance program and lower employee costs in 2005 due to fewer employees.

The largest operations and maintenance increase for the utility energy segment related to $50.0 million of costs that we recognized under lease agreements between We Power and Wisconsin Electric in connection with our PTF strategy.

In addition to the increased lease costs, our nuclear operating and maintenance expense increased approximately $11.0 million due to two scheduled refueling outages in 2005 where we also replaced the reactor vessel heads. In 2004, we had one scheduled refueling outage. This increase was partially offset by a $10.0 million settlement we received to resolve a vendor dispute.

Additionally, in 2004 we recognized $28.2 million of severance related costs due to the voluntary severance program that was implemented in the second half of 2004. In 2005, we had approximately 210 fewer employees, which reduced operation and maintenance costs by $12.9 million.

Benefit costs increased $7.0 million between the comparative periods due to increased pension and medical costs. In October 2005, we announced that we were offering to our retirees a Medicare Advantage program as an option within our existing post-retirement medical and drug plans.

Depreciation, Decommissioning and Amortization Expense

2006 vs. 2005: Depreciation, decommissioning and amortization expenses decreased by $10.1 million or 3.1% when compared to 2005. In January 2006, we implemented new depreciation rates approved by the PSCW which reduced annual depreciation expenses. We estimate that the new rates reduced annual depreciation expense by approximately $17 million, which was offset, in part, by net plant additions in 2006. We expect Depreciation, decommissioning and amortization expenses in 2007 to increase as a result of an overall increase in utility plant assets in service.

2005 vs. 2004: Depreciation, decommissioning and amortization expense increased by $8.6 million in 2005 as compared to 2004. This increase was primarily due to increased depreciable plant balances.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The most significant subsidiary included in this segment is We Power, which constructs and owns power plants associated with our PTF strategy and leases them to Wisconsin Electric. This segment reflects revenues billed under the PWGS 1 lease and the depreciation expense related to PWGS 1.

The following table compares our non-utility energy segment's operating income during 2006, 2005 and 2004.

Non-Utility Energy Segment	2006	2005	2004
	(Millions of Dollars)		
Operating Revenues	$69.1	$40.0	$19.9
Other Operating Expenses			
Other Operation and Maintenance	14.4	14.4	12.9
Depreciation, Decommissioning and Amortization	11.2	5.9	1.4
Property and Revenue Taxes	0.4	0.2	1.0
Operating Income	$43.1	$19.5	$4.6

Note: The PTF lease revenues and lease costs recorded by the non-utility and utility energy segments are eliminated in consolidation.

2006 vs. 2005: Our non-utility energy segment contributed $43.1 million of operating income in 2006 compared to operating income of $19.5 million in 2005. This increase in operating income primarily reflects a full year of operating income from PWGS 1 in 2006, which was placed in service in July 2005. There were no earnings associated with this unit in the first six months of 2005.

Our non-utility energy segment is expected to generate operating income in 2007 that is comparable to 2006 as both years will include 12 months of operations of PWGS 1.

2005 vs. 2004: Our non-utility energy segment had operating income of $19.5 million during 2005 compared with $4.6 million during 2004. The increase in operating income between the comparative periods is primarily due to PWGS 1 commencing service in July 2005. This unit had operating income of $18.9 million during its six months of operation in 2005.

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

2006 vs. 2005: Corporate and other affiliates had an operating loss of $7.4 million in 2006 compared with operating income of $1.0 million in 2005. The operating loss in 2006 is attributable to lower operating earnings at Wispark. In the foreseeable future, we expect to have slight operating losses as we have minimal business operations in this segment.

2005 vs. 2004: Corporate and other affiliates had operating income of $1.0 million in 2005 compared with an operating loss of $3.2 million in 2004. The improved results reflect increased earnings from Wispark.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS, NET

The following table identifies the components of consolidated other income and deductions, net during 2006, 2005 and 2004.

Other Income and Deductions, Net	2006	2005	2004
	(Millions of Dollars)		
Capitalized Carrying Costs	$25.0	$20.4	$12.7
AFUDC - Equity	14.6	9.2	2.8
Gross Receipts Tax Recovery	4.0	2.6	1.5
Gain on Sale of Guardian Investment	2.8	-	-
Debt Redemption Costs	-	-	(22.9)
Other, net	6.7	(3.5)	(8.4)
Total Other Income and Deductions, Net	$53.1	$28.7	($14.3)

2006 vs. 2005: Other income and deductions, net increased by $24.4 million when compared to 2005. The largest increases relate to increased AFUDC - Equity of $5.4 million, capitalized carrying costs of $4.6 million and the pre-tax gain on the sale of our investment in Guardian of $2.8 million. For further information on the sale of Guardian, see Other Matters in Factors Affecting Results, Liquidity and Capital Resources. In 2007, we expect a reduction in AFUDC - Equity as we placed in service the new scrubber at our Pleasant Prairie Power Plant in the fourth quarter of 2006. The scrubber was installed as part of our EPA consent

decree spending. For further information on the consent decree with the EPA, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

2005 vs. 2004: Other income and deductions, net increased by $43.0 million in 2005 compared to 2004. In 2004, we recognized $22.9 million of debt redemption costs associated with the early redemption of approximately $500 million of long-term debt. Similar debt redemption costs were not incurred in 2005. We recognized higher capitalized carrying costs of $7.7 million. The AFUDC - Equity increased $6.4 million in 2005 due to a higher average balance of AFUDC qualifying utility construction projects in 2005.

CONSOLIDATED INTEREST EXPENSE

Interest Expense	2006	2005	2004
	(Millions of Dollars)		
Gross Interest Costs	$212.6	$202.1	$215.5
Less: Capitalized Interest	39.9	28.7	22.1
Interest Expense	$172.7	$173.4	$193.4

2006 vs. 2005: Interest expense decreased by $0.7 million in 2006 when compared with 2005. Our gross interest costs increased by $10.5 million primarily due to increased debt levels; however, our capitalized interest increased by $11.2 million due to higher CWIP balances. In addition, in 2005 we expensed approximately $6.2 million related to the amortization of costs associated with prior debt redemptions. These costs were fully amortized as of July 2005; therefore, there was no similar expense in 2006.

We expect total interest expense in 2007 to increase due to increased debt levels to fund our planned construction activity; however, these increases are mitigated by increases in our capitalized interest. To the extent that we incur debt associated with CWIP, we capitalize the interest costs in accordance with our accounting policies.

2005 vs. 2004: Total interest expense decreased by $20.0 million in 2005 compared with 2004. The decrease in interest expense primarily reflects lower average debt levels in 2005 as compared to 2004. During 2004, we reduced debt levels by $654.2 million primarily with proceeds from the sale of our manufacturing segment. However, due to the increased construction activity our 2005 year end debt balances increased by $291.9 million.

CONSOLIDATED INCOME TAXES

2006 vs. 2005: Our effective tax rate applicable to continuing operations was 35.9% in 2006 compared to 33.0% in 2005. In 2006 and 2005, we reversed $5.8 million and $16.3 million, respectively, of valuation allowance associated with state net operating loss carry forwards as we concluded that it was more likely than not that we would realize these benefits. Excluding these items, our 2006 and 2005 effective tax rate was 37.1% and 36.6%, respectively. For further information see Note H -- Income Taxes in the Notes to Consolidated Financial Statements. We expect our 2007 annual effective tax rate to range between 38% and 39%.

2005 vs. 2004: Our effective tax rate applicable to continuing operations was 33.0% in 2005 compared to 37.7% in 2004. In 2005, we reversed $16.3 million of valuation allowances associated with state net operating loss carry forwards as we concluded that it was more likely than not that we would realize these benefits. Excluding this item, our effective tax rate was 36.6%. For further information see Note H -- Income Taxes in the Notes to Consolidated Financial Statements.

DISCONTINUED OPERATIONS

Our discontinued operations include our Minergy Neenah facility which was sold in September 2006, our Calumet facility which was sold in May 2005 and our manufacturing operations which were sold in July 2004.

The following table identifies the primary components of net income from discontinued operations during 2006, 2005 and 2004.

Discontinued Operations	2006	2005	2004
		(Millions of Dollars)	
Manufacturing	$2.4	$ -	$184.2
Non-Utility and Other	1.5	5.1	(97.4)
Income from Discontinued Operations, Net of Tax	$3.9	$5.1	$86.8

Our 2006 earnings from discontinued operations reflect a loss on the sale of Minergy Neenah, the 2006 operations of the plant and income of approximately $2.4 million related to the favorable resolution of tax liabilities.

Our 2005 earnings from discontinued operations reflect a gain on the sale of the Calumet facility, the favorable resolution of liabilities at Calumet and a downward adjustment to the carrying value of Minergy Neenah.

Our 2004 earnings from discontinued operations reflect an after-tax gain of $152.3 million on the sale of our manufacturing business. Our 2004 earnings from discontinued operations also reflect impairment charges of $79.3 million after-tax related to Calumet and $17.6 million after-tax related to Minergy Neenah.

See Note D -- Asset Sales, Divestitures and Discontinued Operations in the Notes to Consolidated Financial Statements for further information regarding the transactions described above.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2006, 2005 and 2004:

Wisconsin Energy Corporation	2006	2005	2004
		(Millions of Dollars)	
Cash Provided by (Used in)			
Operating Activities	$729.8	$576.9	$599.0
Investing Activities	($939.3)	($697.1)	$242.8
Financing Activities	$173.3	$157.8	($834.3)

Operating Activities

Cash provided by operating activities for 2006 totaled $729.8 million, which is a $152.9 million improvement over 2005. There were two primary areas that drove this improvement in operating cash flows. During 2006, we estimate that our collections of fuel costs improved by nearly $95 million as we had favorable collections in 2006 and unfavorable recoveries and fuel cost deferrals in 2005. The other primary area related to the working capital requirements related to gas in storage. During 2006, we entered into certain contracts that reduced our need to inject gas in storage. In addition, lower gas commodity prices, offset by less withdrawals due to weather, have lowered working capital requirements between the comparative periods. We estimate that these items reduced our cash needs for gas in storage by approximately $77.0 million. Partially offsetting these items was an increase of cash taxes of approximately $107 million due to higher taxable earnings.

Cash provided by operating activities decreased to $576.9 million during 2005 compared with $599.0 million during 2004. This decline reflected increased working capital needs for our utility business and an increase in deferred costs, offset in part by lower cash taxes and increased cash earnings. During 2005, we experienced significant increases in natural gas costs which increased our working capital requirements for natural gas in storage. The increased natural gas costs also led to an increase in accounts receivable as the cost of gas is recovered dollar for dollar in our natural gas revenues. During 2005, we also experienced increased deferred costs related to transmission costs and deferred fuel. During 2005, our cash taxes were lower than 2004 due to the ability to realize tax benefits on the sale of non-utility assets and accelerated tax depreciation on PWGS 1.

Investing Activities

During 2006, net cash outflows from investing activities were $939.3 million compared with net cash outflows of $697.1 million in 2005. This increase is primarily associated with the increased capital expenditures as construction progresses on our new generating plants. During 2006, we had significant capital expenditures related to the Oak Creek expansion and PWGS 2.

During 2005, we had $697.1 million of net cash outflows from investing activities. In 2004, we had net cash inflows from investing activities of $242.8 million. In 2005, capital expenditures increased related to our PTF strategy at We Power and for compliance with the consent decree entered into with the EPA. See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters. In addition, expenditures associated with nuclear fuel purchases were higher during 2005. In 2004, we recognized proceeds of $857.0 million from the sale of our manufacturing segment.

The following table identifies capital expenditures by year:

Capital Expenditures	2006	2005	2004
	(Millions of Dollars)		
Utility Energy	$459.9	$458.6	$426.5
We Power	466.1	276.4	190.4
Other	2.7	10.1	19.6
Total Capital Expenditures	$928.7	$745.1	$636.5

In connection with our growth strategy, which was announced in 2000, we have been focusing on divesting non-core assets and investing in core regulated assets. The sale of assets is a significant component of our investing activities. From 2000 through 2006, we have received approximately $2.2 billion of cash proceeds from the divestiture of assets. In 2007, if we are able to close on the sale of Point Beach, we expect to receive an additional $1 billion of after-tax cash proceeds. However, except for the potential sale of Point Beach, we do not expect to have a significant level of asset sales in the future.

The following table identifies cash proceeds from asset sales.

Asset Sales	2006	2005	2004
	(Millions of Dollars)		
Guardian	$38.5	$ -	$ -
Real Estate	20.1	54.5	38.7
Wisvest	-	37.1	-
We Power	-	34.6	-
Manufacturing	-	-	857.0
Other	43.8	7.6	3.9
Total Asset Sales	$102.4	$133.8	$899.6

Financing Activities

The following table summarizes our cash flows from financing activities:

	2006	2005	2004
	(Millions of Dollars)		
Increase (Reduction) Debt	$ 299.7	$291.9	($654.2)
Dividends on Common Stock	(107.6)	(102.9)	(97.8)
Common Stock, net	(21.2)	(28.1)	(81.8)
Other	2.4	(3.1)	(0.5)
Cash Provided by (Used in) Financing	$ 173.3	$157.8	($834.3)

During 2006, cash provided by financing activities was $173.3 million compared to $157.8 million in 2005. Wisconsin Energy retired at the scheduled maturity date $250.0 million of 5.875% Notes due April 1, 2006. Short-term debt was issued to retire those notes. During 2006, short-term debt increased approximately $455.6 million. In November 2006, Wisconsin Electric issued $300 million of 5.70% Debentures due December 1, 2036. The net proceeds from the sale were used to retire Wisconsin Electric's $200 million of 6-5/8% Debentures due November 15, 2006 at their scheduled maturity and to repay outstanding commercial paper incurred for working capital requirements.

In July 2005, PWGS issued $155.0 million of 4.91% senior notes in a private placement. The senior notes have a mortgage style repayment feature and have an average life approximating 15 years. The final payment is due July 15, 2030. Proceeds from the sale

of the senior notes were used primarily to repay short-term debt incurred during construction at PWGS. For further information, see Note K -- Long-Term Debt in the Notes to Consolidated Financial Statements.

Wisconsin Gas retired at the scheduled maturity date $65 million of 6-3/8% Notes due November 1, 2005. In November 2005, Wisconsin Gas issued $90 million of 5.90% Debentures due December 1, 2035. The proceeds from the sale were used to repay a portion of our outstanding commercial paper. The commercial paper was incurred to both retire the $65 million of 6-3/8% Notes and for working capital requirements.

During 2004, the proceeds from asset sales as well as improved cash flows from operations allowed us to retire $654.2 million of debt, including $200 million of 6.85% Trust Preferred Securities and $300 million of 5.875% senior notes due April 1, 2006.

No new shares of Wisconsin Energy's common stock were issued in 2006 and 2005. During January and February 2004, we issued approximately 0.2 million new shares of common stock in connection with our dividend reinvestment plan and various employee benefit plans and we received payments aggregating $4.8 million. In February 2004, we announced that we did not expect to issue new shares under these programs; rather we instructed the independent plan agents to begin purchasing the shares in the open market in lieu of issuing new shares. During 2006, 2005 and 2004, our plan agents purchased 1.1 million shares at a cost of $48.0 million, 2.0 million shares at a cost of $75.1 million and 3.2 million shares at a cost of $102.3 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2006, 2005, and 2004 we received proceeds of $26.8 million, $47.0 million and $66.1 million related to the exercise of stock options. Prior to February 2004, we issued new shares to fulfill these obligations.

In September 2000, the Board of Directors amended the common stock repurchase program to authorize us to purchase up to $400 million of our shares of common stock in the open market. This program expired in December 2004. In March 2004, we announced that under this plan we would resume purchasing approximately $50 million of our common shares in the open market with the proceeds from the sale of the manufacturing business, which was effective July 31, 2004. During 2004, we purchased approximately 1.6 million shares of common stock for $50.4 million under this plan. We ceased repurchasing shares in October 2004. Over the life of the plan we repurchased and retired 14.9 million shares at a cost of $344.0 million.

CAPITAL RESOURCES AND REQUIREMENTS

In December 2006, we announced that Wisconsin Electric had reached an agreement to sell Point Beach to an affiliate of FPL. If the sale is completed, we expect to receive over $1 billion of after-tax proceeds from the sale and liquidation of decommissioning trust assets. In the short-term, these proceeds would be used to reduce outstanding debt or temporarily invested in short term securities. However, as discussed in Corporate Developments - Corporate Strategy, we have filed an application with the PSCW that outlines our intention to use the gain (net of transaction related costs) on the proceeds for the benefit of our customers as decided by our regulators in future rate proceedings. As such, if the Point Beach sale is approved, we believe that the cash proceeds, after transaction costs and return of invested capital, that will result from the sale will replace revenues that we would have received in future rate proceedings.

In 2000, we announced a growth strategy which, among other things, called for us to sell non-core assets and reduce our debt levels. Our debt to total capital ratio has decreased from 68.3% at September 30, 2000 to 59.5% at December 31, 2006 due primarily to asset sales. Over the next several years, we expect to have some limited asset sales, but at levels significantly lower than the previous seven year level.

Capital Resources

We anticipate meeting our capital requirements during 2007 and the next several years primarily through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt or other capital market (other than common stock) securities depending on market conditions and other factors. During 2007, Wisconsin Energy may issue up to $600 million of debt or debt-like securities depending on market conditions and other factors.

We have access to capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We believe that we have adequate capacity to fund our operations for the foreseeable future through our borrowing arrangements and internally generated cash.

In March 2004, the Governor of Wisconsin signed into law a measure that gives utilities the ability to securitize the portion of customer bills that recovers the cost of certain investments intended to improve the environment. We evaluated the possible issuance of environmental trust bonds for some time. However, after extensive evaluation and analysis, we will not be pursuing an issuance of environmental trust bonds.

Wisconsin Energy, Wisconsin Electric and Wisconsin Gas credit agreements provide liquidity support for each company's obligations with respect to commercial paper and for general corporate purposes.

As of December 31, 2006, we had approximately $1.7 billion of available unused lines under our bank back-up credit facilities on a consolidated basis and approximately $911.9 million of total consolidated short-term debt outstanding.

We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. The following table summarizes such facilities at December 31, 2006.

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration	Facility Term
	(Millions of Dollars)				
Wisconsin Energy	$900.0	$ 1.5	$898.5	April 2011	5 year
Wisconsin Electric	$500.0	$14.1	$485.9	March 2011	5 year
Wisconsin Gas	$300.0	$ -	$300.0	March 2011	5 year

On March 30, 2006, Wisconsin Electric entered into an unsecured five year $500 million bank back-up credit facility to replace a $250 million three year credit facility with an expiration date of June 2007 and a $125 million three year credit facility with an expiration date of November 2007. This new facility will expire in March 2011.

On March 30, 2006, Wisconsin Gas entered into an unsecured five year $300 million bank back-up credit facility to replace a $200 million three year credit facility with an expiration date of June 2007. This new facility will expire in March 2011.

On April 6, 2006, Wisconsin Energy entered into an unsecured five year $900 million bank back-up credit facility to replace a $300 million credit facility that would have expired on April 8, 2006 and a $300 million credit facility with an expiration date of June 2007. This new credit facility will expire in April 2011.

Each of these facilities has a renewal provision for two one-year extensions, subject to lender approval.

The following table shows our consolidated capitalization structure at December 31:

Capitalization Structure	2006		2005	
	(Millions of Dollars)			
Common Equity	$2,889.0	40.1%	$2,680.1	40.0%
Preferred Stock of Subsidiary	30.4	0.4%	30.4	0.5%
Long-Term Debt (including current maturities)	3,370.1	46.8%	3,527.0	52.7%
Short-Term Debt	911.9	12.7%	456.3	6.8%
Total	$7,201.4	100.0%	$6,693.8	100.0%
Ratio of Debt to Total Capital		59.5%		59.5%

As described in Note J -- Common Equity, in the Notes to Consolidated Financial Statements, certain restrictions exist on the ability of our subsidiaries to transfer funds to us. We do not expect these restrictions to have any material effect on our operations or ability to meet our cash obligations.

Access to capital markets at a reasonable cost is determined in large part by credit quality. The following table summarizes the ratings of our debt securities and the debt securities and preferred stock of our subsidiaries by S&P, Moody's and Fitch as of December 31, 2006.

	S&P	Moody's	Fitch
Wisconsin Energy			
Commercial Paper	A-2	P-2	F2
Unsecured Senior Debt	BBB+	A3	A-
Wisconsin Electric			
Commercial Paper	A-2	P-1	F1
Secured Senior Debt	A-	Aa3	AA-
Unsecured Debt	A-	A1	A+
Preferred Stock	BBB	A3	A
Wisconsin Gas			
Commercial Paper	A-2	P-1	F1
Unsecured Senior Debt	A-	A1	A+
Wisconsin Energy Capital Corporation			
Unsecured Debt	BBB+	A3	A-

On June 15, 2006, Fitch affirmed the security ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation and changed the security ratings outlook for Wisconsin Energy and Wisconsin Energy Capital Corporation from stable to negative. The security ratings outlooks assigned by Fitch for Wisconsin Electric and Wisconsin Gas are stable.

On June 8, 2006, S&P affirmed the security ratings and ratings outlook of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas. The security ratings outlooks assigned by S&P for Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation are negative.

The security rating outlooks assigned by Moody's for Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation are all stable. In February 2004, Moody's changed the rating outlook for Wisconsin Energy and Wisconsin Energy Capital Corporation from negative to stable.

We believe these security ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agencies only. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities, but rather an indication of creditworthiness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Capital Requirements

Our current estimated 2007, 2008 and 2009 capital expenditures, excluding the purchase of nuclear fuel, are as follows:

Capital Expenditures	Actual 2006	Estimated 2007	Estimated 2008	Estimated 2009
		(Millions of Dollars)		
Utility Energy	$459.9	$661.0	$551.0	$587.0
We Power	466.1	701.0	475.0	216.0
Other	2.7	9.0	4.0	5.0
Total	$928.7	$1,371.0	$1,030.0	$808.0

Due to changing environmental and other regulations such as air quality standards and electric reliability initiatives that impact our utility energy segments future long-term capital requirements may vary from recent capital requirements.

Our capital requirements include the construction of the PTF units. Through December 31, 2006, we have expended approximately $1.2 billion of the approximately $2.6 billion in capital we estimate will be required to construct the 2,120 MW of new natural gas-fired and coal-fired generating capacity. We anticipate that the PTF units will be completed by 2010.

We expect the capital requirements to support our investment in new generation under PTF to come from a combination of internal and external sources. We Power, a non-utility subsidiary, is constructing the new generating plants, which will be leased to Wisconsin Electric under 25-30 year lease agreements. We expect that Wisconsin Electric will recover the lease payments in its utility rates.

In June 2005, we purchased the development rights to two wind farm projects from Navitas Energy Inc. We plan to develop the wind sites and construct wind turbines with a combined generating capability between 130 and 200 MW. We estimate that the capital cost of the project, excluding AFUDC, will be up to $360 million. We anticipate the cost to build the wind farm projects would be recovered in Wisconsin Electric's rates. We expect the turbines to be placed in service in 2008 dependent upon the availability of wind turbines and the receipt of necessary regulatory approvals. For additional information on Wind Generation see Utility Rates and Regulatory Matters - Wind Generation below.

Investments in Outside Trusts: We have funded our pension obligations, certain other post-retirement obligations and future nuclear obligations in outside trusts. Collectively, these trusts had investments that exceeded $2.1 billion as of December 31, 2006. These trusts hold investments that are subject to the volatility of the stock market and interest rates. For further information see Note I -- Nuclear Operations and Note O -- Benefits in the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements: We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit which support construction projects, commodity contracts and other payment obligations. We believe that these agreements do not have, and are not reasonably likely to have, a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For further information, see Note P -- Guarantees in the Notes to Consolidated Financial Statements.

We have identified three tolling and purchased power agreements with third parties but have been unable to determine if we are the primary beneficiary of any of these three variable interest entities as defined by FIN 46. As a result, we do not consolidate these entities. Instead, we account for one of these contracts as a capital lease and for the other two contracts as operating leases as reflected in the table below. We have included our contractual obligations under all three of these contracts in our Contractual Obligations/Commercial Commitments disclosure that follows. For additional information, see Note G -- Variable Interest Entities in the Notes to Consolidated Financial Statements.

Contractual Obligations/Commercial Commitments: We have the following contractual obligations and other commercial commitments as of December 31, 2006:

	Payments Due by Period				
Contractual Obligations (a)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
		(Millions of Dollars)			
Long-Term Debt Obligations (b)	$6,125.6	$442.4	$708.9	$735.3	$4,239.0
Capital Lease Obligations (c)	547.9	61.7	108.5	82.5	295.2
Operating Lease Obligations (d)	183.9	51.6	58.2	41.2	32.9
Purchase Obligations (e)	3,293.6	1,099.4	1,458.8	300.1	435.3
Other Long-Term Liabilities (f)	84.4	82.2	1.4	0.8	-
Total Contractual Obligations	$10,235.4	$1,737.3	$2,335.8	$1,159.9	$5,002.4

(a) The amounts included in the table are calculated using current market prices, forward curves and other estimates. Contracts with multiple unknown variables have been omitted from the analysis. The table excludes the long-term power purchase commitment which is contingent upon the sale of Point Beach.

(b) Principal and interest payments on our Long-Term Debt and the Long-Term Debt of our affiliates (excluding capital lease obligations).

(c) Capital Lease Obligations of Wisconsin Electric for nuclear fuel lease and purchase power commitments.

(d) Operating Lease Obligations for purchase power commitments and vehicle and rail car leases for Wisconsin Energy and affiliates.

(e) Purchase Obligations under various contracts for the procurement of fuel, power, gas supply and associated transportation related to utility operations and for construction, information technology and other services for utility and We Power operations.

(f) Other Long-Term Liabilities includes the expected 2007 supplemental executive retirement plan obligation and the 2007 non-discretionary pension contribution. For additional information on employer contributions to our benefit plans see Note O -- Benefits in the Notes to Consolidated Financial Statements.

Obligations for utility operations by our utility affiliates have historically been included as part of the rate making process and therefore are generally recoverable from customers. For a discussion of 2007, 2008 and 2009 estimated capital expenditures, see Capital Requirements above.

FACTORS AFFECTING RESULTS, LIQUIDITY AND CAPITAL RESOURCES

MARKET RISKS AND OTHER SIGNIFICANT RISKS

We are exposed to market and other significant risks as a result of the nature of our businesses and the environment in which those businesses operate. These risks, described in further detail below, include but are not limited to:

Large Construction Projects: In December 2002, the PSCW issued a written order granting a CPCN to commence construction of the PWGS consisting of two 545 MW natural gas-fired combined cycle generating units on the site of Wisconsin Electric's existing Port Washington Power Plant. The order approved key financial terms of the leased generation contracts including fixed construction costs of PWGS 1 at $309.6 million and PWGS 2 at $280.3 million (2001 dollars), respectively, subject to escalation at the GDP inflation rate, force majeure, excused events and event of loss provisions. For additional information, see Power the Future -- Port Washington.

In addition, in November 2003, the PSCW issued a written order granting a CPCN to commence construction of two 615 MW super critical pulverized coal generating units adjacent to the site of Wisconsin Electric's existing plant. The order approves key financial terms of the leased generation contracts including a target construction cost of the Oak Creek expansion of $2.191 billion, plus, subject to PSCW approval, cost over-runs of up to 5%, costs attributable to force majeure events, excused events and event of loss provisions. For additional information, see Power the Future -- Oak Creek Expansion.

Large construction projects of this type are subject to usual construction risks over which we will have limited or no control and which might adversely affect project costs and completion time. These risks include, but are not limited to, shortages of, the inability to obtain or the cost of labor or materials, the inability of the general contractor or subcontractors to perform under their contracts, strikes, adverse weather conditions, continuing legal challenges to permits obtained, changes in applicable laws or regulations, adverse interpretation or enforcement of permit conditions, laws and regulations by the permitting agencies, the inability to obtain necessary operating permits in a timely manner, governmental actions and events in the global economy.

If final costs for the construction of PWGS exceed the fixed costs allowed in the PSCW order, absent a finding by the PSCW of extraordinary circumstances such as force majeure conditions, this excess will not adjust the amount of the lease payments recovered from Wisconsin Electric. If final costs of the Oak Creek expansion are within 5% of the target cost, and the additional costs are deemed to be prudent by the PSCW, the final lease payments for the Oak Creek expansion recovered from Wisconsin Electric would be adjusted to reflect the actual construction costs. Costs above the 5% cap would not be included in lease payments or recovered from customers absent a finding by the PSCW of extraordinary circumstances such as force majeure conditions.

Regulatory Recovery: The electric operations of Wisconsin Electric burn natural gas in its leased power plants, in several of its peaking power plants and as a supplemental fuel at several coal-fired plants. In addition, the cost of purchased power is generally tied to the cost of natural gas. Wisconsin Electric bears regulatory risk for the recovery of these fuel and purchased power costs when these costs are higher than the base rate established in its rate structure. For further information on the recovery of fuel and purchase power costs see Commodity Prices.

Our utility energy segment accounts for its regulated operations in accordance with SFAS 71. Our rates are determined by regulatory authorities. Our primary regulator is the PSCW. SFAS 71 allows regulated entities to defer certain costs that would otherwise be charged to expense, if the regulated entity believes the recovery of these costs is probable. We record regulatory assets pursuant to specific orders or by a generic order issued by our regulators, and recovery of these deferred costs in future rates is subject to the review and approval of those regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of these costs is not approved by our regulators, the costs are charged to income in the current period. We expect to recover our outstanding regulatory assets in rates over a period of no longer than 20 years. Regulators can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. Under SFAS 71, we record these items as regulatory liabilities.

Commodity Prices: In the normal course of providing energy, we are subject to market fluctuations of the costs of coal, natural gas and the cost of purchased power. We manage our fuel and gas supply costs through a portfolio of short- and long-term procurement contracts with various suppliers for the purchase of coal, uranium, natural gas and fuel oil. In addition, we manage the risk of price volatility by utilizing gas hedging programs.

Wisconsin's retail electric fuel cost adjustment procedure mitigates some of Wisconsin Electric's risk of electric fuel cost fluctuation. If cumulative fuel and purchased power costs for electric utility operations deviate from a prescribed range when compared to the costs projected in the most recent retail rate proceeding, retail electric rates may be adjusted prospectively. For 2007, we will operate under a traditional fuel cost adjustment clause in the Wisconsin retail jurisdiction whereby fuel revenues may be adjusted prospectively if fuel and purchased power costs fall outside a pre-established annual band of plus or minus 2%. For information regarding the 2006 fuel rules, see Utility Rates and Regulatory Matters.

The PSCW has authorized dollar for dollar recovery for the majority of natural gas costs for our gas utility operations through gas cost recovery mechanisms, which mitigates most of the risk of gas cost variations. For information concerning the electric utility fuel cost adjustment procedure and the natural gas utilities' GCRMs, see Utility Rates and Regulatory Matters.

Natural Gas Costs: Significant increases in the cost of natural gas affect our electric and gas utility operations. Natural gas costs have increased significantly because the supply of natural gas in recent years has not kept pace with the demand for natural gas. We expect that demand for natural gas will remain high into the foreseeable future and that significant price relief will not occur until additional natural gas is added to the nation's energy supply mix.

Higher natural gas costs increase our working capital requirements and result in higher gross receipts taxes in the State of Wisconsin. Higher natural gas costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. Because federal and state energy assistance dollars have not kept pace with rising natural gas costs over the recent year, our risks related to bad debt expenses have increased.

In February 2005, the PSCW authorized the use of the escrow method of accounting for bad debt costs allowing for deferral of Wisconsin residential bad debt expense that exceed amounts allowed in rates. In 2004 and 2003, we had approval from the PSCW to defer residential bad debt net write-offs that exceed amounts allowed in rates.

As a result of GCRMs, our gas distribution subsidiaries receive dollar for dollar recovery on the cost of natural gas. However, increased natural gas costs increase the risk that customers will switch to alternative fuel sources, which could reduce future gas margins.

Weather: Our Wisconsin utility rates are set by the PSCW based upon estimated temperatures which approximate 20-year averages. Wisconsin Electric's electric revenues are unfavorably sensitive to below normal temperatures during the summer cooling season, and to some extent, to above normal temperatures during the winter heating season. Our gas revenues are unfavorably sensitive to above normal temperatures during the winter heating season. A summary of actual weather information in the utility segment's service territory during 2006, 2005 and 2004, as measured by degree-days, may be found above in Results of Operations.

Interest Rate: We have various short-term borrowing arrangements to provide working capital and general corporate funds. We also have variable rate long-term debt outstanding at December 31, 2006. Borrowing levels under these arrangements vary from period to period depending upon capital investments and other factors. Future short-term interest expense and payments will reflect both future short-term interest rates and borrowing levels.

We performed an interest rate sensitivity analysis at December 31, 2006 of our outstanding portfolio of $911.9 million of short-term debt with a weighted average interest rate of 5.37% and $179.0 million of variable-rate long-term debt with a weighted average interest rate of 3.97%. A one-percentage point change in interest rates would cause our annual interest expense to increase or decrease by approximately $9.1 million before taxes from short-term borrowings and $1.8 million before taxes from variable rate long-term debt outstanding.

Marketable Securities Return: We fund our pension, OPEB and nuclear decommissioning obligations through various trust funds, which in turn invest in debt and equity securities. Changes in the market prices of these assets can affect future pension, other post-retirement benefit and nuclear decommissioning expenses. Additionally, future contributions can also be affected by changes in the market price of trust fund assets. We expect that the risk of expense and contribution variations as a result of changes in the market price of trust fund assets would be mitigated in part through future rate actions by our various utility regulators. Through December 31, 2005, we were operating under a PSCW-ordered, qualified five-year rate restriction period. For further information about the rate restriction, see Utility Rates and Regulatory Matters.

At December 31, 2006, we held the following total trust fund assets at fair value, primarily consisting of publicly traded debt and equity security investments.

Wisconsin Energy Corporation	Millions of Dollars
Pension trust funds	$1,057.7
Nuclear decommissioning trust funds	$881.6
Other post-retirement benefits trust funds	$203.7

Fiduciary oversight of the pension and other post-retirement plan trust fund investments is the responsibility of an Investment Trust Policy Committee. Qualified external investment managers are engaged to manage the investments. Asset/liability studies are periodically conducted with the assistance of an outside investment advisor. The current study for the pension fund projects long-term annualized returns of approximately 8.5%.

Fiduciary oversight for the nuclear decommissioning trust fund investments is also the responsibility of the Investment Trust Policy Committee. Qualified external investment managers are also engaged to manage these investments. Asset/liability studies are periodically conducted with the assistance of an outside investment advisor, subject to additional constraints established by the PSCW. The current study projects long-term, annualized returns of approximately 9%. Current PSCW constraints allow a maximum allocation of 65% in equities.

Wisconsin Electric insures various property and outage risks through NEIL. Annually, NEIL reviews its underwriting and investment results and determines the feasibility of granting a distribution to policyholders. Adverse loss experience, rising reinsurance costs or impaired investment results at NEIL could result in increased costs or decreased distributions to Wisconsin Electric.

Credit Ratings: We do not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. We do have certain agreements in the form of commodity and energy services contracts and employee benefit plans that could require, in the event of a credit rating change to below investment grade, a termination payment if collateral is not provided or an accelerated payment. At December 31, 2006, we estimate that the potential payments under these agreements that could result from credit rating downgrades totaled approximately $71.2 million.

Economic Conditions: We are exposed to market risks in the regional midwest economy for our utility energy segment.

Inflation: We continue to monitor the impact of inflation, especially with respect to the rising costs of medical plans, in order to minimize its effects in future years through pricing strategies, productivity improvements and cost reductions. Except for continuance of an increasing trend in the inflation of medical costs and the impacts on our medical and post-retirement benefit plans, we have expectations of low-to-moderate inflation. We do not believe the impact of general inflation will have a material effect on our future results of operations.

For additional information concerning risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information at the beginning of this report.

POWER THE FUTURE

Under our PTF strategy, we expect to meet a significant portion of our future generation needs through the construction of the PWGS and the Oak Creek expansion by We Power. We Power will lease the new plants to Wisconsin Electric under long-term leases, and we expect Wisconsin Electric to recover the lease payments in its electric rates.

The PTF units include PWGS 1, PWGS 2, OC 1 and OC 2. The following table identifies certain key items related to the units:

Unit Name	Expected In Service	Authorized Cash Costs (a)
PWGS 1	July 2005 (Actual)	$ 333 million (Actual)
PWGS 2	Summer 2008	$ 329 million
OC 1	Summer 2009	$ 1,300 million
OC 2	Summer 2010	$ 640 million

(a) Authorized cash costs represent the PSCW approved costs and the increases for factors such as inflation as identified in the PSCW approved lease terms for PWGS 2, and adjusted for our ownership percentages in the case of OC 1 and OC 2.

The lease payments are based on the cash costs authorized by our primary regulator. Under the lease terms, our return is calculated using a 12.7% return on equity and the equity ratio is assumed to be 53% for the PWGS Units and 55% for the OC Units. The interest component of the return is determined up to 180 days prior to the date that the units are placed in service.

Power the Future - Port Washington

Background: In December 2002, the PSCW issued a written order (the Port Order) granting Wisconsin Energy, Wisconsin Electric and We Power a CPCN to commence construction of the PWGS consisting of two 545 MW natural gas-fired combined cycle generating units on the site of Wisconsin Electric's existing Port Washington Power Plant. The Port Order also authorized Wisconsin Gas to proceed with the construction of a connecting natural gas lateral, which was completed in December 2004, and it authorized ATC to construct transmission system upgrades to serve PWGS 1 and PWGS 2. PWGS 1 was completed in July 2005 and placed into service at that time. PWGS 1 was completed within the PSCW approved cost parameters. In October 2003, we received approval from FERC to transfer by long-term lease certain associated FERC jurisdictional transmission related assets from We Power to Wisconsin Electric. Construction of PWGS 2 is well underway. Site preparation, including removal of the old coal units at the site, was completed in early 2006, and all of the major components have been procured. The unit is expected to begin commercial operation in time for the peak summer season in 2008.

Lease Terms: The PSCW approved the lease agreements and related documents under which Wisconsin Electric will staff, operate and maintain PWGS 1 and PWGS 2. Key terms of the leased generation contracts include:

- Initial lease term of 25 years with the potential for subsequent renewals at reduced rates;
- Cost recovery over a 25 year period on a mortgage basis amortization schedule;
- Imputed capital structure of 53% equity, 47% debt;
- Authorized rate of return of 12.7% after tax on equity;
- Fixed construction cost of PWGS 1 and PWGS 2 at $309.6 million and $280.3 million (2001 dollars) subject to escalation at the GDP inflation rate;
- Recovery of carrying costs during construction; and
- Ongoing PSCW supervisory authority over those lease terms and conditions specifically identified in the Port Order, which do not include the key financial terms.

In January 2003, Wisconsin Electric filed a request with the PSCW to defer costs for recovery in future rates. The PSCW approved the request in an open meeting in April 2003. We Power began collecting certain costs from Wisconsin Electric in the third quarter of 2003 as provided for in lease generation contracts that were signed in May 2003. We defer the lease costs on our balance sheet, and we amortize the costs to expense as we recover the costs in rates.

Legal and Regulatory Matters: There are currently no legal challenges to the construction of PWGS and all construction permits have been received for PWGS 1 and PWGS 2. As a result of the enactment of the Energy Policy Act, FERC, through an amendment to Section 203 of the Federal Power Act, has been given jurisdiction over the acquisition of generation (which includes leasing generation), an activity that previously was not subject to FERC's jurisdiction. Under FERC's rules implementing the Energy Policy Act, Wisconsin Energy, Wisconsin Electric and We Power filed a joint application for FERC authorization to transfer the generating assets and limited interconnection facilities of PWGS 2 through a lease arrangement between We Power and Wisconsin Electric. We received approval from FERC for this asset transfer in December 2006.

***Power the Future* - Oak Creek Expansion**

Background: In November 2003, the PSCW issued an order (the Oak Creek Order) granting Wisconsin Energy, Wisconsin Electric and We Power a CPCN to commence construction of two 615 MW coal-fired units (the Oak Creek expansion) to be located adjacent to the site of Wisconsin Electric's existing Oak Creek Power Plant. We anticipate OC 1 will be operational in 2009 and OC 2 will be operational in 2010. The Oak Creek Order concluded, among other things, that there was a need for additional electric generation for Southeastern Wisconsin and that a diversity of fuel sources best serves the interests of the State. The total cost for the two units was set at $2.191 billion, and the order provided for recovery of excess costs of up to 5% of the total project, subject to a prudence review by the PSCW. The CPCN was granted contingent upon us obtaining the necessary environmental permits. All necessary permits have been received at this time. In June 2005, construction commenced at the site.

In November 2005, we completed the sale of approximately a 17% interest in the project to two unaffiliated entities, who will share ratably in the construction costs.

Lease Terms: In October 2004, the PSCW approved the lease generation contracts between Wisconsin Electric and We Power for the Oak Creek expansion. Key terms of the leased generation contracts include:

- Initial lease term of 30 years with the potential for subsequent renewals at reduced rates;
- Cost recovery over a 30 year period on a mortgage basis amortization schedule with the potential for subsequent renewals at reduced rates;
- Imputed capital structure of 55% equity, 45% debt;
- Authorized rate of return of 12.7% after tax on equity;
- Recovery of carrying costs during construction; and
- Ongoing PSCW supervisory authority over those lease terms and conditions specifically identified in the Oak Creek Order, which do not include the key financial terms.

Legal and Regulatory Matters: The CPCN granted for the construction of the Oak Creek expansion was the subject of a number of legal challenges by third parties; these legal challenges were resolved in June 2005. We have received all permits necessary to commence construction. Certain of these permits continue to be contested, but remain in effect unless and until overturned by a reviewing court or administrative law judge. The major permits are discussed below.

The WDNR issued a Chapter 30 permit for wetlands and waterways alterations and construction on the bed of Lake Michigan for the construction of the Oak Creek expansion. The permit has been the subject of appeals since 2003. The final appeal was resolved by the Wisconsin Court of Appeals in February 2006, and the period for appeal of that decision to the Wisconsin Supreme Court has expired.

We applied to the WDNR to modify the existing WPDES permit that is required for operation of the water intake and discharge system for the planned Oak Creek expansion and existing Oak Creek generating units. In March 2005, the WDNR determined that the proposed cooling water intake structure and water discharge system meets regulatory requirements and reissued the WPDES permit with specific limitations and conditions. The opponents filed a petition for judicial review in Dane County Circuit Court and a request for a contested case proceeding with the WDNR. In September 2005, the judicial review petition was dismissed by agreement of the parties. The WDNR granted a contested case hearing that was held in March 2006. The administrative law judge upheld the issuance of the permit in a decision issued in July 2006. In August 2006, the opponents filed for judicial review of the administrative law judge's decision upholding the issuance of the permit. Briefing was completed in December 2006. However, based on the federal court decision discussed below, the opponents filed a motion on January 26, 2007 requesting supplemental briefing. In a telephone conference on February 2, 2007, the Court said that additional briefing was not necessary, but that it might request oral argument before issuing its decision regarding review of the permit. We anticipate a decision in the case in 2007.

On January 26, 2007, the Federal Court of Appeals for the Second Circuit, issued a decision in Riverkeeper, Inc. v. EPA, Nos. 04-6692-ag(L) et al. (2d Cir. 2007) relating to the 316(b) rules for cooling water intake systems for existing large utility plants. The Second Circuit Court found certain portions of the rule impermissible and remanded several parts of the rule to the EPA for further consideration or potential additional rulemaking. The WPDES permit for our Oak Creek expansion and existing Oak Creek generating units is a state permit, issued by WDNR with concurrence of EPA. Based on our review of the Second Circuit

decision, we do not believe the decision invalidates the WPDES permit for Oak Creek. However, we cannot predict what, if any, impact the decision may have on the court's decision in the Dane County Circuit Court case.

In May 2005, we received the Army Corps of Engineers federal permit necessary for the construction of the Oak Creek expansion. Opponents may appeal the permit in federal court.

In addition, as a result of the enactment of the Energy Policy Act, FERC, through an amendment to Section 203 of the Federal Power Act, has been given jurisdiction over the acquisition of generation (which includes leasing generation), an activity that previously was not subject to FERC's jurisdiction. Under FERC's rules implementing the Energy Policy Act, Wisconsin Energy, Wisconsin Electric and We Power filed a joint application for FERC authorization to transfer the generating assets and limited interconnection facilities of OC 1 and OC 2 through a lease arrangement between We Power and Wisconsin Electric. We received approval from FERC on these leases in December 2006.

UTILITY RATES AND REGULATORY MATTERS

The PSCW regulates our retail electric, natural gas, steam and water rates in the State of Wisconsin, while FERC regulates our wholesale power, electric transmission and interstate gas transportation service rates. The MPSC regulates our retail electric rates in the State of Michigan. Within our regulated segment, we estimate that approximately 88% of our electric revenues are regulated by the PSCW, 7% are regulated by the MPSC and the balance of our electric revenues are regulated by FERC. All of our natural gas revenues are regulated by the PSCW. Orders from the PSCW can be viewed at http://psc.wi.gov/ and orders from the MPSC can be viewed at www.michigan.gov/mpsc/.

Overview: For the period from March 2000 until December 31, 2005, the rates of Wisconsin Electric and Wisconsin Gas were governed by an order from the PSCW in connection with the approval of the WICOR acquisition. Under this order, Wisconsin Electric and Wisconsin Gas were restricted from increasing Wisconsin rates for a five year period ending December 31, 2005, with certain limited exceptions.

The table below summarizes the anticipated annualized revenue impact of the recent Wisconsin Electric rate changes.

Service - Wisconsin Electric	Incremental Annualized Revenue Increase (Millions)	Percent Change in Rates (%)	Effective Date
Fuel Electric, Michigan	$3.4	7.5%	January 1, 2007
Retail electric, Wisconsin	$222.0	10.6%	January 26, 2006
Retail gas, Wisconsin	$21.4	2.9%	January 26, 2006
Retail steam, Wisconsin (a)	$7.8	31.5%	January 26, 2006
Fuel electric, Michigan	$2.7	5.9%	January 1, 2006
Fuel electric, Wisconsin (b)	$7.7	0.3%	November 24, 2005
Fuel electric, Michigan	$2.5	5.8%	November 1, 2005
Retail electric, Wisconsin	$59.7	3.1%	May 19, 2005
Retail steam, Wisconsin	$0.5	3.6%	May 19, 2005
Fuel electric, Wisconsin (b)	$114.9	5.9%	March 18, 2005
Fuel electric, Michigan	$3.4	8.0%	January 1, 2005
Fuel electric, Michigan	$1.3	3.1%	October 1, 2004
Retail steam, Wisconsin	$0.5	3.4%	May 5, 2004
Retail electric, Wisconsin (c)	$59.0	3.3%	May 5, 2004
Fuel electric, Michigan	$3.3	7.6%	January 1, 2004

(a) In January 2006, the PSCW issued a final order authorizing an increase in steam rates of $7.8 million over the two year period of 2006 and 2007.

(b) In November 2005, the PSCW issued a final order authorizing a fuel surcharge for $7.7 million of additional fuel costs. In March 2005, the PSCW issued an interim order authorizing a fuel surcharge for $114.9 million that was effective until the November 2005 final order was issued by the PSCW. The final November 2005 order for $122.6 million superseded the March 2005 interim order.

(c) In May 2004, the PSCW issued a final order authorizing an increase in electric rates for costs associated with the PWGS under construction and increased costs associated with low-income energy assistance.

2006 Pricing: In January 2006, Wisconsin Electric received an order from the PSCW that allowed it to increase annual electric revenues by approximately $222.0 million or 10.6% to recover increased costs associated with investments in our PTF units, transmission services and fuel and purchased power, as well as costs associated with additional sources of renewable energy. The rate increase was based on an authorized return on equity of 11.2%. The order also required Wisconsin Electric to refund to customers, with interest, any fuel revenues that it receives that are in excess of fuel and purchased power costs that it incurs, as defined by the Wisconsin fuel rules. The original order stipulated that any refund would also include interest at short-term rates. This refund provision does not extend past December 31, 2006.

During 2006, we experienced lower than expected fuel and purchased power costs. In September 2006, we requested and received approval from the PSCW to refund favorable fuel recoveries including accrued interest at a short-term rate. In addition, in September 2006 the PSCW determined that if the total recoveries for 2006 exceeded $36 million, interest on the amount in excess of $36 million would be paid at the rate of 11.2%, our authorized return on equity rather than at short-term rates as originally set forth in the order. During October 2006, we refunded $28.7 million including interest to Wisconsin retail customers as a credit on their bill and we received approval from the PSCW to refund an additional $10 million, including interest in the first quarter of 2007.

For 2007, Wisconsin Electric expects to operate under a traditional fuel cost adjustment clause in the Wisconsin retail jurisdiction whereby fuel revenues may be adjusted prospectively if fuel and purchased power costs fall outside a pre-established annual band of plus or minus 2%.

Our gas operations went through a traditional rate proceeding whereby the revenues were set to recover projected costs and to provide a return on rate base. The January 2006 order provided for increases in gas revenues totaling $60.1 million ($21.4 million or 2.9% for Wisconsin Electric gas operations and $38.7 million or 3.7% for Wisconsin Gas gas operations). The rate increases were based on an authorized return on equity of 11.2% for the gas operations of both Wisconsin Electric and Wisconsin Gas.

The steam rate proceeding was a traditional rate proceeding. The January 2006 order provided for an increase in steam rates of $7.8 million or 31.5% to be phased in over a two year period beginning in 2006. The rate increase was based on an authorized return on equity of 11.2%.

2004 Wisconsin Gas Pricing: In March 2004, the PSCW approved an annual rate increase of $25.9 million related to increased costs associated with the construction of the Ixonia lateral and for increased costs associated with low-income energy assistance.

2008 Pricing: We anticipate filing rate cases for Wisconsin Electric and Wisconsin Gas in May 2007 for new rates effective in January 2008.

Limited Rate Adjustment Requests

2005 Fuel Recovery Filing: In February 2005, Wisconsin Electric filed an application with the PSCW for an increase in electric rates in the amount of $114.9 million due to the increased costs of fuel and purchased power as a result of customer growth and the increase in the reliance upon natural gas as a fuel source. We received approval for the increase in fuel recoveries on an interim basis in March 2005. In November 2005, we received the final rate order, which authorized an additional $7.7 million in rate increases, for a total increase of $122.6 million (6.2%). In December 2005, two parties filed suit against the PSCW in Dane County Circuit Court challenging the PSCW's decision to allow fuel cost recovery, while allowing us to keep the savings that resulted from the WICOR acquisition. As a condition of the PSCW approval of the WICOR acquisition, Wisconsin Electric and Wisconsin Gas were restricted from increasing Wisconsin rates for a five year period ending December 31, 2005, with certain limited exceptions, but we were allowed to keep the savings generated from the merger. In July 2006, the Dane County Circuit Court affirmed the PSCW's decision. In August 2006, the opponents appealed this decision to the Wisconsin Court of Appeals. We anticipate a decision from the Wisconsin Court of Appeals in 2007.

2005 Revenue Deficiencies: In May 2004, Wisconsin Electric filed an application with the PSCW for an increase in electric and steam rates for anticipated 2005 revenue deficiencies associated with (1) costs for the new PWGS and the Oak Creek expansion being constructed as part of our PTF strategy, (2) costs associated with our energy efficiency procurement plan and (3) costs associated with making changes to our steam utility systems as part of the reconstruction of the Marquette Interchange highway project in downtown Milwaukee, Wisconsin. The filing identified anticipated revenue deficiencies in 2005 attributable to Wisconsin in the amount of $84.8 million (4.5%) for the electric operations of Wisconsin Electric and $0.5 million (3.6%) for Wisconsin Electric's steam operations. In January 2005, as a result of the litigation involving our Oak Creek expansion, we amended this filing to reduce the total revenue request to $52.4 million. In May 2005, the PSCW issued its final written order implementing an annualized increase in electric rates of $59.7 million (3.1%) and an increase of $0.5 million (3.6%) in steam rates.

Other Utility Rate Matters

Electric Transmission Cost Recovery: Wisconsin Electric divested of its transmission assets with the formation of ATC in January 2001. We now procure transmission service from ATC at FERC approved tariff rates. In connection with the formation of the ATC, our transmission costs have escalated due to the socialization of costs within the ATC and increased transmission infrastructure requirements in the state. In 2002, in connection with the increased costs experienced by our customers, the PSCW issued an order which allowed the deferral of transmission costs in excess of amounts imbedded in rates. We are allowed to earn a return on the unrecovered transmission costs at our weighted average cost of capital. As of December 31, 2006, we have deferred $192.2 million of unrecovered transmission costs. In January 2006, our rates were increased by approximately $67.5 million annually to recover transmission costs that were not currently in rates. We will continue to accrue carrying costs on the unrecovered balances.

Fuel Cost Adjustment Procedure: Within the State of Wisconsin, Wisconsin Electric operates under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity and purchase power contracts. Imbedded within its base rates is an amount to recover fuel costs. Under the current fuel rules, no adjustments are made to rates as long as fuel and purchased power costs are expected to be within a band of the costs imbedded in current rates for the twelve month period ending December 31. If, however, annual fuel costs are expected to fall outside of the band, and actual costs fall outside of established fuel bands, then we may file for a change in fuel recoveries on a prospective basis. For 2006, the upper band was 2%. As discussed above, during 2006, we experienced lower than expected fuel and purchased power costs. In September 2006, we requested and received approval from the PSCW to refund favorable fuel recoveries including accrued interest at short-term rates. Approximately $28.7 million, including interest, in refunds were issued as a credit on customer bills in October 2006. We had favorable fuel recoveries of approximately $37.4 million, excluding interest, for 2006. We received approval from the PSCW to refund an additional $10 million, including interest, during the first quarter of 2007. In September 2006, the PSCW determined that if the total favorable recoveries for 2006 exceeded $36 million, interest on the favorable recoveries in excess of $36 million will be paid at the rate of 11.2%, our authorized return on equity, rather than at short-term rates as originally set forth in the order. For 2007, the band is plus or minus 2%.

In June 2006, the PSCW opened a docket (01-AC-224) in which it was looking into revising the current fuel rules (Chapter PSC 116). In February 2007, five Wisconsin utilities regulated by the fuel rules, including Wisconsin Electric, filed a joint proposal to modify the existing rules in this docket. The proposal recommends modifying the rules to allow for escrow accounting for fuel costs outside a plus or minus 1% annual band width of fuel costs allowed in rates. It further recommends that the escrow balance be trued-up annually following the end of each calendar year. We are unable to predict if or when the PSCW will make any changes to the existing fuel rules.

Edison Sault and Wisconsin Electric's operations in Michigan operate under a Power Supply Cost Recovery mechanism which generally allows for the recovery of fuel and purchase power costs on a dollar for dollar basis.

Gas Cost Recovery Mechanism: Our natural gas operations operate under a GCRM as approved by the PSCW. Generally, the GCRM allows for a dollar for dollar recovery of gas costs. There is an incentive mechanism under the GCRM which allows for increased revenues if we acquire gas lower than benchmarks approved by the PSCW. During 2006 and 2005, no additional revenues were earned under the incentive portion of the GCRM and $0.2 million of additional revenues were earned in 2004 under the GCRM.

Bad Debt Costs: In 2004, due to a combination of unusually high natural gas prices, a soft economy within our utility service territories, and limited governmental assistance available to low-income customers, we saw a significant increase in residential uncollectible accounts receivable. These factors led us to request and receive letters from the PSCW which allowed us to defer the costs of residential bad debts to the extent that the costs exceeded the amounts allowed in rates. As a result of these letters from the PSCW, we deferred approximately $21.2 million in 2004 related to bad debt costs.

In January 2006, the PSCW issued an order approving the amortization over the next five years of the bad debts deferred in 2004 for our gas operations. The bad debts deferred in 2004 related to electric operations will be considered for recovery in future rates, subject to audit and approval of the PSCW.

In December 2004, we filed with the PSCW a request to implement a pilot program, which, among other things, is designed to better match our collection efforts with the ability of low income customers to pay their bills. Included in this filing was a request to implement escrow accounting for all residential bad debt costs. In February 2005, the PSCW approved our pilot program and our request for the use of escrow accounting. The final decision was received in March 2005. The escrow method of accounting for bad debt costs allows for deferral of Wisconsin residential bad debt expense that exceed amounts allowed in rates. As a result of this approval from the PSCW, we escrowed approximately $3.7 million in 2006 and $17.2 million in 2005 related to bad debt costs. These amounts were not addressed in the January 2006 rate order, and will therefore be considered for recovery in future rates, subject to audit and approval of the PSCW. We will continue following the escrow method of accounting for bad debts as approved in the March 2005 PSCW order.

MISO Midwest Market: In January 2005, we requested deferral accounting treatment from the PSCW for certain incremental costs or benefits that may occur due to the implementation on April 1, 2005 of the MISO Midwest Market. We received approval for this accounting treatment in March 2005. Additionally, in March 2005 we submitted a joint proposal to the PSCW with other utilities requesting escrow accounting treatment for the MISO Midwest Market costs until each utility's first rate case following April 1, 2008. The purpose of the March 2005 request for escrow accounting was to provide clarification on costs not included in the March 2005 approval for deferral accounting treatment. The PSCW approved deferral treatment for these costs in June 2006. For additional information see Industry Restructuring and Competition -- Electric Transmission and Energy Markets -- MISO.

Wholesale Electric Rates: On August 1, 2006, Wisconsin Electric filed a wholesale rate case with FERC. The filing requests an annual increase in rates of approximately $16.7 million applicable to four existing wholesale electric customers. In November 2006, FERC accepted the rate filing subject to refund with interest; however, the rates have not yet been approved. Three of the existing customer's rates are effective January 1, 2007 and the remaining $16.5 million for the largest wholesale customers' rates will be effective May 1, 2007. The rates are subject to refund and hearing and settlement procedures.

Depreciation Rates: In January 2005, Wisconsin Electric and Wisconsin Gas filed a joint application with the PSCW for certification of depreciation rates for specific classes of utility plant assets. In November 2005, we received notice from the PSCW that the proposed estimated lives, net salvage values and depreciation rates were approved and became effective January 1, 2006. For more information, see Note A -- Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements.

Nuclear Refueling Outages - 2005: In May 2005, we requested and received approval from the PSCW to defer replacement power costs incurred after May 30, 2005 due to the longer-than-expected outage at Point Beach Unit 2. We deferred $22.1 million of incremental purchased power costs related to the extended outage.

Renewables, Efficiency and Conservation: In March 2006, Wisconsin enacted new public benefits legislation, Act 141. This legislation changes the renewable energy requirements for utilities. Act 141 requires Wisconsin utilities to provide 2% more of their total retail energy from renewable resources than their current levels by 2010, and 6% more renewable energy than their current levels by 2015. Act 141 establishes a statewide goal that 10% of all electricity in Wisconsin be generated by renewable resources by December 31, 2015. Assuming the bulk of additional renewables is wind turbines, Wisconsin Electric must obtain approximately 210 MW of additional renewable capacity by 2010 and another approximately 610 MW of additional renewable capacity by 2015 to meet the retail energy delivered requirements. We have already started development of additional sources of renewable energy to comply with commitments made as part of our PTF initiative which will assist us in complying with Act 141. See Wind Generation discussion below.

Act 141 allows the PSCW to delay a utility's implementation of the renewable portfolio standard if it finds that achieving the renewable requirement would be too expensive or would lessen reliability, or that new renewable projects could not be permitted on a timely basis or could not be served by adequate transmission facilities. The previous law did not include similar provisions. Act 141 provides that if a utility is in compliance with the renewable energy and energy efficiency requirements as determined by the PSCW, then the utility is considered in compliance with the Energy Priorities law. Prior to Act 141, there had been no agreement on how to determine compliance with the Energy Priorities law, which provides that it is the policy of the PSCW, to the extent it is cost-effective and technically feasible, to consider the following options in the listed order when reviewing energy-related applications: (1) energy conservation and efficiency, (2) noncombustible renewable energy resources, (3) combustible renewable energy resources, (4) natural gas, (5) oil or low sulfur coal and (6) high sulfur coal and other carbon-based fuels.

We are evaluating the requirements of Act 141. Additionally, the details of the new requirements are subject to administrative rulemaking that could take until March 2007 to complete.

Act 141 also redirects the administration of energy efficiency, conservation and renewable programs from the DOA back to the utilities and/or contracted third parties. In addition, the law requires that 1.2% of utilities' operating revenues be set aside for these programs. We do not expect the impact of this action to be material as the 1.2% approximates the amounts currently in our rates for these matters. The effective date of this action is July 1, 2007. The PSCW is expected to develop implementation plans over the upcoming months.

Wind Generation: In June 2005, we purchased the development rights to two wind farm projects (Blue Sky Green Field) from Navitas Energy Inc. We plan to develop the wind sites and construct wind turbines with a combined generating capacity of between approximately 130 and 200 MW. We filed for approval of a CPCN with the PSCW in March 2006. A prehearing conference was held in September 2006. In addition, our direct testimony was filed in September 2006. Staff and intervenor testimony was filed in October 2006 and rebuttal testimony by all parties was filed in November 2006. Hearings were held at the end of November 2006. In February 2007, the PSCW issued a written notice approving the CPCN. In addition to the CPCN approval, we are working to secure any additional permits necessary to commence construction. In early 2006, the United States Congress directed the Department of Defense and the Department of Homeland Security to investigate possible conflicts between military radar and wind turbine installations. In November 2006, we received confirmation that Blue Sky Green Field poses no such conflict, and to date the FAA has issued all requested permits for Blue Sky Green Field.

We estimate that the capital cost of the project, excluding AFUDC, will be up to $360 million. The demand for wind turbine equipment has been strong, pushing off equipment deliveries to dates later than originally anticipated. We currently expect the turbines to be placed in service by the end of 2008, dependent upon the availability of wind turbines and the receipt of necessary regulatory approvals.

ELECTRIC SYSTEM RELIABILITY

In response to customer demand for higher quality power required by modern equipment, we are evaluating and updating our electric distribution system. We are taking steps to reduce the likelihood of outages by upgrading substations and rebuilding lines to upgrade voltages and reliability. These improvements, along with better technology for analysis of our existing system, better resource management to speed restoration and improved customer communication, are near-term efforts to enhance our current electric distribution infrastructure. For the long-term, we have developed a distribution system asset management strategy that requires increased levels of automation of both substations and line equipment to consistently provide the level of reliability needed for a digital economy.

We had adequate capacity to meet all of our firm electric load obligations during 2006. All of our generating plants performed well during the warmest periods of the summer and all power purchase commitments under firm contract were received. During this period, public appeals for conservation were not required; however, pursuant to MISO's orders, we did interrupt or curtail service to non-firm customers who participate in load management programs in exchange for discounted rates.

We expect to have adequate capacity to meet all of our firm load obligations during 2007. However, extremely hot weather, unexpected equipment failure or unavailability could require us to call upon load management procedures during 2007 as we have in past years.

ENVIRONMENTAL MATTERS

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation challenges related to current and past operations. Specific environmental issues affecting our utility and non-utility energy segments include but are not limited to (1) air emissions such as CO_2, SO_2, NO_x, small particulates and mercury, (2) disposal of combustion by-products such as fly ash, (3) remediation of former manufactured gas plant sites, (4) disposal of used nuclear fuel and (5) the eventual decommissioning of Point Beach.

We are currently pursuing a proactive strategy to manage our environmental issues including (1) substituting new and cleaner generating facilities for older facilities as part of our PTF strategy, (2) developing additional sources of renewable electric energy supply, (3) water quality matters such as discharge limits and cooling water requirements, (4) adding emission control equipment to existing facilities to comply with new ambient air quality standards and federal clean air rules, (5) entering into agreements with the WDNR and EPA to reduce emissions of SO_2 and NO_x by more than 65% and mercury by 50% by 2013 from our coal-fired power plants in Wisconsin and Michigan, (6) evaluating and implementing improvements to our cooling water intake systems, (7) recycling of ash from coal-fired generating units and (8) the clean-up of former manufactured gas plant sites. The capital cost of implementing the EPA consent decree is estimated to be approximately $1 billion over the 10 years ending 2013. These costs are principally associated with the installation of air quality controls on Pleasant Prairie Units 1 and 2 and Oak Creek Units 5-8. Through December 31, 2006, we have spent approximately $355.0 million associated with implementing the EPA agreement. For further information concerning the consent decree, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in this report. For further information concerning disposal of used nuclear fuel and nuclear power plant decommissioning, see Nuclear Operations below and Note I -- Nuclear Operations in the Notes to Consolidated Financial Statements in this report, respectively.

National Ambient Air Quality Standards: In 2000 and 2001, Michigan and Wisconsin finalized state rules implementing phased emission reductions required to meet the NAAQS for 1-hour ozone. In 2004, the EPA began implementing NAAQS for 8-hour ozone and $PM_{2.5}$. The states are currently developing rules to implement the new standards. Although specific emission control requirements are not yet defined, we believe that the revised standards will likely require significant reductions in SO_2 and NO_x emissions from coal-fired generating facilities. We expect that reductions needed to achieve compliance with the 8-hour ozone attainment standard will be implemented in stages. Reductions associated with the fine particulate matter standards are expected to be implemented in stages after the year 2010 and extending to the year 2017. We are currently unable to predict the impact that the revised air quality standards might have on the operations of our existing coal-fired generating facilities until the states develop rules and submit State Implementation Plans (SIP) to the EPA to demonstrate how they intend to comply with the 8-hour ozone and fine particulate matter NAAQS.

8-hour Ozone Standard: In April 2004, the EPA designated 10 counties in Southeastern Wisconsin as nonattainment areas for the 8-hour ozone NAAQS. States are required to develop and submit SIPs to the EPA by June 2007 to demonstrate how they intend to comply with the 8-hour ozone NAAQS. We expect that reductions needed to achieve compliance with the 8-hour ozone attainment standard will be implemented in stages and that some or all of these reductions will be accomplished through implementation of the CAIR. See below for further information regarding CAIR. We believe that compliance with the NO_x emission reductions requirements under the agreements with the WDNR and EPA will substantially mitigate costs to comply with the EPA's 8-hour ozone NAAQS. However, the timing of the requirements may be impacted by requiring earlier installation of NO_x controls at some units, depending on how the states implement the rules.

$PM_{2.5}$ Standard: In December 2004, the EPA designated $PM_{2.5}$ non-attainment areas in the country. All counties in the State of Wisconsin and all counties in the Upper Peninsula of Michigan were designated as in attainment with the standard. It is unknown at this time whether Wisconsin or Michigan will require additional emission reductions as part of state or regional implementation of the $PM_{2.5}$ standard and what impact those requirements would have on operation of our existing coal-fired generation facilities.

Clean Air Interstate Rule: The EPA issued the final CAIR regulation in March 2005 to facilitate the states in meeting the 8-hour ozone and $PM_{2.5}$ standards by addressing the regional transport of SO_2 and NO_x. CAIR requires NO_x and SO_2 emission reductions in two phases from electric generating units located in a 28-state region within the eastern United States. Wisconsin and Michigan are affected states under CAIR. The phase 1 compliance deadline is January 1, 2009 for NO_x and January 1, 2010 for SO_2, and the phase 2 compliance deadline is January 1, 2015 for both NO_x and SO_2. Overall, the CAIR is expected to result in a 70% reduction in SO_2 emissions and a 65% reduction in NO_x emissions from 2002 emission levels. The states are required to develop and submit implementation plans by no later than March 2007. In Wisconsin, a final CAIR rule has been approved by the WDNR and is proceeding through the administrative process. Although the impacts are uncertain until the states' implementation plans are in place, we believe that compliance with the NO_x and SO_2 emission reductions requirements under the agreements with the WDNR and EPA will substantially mitigate costs to comply with the CAIR rule.

Clean Air Mercury Rule: The EPA issued the final CAMR in March 2005 following the agency's 2000 regulatory determination that utility mercury emissions should be regulated. CAMR limits mercury emissions from new and existing coal-fired power plants, and caps utility mercury emission in two phases, applicable in 2010 and 2018. The caps limit emissions at approximately 20% and ultimately 70% below today's utility mercury levels. The states were required to develop and submit implementation plans by November 2006, but neither state has finalized its plan yet. Until those plans are in place, it is not possible to estimate the final impact of the CAMR, but additional expenditures are anticipated in order to meet both phases of the federal rule. Because the technology is under development, it is difficult to estimate the cost. We believe the range of possible expenditures could be approximately $50 million to $200 million. The construction air permit issued for the Oak Creek expansion is not impacted by the new rule.

The federal rule is being challenged by a number of states including Wisconsin and Michigan. Depending on the litigation, the timing for compliance may be affected.

The WDNR independently developed mercury emission control rules that affect electric utilities in Wisconsin and issued state-only mercury control rules in October 2004. The rules explicitly recognize an underlying state statutory restriction that state regulations cannot be more stringent than those included in any federal program. The rules state that the WDNR must adopt state rule changes within 18 months of publication of any federal rules. State rules are to be changed to be consistent with, and no more restrictive than, any federal rules. It is not possible to determine if there will be requirements in addition to CAMR until a rule is in place or the existing rule is set aside. Because the 18 month deadline has passed, we are reviewing our options.

Clean Air Visibility Rule: The EPA issued the CAVR in June 2005 to address regional haze, or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines BART requirements for electric generating units and how BART will be addressed in the 28 states subject to EPA's CAIR. Under CAVR, states are required to identify certain industrial facilities and power plants that affect visibility in the nation's 156 Class I protected areas. States then determine the types of emission controls that those facilities must use to control their emissions. The pollutants from power plants that reduce visibility include particulate matter or compounds that contribute to fine particulate formation, NO_x, SO_2 and ammonia. States must submit plans to implement CAVR to the EPA by December 2007. The reductions associated with the state plans are scheduled to begin to take effect in 2014 with full implementation before 2018. We are currently unable to predict the impact that CAVR might have on the operations of our existing coal-fired generating facilities until the states develop rules and submit implementation plans to the EPA.

Clean Water Act: Section 316(b) of the CWA requires that the location, design, construction and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact. This law dates back to 1972; however, prior to September 2004, there were no federal rules that defined precisely how states and EPA regions determined that an existing intake met BTA requirements. This rule established, for the first time, national performance standards and compliance alternatives for existing facilities that are designed to minimize the potential adverse environmental impacts to aquatic organisms associated with water withdrawals from cooling water intakes. Costs associated with implementation of the rule for Wisconsin Electric's Oak Creek Power Plant, We Power's Oak Creek expansion and PWGS have been included in project costs. Studies to determine what costs, if any, that may be associated with Wisconsin Electric's other existing facilities are expected to take place over the next two years.

On January 26, 2007, the Federal Court of Appeals for the Second Circuit issued a decision concerning the 316(b) rule for existing facilities (Riverkeeper, Inc. v. EPA, Nos. 04-6692-ag(L) (2d Cir. 2007)). The Second Circuit Court found certain portions of the rule impermissible and remanded several parts of the rule to the EPA for further consideration or potential additional rulemaking. Until such time as the EPA completes those actions, we cannot predict what impact the changes, if any, to the rule may have on our facilities.

Manufactured Gas Plant Sites: We are voluntarily reviewing and addressing environmental conditions at a number of former manufactured gas plant sites. For further information, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Ash Landfill Sites: We aggressively seek environmentally acceptable, beneficial uses for our combustion byproducts. For further information, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

EPA - Proposed Consent Decree: Wisconsin Electric entered into a proposed consent decree with the EPA to address all matters relating to information requests received from the EPA pursuant to Section 114(a) of the Clean Air Act. For further information, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Greenhouse Gases: There have been international efforts seeking legally binding reductions in emissions of greenhouse gases, principally CO_2, including the United Nations Framework Convention on Climate Change held in Kyoto, Japan. While the Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other legislation requiring reductions in CO_2, in 2002, the Bush Administration announced a goal of reducing the greenhouse gas intensity of the U.S. economy by 18% by 2012. In addition, in December 2004, the DOE announced the Climate VISION program in furtherance of reduced greenhouse gas emissions. We continue to take voluntary measures to reduce our emissions of greenhouse gases. However, legislative proposals that would impose mandatory restrictions on CO_2 continue to be considered in Congress. The impact of any future legislation that would require reductions in greenhouse gases cannot be assessed at this time.

We continue to support flexible, market-based strategies to curb greenhouse gas emissions. These strategies include emissions trading, joint implementation projects and credit for early actions. We also support a voluntary approach that encourages technology development and transfer and includes all sectors of the economy and all significant global emitters.

Our emissions in future years will continue to be influenced by several actions completed, planned or underway as part of the PTF strategy, including:

- Repowering the Port Washington Power Plant from coal to natural gas combined cycle units.
- Adding coal-fired units using state-of-the-art technology as part of the Oak Creek expansion.
- Increasing investment in energy efficiency and conservation.
- Maintaining and increasing non-emitting generation by potentially adding approximately 130 to 200 MW of wind capacity and increasing customer participation in the Energy for Tomorrow ® renewable energy program.
- Successful renewal of the Point Beach units' operating licenses.

LEGAL MATTERS

Arbitration Proceedings: Our largest electric customers, two iron ore mines, operate in the Upper Peninsula of Michigan. The mines represent approximately 6% to 7% of our annual electric sales; however, the earnings are insignificant to us. The mines have special negotiated contracts that expire in December 2007. The contracts have price caps for approximately 80% of the energy sales. We do not recognize revenue on amounts billed that exceed the price caps.

The incremental power costs in the Upper Peninsula of Michigan are now determined by MISO. In April 2005, we began to bill the mines the incremental power costs as quantified by the MISO Midwest Market. The mines have notified us that they are disputing these billings and a portion of these disputed amounts have been deposited in escrow. In September 2005, the mines notified us that they filed for formal arbitration related to the contracts. We have notified the mines that we believe that they have failed to comply with certain notification provisions related to annual production as specified within the contracts. The arbitration hearings previously

scheduled for October 2006 have been postponed and rescheduled for the third quarter of 2007 and we anticipate a decision in the fourth quarter of 2007. As of December 31, 2006, the mines have placed $29.3 million in escrow. As of December 31, 2005, the mines had placed $70.6 million in escrow. The decrease in the escrow balance relates to amounts that we refunded without interest for the amounts billed in 2005 that exceeded the price caps. At this time, we are unable to predict the outcome of the formal arbitration process, but we believe that it will not have a material adverse impact on our financial condition or results of operations.

Although it is currently uncertain, we anticipate that we will provide power to the mines under the terms of one or more regulated tariffs to be approved by the MPSC beginning January 1, 2008.

Stray Voltage: On July 11, 1996, the PSCW issued a final order regarding the stray voltage policies of Wisconsin's investor-owned utilities. The order clarified the definition of stray voltage, affirmed the level at which utility action is required, and placed some of the responsibility for this issue in the hands of the customer. Additionally, the order established a uniform stray voltage tariff which delineates utility responsibility and provides for the recovery of costs associated with unnecessary customer demanded services.

In recent years, dairy farmers have commenced actions or made claims against Wisconsin Electric for loss of milk production and other damages to livestock allegedly caused by stray voltage, and more recently, ground currents resulting from the operation of its electrical system, even though that electrical system has been operated within the parameters of the PSCW's order. In 2003, the Wisconsin Supreme Court upheld a Court of Appeals' affirmance of a jury verdict against Wisconsin Electric, awarding $1.2 million to the plaintiffs in a stray voltage lawsuit. The Supreme Court rejected the argument that if a utility company's measurement of stray voltage is below the PSCW "level of concern," that utility could not be found negligent in stray voltage cases. Additionally, the Court held that the PSCW regulations regarding stray voltage were only minimum standards to be considered by a jury in stray voltage litigation.

As a result of this case, claims by dairy farmers for livestock damage have been based upon ground currents with levels measuring less than the PSCW level of concern. Even though the claims which have been made against Wisconsin Electric with respect to stray voltage and ground currents are not expected to have a material adverse effect on its financial statements, we continue to evaluate various options and strategies to mitigate this risk.

NUCLEAR OPERATIONS

Point Beach Nuclear Plant: Wisconsin Electric owns two 518 MW electric generating units (Unit 1 and Unit 2) at Point Beach in Two Rivers, Wisconsin. Point Beach is operated by NMC, a joint venture of the Company and affiliates of other unaffiliated utilities. During 2006, 2005 and 2004, Point Beach provided approximately 25.3%, 20.0% and 23.7%, respectively, of Wisconsin Electric's net electric energy supply.

Each unit at Point Beach has a scheduled refueling outage approximately every 18 months. A refueling outage is scheduled for first quarter 2007. In the fourth quarter of 2006, Unit 2 had a scheduled refueling outage. In 2005, Unit 2 had a scheduled refueling outage over the second and third quarters, and Unit 1 had a scheduled refueling outage over the third and fourth quarters. During the 2005 scheduled refueling outages we replaced the reactor vessel heads at each unit. As expected, this work, along with other planned maintenance, resulted in longer than normal outages. During scheduled refueling outages, we incur significant operations and maintenance costs for work performed during the outages and we incur costs associated with replacement power. See Results of Operations for further discussion regarding the costs associated with nuclear outages. In 2004, Unit 1 had a scheduled refueling outage in the second quarter.

In December 2005, the NRC approved the request of NMC and Wisconsin Electric for license renewal. The new operating licenses expire in October 2030 for Unit 1 and March 2033 for Unit 2.

In February 2006, we announced that we were undertaking a formal review during 2006 regarding our options for the ownership and operation of Point Beach. At December 31, 2006, NMC operated six nuclear generating units. In addition, another owner has announced the planned sale of its unit. This sale would further reduce the size of the fleet operated by NMC. Given these changes, we believed it was prudent to evaluate a range of options for Point Beach. The options that we evaluated included: (1) continued operation by NMC, (2) continued operation by a third party operator other than NMC, (3) a return to in-house operation of the plant by Wisconsin Electric, (4) a sale of the Point Beach facility and (5) a partial sale of the plant with us retaining a minority interest in the Plant. Under this fifth option, the new majority owner would operate the plant. As part of our continuing review, we invited qualified third parties to tour Point Beach and review the data necessary to submit a bid to operate the plant or purchase all or part of the plant and operate it. We evaluated the bids received in comparison to continued operation of Point Beach by NMC or Wisconsin Electric. In December 2006, we announced that we had reached a definitive agreement to sell Point Beach to an affiliate of FPL. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us) NMC would transfer Point Beach's operating licenses to the buyer and we would withdraw from NMC and our relationship with NMC would be terminated. We would be required to pay a termination fee of approximately $12 million to withdraw from NMC and write-off our investment in NMC which is approximately $5 million at December 31, 2006. We also entered into a long-term power purchase agreement to

purchase all of the existing capacity and energy of the plant, which will become effective upon the closing of the sale. Wisconsin Electric will have the unilateral option, subject to PSCW direction, to select a term for the power purchase agreement of either (i) an estimated 23 years for Unit 1 and 26 years for Unit 2, or (ii) 16 years for Unit 1 and 17 years for Unit 2. The sale of the plant and the long-term power purchase agreement are subject to review and approval by various regulatory agencies including the NRC, the PSCW, the MPSC and FERC. We have submitted a request to the PSCW to defer any gain (net of transaction related costs) as a regulatory liability that would be applied to the benefit of our customers in future rate proceedings.

In July 2000, our senior management authorized the commencement of initial design work for the power uprate of both units at Point Beach. Subject to approval by the PSCW, the project could add approximately 90 MW of electrical output to Point Beach. In February 2003, Point Beach completed an equipment upgrade which resulted in a capacity increase of 7 MW per generating unit. If the proposed sale of Point Beach is completed, the uprate will be the responsibility of the new owner, FPL. In light of this, both companies are currently evaluating the timing for implementation of the power uprate project.

During 2002 and 2003, the NRC issued Final Significance Determination letters for two red (high safety significance) inspection findings regarding problems identified by Point Beach with the performance of the auxiliary feedwater system recirculation lines. During 2003, the NRC conducted a three-phase supplemental inspection of Point Beach in accordance with NRC Inspection Procedure 95003 to review corrective actions for the findings as well as the effectiveness of the corrective action, emergency preparedness and engineering programs.

The inspection results were presented at a public meeting in December 2003, and documented in a February 2004 NRC letter to NMC. The NRC determined that the plant is being operated in a manner that ensures public safety but also identified several performance issues in the areas of problem identification and resolution, emergency preparedness, electrical design basis calculation control and engineering-operations communication.

NMC responded to the supplemental inspection in February 2004 with specific commitments to address the NRC concerns, including revision of the Point Beach Excellence Plan. We were assessed a fine of $60,000 related to issues identified with our emergency preparedness. NRC reviewed the adequacy of the revised Excellence Plan and its implementation, and NMC received a confirmatory action letter in April 2004. Since then, the NRC has conducted numerous inspections and completed reviews of activities and meetings, noting the overall results were satisfactory. As a result, in the fourth quarter of 2006, the NRC closed the confirmatory action letter and concluded that the red findings received in 2002 and 2003 will no longer be considered in the NRC's assessment process. Point Beach will now receive routine baseline inspection by the NRC.

As a result of the September 11, 2001 terrorist attacks, the NRC and the industry have been strengthening security at nuclear power plants. Security at Point Beach remains at a high level, with limited access to the site continuing. Point Beach has responded to the NRC's February 2002 Order for interim safeguards and security compensatory measures. Point Beach has also responded to NRC orders regarding security of independent spent fuel storage installations, design basis threat and security officer training and work hours.

Used Nuclear Fuel Storage and Disposal: Wisconsin Electric is authorized by the PSCW to load and store sufficient dry fuel storage containers to allow Point Beach Units 1 and 2 to operate to the end of their original operating licenses, but not to exceed the original 48-canister capacity of the dry fuel storage facility. The original operating licenses were set to expire in October 2010 for Unit 1 and in March 2013 for Unit 2 before they were renewed and extended by the NRC in December 2005.

Temporary storage alternatives at Point Beach are necessary until the DOE takes ownership of and permanently removes the used fuel as mandated by the Nuclear Waste Policy Act of 1982, as amended in 1987. The Nuclear Waste Policy Act established the Nuclear Waste Fund which is composed of payments made by the generators and owners of such waste and fuel. Effective January 31, 1998, the DOE failed to meet its contractual obligation to begin removing used fuel from Point Beach, a responsibility for which Wisconsin Electric has paid a total of $215.2 million into the Nuclear Waste Fund over the life of Point Beach.

On August 13, 2000, the United States Court of Appeals for the Federal Circuit ruled in a lawsuit brought by Maine Yankee and Northern States Power Company that the DOE's failure to begin performance by January 31, 1998 constituted a breach of the Standard Contract, providing clear grounds for filing complaints in the Court of Federal Claims. Consequently, Wisconsin Electric filed a complaint on November 16, 2000 against the DOE in the Court of Federal Claims. In October 2004, the Court of Federal Claims granted Wisconsin Electric's motion for summary judgment on liability. The Court has subsequently scheduled a trial to determine damages for September 2007. Wisconsin Electric has incurred substantial damages to date and damages continue to accrue. We are seeking recovery of our damages in this lawsuit and we expect that any recoveries would be considered in setting future rates.

In July 2002, the President signed a resolution which allowed the DOE to begin preparation of the application to the NRC for a license to design and build a spent fuel repository in Yucca Mountain, Nevada. In July 2006, the DOE announced plans to submit a license application to the NRC for a nuclear waste repository at Yucca Mountain no later than June 30, 2008. The DOE also announced that if the requested legislative changes are enacted, the repository would be able to accept spent nuclear fuel starting in early 2017. It is not possible, at this time, to predict with certainty when the DOE will actually begin accepting used nuclear fuel.

INDUSTRY RESTRUCTURING AND COMPETITION

Electric Utility Industry

The regulated energy industry continues to experience significant changes. FERC continues to support large RTOs, which will affect the structure of the wholesale market. To this end, the MISO implemented a bid-based market, the MISO Midwest Market, including the use of LMP to value electric transmission congestion and losses. The MISO Midwest Market commenced operation on April 1, 2005. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us. It is uncertain when retail access might be implemented in Wisconsin; however, Michigan has adopted retail choice which potentially affects our Michigan operations. In August 2005, President Bush signed into law the Energy Policy Act, which impacts the electric utility industry. (See Other Matters below for additional information on the Energy Policy Act). In addition, major issues in industry restructuring, implementation of RTO markets and market power mitigation received substantial attention in 2006 and prior years. We continue to focus on infrastructure issues through our PTF growth strategy.

Restructuring in Wisconsin: Electric utility revenues in Wisconsin are regulated by the PSCW. Due to many factors, including relatively competitive electric rates charged by the state's electric utilities, the PSCW has been focused in recent years on electric reliability infrastructure issues for the State of Wisconsin. These issues include:

- Addition of new generating capacity in the state;
- Modifications to the regulatory process to facilitate development of merchant generating plants;
- Development of a regional independent electric transmission system operator;
- Improvements to existing and addition of new electric transmission lines in the state; and
- Addition of renewable generation.

The PSCW continues to maintain the position that the question of whether to implement electric retail competition in Wisconsin should ultimately be decided by the Wisconsin legislature. No such legislation has been introduced in Wisconsin to date.

Restructuring in Michigan: Electric utility revenues are regulated by the MPSC. In June 2000, the Governor of Michigan signed the "Customer Choice and Electric Reliability Act" into law empowering the MPSC to implement electric retail access in Michigan. The new law provides that as of January 1, 2002, all Michigan retail customers of investor-owned utilities have the ability to choose their electric power producer.

As of January 1, 2002, our Michigan retail customers were allowed to remain with their regulated utility at regulated rates or choose an alternative electric supplier to provide power supply service. We have maintained our generation capacity and distribution assets and provide regulated service as we have in the past. We continue providing distribution and customer service functions regardless of the customer's power supplier.

Competition and customer switching to alternative suppliers in the companies' service territories in Michigan has been limited. With the exception of two general inquiries, no alternate supplier activity has occurred in our service territories in Michigan, reflecting the small market area, our competitive regulated power supply prices and a lack of interest in general in the Upper Peninsula of Michigan as a market for alternative electric suppliers.

Restructuring in Illinois: In 1999, the State of Illinois passed legislation that introduced retail electric choice for large customers and introduced choice for all retail customers in May 2002. This legislation has not had, and is not expected to have a material impact on Wisconsin Electric's business. Wisconsin Electric had one wholesale customer in Illinois, the City of Geneva, whose contract expired on December 31, 2005.

Electric Transmission and Energy Markets

ATC: ATC is regulated by FERC for all rate terms and conditions of service and is a transmission-owning member of MISO. As of February 1, 2002, operational control of ATC's transmission system was transferred to MISO, and Wisconsin Electric and Edison Sault became non-transmission owning members and customers of MISO.

MISO: In connection with its status as a FERC approved RTO, MISO implemented a bid-based energy market, the MISO Midwest Market, which commenced operations on April 1, 2005. As part of this energy market, the MISO developed a market-based platform for valuing transmission congestion and losses premised upon the LMP system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through the use of FTRs. FTRs are allocated to market participants by MISO. A new allocation of FTRs was completed for the period of June 1, 2006 through May 31, 2007. We were granted substantially all of the FTRs that we were permitted to request during the allocation process. Previously, our unhedged congestion costs had not been explicitly identified and were embedded in our fuel and purchased power expenses. Due to

certain changes in the units that MISO is dispatching, our unhedged congestion costs increased in 2006. These incremental congestion charges are deferred as approved by the PSCW, and we expect to recover these costs in future rates, subject to review and approval by the PSCW.

MISO deferred the costs to develop and start-up its energy market (new software systems and personnel). Now that the market is operational, the development and start-up costs are charged to MISO market participants, including Wisconsin Electric and Edison Sault.

To mitigate the risks of this new bid-based energy market, we requested deferral accounting treatment from the PSCW in January 2005 for certain incremental costs or benefits that may occur due to the implementation of the MISO Midwest Market. Our request excluded LMP energy costs because these costs are subject to recovery under the Wisconsin Fuel Cost Adjustment Procedure. In March 2005, the PSCW accepted our request. We submitted another joint proposal with other utilities in March 2005, requesting escrow accounting treatment for MISO Midwest Market costs until each utility's first rate case following April 1, 2008. The purpose of the March 2005 request for escrow accounting was to provide clarification on costs not included in the March 2005 approval for deferral accounting treatment. The PSCW approved deferral treatment for these costs in June 2006.

In MISO, base transmission costs are currently being paid by LSE's located in the service territories of each MISO transmission owner. The current license plate transmission rate design is scheduled to be replaced on February 1, 2008. A filing delineating a new rate design, or substantiation for maintaining the existing rate design is due at FERC by August 1, 2007. At this time, we are not able to determine the impact of this rate design change on our transmission costs. FERC also ordered a seams elimination charge to be paid by MISO LSE's from December 1, 2004 until March 31, 2006, to compensate transmission owners for the loss of revenues resulting from the joining of a RTO and/or FERC's elimination of through and out transmission charges between the MISO and PJM. FERC ordered that certain existing transmission transactions continue to pay for through and out service from December 1, 2004 until March 31, 2006. The details of the seams elimination charge and the quantification of the existing transaction charge are the subject of a hearing process initiated by FERC in a February 2005 order. In January 2006, Wisconsin Electric along with certain other parties to the proceeding, submitted an offer of settlement to the presiding administrative law judge that resolved all issues set for hearing that impact Wisconsin Electric with regard to the continued payment of through and out transmission charges as well as the seams elimination charge. The administrative law judge certified the settlement to FERC, and FERC approved the settlement in April 2006.

In April 2006, FERC issued an order determining that MISO had not applied its energy markets tariff correctly in the assessment of Revenue Sufficiency Guarantee charges. FERC ordered MISO to resettle all affected transactions retroactive to April 1, 2005. In October 2006, we received a ruling from FERC. Since the ruling, FERC's order has been challenged by MISO and numerous other market participants. Any resettlement associated with the order is expected in 2007 and early 2008. Due to the complexity of the order, we are unable to precisely determine the overall financial implication to us. However, we do not believe that the result will have a material impact on our results of operations.

MISO is in the process of developing a market for two ancillary services, regulation reserves and contingency reserves. The MISO ancillary services market is currently proposed to begin in 2008. We currently self-provide both regulation reserves and contingency reserves. In the MISO ancillary services market, we expect that we will buy/sell regulation and contingency reserves from/to the market. The MISO ancillary services market is expected to reduce overall ancillary services costs in the MISO footprint. We anticipate achieving a net reduction in fuel costs, but are unable to determine the amount of savings we will realize at this time. The MISO ancillary services market is expected to also enable MISO to assume significant balancing area responsibilities such as frequency control and disturbance control.

Natural Gas Utility Industry

Restructuring in Wisconsin: The PSCW previously instituted generic proceedings to consider how its regulation of gas distribution utilities should change to reflect the changing competitive environment in the natural gas industry. To date, the PSCW has made a policy decision to deregulate the sale of natural gas in customer segments with workably competitive market choices and has adopted standards for transactions between a utility and its gas marketing affiliates. However, work on deregulation of the gas distribution industry by the PSCW is presently on hold. Currently, we are unable to predict the impact of potential future deregulation on our results of operations or financial position.

OTHER MATTERS

Energy Policy Act: In August 2005, President Bush signed into law the Energy Policy Act. Among other things, the Energy Policy Act includes tax subsidies for electric utilities and the repeal of PUHCA 1935. The Energy Policy Act also amends federal energy laws and provides FERC with new oversight responsibilities for the electric utility industry. Implementation of the Energy Policy Act requires the development of regulations by federal agencies, including FERC. As noted above, the Energy Policy Act and corresponding rules required us to seek FERC authorization to allow Wisconsin Electric to lease from We Power the three PTF units that are currently being constructed by We Power. We received approval of these leases from FERC in December 2006.

Additionally, the Energy Policy Act repealed PUHCA 1935 and enacted PUHCA 2005, transferring jurisdiction over holding companies from the SEC to FERC. Wisconsin Energy and Wisconsin Electric were exempt holding companies under PUHCA 1935, and, accordingly, were exempt from that law's provisions other than with respect to certain acquisitions of securities of a public utility. In March 2006, Wisconsin Energy and Wisconsin Electric each filed with FERC notification of its status as a holding company as required under FERC regulations implementing PUHCA 2005 and a request for exempt status similar to that held under PUHCA 1935. In June 2006, Wisconsin Energy and Wisconsin Electric received notice from FERC confirming their status as holding companies as required under FERC regulations implementing PUHCA 2005 and granting exempt status similar to that held under PUHCA 1935. As federal agencies continue to develop new rules to implement the Energy Policy Act, we expect additional impacts on Wisconsin Energy and its subsidiaries in the future.

Pension Reform: In August 2006, President Bush signed the Pension Protection Act of 2006. We are currently evaluating the Pension Protection Act of 2006, but we do not anticipate it will have a material impact on our results of operations or cash flows from operating activities.

Guardian: In April 2006, we sold our one-third interest in Guardian to an affiliate of Northern Border Partners, L.P. for approximately $38.5 million. The sale generated an after-tax gain of approximately $1.7 million. Guardian owns an interstate natural gas pipeline from the Joliet, Illinois market hub to southeastern Wisconsin that is designed to serve the growing demand for natural gas in Wisconsin and Northern Illinois. Guardian Pipeline began commercial operation in early December 2002. We have committed to purchase 650,000 Dth (approximately 87% of the pipeline's total capacity) per day of capacity on the pipeline over a long-term contract that expires in December 2022.

ACCOUNTING DEVELOPMENTS

New Pronouncements: See Note B -- Recent Accounting Pronouncements in the Notes to Consolidated Financial Statements in this report for information on new accounting pronouncements.

CRITICAL ACCOUNTING ESTIMATES

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions. In addition, the financial and operating environment also may have a significant effect, not only on the operation of our business, but on our results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed.

The following is a list of accounting policies that are most significant to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective or complex judgments.

Regulatory Accounting: Our utility subsidiaries operate under rates established by state and federal regulatory commissions which are designed to recover the cost of service and provide a reasonable return to investors. Under SFAS 71, the actions of our regulators may allow us to defer costs that non-regulated entities would expense. The actions of our regulators may also require us to accrue liabilities that non-regulated companies would not. As of December 31, 2006, we had $1,091.0 million in regulatory assets and $1,472.1 million in regulatory liabilities. In the future, if we move to market based rates or if the actions of our regulators change we may conclude that we are unable to follow SFAS 71. In this situation, continued deferral of certain regulatory asset and liability amounts on the utilities' books, as allowed under SFAS 71, may no longer be appropriate and the unamortized regulatory assets net of the regulatory liabilities would be recorded as an extraordinary after-tax non-cash charge to earnings. We continually review the applicability of SFAS 71 and have determined that it is currently appropriate to continue following SFAS 71. In addition, each quarter we perform a review of our regulatory assets and our regulatory environment and we evaluate whether we believe that it is probable that we will recover the regulatory assets in future rates. See Note C -- Regulatory Assets and Liabilities in the Notes to Consolidated Financial Statements for additional information.

Pension and Other Post-retirement Benefits: Our reported costs of providing non-contributory defined pension benefits (described in Note O -- Benefits in the Notes to Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension costs are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions made to plans and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

In accordance with SFAS 87 and SFAS 158, changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants.

The following chart reflects pension plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant.

Pension Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate	$7.3
0.5% decrease in expected rate of return on plan assets	$4.8

In addition to pension plans, we maintain other post-retirement benefit plans which provide health and life insurance benefits for retired employees (described in Note O -- Benefits in the Notes to Consolidated Financial Statements). We account for these plans in accordance with SFAS 106. Our reported costs of providing these post-retirement benefits are dependent upon numerous factors resulting from actual plan experience including employee demographics (age and compensation levels), our contributions to the plans, earnings on plan assets and health care cost trends. Changes made to the provisions of the plans may also impact current and future post-retirement benefit costs. Other post-retirement benefit costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the post-retirement benefit obligation and post-retirement costs. Our other post-retirement benefit plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns, as well as changes in general interest rates, may result in increased or decreased other post-retirement costs in future periods. Similar to accounting for pension plans, the regulators of our utility segment have adopted SFAS 106 for rate making purposes.

The following chart reflects other post-retirement benefit plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant.

OPEB Plans Actuarial Assumption	Impact on Reported Annual Cost (Millions of Dollars)
0.5% decrease in discount rate	$2.1
0.5% decrease in health care cost trend rate	($2.8)
0.5% decrease in expected rate of return on plan assets	$0.9

Unbilled Revenues: We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses and applicable customer rates. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total utility operating revenues during 2006 of $3,979.0 million included accrued utility revenues of $257.8 million as of December 31, 2006.

Asset Retirement Obligations: We account for legal liabilities for asset retirements at fair value in the period in which they are incurred according to the provisions of SFAS 143 and FIN 47. SFAS 143 applies primarily to decommissioning costs for Point Beach included in our utility energy segment. Using a discounted future cash flow methodology, our estimated nuclear asset retirement obligation was approximately $325.6 million at December 31, 2006. As it relates to our operations, FIN 47 applies primarily to asbestos removal costs. At December 31, 2006, we recorded an obligation of $39.6 million related to asbestos.

Calculation of the nuclear decommissioning asset retirement obligation is based upon projected decommissioning costs calculated by an independent decommissioning consulting firm, as well as several significant assumptions including the timing of future cash flows, future inflation rates and the discount rate applied to future cash flows. Assuming the following changes in key assumptions and holding all other assumptions constant, we estimate that our nuclear asset retirement obligation at December 31, 2006 would have changed by the following amounts:

Change in Assumption	Change in Liability (Millions of Dollars)
1% increase in inflation rate	$106.7
1% decrease in inflation rate	($79.8)

We were unable to identify a viable market for or third party who would be willing to assume this liability. Accordingly, we have used a market-risk premium of zero when measuring our nuclear asset retirement obligation. We estimate that for each 1% increment that would be included as a market-risk premium, our nuclear asset retirement obligation would increase by approximately $3.3 million.

For additional information concerning SFAS 143 and our estimated nuclear asset retirement obligation, see Note F -- Asset Retirement Obligations and Note I -- Nuclear Operations in the Notes to Consolidated Financial Statements.

Deferred Tax Assets Valuation Allowance: We record deferred tax asset valuation allowances in accordance with SFAS 109. As of December 31, 2006, we had approximately $3.4 million of valuation allowances that relate to state NOLs of various non-utility subsidiaries. These NOLs begin to expire in 2008 and it is not likely that we will be able to utilize them.

During 2006 and 2005, we reduced our valuation allowances by $5.8 million and $16.3 million respectively, as we were able to conclude that it was likely that we would be able to realize certain state NOLs recorded at certain of the non-utility subsidiaries in 2006 and at the Parent company in 2005. The 2005 conclusion was based on the favorable decision by the Supreme Court of Wisconsin in June 2005 that allowed the construction of the Oak Creek expansion as part of our PTF plan.

The PTF generating units will be owned by our subsidiaries organized as LLCs. Once the plants become operational, taxable income or loss of the LLCs will flow through to and be reported in the separate state income tax return of the Parent. As a result, the Parent no longer expects to generate large state taxable losses if all plants are in service. During 2005, the first of the four generating units was put into service. The determination of future state taxable income of the Parent is a significant estimate. Factors affecting the estimate include the amounts spent and timing for construction of the PTF generating units, the amount of debt and interest expense at the Parent and the consideration of available tax planning strategies.

If we would conclude in a future period that it was more likely than not that some or all of the remaining state NOLs would be realized before expiration, GAAP would require that we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported as an increase or decrease in income.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED INCOME STATEMENTS
Year Ended December 31

	2006	2005	2004
	(Millions of Dollars, Except Per Share Amounts)		
Operating Revenues	$ 3,996.4	$ 3,815.5	$ 3,406.1
Operating Expenses			
Fuel and purchased power	802.0	776.7	591.7
Cost of gas sold	1,018.3	1,047.3	890.9
Other operation and maintenance	1,183.7	1,007.9	986.7
Depreciation, decommissioning and amortization	326.4	332.0	319.5
Property and revenue taxes	97.5	88.7	87.3
Total Operating Expenses	3,427.9	3,252.6	2,876.1
Operating Income	568.5	562.9	530.0
Equity in Earnings of Transmission Affiliate	38.6	34.6	30.1
Other Income and Deductions, net	53.1	28.7	(14.3)
Interest Expense	172.7	173.4	193.4
Income from Continuing Operations Before Income Taxes	487.5	452.8	352.4
Income Taxes	175.0	149.2	132.8
Income from Continuing Operations	312.5	303.6	219.6
Income from Discontinued Operations, Net of Tax	3.9	5.1	86.8
Net Income	$ 316.4	$ 308.7	$ 306.4
Earnings Per Share (Basic)			
Continuing Operations	$ 2.67	$ 2.59	$ 1.87
Discontinued Operations	0.03	0.05	0.73
Total Earnings Per Share (Basic)	$ 2.70	$ 2.64	$ 2.60
Earnings Per Share (Diluted)			
Continuing Operations	$ 2.64	$ 2.56	$ 1.84
Discontinued Operations	0.03	0.05	0.73
Total Earnings Per Share (Diluted)	$ 2.67	$ 2.61	$ 2.57
Weighted Average Common Shares Outstanding (Millions)			
Basic	117.0	117.0	117.7
Diluted	118.4	118.4	119.1

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31

ASSETS

	2006	2005
	(Millions of Dollars)	
Property, Plant and Equipment		
In service	$ 9,265.4	$ 8,849.6
Accumulated depreciation	(3,423.7)	(3,288.5)
	5,841.7	5,561.1
Construction work in progress	992.4	596.6
Leased facilities, net	87.5	93.2
Nuclear fuel, net	130.9	112.0
Net Property, Plant and Equipment	7,052.5	6,362.9
Investments		
Nuclear decommissioning trust fund	881.6	782.1
Equity investment in transmission affiliate	228.5	205.8
Other	54.7	92.1
Total Investments	1,164.8	1,080.0
Current Assets		
Cash and cash equivalents	37.0	73.2
Accounts receivable, net of allowance for doubtful accounts of $35.1 and $36.6	379.3	441.8
Accrued revenues	257.8	262.9
Materials, supplies and inventories	417.2	451.6
Prepayments and other	136.7	147.5
Total Current Assets	1,228.0	1,377.0
Deferred Charges and Other Assets		
Regulatory assets	1,091.0	1,025.6
Goodwill, net	441.9	441.9
Other	152.0	174.6
Total Deferred Charges and Other Assets	1,684.9	1,642.1
Total Assets	$ 11,130.2	$ 10,462.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31

CAPITALIZATION AND LIABILITIES

	2006	2005
	(Millions of Dollars)	
Capitalization		
Common equity	$ 2,889.0	$ 2,680.1
Preferred stock of subsidiary	30.4	30.4
Long-term debt	3,073.4	3,031.0
Total Capitalization	5,992.8	5,741.5
Current Liabilities		
Long-term debt due currently	296.7	496.0
Short-term debt	911.9	456.3
Accounts payable	404.5	418.1
Payroll and vacation accrued	79.3	75.2
Accrued taxes	56.6	31.0
Accrued interest	25.3	28.2
Other	113.7	142.0
Total Current Liabilities	1,888.0	1,646.8
Deferred Credits and Other Liabilities		
Regulatory liabilities	1,472.1	1,373.2
Asset retirement obligations	371.7	355.5
Deferred income taxes - long-term	572.9	593.7
Accumulated deferred investment tax credits	52.0	56.3
Pension liability	195.9	274.4
Other long-term liabilities	584.8	420.6
Total Deferred Credits and Other Liabilities	3,249.4	3,073.7
Commitments and Contingencies (Note S)		
Total Capitalization and Liabilities	$ 11,130.2	$ 10,462.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
Year Ended December 31

	2006	2005	2004
		(Millions of Dollars)	
Operating Activities			
Net income	$ 316.4	$ 308.7	$ 306.4
Reconciliation to cash			
Depreciation, decommissioning and amortization	336.8	350.0	352.6
Nuclear fuel expense amortization	28.7	23.0	24.0
Equity in earnings of transmission affiliate	(38.6)	(34.6)	(30.1)
Distributions from transmission affiliate	30.4	27.0	23.2
Deferred income taxes and investment tax credits, net	(54.0)	63.4	6.5
Deferred revenue	80.3	54.7	44.8
Change in - Accounts receivable and accrued revenues	61.2	(124.6)	(48.9)
Inventories	34.4	(48.5)	(20.4)
Other current assets	(26.5)	6.5	(20.0)
Accounts payable	(36.3)	93.4	37.6
Accrued income taxes, net	50.2	6.1	(8.5)
Deferred costs, net	(29.1)	(132.6)	(36.3)
Other current liabilities and other	(24.1)	(15.6)	(31.9)
Cash Provided by Operating Activities	729.8	576.9	599.0
Investing Activities			
Capital expenditures	(928.7)	(745.1)	(636.5)
Investment in transmission affiliate	(14.6)	(10.5)	(26.4)
Proceeds from asset sales, net	102.4	133.8	899.6
Nuclear fuel	(47.7)	(49.7)	(30.0)
Nuclear decommissioning funding	(17.6)	(17.6)	(17.6)
Proceeds from investments within nuclear decommissioning trust	530.7	435.7	327.2
Purchases of investments within nuclear decommissioning trust	(530.7)	(435.7)	(327.2)
Cash from discontinued operations	-	-	32.4
Other	(33.1)	(8.0)	21.3
Cash (Used in) Provided by Investing Activities	(939.3)	(697.1)	242.8
Financing Activities			
Exercise of stock options	26.8	47.0	70.9
Purchase of common stock	(48.0)	(75.1)	(152.7)
Dividends paid on common stock	(107.6)	(102.9)	(97.8)
Issuance of long-term debt	337.9	285.8	397.0
Retirement of long-term debt	(493.8)	(112.2)	(798.4)
Change in short-term debt	455.6	118.3	(252.8)
Other, net	2.4	(3.1)	(0.5)
Cash Provided by (Used in) Financing Activities	173.3	157.8	(834.3)
Change in Cash and Cash Equivalents	(36.2)	37.6	7.5
Cash and Cash Equivalents at Beginning of Year	73.2	35.6	28.1
Cash and Cash Equivalents at End of Year	$ 37.0	$ 73.2	$ 35.6
Discontinued Operations:			
Cash Provided by Operating Activities	$ 0.2	$ 2.1	$ 36.6
Cash Used in Investing Activities	(0.2)	(2.1)	(41.0)
Cash Used in Financing Activities	-	-	(2.0)
Change in Cash classified as held for sale	$ -	$ -	$ (6.4)
Supplemental Information - Cash Paid For			
Interest (net of amount capitalized)	$183.4	$ 162.3	$ 192.6
Income taxes (net of refunds)	$154.2	$ 47.5	$ 100.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock	Other Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned Compensation	Stock Options Exercisable	Total
				(Millions of Dollars)			
Balance - December 31, 2003	$ 1.2	$ 841.8	$ 1,510.1	$ 3.1	$ (4.7)	$ 7.2	$ 2,358.7
Net income			306.4				306.4
Other comprehensive income							
Foreign currency translation				(8.6)			(8.6)
Minimum pension liability				(3.7)			(3.7)
Hedging, net				1.8			1.8
Comprehensive income	-	-	306.4	(10.5)	-	-	295.9
Common stock cash dividends of $0.83 per share			(97.8)				(97.8)
Common stock issued		70.9					70.9
Repurchase of common stock		(152.7)					(152.7)
Restricted stock and performance share awards		5.9			(6.5)		(0.6)
Amortization and forfeiture of performance shares and restricted stock		(0.9)			3.6		2.7
Stock options exercised		4.8				(4.8)	-
Tax benefit from exercise of stock options		15.3					15.3
Balance - December 31, 2004	1.2	785.1	1,718.7	(7.4)	(7.6)	2.4	2,492.4
Net income			308.7				308.7
Other comprehensive income							
Minimum pension liability				(4.1)			(4.1)
Comprehensive income	-	-	308.7	(4.1)	-	-	304.6
Common stock cash dividends of $0.88 per share			(102.9)				(102.9)
Common stock issued		47.0					47.0
Repurchase of common stock		(75.1)					(75.1)
Restricted stock and performance share awards		0.9			(1.5)		(0.6)
Amortization and forfeiture of performance shares and restricted stock		-			3.7		3.7
Tax benefit from exercise of stock options		11.1					11.1
Other		1.3				(1.4)	(0.1)
Balance - December 31, 2005	1.2	770.3	1,924.5	(11.5)	(5.4)	1.0	2,680.1
Net income			316.4				316.4
Other comprehensive income							
Minimum pension liability				2.5			2.5
Hedging, net				0.4			0.4
Comprehensive income	-	-	316.4	2.9	-	-	319.3
Common stock cash dividends of $0.92 per share			(107.6)				(107.6)
Common stock issued		26.8					26.8
Repurchase of common stock		(48.0)					(48.0)
Tax benefit from exercise of stock options		8.4					8.4
Stock-based compensation and awards of restricted stock		9.8					9.8
Modification of performance share awards		(6.3)					(6.3)
Reclassification of unearned compensation to Other Paid In Capital upon the adoption of SFAS 123R -- Note J		(5.4)			5.4		-
Adoption of SFAS 158				7.0			7.0
Other		(0.1)				(0.4)	(0.5)
Balance - December 31, 2006	$ 1.2	$ 755.5	$ 2,133.3	$ (1.6)	$ -	$ 0.6	$ 2,889.0

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31

	2006	2005
	(Millions of Dollars)	
Common Equity (See Consolidated Statements of Common Equity)		
Common stock - $.01 par value; authorized 325,000,000 shares; outstanding - 116,969,063 and 116,980,775 shares	$ 1.2	$ 1.2
Other paid in capital	755.5	770.3
Retained earnings	2,133.3	1,924.5
Accumulated other comprehensive (loss)	(1.6)	(11.5)
Unearned compensation - restricted stock and performance share awards	-	(5.4)
Stock options exercisable	0.6	1.0
Total Common Equity	2,889.0	2,680.1
Preferred Stock		
Wisconsin Energy		
$.01 par value; authorized 15,000,000 shares; none outstanding	-	-
Wisconsin Electric		
Six Per Cent. Preferred Stock - $100 par value; authorized 45,000 shares; outstanding - 44,498 shares	4.4	4.4
Serial preferred stock -		
$100 par value; authorized 2,286,500 shares; 3.60% Series redeemable at $101 per share; outstanding - 260,000 shares	26.0	26.0
$25 par value; authorized 5,000,000 shares; none outstanding	-	-
Total Preferred Stock	30.4	30.4
Long-Term Debt		
Debentures (unsecured)		
6-5/8% due 2006	-	200.0
9.47% due 2006	-	0.7
3.50% due 2007	250.0	250.0
4.50% due 2013	300.0	300.0
6.60% due 2013	45.0	45.0
5.20% due 2015	125.0	125.0
6-1/2% due 2028	150.0	150.0
5.625% due 2033	335.0	335.0
5.90% due 2035	90.0	90.0
5.70% due 2036	300.0	-
6-7/8% due 2095	100.0	100.0
Notes (secured, nonrecourse)		
6.36% effective rate due 2006	-	1.1
7.25% variable rate due 2006 (b)	-	9.3
2% stated rate due 2011	0.2	1.2
5.55% variable rate due 2028 (a)	14.6	15.1
4.81% effective rate due 2030	2.0	2.0
4.91% due 2007-2030	150.4	153.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION - (Cont'd)
December 31

		2006	2005
		(Millions of Dollars)	
Long-Term Debt - (Cont'd)			
Notes (unsecured)			
	3.55% variable rate due 2006 (b)	$ -	$ 1.0
	5.875% due 2006	-	250.0
	6.36% effective rate due 2006	-	1.2
	7.75% due 2007-2008	0.6	0.8
	5.50% due 2008	300.0	300.0
	6.21% due 2008	20.0	20.0
	6.48% due 2008	25.4	25.4
	5-1/2% due 2009	50.0	50.0
	6.25% due 2010	10.0	-
	6.50% due 2011	450.0	450.0
	6.51% due 2013	30.0	30.0
	4.08% variable rate due 2015 (a)	17.4	17.4
	3.80% variable rate due 2016 (a)	67.0	67.0
	6.94% due 2028	50.0	50.0
	3.80% variable rate due 2030 (a)	80.0	80.0
	6.20% due 2033	200.0	200.0
Obligations under capital leases		231.4	230.8
Unamortized discount, net and other		(23.9)	(24.7)
Long-term debt due currently		(296.7)	(496.0)
Total Long-Term Debt		3,073.4	3,031.0
Total Capitalization		$ 5,992.8	$ 5,741.5

(a) Variable interest rate as of December 31, 2006.
(b) Variable interest rate as of December 31, 2005.

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

WISCONSIN ENERGY CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General: Our consolidated financial statements include the accounts of Wisconsin Energy Corporation (Wisconsin Energy, the Company, our, we or us), a diversified holding company, as well as our principal subsidiaries in the following operating segments:

- ***Utility Energy Segment*** -- Consisting of Wisconsin Electric, Wisconsin Gas and Edison Sault; engaged primarily in the generation of electricity and the distribution of electricity and natural gas; and

- ***Non-Utility Energy Segment*** -- Consisting primarily of We Power; engaged principally in the design, development, construction and ownership of electric power generating facilities for long-term lease to Wisconsin Electric.

Our Corporate and Other segment primarily includes Wispark, which develops and invests in real estate. We have eliminated all significant intercompany transactions and balances from the consolidated financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications: We have reclassified certain prior year financial statement amounts to conform to their current year presentation. These reclassifications had no effect on total assets, net income or earnings per share.

Our Consolidated Statements of Cash Flows has been modified to present separately cash flows from continuing operations and cash flows from discontinued operations. Previously, we presented cash flows from continuing operations on our Consolidated Statements of Cash Flows and cash flows from discontinued operations were presented separately in the notes to the Financial Statements.

Revenues: We recognize energy revenues on the accrual basis and include estimated amounts for services rendered but not billed.

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchase power costs. The electric fuel rules in Wisconsin allow us to request rate increases if fuel and purchased power costs exceed bands established by the PSCW. In a rate order issued in January 2006, the PSCW approved a plan to refund any over-collected fuel on an annual basis for 2006. For 2007, the band is plus or minus 2%.

Our retail gas rates include monthly adjustments which permit the recovery or refund of actual purchased gas costs. We defer any difference between actual gas costs incurred (adjusted for a sharing mechanism) and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year.

Accounting for MISO Energy Transactions: MISO implemented the MISO Midwest Market on April 1, 2005. The MISO Midwest Market operates under both day-ahead and real-time markets. We record energy transactions in the MISO on a net basis for each hour.

Other Income and Deductions, Net: We recorded the following items in Other Income and Deductions, net for the years ended December 31:

Other Income and Deductions, Net	2006	2005	2004
		(Millions of Dollars)	
Capitalized Carrying Costs	$25.0	$20.4	$12.7
AFUDC - Equity	14.6	9.2	2.8
Gross Receipts Tax Recovery	4.0	2.6	1.5
Gain on Sale of Guardian Investment	2.8	-	-
Debt Redemption Costs	-	-	(22.9)
Other, net	6.7	(3.5)	(8.4)
Total Other Income and Deductions, Net	$53.1	$28.7	($14.3)

Property and Depreciation: We record property, plant and equipment at cost. Cost includes material, labor, overheads and capitalized interest. Utility property also includes AFUDC - Equity. Additions to and significant replacements of property are charged to property, plant and equipment at cost; minor items are charged to maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We had the following property in service by segment at December 31:

Property In Service	2006	2005
	(Millions of Dollars)	
Utility Energy	$8,781.5	$8,311.0
Non-Utility Energy	389.5	389.0
Other	94.4	149.6
Total	$9,265.4	$8,849.6

We include capitalized software costs associated with our utility energy segment under the caption "Property, Plant and Equipment" on the Consolidated Balance Sheets. As of December 31, 2006 and 2005, the net book value of regulated capitalized software totaled $17.8 million and $22.3 million, respectively. The net book value of other capitalized software was approximately $1.7 million and $2.4 million as of December 31, 2006 and 2005, respectively. The estimated useful life of our capitalized software is 5 years.

Our utility depreciation rates are certified by the state regulatory commissions and include estimates for salvage value and removal costs. Depreciation as a percent of average depreciable utility plant was 3.7% in 2006, 3.9% in 2005 and 4.0% in 2004. Nuclear plant decommissioning costs are accrued and included in depreciation expense (see Note I). The decline in depreciation as a percent of average depreciable utility plant was due to new depreciation rates approved by the PSCW, which became effective January 1, 2006.

For assets other than our regulated assets, we accrue depreciation expense at straight-line rates over the estimated useful lives of the assets. Estimated useful lives for non-regulated assets are 3 to 40 years for furniture and equipment, 2 to 5 years for software and 30 to 40 years for buildings.

Our regulated utilities collect in their rates amounts representing future removal costs for many assets that do not have an associated ARO. We record a regulatory liability on our balance sheet for the estimated amounts we have collected in rates for future removal costs less amounts we have spent in removal activities. This regulatory liability was $630.6 million as of December 31, 2006 and $604.2 million as of December 31, 2005.

We recorded the following CWIP by segment at December 31:

	2006	2005
	(Millions of Dollars)	
Utility Energy	$103.5	$237.7
Non-Utility Energy	865.9	354.5
Other	23.0	4.4
Total	$992.4	$596.6

Allowance For Funds Used During Construction - Regulated: AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC - Debt) used during plant construction and a return on stockholders' capital (AFUDC - Equity) used for construction purposes. AFUDC - debt is recorded as a reduction of interest expense and AFUDC - Equity is recorded in Other Income, net.

During 2006, Wisconsin Electric accrued AFUDC at a rate of 8.94%, as authorized by the PSCW. During 2005 and 2004, the authorized rate was 10.18%. Wisconsin Electric accrues AFUDC on all electric utility NO_x, SO_2 and particulates remediation projects. Wisconsin Electric's rates were set to provide a full return on electric safety and reliability projects so AFUDC is not accrued on these projects. Wisconsin Electric accrued AFUDC on 50% of the remaining electric, gas and steam projects in CWIP and rates were set assuming that 50% of the CWIP balances were included in rate base.

During 2006, Wisconsin Gas accrued AFUDC at a rate of 11.31%, as authorized by the PSCW. During 2005 and 2004, the authorized rate was 10.32%. Wisconsin Gas accrued AFUDC on specific large construction projects during 2005 and 2004. During 2006, Wisconsin Gas accrued AFUDC on 50% of CWIP balances.

Our regulated segment recorded the following AFUDC for the years ended December 31:

	2006	2005	2004
	(Millions of Dollars)		
AFUDC - Debt	$5.2	$4.6	$1.5
AFUDC - Equity	$14.5	$9.2	$2.8

Capitalized Interest and Carrying Costs - Non-Regulated Energy: As part of the construction of the power plants under our PTF program, we capitalize interest during construction in accordance with SFAS 34. Under the lease agreements associated with our PTF power plants, we are able to collect from utility customers the carrying costs associated with the construction of these power plants. We defer these carrying costs collected on our balance sheet and they will be amortized to revenue over the individual lease term. For further information on the accounting for capitalized interest and deferred carrying costs associated with the construction of our PTF power plants, see Note E.

Earnings Per Common Share: We compute basic earnings per common share by dividing our net income by the weighted average number of common shares outstanding. Diluted earnings per common share reflect the potential reduction in earnings per common share that could occur when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable relating to stock options utilizing the treasury stock method. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. Shares that are anti-dilutive are not included in the calculation.

Materials, Supplies and Inventories: Our inventory at December 31 consists of:

Materials, Supplies and Inventories	2006	2005
	(Millions of Dollars)	
Fossil Fuel	$121.0	$ 90.4
Natural Gas in Storage	188.6	265.5
Materials and Supplies	107.6	95.7
Total	$417.2	$451.6

Substantially all fossil fuel, materials and supplies and natural gas in storage inventories are recorded using the weighted-average method of accounting.

Regulatory Accounting: Our utility energy segment accounts for its regulated operations in accordance with SFAS 71. This statement sets forth the application of GAAP to those companies whose rates are determined by an independent third-party regulator. The economic effects of regulation can result in regulated companies recording costs that have been or are expected to be allowed in the rate making process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as assets in the balance sheet (regulatory assets) and recorded as expenses in the periods when those same amounts are reflected in rates. We defer all of our regulatory assets pursuant to specific orders or by a generic order issued by our primary regulator. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities). We expect to recover our outstanding regulatory assets in rates over a period of no longer than 20 years. For further information, see Note C.

Derivative Financial Instruments: We have derivative physical and financial instruments as defined by SFAS 133 which we report at fair value. However, our use of financial instruments is limited. For further information, see Note J.

Cash and Cash Equivalents: Cash and cash equivalents include marketable debt securities acquired three months or less from maturity.

We have nuclear decommissioning trusts that hold investments in debt and equity securities. All assets within the nuclear decommissioning trusts are restricted to nuclear decommissioning activities as set forth by regulations promulgated by the IRS and by the PSCW. The accompanying Consolidated Statements of Cash Flows includes proceeds from investments within the nuclear decommissioning trusts and purchases of investments within the nuclear decommissioning trusts.

Margin Accounts: Cash deposited in brokerage accounts for margin requirements is recorded in Other Current Assets on our Consolidated Balance Sheets.

Asset Retirement Obligations: We adopted SFAS 143 effective January 1, 2003. We adopted FIN 47 effective December 31, 2005. FIN 47 defines the term conditional ARO as used in SFAS 143. As defined in FIN 47, a conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Consistent with SFAS 143, we record a liability at fair value for a legal ARO in the period in which it is incurred. When a new legal obligation is recorded, we capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. At the end of the asset's useful life, we settle the obligation for its recorded amount or incur a gain or loss. As it relates to our regulated operations, we apply SFAS 71 and recognize regulatory assets or liabilities for the timing differences between when we recover legal AROs in rates and when we would recognize these costs under SFAS 143. For further information, see Note F.

Goodwill and Intangible Assets: We account for goodwill and other intangible assets following SFAS 142, effective January 1, 2002. As of December 31, 2006 and 2005, we had $441.9 million of goodwill recorded at the utility energy segment, which related to our acquisition of Wisconsin Gas in 2000.

Under SFAS 142, goodwill and other intangibles with indefinite lives are not subject to amortization. However, goodwill and other intangibles are subject to fair value-based rules for measuring impairment, and resulting write-downs, if any, are to be reflected in operating expense. We assess the fair value of our SFAS 142 reporting unit by considering future discounted cash flows, a comparison of fair value based on public company trading multiples, and merger and acquisition transaction multiples for similar companies. This evaluation utilizes the information available under the circumstances, including reasonable and supportable assumptions and projections. We perform our annual impairment test for the reporting unit as of August 31. There was no impairment to the recorded goodwill balance as of our annual 2006 impairment test date for our reporting unit.

Impairment or Disposal of Long Lived Assets: We carry property, equipment and goodwill related to businesses held for sale at the lower of cost or estimated fair value less costs to sell. As of December 31, 2006, we had no assets classified as Held for Sale. Consistent with SFAS 144, long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable from the use and eventual disposition of the asset based on the remaining useful life. An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds the fair value of the asset. The carrying amount of an asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset. For further information, see Note D.

Investments: We account for investments in other affiliated companies in which we do not maintain control using the equity method. As of December 31, 2006 and 2005, we had a total ownership interest of approximately 29.4% and 33.5%, in ATC. We are represented by one out of ten ATC board members, each of whom has one vote. Due to the voting requirements, no individual member has more than 10% of the voting control. For further information regarding such investments, see Note R.

Income Taxes: We follow the liability method in accounting for income taxes as prescribed by SFAS 109. SFAS 109 requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. We have established a valuation allowance against certain deferred tax assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

Tax credits associated with regulated operations are deferred and amortized over the life of the assets. We file a consolidated Federal income tax return. Accordingly, we allocate Federal current tax expense benefits and credits to our subsidiaries based on their separate tax computations. For further information, see Note H.

We recognize interest and penalties accrued related to unrecognized tax benefits in Income Taxes in our Consolidated Income Statements, as well as Regulatory Assets or Regulatory Liabilities in our Consolidated Balance Sheets.

We collect sales and use taxes from our customers and remit these taxes to governmental authorities. These taxes are recorded in our Consolidated Income Statements on a net basis.

Stock Options: Effective January 1, 2006, we adopted SFAS 123R, using the modified prospective method. We use a binomial pricing model to estimate the fair value of stock options granted subsequent to December 31, 2005. Prior to January 1, 2006, we accounted for share based compensation under APB 25, Accounting for Stock Issued to Employees, and we disclosed the pro forma impact of share based compensation expense under SFAS 123. Historically, all stock options have been granted with an exercise price equal to the fair market value of the common stock on the date of grant and expire no later than ten years from the grant date. Accordingly, no compensation expense was recognized in connection with option grants. All options granted subsequent to December 31, 2004 vest on a cliff-basis after a three year period. Prior to January 1, 2006, we reported benefits of tax deductions in excess of recognized compensation costs as operating cash flows. SFAS 123R requires that excess tax benefits be reported as a financing cash inflow rather than as an operating cash inflow. In addition, we previously recorded unearned stock-based compensation for non-vested restricted stock and performance share awards as "unearned compensation" in our Consolidated Statements of Common Equity. For further discussion of this new standard and the impacts to our Consolidated Financial Statements, see Note J.

We previously adopted the disclosure provisions of SFAS 123 as amended by SFAS 148. The fair value of our stock options at date of grant for 2006 was calculated using a binomial option-pricing model. For 2005 and 2004, the fair value of options at the date of grant was estimated using the Black-Scholes option-pricing model with the following weighted average assumptions:

	Binomial	Black-Scholes	
	2006	2005	2004
Risk free interest rate	4.3% - 4.4%	4.4%	4.6%
Dividend yield	2.4%	2.5%	2.5%
Expected volatility	17.0% - 20.0%	19.0%	23.1%
Expected life (years)	6.3	10.0	10.0
Pro forma weighted average fair value of our stock options granted	$7.55	$8.32	$9.45

As described more fully in the following table, our diluted earnings would have been reduced by $0.02 and $0.24 per share, respectively, had we expensed the 2005 and 2004 grants for stock-based compensation plans under SFAS 123. In 2004, the pro forma expense increased, in part, due to the effect of accelerating the vesting of stock options, which resulted in a pro forma expense of $0.16 per share. For further information regarding equity based compensation, see Note J.

	2005	2004
	(Millions of Dollars, Except per share amounts)	
Net Income - as reported	$308.7	$306.4
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	2.3	2.5
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	4.5	31.5
Net Income - Pro forma	$306.5	$277.4
Basic Earnings Per Common Share		
As reported	$2.64	$2.60
Pro forma	$2.62	$2.36
Diluted Earnings Per Common Share		
As reported	$2.61	$2.57
Pro forma	$2.59	$2.33

Nuclear Fuel Amortization: We amortize our nuclear fuel inventory to fuel expense as the power is generated, generally over a period of 60 months.

B – RECENT ACCOUNTING PRONOUNCEMENTS

Share Based Compensation: In December 2004, the FASB issued SFAS 123R. In March 2005, the SEC issued SAB 107 regarding the SEC's interpretation of SFAS 123R and the valuation of share-based payment for public companies. This statement requires that the compensation costs relating to such transactions be recognized in the consolidated income statement. We adopted SFAS 123R and SAB 107 effective January 1, 2006 using the modified prospective method. For additional information, see Note J.

Implicit Variable Interests: In April 2006, the FASB issued FSP FIN 46R-6.. FSP FIN 46R-6 addresses the requirement to determine the variability to be considered in applying FIN 46R-6 based on an analysis of the design of the entity. As required, we adopted FSP FIN 46R-6 effective July 1, 2006 for any new arrangements entered into after the effective date. For further information, see Note G.

Uncertainty in Income Taxes: In July 2006, the FASB issued FIN 48, an interpretation of SFAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the enterprise's financial statements in accordance with SFAS 109. We adopted FIN 48 effective January 1, 2007. For further information, see Note H.

Fair Value Measurements: In September 2006, the FASB issued SFAS 157.. SFAS 157 provides guidance for using fair value to measure assets and liabilities. SFAS 157 defines fair value, provides a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently evaluating the provisions of SFAS 157 and we expect to adopt SFAS 157 on January 1, 2008.

Pension and Other Post-retirement Plans: In September 2006, the FASB issued SFAS 158, an amendment of SFAS 87, 88, 106 and 132R. SFAS 158 requires recognition of the overfunded or underfunded status of a defined benefit post-retirement plan as an asset or liability on the balance sheet and recognition of changes in that funded status in the year in which the changes occur through comprehensive income. SFAS 158 also requires an employer to measure the funded status of a plan as of the date of its year end balance sheet. We adopted SFAS 158 as of December 31, 2006. For further information, see Note O.

Financial Statement Errors: In September 2006, the SEC staff issued SAB 108. SAB 108 addresses the diversity in practice by registrants when quantifying the effect of an error on the financial statements. SAB 108 provides guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements. We adopted the provisions of SAB 108 effective December 31, 2006. The adoption of SAB 108 did not have any financial impact on our consolidated financial statements.

C -- REGULATORY ASSETS AND LIABILITIES

Our utility energy segment accounts for its regulated operations in accordance with SFAS 71.

Our primary regulator considers our regulatory assets and liabilities in two categories, escrowed and deferred. In escrow accounting we expense amounts that are included in rates. If actual costs exceed, or are less than the amounts that are allowed in rates, the difference in cost is escrowed on the balance sheet as a regulatory asset or regulatory liability and the escrowed balance is considered in setting future rates. Under deferred cost accounting, we defer amounts to our balance sheet based upon specific orders or correspondence with our primary regulator. These deferred costs will be considered in future rate setting proceedings. As of December 31, 2006, we had approximately $55.0 million of net regulatory assets that were not earning a return.

Our regulatory assets and liabilities as of December 31 consist of:

	2006	2005
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs (see Note O)	$357.2	$377.2
Escrowed electric transmission costs	192.2	169.4
Deferred income tax related	98.3	96.6
Deferred fuel related costs	79.1	72.8
Deferred plant related -- capital lease (see Note K)	71.8	67.0
Deferred unrecognized OPEB costs (see Note O)	70.5	17.3
Deferred environmental costs	68.2	64.2
Escrowed bad debt costs	57.0	58.1
Escrowed unrecovered plant costs	31.6	56.5
Other, net	65.1	46.5
Total long-term regulatory assets	$1,091.0	$1,025.6
Regulatory Liabilities		
Deferred cost of removal obligations (see Notes F and I)	$630.6	$604.2
Deferred asset retirement obligations (see Notes F and I)	537.1	475.3
Deferred pension benefit	62.3	71.0
Deferred income tax related	95.4	103.8
Other, net	146.7	118.9
Total long-term regulatory liabilities	$1,472.1	$1,373.2
Net long-term regulatory liabilities	$381.1	$347.6

As of December 31, 2005, we recorded a minimum pension liability to reflect the funded status of our pension plans (see Note O). Under SFAS 158, which we adopted effective December 31, 2006, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

Our regulated subsidiaries record deferred regulatory assets and liabilities representing the future expected impact of deferred taxes on utility revenues (see Note A).

In October 2002, the PSCW issued an order authorizing Wisconsin Electric to implement a surcharge for recovery of annual electric transmission costs projected through 2005. In addition, the PSCW order authorized escrow accounting treatment for transmission costs.

As of December 31, 2006, we have deferred $79.1 million of fuel related costs. The majority of these deferred costs were incurred in 2005 as a result of an extended outage at Point Beach, increased costs associated with reduced coal deliveries due to a railroad transportation problem and increased costs associated with the MISO Midwest Market.

Consistent with a generic order from and past rate-making practices of the PSCW, we defer as a regulatory asset costs associated with the remediation of former manufactured gas plant sites. As of December 31, 2006, we have recorded $68.2 million of environmental costs associated with manufactured gas plant sites as a regulatory asset, including $37.7 million of deferrals for actual remediation costs incurred and a $30.5 million accrual for estimated future site remediation (See Note S). In addition, we have deferred $8.8 million of insurance recoveries associated with the environmental costs as regulatory liabilities. We included total actual

remediation costs incurred net of the related insurance recoveries in our 2006 rate case. We began amortizing these costs upon receiving PSCW approval in January 2006. The amortization period for these costs is five years.

As part of our PTF strategy, the PSCW approved the retirement and removal of the Port Washington Power Plant coal units to make way for construction of gas-fired facilities. In a September 27, 2003 order, the PSCW authorized transferring the undepreciated costs and related removal amounts to a regulatory asset account. The escrowed unrecovered plant costs totaled $31.6 million at December 31, 2006.

As of December 31, 2006, we have $57.0 million of escrowed bad debt costs. In 2005 and 2004, the PSCW approved our request to account for residential bad debt costs on an escrow basis at Wisconsin Gas and Wisconsin Electric whereby they defer actual bad debt write-offs that exceed amounts allowed in rates, and that treatment continued through 2006.

In connection with the WICOR acquisition, we recorded the funded status of the Wisconsin Gas pension and post-retirement medical plans at fair value at the acquisition date. Due to the expected regulatory treatment of these items, we record a regulatory liability (Deferred pension) that is being amortized over an average remaining service life of 15 years ending 2015.

D -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

Minergy Neenah: Effective September 27, 2006, we sold 100% of the membership interest in Minergy Neenah to a third party. The primary assets of Minergy Neenah were a Glass Aggregate plant and related operating contracts. The plant recycled paper sludge from area paper mills into renewable energy and glass aggregate using our patented Glass Aggregate technology. The largest source of revenue for Minergy Neenah had been a long-term steam contract with an adjacent paper mill. The mill was permanently closed as of June 30, 2006. Pursuant to the steam contract, the mill owner paid Minergy Neenah a contract termination payment. In the third quarter of 2006, we received gross proceeds from the sale of the plant and the contract termination totaling $12.2 million and we recorded a net loss of $0.4 million that is included in Income from Discontinued Operations, net of tax. Previously, in the third quarter of 2004, we concluded the asset was impaired and recorded a non-cash asset valuation charge of $27.0 million ($17.6 million after tax).

Wisvest - Calumet: Effective May 31, 2005, we sold our Calumet facility for approximately $37.0 million in cash to Tenaska Power Fund, L.P. The primary assets of Calumet were a 308 MW natural gas-fired peaking power facility in Chicago, Illinois and related operating contracts. The transaction generated an after tax gain of approximately $4.7 million upon closing and generated approximately $32.0 million in cash tax benefits. In the third quarter of 2004, we concluded that this asset was impaired and recorded a non-cash asset valuation charge of $122.0 million ($79.3 million after tax).

Manufacturing Segment: Effective July 31, 2004, we sold WICOR, Inc. to Pentair, Inc. and received cash proceeds of $857 million, and Pentair, Inc. assumed approximately $25 million of third party debt.

WICOR's only asset at the time of the sale consisted of its interest in WICOR Industries. As a condition of the sale, WICOR transferred its ownership of Wisconsin Gas to Wisconsin Energy through a stock redemption. Prior to the transaction, Wisconsin Gas converted from a corporation to a limited liability company (collectively the "Wisconsin Gas transfer"). We expect the final determination of cash taxes to be approximately $105 million as a result of the stock redemption described above. However, we also expect to receive future tax deductions from a step-up in the tax basis of the Wisconsin Gas assets as a result of the Wisconsin Gas transfer. We therefore expect that substantially all of the cash taxes paid on the stock redemption will be recovered as deferred income tax assets through future deductions.

In accordance with SFAS 144, we have reclassified the assets and liabilities of Minergy Neenah as Assets held for sale in the accompanying Consolidated Balance Sheets. Total assets held for sale for Minergy Neenah were $17.4 million at December 31, 2005. In addition, we have recorded the operating results of Minergy Neenah, Calumet and the Manufacturing Segment as Income from Discontinued Operations, Net of Tax in the accompanying Consolidated Income Statements for the years ended December 31, 2006, 2005 and 2004. Previously, Minergy Neenah's results were included in corporate and other and the Calumet operations were included in the non-utility energy segment. See below for a summary of the components of Discontinued Operations in our Consolidated Income Statements.

	Year End December 31		
	2006 (a)	2005 (b)	2004 (c)
	(Millions of Dollars)		
Operating Revenues			
Manufacturing Segment	$ -	$ -	$481.0
Calumet	-	2.3	5.2
Minergy Neenah	14.3	18.1	19.8
Total	$14.3	$20.4	$506.0
Income (Loss) Before Income Taxes			
Manufacturing Segment	$ -	$ -	$50.9
Calumet	-	0.4	(125.0)
Minergy Neenah	2.4	(6.4)	(24.9)
Total	$2.4	($6.0)	($99.0)
Gain (Loss) on Sale - After-Tax			
Manufacturing Segment	$2.4	$ -	$152.3
Calumet	-	4.7	-
Minergy Neenah (d)	(0.4)	-	-
Total	$2.0	$4.7	$152.3

(a) Includes the results of Minergy through September 27, 2006.
(b) Includes the results of Calumet through May 31, 2005.
(c) Includes the results of our manufacturing segment through July 31, 2004.
(d) In the third quarter of 2006, we received gross proceeds from the sale of the plant and the contract termination totaling $12.2 million, and we recorded a net loss of $0.4 million that is included in Income from Discontinued Operations, net of tax.

E -- ACCOUNTING AND REPORTING FOR POWER THE FUTURE GENERATING UNITS

Background: As part of our PTF strategy, our non-utility subsidiary, We Power, is building four new generating units that will be leased to our utility subsidiary, Wisconsin Electric, under long-term leases that have been approved by the PSCW, our primary regulator. The leases are designed to recover the capital costs of the plant including a return. The first of the four generating units was placed in service in July 2005 and is being leased to Wisconsin Electric. Wisconsin Electric will be responsible for all of the operating costs, including fuel, of the PTF units once they are placed in service and we anticipate that we will recover the operating costs of these plants in rates. The accompanying consolidated financial statements eliminate all intercompany transactions between We Power and Wisconsin Electric, and reflect the cash inflows from Wisconsin Electric customers and the cash outflows to our vendors and suppliers. The PTF units include PWGS 1, PWGS 2, OC 1 and OC 2.

During Construction: Under the terms of each lease, we collect in current rates amounts representing our pre-tax cost of capital (debt and equity) associated with capital expenditures for the PTF units. Our pre-tax cost of capital is approximately 14%. The carrying costs that we collect in rates are recorded as deferred revenue, and they will be amortized to revenue over the term of each lease, once the respective unit is placed into service. During the construction of the PTF units, we capitalize interest costs at an overall weighted-average pre-tax cost of interest of approximately 6%. Capitalized interest is included in the total cost of the PTF units.

Cash Flows: The following table identifies key pre-tax cash outflows and inflows related to the construction of our PTF units for the twelve months ended December 31, 2006 and 2005 and compares it to total WEC.

	Capital Expenditures (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2006	$ -	$121.3	$268.0	$76.8	$466.1	$928.7
2005	$52.6	$45.6	$141.1	$37.1	$276.4	$745.1

	Capitalized Interest (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2006	$ -	$8.3	$19.3	$6.8	$34.4	$39.9
2005	$10.8	$2.8	$7.7	$3.0	$24.3	$28.7

	Deferred Revenue (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2006	$ -	$19.1	$45.3	$15.9	$80.3	$80.3
2005	$23.9	$6.3	$17.6	$6.9	$54.7	$54.7

Balance Sheet: As noted above, we collect in current rates carrying costs that are calculated based on the cash expenditures included in CWIP multiplied by our pre-tax cost of capital (approximately 14%). The carrying costs are recorded as deferred revenue and included in Other long-term liabilities. Our total CWIP balance includes cash expenditures, capitalized interest and accruals. The following table identifies key amounts related to our PTF units that are recorded on our balance sheet as of December 31, 2006 and 2005:

	CWIP - Cash Expenditures (Millions of Dollars)				Total
	PWGS 1	PWGS 2	OC 1	OC 2	PTF
December 31, 2006	$ -	$196.2	$487.7	$152.6	$836.5
December 31, 2005	$ -	$67.5	$198.9	$74.9	$341.3

	Total CWIP (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
December 31, 2006	$ -	$207.7	$517.3	$163.5	$888.5	$992.4
December 31, 2005	$ -	$70.7	$209.2	$78.9	$358.8	$596.6

	Net Plant in Service (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
December 31, 2006	$350.1	$ -	$ -	$ -	$350.1	$5,841.7
December 31, 2005	$359.9	$ -	$ -	$ -	$359.9	$5,561.1

	Deferred Revenue Included in Other Long-term Liabilities (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
December 31, 2006	$68.3	$27.5	$66.0	$24.4	$186.2	$186.2
December 31, 2005	$71.2	$8.5	$20.6	$8.5	$108.8	$108.8

Income Statement: Once the PTF units are placed in service, we will recover in rates the lease costs which reflect the authorized cash construction cost of the units plus a return. The authorized cash costs are established by the PSCW. The authorized cash costs exclude capitalized interest since carrying costs are recovered during the construction of the units. The lease payments are expected to be levelized, except that OC 1 and OC 2 will be recovered on a levelized basis that has a one time 10.6% escalation after the first 5 years of the leases. The leases established a set return on equity component of 12.7% after tax. The interest component of the return is determined up to 180 days prior to the date that the units are placed in service.

We recognize revenues related to the lease payments that are included in our rates. In addition, our revenues will include the amortization of the deferred revenues that reflect the carrying costs that are collected during construction. The deferred revenue will

be amortized on a straight line basis over the lease term. We will depreciate the units on a straight line basis over their expected service life.

In July 2005, PWGS 1 was placed in service. This asset had a cost of approximately $364.3 million which included approximately $31.1 million of capitalized interest. The asset is being depreciated over its estimated useful life of approximately 37 years. The cost of the plant, plus a return, is expected to be recovered through Wisconsin Electric's rates over a 25 year period at an annual amount of approximately $48 million.

F -- ASSET RETIREMENT OBLIGATIONS

The following table presents the change in our asset retirement obligations during 2006.

	Balance at December 31, 2005	Liabilities Incurred	Liabilities Settled	Accretion	Balance at December 31, 2006
		(Millions of Dollars)			
Asset Retirement Obligations	$355.5	$ -	($2.1)	$18.3	$371.7

SFAS 143 primarily applies to the future decommissioning costs for Point Beach. Prior to January 2003, we recorded a long-term liability for accrued nuclear decommissioning costs. See Note I for further information about the nuclear decommissioning of Point Beach, including our investments in nuclear decommissioning trusts that are restricted to nuclear decommissioning.

In March 2005, the FASB issued FIN 47. FIN 47 defines a conditional asset retirement obligation as a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. We adopted FIN 47 effective December 31, 2005. At adoption, we recorded additional asset retirement obligations related to asbestos removal costs.

The adoption of FIN 47 had no impact on our net income in 2006 or 2005. As it relates to our regulated operations, we apply SFAS 71 and recognize regulatory assets or liabilities for the timing differences between when we recover legal asset retirement obligations in rates and when we would recognize these costs under FIN 47. This treatment is consistent with the adoption of SFAS 143 for our regulated operations.

G -- VARIABLE INTEREST ENTITIES

Under FIN 46 and FIN 46R, the primary beneficiary of a variable interest entity must consolidate the related assets and liabilities.

We continue to evaluate our tolling and purchased power agreements with third parties on a quarterly basis. After making an exhaustive effort, we concluded that for three of these agreements, we are unable to obtain the information necessary to determine whether these entities are variable interest entities. Pursuant to the terms of two of the three agreements, we deliver fuel to the entity's facilities and receive electric power. We pay the entity a "toll" to convert our fuel into the electric energy. The output of the facility is available for us to dispatch during the term of the respective agreement. In the other agreement, we have rights to the firm capacity of the entity's facility. We have approximately $603.0 million of required payments over the remaining term of these three agreements, which expire over the next 16 years. We believe the required payments will continue to be recoverable in rates. We account for one of these agreements as a capital lease.

In April 2006, the FASB issued FSP FIN 46R-6. As required, we adopted FSP FIN 46R-6 effective July 1, 2006 for any new arrangements entered into after the effective date. Although the adoption of FSP FIN 46R-6 did not have a material financial impact in the current period, we currently are unable to determine the potential impact in future periods.

H – INCOME TAXES

The following table is a summary of income tax expense for each of the years ended December 31:

Income Taxes	2006	2005	2004
	(Millions of Dollars)		
Current tax expense	$229.0	$63.7	$126.3
Deferred income taxes, net	(49.7)	90.2	11.3
Investment tax credit, net	(4.3)	(4.7)	(4.8)
Total Income Tax Expense	$175.0	$149.2	$132.8

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable U.S. statutory federal income tax rate to income before income taxes as a result of the following:

	2006		2005		2004	
Income Tax Expense	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
			(Millions of Dollars)			
Expected tax at statutory federal tax rates	$170.6	35.0%	$158.5	35.0%	$123.4	35.0%
State income taxes net of federal tax benefit	24.1	4.9%	21.2	4.7%	20.2	5.7%
Reversal of valuation allowances	(5.8)	(1.1%)	(16.3)	(3.6%)	-	- %
Investment tax credit restored	(4.3)	(0.9%)	(4.7)	(1.0%)	(4.8)	(1.4%)
Other, net	(9.6)	(2.0%)	(9.5)	(2.1%)	(6.0)	(1.6%)
Total Income Tax Expense	$175.0	35.9%	$149.2	33.0%	$132.8	37.7%

The components of SFAS 109 deferred income taxes classified as net current liabilities and net long-term liabilities at December 31 are as follows:

	2006	2005
	(Millions of Dollars)	
Deferred Tax Assets		
Current		
Employee benefits and compensation	$13.9	$13.8
Recoverable gas costs	9.0	3.3
Other	3.8	5.8
Total Current Deferred Tax Assets	$26.7	$22.9
Non-current		
Employee benefits and compensation	$110.4	$117.3
Decommissioning trust	98.1	85.8
Construction advances	84.8	71.6
Property-related	73.2	45.5
Deferred revenues	84.4	28.4
State NOL's	29.2	28.0
Valuation allowance	(3.4)	(11.8)
Emission allowances	19.0	18.4
Other	38.3	34.9
Total Non-current Deferred Tax Assets	$534.0	$418.1
Total Deferred Tax Assets	$560.7	$441.0
Deferred Tax Liabilities		
Current		
Prepaid items	$39.1	$33.2
Uncollectible account expense	9.1	8.8
Total Current Deferred Tax Liabilities	$48.2	$42.0
Non-current		
Property-related	$848.5	$792.0
Employee benefits and compensation	71.8	68.8
Deferred transmission costs	76.5	64.6
Investment in transmission affiliate	44.3	40.4
Other	65.8	46.0
Total Non-current Deferred Tax Liabilities	$1,106.9	$1,011.8
Total Deferred Tax Liabilities	$1,155.1	$1,053.8

Consolidated Balance Sheet Presentation	2006	2005
Current Deferred Tax Asset (Liability)	($21.5)	($19.1)
Non-current Deferred Tax Asset (Liability)	($572.9)	($593.7)

Consistent with ratemaking treatment, deferred taxes are offset in the above table for temporary differences which have related regulatory assets or liabilities.

As of December 31, 2006 and 2005, we had recorded $3.4 million and $11.8 million of valuation allowances primarily related to the uncertainty of our ability to benefit from state loss carryforwards in the future. In connection with the favorable decision by the Supreme Court of Wisconsin in June 2005 to uphold the CPCN granted by the PSCW for the construction of the Oak Creek expansion, we have concluded that it is more likely than not that we will be able to utilize certain tax benefits associated with state net operating losses of the Parent that have been carried forward from prior years. As such, in 2006 and 2005 we reversed $5.8 million and $16.3 million of valuation allowances associated with the state tax net operating losses that have been carried forward to future years. The remaining state loss carryforwards begin to expire in 2008 and have been reduced by a valuation allowance.

In July 2006, the FASB issued FIN 48, an interpretation of SFAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the enterprise's financial statements in accordance with SFAS 109. FIN 48 provides clarification on the accounting for

income taxes by setting forth a minimum recognition threshold an uncertain tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on de-recognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. We adopted FIN 48 effective January 1, 2007. As a result of the adoption of FIN 48, we estimate that the cumulative effect on retained earnings is immaterial.

I – NUCLEAR OPERATIONS

Point Beach Nuclear Plant: We own two 518 MW electric generating units at Point Beach in Two Rivers, Wisconsin. NMC operates the units on our behalf. The units were placed in service in the early 1970's and the original operating licenses were effective through 2010 and 2013. In December 2005, the NRC renewed the operating licenses through October 2030 for Unit 1 and March 2033 for Unit 2.

Proposed Sale of Point Beach: In December 2006, we announced that Wisconsin Electric signed a definitive agreement with an affiliate of FPL to sell Point Beach for approximately $998 million, subject to closing price adjustments. Under the terms of the sale, the buyer would assume the obligation to decommission the plant, and we would transfer assets in a qualified trust for decommissioning. We would retain assets in a non-qualified decommissioning trust. Wisconsin Electric also entered into a long-term power purchase agreement to purchase all of the existing capacity and energy of the plant, which will become effective upon closing of the sale. Wisconsin Electric will have the unilateral option, subject to PSCW direction, to select a term for the power purchase agreement of either (i) an estimated 23 years for Unit 1 and 26 years for Unit 2, or (ii) 16 years for Unit 1 and 17 years for Unit 2. The sale of the plant and the long-term power purchase agreement are subject to review and approval by various regulatory agencies including the NRC, PSCW, MPSC and FERC. We anticipate closing the sale during the third quarter of 2007. We have submitted a request to the PSCW to defer any gain (net of transaction related costs) as a regulatory liability that would be applied to the benefit of our customers in future rate proceedings.

Nuclear Insurance: The Price-Anderson Act currently limits the total public liability for damages arising from a nuclear incident at a nuclear power plant to approximately $10.8 billion, of which $300 million is covered by liability insurance purchased from private sources. The remaining $10.5 billion is covered by an industry retrospective loss sharing plan whereby, in the event of a nuclear incident resulting in damages exceeding the private insurance coverage, each owner of a nuclear plant would be assessed a deferred premium of up to $100.6 million per reactor with a limit of $15 million per reactor within one calendar year. We have two reactors. We are obligated to pay our proportionate share of any such assessment as long as we own Point Beach.

Wisconsin Electric, through its membership in NEIL, carries decontamination, property damage and decommissioning shortfall insurance covering losses of up to $2.1 billion at Point Beach. Under policies issued by NEIL, the insured member may be liable for a retrospective premium in the event of catastrophic losses exceeding the full financial resources of NEIL. Wisconsin Electric's maximum retrospective liability under the above policies is $17.8 million.

Wisconsin Electric also maintains insurance with NEIL through which it can recover up to $3.5 million per week, subject to a total limit of $490 million, during any prolonged outage at Point Beach caused by accidental property damage. Wisconsin Electric's maximum retrospective liability under this policy is $9.8 million.

It should not be assumed that, in the event of a major nuclear incident, any insurance or statutory limitation of liability would protect Wisconsin Electric from material adverse impact.

Nuclear Decommissioning: We record decommissioning expense in amounts equal to the amounts collected in rates and funded to the external trusts. Nuclear decommissioning costs are accrued over the expected service lives of the nuclear generating units and are included in electric rates. Decommissioning funding was $17.6 million for each of the years ended 2006, 2005 and 2004. As of December 31, 2006, our non-qualified investments were $303.7 million and our qualified investments were $577.9 million. We had the following investments in Nuclear Decommissioning Trusts, stated at fair value as of December 31, 2006 and 2005:

	2006	2005
	(Millions of Dollars)	
Funding and Realized Earnings	$607.2	$566.6
Unrealized Gains	274.4	215.5
Total Investments	$881.6	$782.1

As of December 31, 2006, approximately 66.5% of the trust funds were invested in equity securities and 33.5% were invested in debt securities. In accordance with SFAS 115 Wisconsin Electric's debt and equity security investments in the trusts are classified as

available for sale. Gains and losses on the fund are determined on the basis of specific identification; net unrealized gains on the fund are recorded as part of the fund. Our investments in the trusts are recorded at fair value and we are allowed regulatory treatment for the fair value adjustment. Realized gains and losses for the years ended December 31, 2006 and 2005 were as follows:

	2006	2005
	(Millions of Dollars)	
Realized Gains	$21.2	$19.1
Realized (Losses)	(10.6)	(9.1)
Net Realized Gain	$10.6	$10.0

Total gains and total losses by security type for the years ended December 31, 2006 and 2005 were as follows:

December 31, 2006	Total Gains	Total (Losses)	Net Gain (Loss)
Debt	$1.4	($5.2)	($3.8)
Equity	296.5	(7.7)	288.8
Total	$297.9	($12.9)	$285.0

December 31, 2005	Total Gains	Total (Losses)	Net Gain (Loss)
Debt	$2.1	($5.0)	($2.9)
Equity	236.5	(8.1)	228.4
Total	$238.6	($13.1)	$225.5

The contractual maturities of debt securities at December 31, 2006 are as follows: $14.8 million in 2007; $52.0 million in 2008-2011; $97.9 million in 2012-2016; and $125.2 million thereafter.

The PSCW requires us to perform periodic Decommissioning Cost Studies to evaluate the funded status of our Nuclear Decommissioning Trusts as compared with the estimated costs to perform the decommissioning work. In June 2005, we filed a new Decommissioning Cost Study with the PSCW. The study was performed by an outside consultant and it included several assumptions as to the timing and scope of the decommissioning work. This study estimated that the cost to decommission the plant would be $712.5 million in 2004 dollars. A prior study had estimated the cost to be $1.1 billion in 2003 dollars. The reduction in the estimated cost to decommission the plant was driven by several factors, including the timing and the scope of the work to be performed.

The June 2005 Decommissioning Cost Study was also used to estimate our ARO for nuclear decommissioning. We record an ARO for future decommissioning costs based upon the net present value of the expected cash flows associated with our legal obligation to decommission our plants. Under SFAS 143, certain costs included in the June 2005 Decommissioning Cost Study that related to fuel management and non-nuclear demolition were excluded from the ARO calculation. Using the June 2005 study, our estimated costs for decommissioning, following SFAS 143, were $473.2 million. Our ARO for nuclear decommissioning as of December 31, 2006 was $325.6 million.

We recover decommissioning costs in our regulated rates. We have established a regulatory liability to reflect the difference between nuclear decommissioning costs recovered in rates and cumulative investment gains (our nuclear decommissioning trust investments) in comparison to the ARO for nuclear decommissioning that is calculated under SFAS 143. For further information on AROs, see Note F.

The ultimate timing and amount of future cash flows associated with nuclear decommissioning is dependent upon many significant variables including the scope of work involved, the ability to relicense the plants in the future, future inflation rates and discount rates. Because of our announced agreement to sell Point Beach to an affiliate of FPL, we do not expect to remain obligated to decommission Point Beach if the sale is consummated. However, if that sale is not completed, based on the license renewal received by the NRC in December 2005, we do not expect to make any significant nuclear decommissioning expenditures before the year 2030.

Decontamination and Decommissioning Fund: The Energy Policy Act of 1992 established a D&D Fund for the DOE's nuclear fuel enrichment facilities. Deposits to the D&D Fund are derived in part from special assessments on utilities using enrichment services. In October 2006, a final payment was made to the DOE. As a result, a liability no longer exists for this fund. The deferred regulatory asset will be amortized to nuclear fuel expense and included in utility rates through September 2007.

J -- COMMON EQUITY

Share-Based Compensation Plans: We have a plan that was approved by stockholders that enables us to provide a long-term incentive through equity interests in Wisconsin Energy, to outside directors, selected officers and key employees of the Company. The plan provides for the granting of stock options, stock appreciation rights, restricted stock awards and performance shares. Awards may be paid in common stock, cash or a combination thereof. All share-based compensation is fulfilled by purchases on the open market and do not dilute shareholders' ownership.

The following is a summary of our stock options issued through December 31, 2006:

	2006		2005		2004	
Stock Options	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price	Number of Options	Weighted-Average Exercise Price
Outstanding at January 1	7,569,619	$28.10	8,290,311	$25.88	9,823,935	$22.87
Granted	1,304,275	$39.50	1,328,966	$34.20	1,844,765	$33.44
Exercised	(1,111,807)	$24.34	(2,044,145)	$23.05	(3,249,688)	$20.97
Forfeited	(40,261)	$36.93	(5,513)	$32.47	(128,701)	$28.21
Outstanding at December 31	7,721,826	$30.52	7,569,619	$28.10	8,290,311	$25.88
Exercisable at December 31	5,133,977	$27.36	6,209,466	$26.82	8,090,987	$25.99

The following table summarizes information about stock options outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number	Exercise Price	Remaining Contractual Life (years)	Number	Exercise Price	Remaining Contractual Life (years)
$11.58 to $23.05	1,564,474	$21.40	4.4	1,564,474	$21.40	4.4
$25.31 to $31.07	1,907,679	$26.90	5.4	1,898,794	$26.91	5.4
$33.44 to $42.56	4,249,673	$35.50	7.9	1,670,709	$33.45	7.0
	7,721,826	$30.52	6.6	5,133,977	$27.36	5.6

Aggregate Intrinsic Value (Millions)	Options Outstanding	Options Exercisable
December 31, 2006	$130.8	$103.2

In January 2007, the Compensation Committee awarded 1,371,590 non-qualified stock options at the average market price of $47.76 to our officers and key employees under its normal schedule of awarding long-term incentive compensation.

We utilize the straight-line attribution method for recognizing stock-based compensation expense under SFAS 123R. We recorded compensation expense, net of tax, for stock option awards made to our officers and other key employees of $4.6 million ($0.04 per share) for the twelve months ended December 31, 2006.

The aggregate intrinsic value of stock options exercised during the twelve months ended December 31, 2006 was approximately $21.1 million. Tax benefits associated with our stock option awards for the twelve months ended December 31, 2006 were $8.4 million.

The exercise price of a stock option under the plan is to be no less than 100% of the common stock's fair market value on the grant date and options may not be exercised within six months of the grant date except in the event of a change in control. In December 2004, the Compensation Committee approved the acceleration of vesting of all unvested options awarded to officers and other key

employees in 2002, 2003 and 2004. In addition, the Compensation Committee determined that future option grants would be non-qualified stock options and they would vest on a cliff-basis after a three year period. The stock options that were granted prior to 2005 generally vest on a straight line basis over a four year period. Generally, options expire no later than ten years from the date of grant. In 2004, we recorded a $0.4 million charge, net of tax, in connection with the accelerated vesting of unvested stock options. For further information regarding the accounting changes related to stock based compensation, see Note A and Note B.

On December 31, 2005, the value of our non-vested stock options outstanding was $11.3 million, or $8.30 per share on a weighted average grant date fair value basis. On December 31, 2006 the value of our non-vested stock options outstanding was $20.5 million or $7.94 per share on a weighted average grant date fair value basis. During the year, 36,318 stock options vested and 40,261 stock options were forfeited on a weighted average grant date fair value of $6.71 and $7.99, respectively.

As of December 31, 2006, total compensation costs related to non-vested stock options not yet recognized was approximately $9.1 million, which is expected to be recognized over the next 19 months on a weighted-average basis.

The Compensation Committee has also approved restricted stock grants to certain key employees and directors. The following restricted stock activity occurred during 2006, 2005 and 2004:

	2006		2005		2004	
Restricted Shares	Number of Shares	Weighted-Average Market Price	Number of Shares	Weighted-Average Market Price	Number of Shares	Weighted-Average Market Price
Outstanding at January 1	193,657		221,363		294,920	
Granted	18,152	$39.97	18,137	$34.33	16,570	$33.36
Released	(27,144)	$28.68	(45,843)	$27.77	(90,127)	$22.87
Outstanding at December 31	184,665		193,657		221,363	

Recipients of the restricted shares, who have the right to vote the shares and to receive dividends, are not required to provide consideration to us other than rendering service. Forfeiture provisions on the restricted stock generally expire 10 years after award grant subject to an accelerated expiration schedule for some of the shares based on the achievement of certain financial performance goals.

We record the market value of the restricted stock awards on the date of grant and then we charge their value to expense over the vesting period of the awards. We also adjust expense for acceleration of vesting due to achievement of performance goals. We recorded compensation expense, net of tax, for restricted stock awards made to our employees and directors of $0.7 million for the twelve months ended December 31, 2006. The impact was less than $0.01 per share for the twelve months ended December 31, 2006. Tax benefits realized for our restricted stock awards were $0.5 million for the twelve months ended December 31, 2006. As of December 31, 2006, total compensation cost related to non-vested restricted stock awards not yet recognized was approximately $2.6 million, which is expected to be recognized over the next 52 months on a weighted-average basis.

In January 2004, the Compensation Committee granted 159,159 performance shares to our officers and other key employees. In January 2007, 2006 and 2005 the Compensation Committee granted 136,905, 150,281 and 101,834 performance units to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units which will be awarded is dependent upon the achievement of certain financial performance of our stock over a three year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance award. We are accruing compensation costs over the three year period based on our estimate of the final expected value of the award. In July 2006, the Compensation Committee amended the terms of the performance shares to allow the recipients of 2004 grants to receive cash or common stock upon settlement. During the third quarter of 2006, we transferred $6.3 million from Common Equity to Other Liabilities to reflect participant elections to take cash under this amendment. The 2005, 2006 and 2007 grants will be settled in cash. We recorded compensation expense, net of tax, for performance awards made to our employees of $4.3 million ($0.04 per share) for the twelve months ended December 31, 2006. We have not realized any tax benefits associated with our performance awards during the twelve months ended December 31, 2006. As of December 31, 2006, total compensation cost related to non-vested performance awards not yet recognized was approximately $6.4 million, which is expected to be recognized over the next 21 months on a weighted-average basis. The final value of the 2004 performance share award was approximately $7.2 million, which was paid to our officers and key employees in January 2007.

Common Stock Activity: In September 2000, the Board of Directors amended the common stock repurchase plan to authorize us to purchase up to $400 million of our shares of common stock in the open market. In 2004, we purchased and retired approximately

1.6 million shares of common stock for $50.4 million. The repurchase plan expired on December 31, 2004. Over the life of the repurchase plan we purchased and retired approximately 14.9 million shares of common stock for $344.0 million.

No new shares of common stock were issued in 2006 and 2005. Prior to February 2004, we issued shares of our common stock to fulfill obligations under various employee benefit plans and the dividend reinvestment plan. We received proceeds of approximately $4.8 million during 2004, related to these share issuances. In February 2004, we announced that we did not expect to issue new shares under these programs; rather we instructed the independent plan agents to begin purchasing the shares in the open market in lieu of issuing new shares. During 2006 and 2005, our plan agents purchased 1.1 million shares at a cost of $48.0 million and 2.0 million shares at a cost of $75.1 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2006 and 2005, we received proceeds of $26.8 million and $47.0 million, respectively, related to the exercise of stock options.

Restrictions: Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from our principal utility subsidiaries, Wisconsin Electric and Wisconsin Gas. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our principal utility subsidiaries to transfer funds to Wisconsin Energy in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy.

The Wisconsin Electric January 2006 rate order from the PSCW requires Wisconsin Electric to maintain a capital structure (i.e., the percentage by which each of common stock, preferred stock and debt constitute the total capital invested in the utility), which has a common equity ratio range of between 48.5% and 53.5% (including certain off-balance sheet obligations and capitalized leases, but excluding the PWGS 1 capitalized lease). The Wisconsin Gas January 2006 rate order established a test year average common equity ratio of 50.2%. Previously in a June 2004 decision, the PSCW determined that both Wisconsin Electric and Wisconsin Gas must obtain specific approval to pay dividends that exceed normal levels as long as any tax issue or appeals related to the sale of the manufacturing business and/or the conversion of Wisconsin Gas to a limited liability company remain outstanding. The PSCW may modify such provisions by a future order.

Wisconsin Electric may not pay common dividends to Wisconsin Energy under Wisconsin Electric's Restated Articles of Incorporation if any dividends on Wisconsin Electric's outstanding preferred stock have not been paid. In addition, pursuant to the terms of Wisconsin Electric's 3.60% Serial Preferred Stock, Wisconsin Electric's ability to declare common dividends would be limited to 75% or 50% of net income during a twelve month period if Wisconsin Electric's common stock equity to total capitalization, as defined, is less than 25% and 20%, respectively.

As of December 31, 2006, the restricted net assets of consolidated and unconsolidated subsidiaries and our equity in undistributed earnings of 50 percent or less owned investees accounted for by the equity method total approximately $2.6 billion. This amount exceeds 25 percent of our consolidated net assets as of December 31, 2006.

See Note L for discussion of certain financial covenants related to the bank back-up credit agreements of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

K -- LONG-TERM DEBT

Debentures and Notes: As of December 31, 2006, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2007	$268.3
2008	349.5
2009	53.9
2010	14.1
2011	454.3
Thereafter	2,022.5
Total	$3,162.6

We amortize debt premiums, discounts and debt issuance costs over the lives of the debt and we include the costs in interest expense.

In November 2006, Wisconsin Electric issued $300 million of 5.70% Debentures due December 1, 2036. The securities were issued under an existing $665 million shelf registration statement filed with the SEC. The net proceeds from the sale were used to retire Wisconsin Electric's $200 million of 6-5/8% Debentures due November 15, 2006 at their scheduled maturity and to repay outstanding commercial paper incurred for working capital requirements.

Wisconsin Energy retired at the scheduled maturity date $250.0 million of 5.875% Notes due April 1, 2006. Short-term debt was issued to retire these notes.

In July 2005, PWGS issued $155 million of 4.91% senior notes in a private placement. The senior notes have a mortgage style repayment feature with monthly payments of approximately $0.9 million including principal and interest. The final payment is due July 15, 2030. The senior notes are secured by a collateral assignment of the leases between PWGS and Wisconsin Electric relating to the first PWGS gas unit that went into service in July 2005.

Wisconsin Gas retired at the scheduled maturity date $65 million of 6-3/8% Notes due November 1, 2005. In November 2005, Wisconsin Gas issued $90 million of 5.90% Debentures due December 1, 2035. The securities were issued under shelf registration statements filed with the SEC. The proceeds from the sale were used to repay a portion of our outstanding commercial paper. The commercial paper was incurred to both retire the $65 million of 6-3/8% Notes and for working capital requirements.

Obligations Under Capital Leases: In 1997, Wisconsin Electric entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MW of firm capacity from a gas-fired cogeneration facility, includes no minimum energy requirements. When the contract expires in 2022, Wisconsin Electric may, at its option and with proper notice, renew for another ten years or purchase the generating facility at fair value or allow the contract to expire. We account for this contract as a capital lease and recorded the leased facility and corresponding obligation under the capital lease at the estimated fair value of the plant's electric generating facilities. We are amortizing the leased facility on a straight-line basis over the original 25-year term of the contract.

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as purchased power expense on the Consolidated Income Statements. We paid a total of $26.1 million, $25.2 million and $24.3 million in minimum lease payments during 2006, 2005, and 2004, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting as a deferred regulatory asset on our Consolidated Balance Sheets (see Regulatory Assets - Deferred plant related -- capital lease in Note C). Due to the timing and the amounts of the minimum lease payments, we expect the regulatory asset to increase to approximately $78.5 million by the year 2009 at which time the regulatory asset will be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $159.4 million at December 31, 2006 and will decrease to zero over the remaining life of the contract.

Wisconsin Electric also has a nuclear fuel leasing arrangement with Wisconsin Electric Fuel Trust (Trust) which is treated as a capital lease. We lease and amortize the nuclear fuel to fuel expense as power is generated, generally over a period of 60 months. Lease payments include charges for the cost of fuel burned, financing costs and management fees. In the event that Wisconsin Electric or the Trust terminates the lease, the Trust would recover its unamortized cost of nuclear fuel from Wisconsin Electric. Under the lease terms, Wisconsin Electric is in effect the ultimate guarantor of the Trust's commercial paper and line of credit borrowings that finance the investment in nuclear fuel. We recorded $4.2 million, $1.7 million and $1.4 million of interest expense on the nuclear fuel lease in fuel expense during 2006, 2005 and 2004, respectively.

Following is a summary of our capitalized leased facilities and nuclear fuel as of December 31.

Capital Lease Assets	2006	2005
	(Millions of Dollars)	
Leased Facilities		
Long-term purchase power commitment	$140.3	$140.3
Accumulated amortization	(52.8)	(47.1)
Total Leased Facilities	$87.5	$93.2
Nuclear Fuel		
Under capital lease	$136.0	$125.6
Accumulated amortization	(70.4)	(60.2)
In process/stock	65.3	46.6
Total Nuclear Fuel	$130.9	$112.0

Future minimum lease payments under our capital leases and the present value of our net minimum lease payments as of December 31, 2006 are as follows:

Capital Lease Obligations	Purchase Power Commitment	Nuclear Fuel Lease	Total
	(Millions of Dollars)		
2007	$32.4	$29.2	$61.6
2008	33.6	24.6	58.2
2009	34.9	15.4	50.3
2010	36.2	5.9	42.1
2011	37.5	2.9	40.4
Thereafter	295.3	-	295.3
Total Minimum Lease Payments	469.9	78.0	547.9
Less: Estimated Executory Costs	(103.8)	-	(103.8)
Net Minimum Lease Payments	366.1	78.0	444.1
Less: Interest	(206.7)	(6.0)	(212.7)
Present Value of Net Minimum Lease Payments	159.4	72.0	231.4
Less: Due Currently	(2.0)	(26.4)	(28.4)
	$157.4	$45.6	$203.0

L -- SHORT-TERM DEBT

Short-term notes payable balances and their corresponding weighted-average interest rates as of December 31 consist of:

Short-Term Debt	2006 Balance	2006 Interest Rate	2005 Balance	2005 Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial paper	$911.9	5.37%	$456.3	4.39%

On December 31, 2006, we had approximately $1.7 billion of available unused lines under our bank back-up credit facilities on a consolidated basis. Our bank back-up credit facilities expire in March 2011 and April 2011.

The following information relates to Short-Term Debt for the years ending December 31, 2006 and 2005:

	2006	2005
	(Millions of Dollars, except for percentages)	
Maximum Short-Term Debt Outstanding	$943.7	$464.2
Average Short-Term Debt Outstanding	$549.8	$222.8
Weighted Average Interest Rate	5.13%	3.20%

Wisconsin Energy, Wisconsin Electric and Wisconsin Gas have entered into various bank back-up credit agreements to maintain short-term credit liquidity which, among other terms, require the companies to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 70%, 65% and 65%, respectively.

The Wisconsin Energy, Wisconsin Electric and Wisconsin Gas bank back-up credit agreements contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit agreements also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy

proceedings, certain judgments, ERISA defaults and change of control. In addition, pursuant to the terms of Wisconsin Energy's credit agreement, Wisconsin Energy must ensure that certain of its subsidiaries comply with many of the covenants contained therein.

At December 31, 2006, we were in compliance with all covenants.

M – DERIVATIVE INSTRUMENTS

We follow SFAS 133 as amended by SFAS 149, which requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives under SFAS 133, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. As of December 31, 2006, we recognized $36.6 million in regulatory assets related to derivatives in comparison to $4.8 million at December 31, 2005.

We had a limited number of financial contracts that are defined as derivatives under SFAS 133 and qualify for cash flow hedge accounting. These contracts were utilized to manage the cost of gas for utility operations. In addition, these contracts were utilized in 2004 and the first half of 2005, for gas used in testing a new generating unit under construction. Changes in the fair market values of these instruments were recorded in Accumulated Other Comprehensive Income. At the date the underlying transaction occurs, the amounts in Accumulated Other Comprehensive Income for utility operations were reported in earnings and amounts related to the new generating unit were capitalized.

For the year ended December 31, 2005 the amount of hedge ineffectiveness was immaterial. We did not exclude any components of derivative gains or losses from the assessment of hedge effectiveness.

For the years ended December 31, 2006, 2005 and 2004, we reclassified $0.4 million, $0.6 million and $0.8 million in treasury lock agreement settlement payments deferred in Accumulated Other Comprehensive Income as an increase to Interest Expense. We estimate that during the next twelve months, $0.4 million will be reclassified from Accumulated Other Comprehensive Income as a reduction in earnings.

In addition, during 2004, in conjunction with the redemption of $300 million of Wisconsin Energy 5.875% senior notes due April 1, 2006, $0.6 million of a treasury lock agreement settlement payment previously deferred in Accumulated Other Comprehensive Income was reclassified to Other Income and Deductions, Net.

N -- FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amount and estimated fair value of certain of our recorded financial instruments as of December 31 are as follows:

	2006		2005	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Nuclear decommissioning assets	$881.6	$881.6	$782.1	$782.1
Preferred stock, no redemption required	$30.4	$22.6	$30.4	$22.6
Long-term debt including current portion	$3,162.6	$3,172.1	$3,320.9	$3,386.2

The carrying value of cash and cash equivalents, net accounts receivable, accounts payable and short-term borrowings approximates fair value due to the short term nature of these instruments. The nuclear decommissioning assets are carried at fair value as reported by the trustee (see Note I). The fair value of our preferred stock is estimated based upon the quoted market value for the same or similar issues. The fair value of our long-term debt, including the current portion of long-term debt but excluding capitalized leases, is estimated based upon quoted market value for the same or similar issues or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. The fair values of derivative financial instruments and associated margin accounts are equal to their carrying values as of December 31, 2006.

O – BENEFITS

Pensions and Other Post-retirement Benefits: We have noncontributory defined benefit pension plans that cover substantially all of our employees. The plans provide defined benefits based upon years of service and final average salary. In October 2006, we announced that we were making a change to pension benefits for new management employees hired subsequent to October 2006 and for those represented employees whose unions have adopted this plan. The retirement benefit for new employees is an enhanced 401(k) plan. Existing employee's pension benefits are unchanged. Our 2007 combined pension and savings plan costs are not expected to be materially affected as a result of this change to the plan.

We also have OPEB plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually; the life insurance plans are noncontributory. The accounting for the health care plans anticipates future cost-sharing changes to the written plans that are consistent with our expressed intent to maintain the current cost sharing levels. The post-retirement health care plans include a limit on our share of costs for recent and future retirees. We use a year end measurement date for all of our pension and OPEB plans.

In September 2006, the FASB issued SFAS 158, which requires employers to recognize all obligations related to their pension and OPEB plans and to quantify the funded status of the pension and OPEB plans as an asset or liability on their statement of financial position. In addition, SFAS 158 requires employers to measure the funded status of their plans as of the date of their year-end statement of financial position.

We adopted SFAS 158 prospectively on December 31, 2006, and will continue to use a year end measurement date for all of our pension and OPEB plans. Prior to the issuance of SFAS 158, we recorded a minimum pension liability to reflect the funded status of our pension plans. Due to the regulatory nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following table shows the incremental effect of applying SFAS 158 on individual line items in our year-end statement of financial position and compares prior year-end balances:

	December 31, 2006			
	Before SFAS 158	Impact	As Reported	December 31, 2005
	(Millions of Dollars)			(Millions of Dollars)
Regulatory Asset - Pension	$280.1	$ 77.1	$357.2	$377.2
Regulatory Asset - OPEB	$ 14.6	$ 55.9	$ 70.5	$ 17.3
Other Deferred Charges - Pension	$ 30.5	$(30.5)	$ -	$ 32.4
Other Deferred Charges - OPEB	$ 40.8	$(26.1)	$ 14.7	$ 53.5
Pension Liability	$161.0	$ 34.9	$195.9	$274.4
OPEB Liability	$114.2	$ 29.8	$144.0	$129.9
Other Comprehensive Income	$(11.7)	$ 11.7	$ -	$(15.9)

The following table presents additional details about our pension and OPEB plans.

Status of Benefit Plans	Pension 2006	Pension 2005	OPEB 2006	OPEB 2005
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	$1,299.7	$1,205.0	$331.9	$395.5
Service cost	33.8	33.3	12.3	13.6
Interest cost	69.6	69.7	17.9	21.0
Plan amendments	3.6	3.3	-	(85.5)
Actuarial loss (gain)	(51.5)	79.6	(18.0)	4.1
Benefits paid	(101.6)	(91.2)	(12.1)	(16.8)
Federal Subsidy on benefits paid	N/A	N/A	0.9	N/A
Benefit Obligation at December 31	$1,253.6	$1,299.7	$332.9	$331.9
Change in Plan Assets				
Fair Value at January 1	$976.9	$998.5	$186.0	$183.6
Actual earnings on plan assets	121.5	65.4	14.7	6.9
Employer contributions	60.9	4.2	15.1	12.3
Benefits paid	(101.6)	(91.2)	(12.1)	(16.8)
Fair Value at December 31	$1,057.7	$976.9	$203.7	$186.0
Funded Status of Plans				
Funded status at December 31	($195.9)	($322.8)	($129.3)	($145.9)
Unrecognized (1)				
Net actuarial loss	N/A	441.7	N/A	134.1
Prior service cost	N/A	32.2	N/A	(67.0)
Net transition (asset) obligation	N/A	-	N/A	2.4
Net Asset (Accrued Benefit Cost)	($195.9)	$151.1	($129.3)	($76.4)

(1) After adoption of SFAS 158 on December 31, 2006, these amounts are recorded and this reconciliation is no longer needed.

The accumulated benefit obligation for all defined benefit plans was $1,218.7 million and $1,251.6 million as of December 31, 2006 and 2005, respectively.

Information for pension plans with an accumulated benefit obligation in excess of the fair value of assets is as follows:

	2006	2005
	(Millions of Dollars)	
Projected benefit obligation	$1,253.6	$1,299.7
Accumulated benefit obligation	$1,218.7	$1,251.6
Fair value of plan assets	$1,057.7	$976.9

The components of net periodic pension and OPEB costs are:

Benefit Plan Cost Components	Pension			OPEB		
	2006	2005	2004	2006	2005	2004
			(Millions of Dollars)			
Net Periodic Benefit Cost						
Service cost	$33.8	$33.3	$30.2	$12.3	$13.6	$12.0
Interest cost	69.6	69.7	69.1	17.9	21.0	21.8
Expected return on plan assets	(81.6)	(87.6)	(85.6)	(14.9)	(15.4)	(14.1)
Amortization of:						
Transition (asset) obligation	-	-	(2.3)	0.3	1.3	1.6
Prior service cost	5.4	5.2	4.8	(13.4)	(2.8)	0.7
Actuarial loss	23.4	20.6	15.0	8.8	7.7	6.6
Net Periodic Benefit Cost	$50.6	$41.2	$31.2	$11.0	$25.4	$28.6
Weighted-Average assumptions used to determine benefit obligations at Dec. 31						
Discount rate	5.75%	5.50%	5.75%	5.75%	5.50%	5.75%
Rate of compensation increase	4.5 to 5.0	4.5 to 5.0	4.0 to 5.0	4.5 to 5.0	4.5 to 5.0	4.0 to 5.0
Weighted-Average assumptions used to determine net cost for year ended Dec. 31						
Discount rate	5.50%	5.75%	6.25%	5.50%	5.75%	6.25%
Expected return on plan assets	8.5	9.0	9.0	8.5	9.0	9.0
Rate of compensation increase	4.5 to 5.0	4.0 to 5.0	4.0 to 5.0	4.5 to 5.0	4.0 to 5.0	4.0 to 5.0
Assumed health care cost trend rates at Dec. 31						
Health care cost trend rate assumed for next year (Pre 65 / Post 65)				9/11	10	10
Rate that the cost trend rate gradually adjusts to				5	5	5
Year that the rate reaches the rate it is assumed to remain at				2011	2011	2010

The expected long-term rate of return on plan assets was 8.5% in 2006 and 9% in 2005 and 2004. This return expectation on plan assets was determined by reviewing actual pension historical returns as well as calculating expected total trust returns using the weighted average of long-term market returns for each of the asset categories utilized in the pension fund.

Other Post-retirement Benefits Plans: We use various Employees' Benefit Trusts to fund a major portion of OPEB. The majority of the trusts' assets are mutual funds or commingled indexed funds.

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(Millions of Dollars)	
Effect on		
Post-retirement benefit obligation	$26.5	($22.4)
Total of service and interest cost components	$3.8	($3.1)

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) was signed into law. The Act introduced a prescription drug benefit program under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans. In 2004, the FASB issued FSP SFAS 106-2.

In 2004, in accordance with FSP SFAS 106-2, we chose to recognize the effects of the Act retroactively effective January 1, 2004. Calculated actuarially, the Act resulted in a reduction of $24.1 million in our benefit obligation. In addition, we recorded a reduction to SFAS 106 expense of $4.7 million in 2004. In January 2005, the Centers for Medicare & Medicaid Services released final

regulations to implement the new prescription drug benefit under Part D of Medicare. It was determined that our employer sponsored plans met these regulations and that the previously determined actuarial measurements do not need to be revised.

In October 2005, we announced that we were offering to our retirees a Medicare Advantage program as an option within our existing post-retirement medical and drug plans. The Medicare Advantage program is part of the Act, and offers post-65 medical and drug benefits through private insurance carriers. The Medicare Advantage program is expected to reduce the cost of post-65 medical and drug costs for our retirees and the Company. Due to this change, we remeasured the fair value of our OPEB plans in the fourth quarter of 2005 in accordance with SFAS 106. In 2005, the impact of this remeasurement and the FSP SFAS 106-2 benefit was approximately a $4.4 million reduction to SFAS 106 expense.

Plan Assets: In our opinion, current pension trust assets and amounts which are expected to be contributed to the trusts in the future will be adequate to meet pension payment obligations to current and future retirees. Our pension plans asset allocation at December 31, 2006 and 2005, and our target allocation for 2007, by asset category, are as follows:

Asset Category	Target Allocation	Actual Allocation	
	2007	2006	2005
Equity Securities	65%	61%	65%
Debt Securities	35%	39%	35%
Total	100%	100%	100%

Our OPEB plans asset allocation at December 31, 2006 and 2005, and our target allocation for 2007, by asset category, are as follows.

Asset Category	Target Allocation	Actual Allocation	
	2007	2006	2005
Equity Securities	54%	45%	45%
Debt Securities	46%	54%	54%
Other	-%	1%	1%
Total	100%	100%	100%

Our common stock is not included in equity securities. Investment managers are specifically prohibited from investing in our securities or any affiliate of ours except if part of a commingled fund or index fund.

The target asset allocations were established by our Investment Trust Policy Committee, which oversees investment matters related to all of our funded benefit plans. The asset allocations are monitored by the Investment Trust Policy Committee.

Cash Flows:

Employer Contributions	Pension	OPEB
	(Millions of Dollars)	
2004	$77.5	$19.4
2005	$4.2	$12.3
2006	$60.9	$15.1

Based on our PSCW approved funding policy and current IRS funding requirements, we expect to contribute $38.3 million to fund pension benefits and $12.5 million to fund OPEB plans in 2007. Of the $38.3 million expected to be contributed to fund pension benefits in 2007, we estimate $33.0 million will be for our qualified pension plans. We contributed $55.4 million to our qualified pension plans during 2006. We did not make a contribution to our qualified pension plan during 2005.

The entire contribution to the OPEB plans during 2006 was discretionary as the plans are not subject to any minimum regulatory funding requirements.

The following table identifies our expected benefit payments over the next 10 years.

Year	Pension	Gross OPEB	Expected Medicare Part D Subsidy
		(Millions of Dollars)	
2007	$81.5	$22.2	($1.2)
2008	$87.3	$21.6	($1.0)
2009	$91.1	$19.4	$ -
2010	$93.2	$19.5	$ -
2011	$104.9	$20.0	$ -
2012-2016	$530.3	$120.1	$ -

Savings Plans: We sponsor savings plans which allow employees to contribute a portion of their pre-tax and or after-tax income in accordance with plan-specified guidelines. Under these plans we expensed matching contributions of $10.4 million, $10.7 million and $10.5 million during 2006, 2005 and 2004, respectively.

Severance Plans: In 2004, we incurred $30.5 million ($18.3 million after-tax) of severance costs. The majority of the severance costs related to an enhanced severance package offered to selected management employees of Wisconsin Energy and its subsidiaries who voluntarily resigned in the fourth quarter of 2004. The program was enacted to help reduce the upward pressure on operating expenses.

Approximately 200 employees received severance benefits during 2004. At December 31, 2004, we accrued $6.6 million for severance benefits. As of December 31, 2006, all of the severance related benefits were paid.

P -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties on behalf of our affiliates. As of December 31, 2006, we had the following guarantees:

	Maximum Potential Future Payments	Outstanding at Dec 31, 2006	Liability Recorded at Dec 31, 2006
		(Millions of Dollars)	
Wisconsin Energy			
Non-Utility Energy	$ -	$ -	$ -
Other	6.9	6.9	-
Wisconsin Electric	235.2	0.1	-
Subsidiary	11.4	11.0	0.9
Total	$253.5	$18.0	$ 0.9

A non-utility energy segment guarantee in support of Wisvest-Connecticut, which we sold in December 2002 to PSEG, provides financial assurance for potential obligations relating to environmental remediation under the original purchase agreement for Wisvest-Connecticut with United Illuminating. The potential obligations for environmental remediation, which are unlimited, are reimbursable by PSEG under the terms of the sale agreement in the event that we are required to perform under the guarantee.

Other guarantees support obligations of our affiliates to third parties under loan agreements and surety bonds. In the event our affiliates fail to perform, we would be responsible for the obligations.

Wisconsin Electric guarantees the potential retrospective premiums that could be assessed under Wisconsin Electric's nuclear insurance program (see Note I).

Subsidiary guarantees support loan obligations and surety bonds between our affiliates and third parties. In the event our affiliates fail to perform, our subsidiary would be responsible for the obligations.

Postemployment benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability, excluding severance benefits, for such benefits was $13.0 million as of December 31, 2006.

Q – SEGMENT REPORTING

Our reportable operating segments at December 31, 2006 include a utility energy segment and a non-utility energy segment. In July 2004, our manufacturing segment was sold to Pentair, Inc. We have organized our reportable operating segments based in part upon the regulatory environment in which our utility subsidiaries operate. In addition, the segments are managed separately because each business requires different technology and marketing strategies. The accounting policies of the reportable operating segments are the same as those described in Note A.

Our utility energy segment primarily includes our electric and natural gas utility operations. Our electric utility operation engages in the generation, distribution and sale of electric energy in southeastern (including metropolitan Milwaukee), east central and northern Wisconsin and in the Upper Peninsula of Michigan. Our natural gas utility operation is engaged in the purchase, distribution and sale of natural gas to retail customers and the transportation of customer-owned natural gas throughout Wisconsin. Our non-utility energy segment derives its revenues primarily from the ownership of electric power generating facilities for long-term lease to Wisconsin Electric and economic interests in other energy-related entities.

Summarized financial information concerning our reportable operating segments for each of the years ended December 31, 2006, 2005 and 2004, is shown in the following table. The segment information below includes non-cash impairment charges of $149.0 million ($96.9 million after tax or $0.81 per share) in 2004, which are now included in income from discontinued operations as the sale of these businesses was announced or completed in 2005. These impairment charges are primarily related to the non-utility energy segment (see Note D). Substantially all of our long-lived assets and operations are domestic.

	Reportable Operating Segments			Corporate (b) & Other (c) & Reconciling	Total
	Energy				
Year Ended	Utility	Non-Utility(a)	Manufacturing (b)	Eliminations(d)	Consolidated
	(Millions of Dollars)				
December 31, 2006					
Operating Revenues (d)	$3,979.0	$69.1	$ -	($51.7)	$3,996.4
Depreciation, Decommissioning and Amortization	$314.0	$11.2	$ -	$1.2	$326.4
Operating Income (Loss)	$532.8	$43.1	$ -	($7.4)	$568.5
Equity in Earnings of Unconsolidated Affiliates	$38.6	$ -	$ -	$4.5	$43.1
Interest Expense	$108.0	$14.8	$ -	$49.9	$172.7
Income Tax Expense (Benefit)	$192.3	$11.7	$ -	($29.0)	$175.0
Income from Discontinued Operations, Net of Tax	$ -	$ -	$2.4	$1.5	$3.9
Net Income (Loss)	$315.2	$18.3	$ -	($17.1)	$316.4
Capital Expenditures	$459.9	$468.6	$ -	$0.2	$928.7
Total Assets	$10,133.9	$1,265.2	$ -	($268.9)	$11,130.2

Year Ended	Reportable Operating Segments: Energy: Utility	Energy: Non-Utility(a)	Manufacturing (b)	Corporate (b) & Other (c) & Reconciling Eliminations(d)	Total Consolidated
	(Millions of Dollars)				
December 31, 2005					
Operating Revenues (d)	$3,793.0	$40.0	$ -	($17.5)	$3,815.5
Depreciation, Decommissioning and Amortization	$324.1	$5.9	$ -	$2.0	$332.0
Operating Income	$542.4	$19.5	$ -	$1.0	$562.9
Equity in Earnings (Losses) of Unconsolidated Affiliates	$34.6	$ -	$ -	($0.6)	$34.0
Interest Expense	$106.1	$14.4	$ -	$52.9	$173.4
Income Tax Expense (Benefit)	$184.9	$4.5	$ -	($40.2)	$149.2
Income from Discontinued Operations, Net of Tax	$ -	$5.0	$ -	$0.1	$5.1
Net Income (Loss)	$314.2	$6.7	$ -	($12.2)	$308.7
Capital Expenditures	$458.6	$276.6	$ -	$9.9	$745.1
Total Assets	$9,601.6	$749.5	$ -	$110.9	$10,462.0
December 31, 2004					
Operating Revenues (d)	$3,375.4	$19.9	$ -	$10.8	$3,406.1
Depreciation, Decommissioning and Amortization	$315.5	$1.4	$ -	$2.6	$319.5
Operating Income (Loss)	$528.6	$4.6	($3.0)	($0.2)	$530.0
Equity in Earnings of Unconsolidated Affiliates	$30.1	$ -	$ -	$0.8	$30.9
Interest Expense	$108.6	$14.6	$9.9	$60.3	$193.4
Income Tax Expense	$174.5	($4.3)	($5.0)	($32.4)	$132.8
Income (Loss) from Discontinued Operations, Net of Tax	$ -	($81.2)	$31.9	$136.1	$86.8
Net Income (Loss)	$283.9	($86.6)	$26.6	$82.5	$306.4
Capital Expenditures	$426.5	$191.0	$ -	$19.0	$636.5
Total Assets	$8,775.3	$506.8	$ -	$283.3	$9,565.4

(a) The non-utility energy segment includes discontinued operations for the Calumet operations. The sale of Calumet was completed effective May 31, 2005. In 2005, Calumet is reported as discontinued operations for the five months ended May 31, 2005. The after tax gain of $4.7 million recorded for the sale is included in Income from Discontinued Operations, Net of Tax. Certain overheads reported for Calumet continued to exist following the sale and are reported in continuing operations. Certain other costs are directly attributable to the discontinued operations. Total assets in the non-utility segment include the assets held for sale of Calumet of $29.8 million at December 31, 2004.

(b) The sale of our manufacturing segment was completed effective July 31, 2004. The financial information presented for the manufacturing segment in 2004 is for the seven months ended July 31, 2004. The gain on the sale of the manufacturing segment and a 2006 tax adjustment are reflected in Corporate and Other. Certain corporate overheads reported in the manufacturing segment continue to exist following the sale and are reported in continuing operations. Certain other corporate costs are directly attributable to the discontinued operations.

(c) Other includes all other non-utility activities, primarily non-utility real estate investment and development by Wispark, non-utility investment in renewable energy and recycling technologies by Minergy as well as interest on corporate debt and in 2004, the gain on the sale of the manufacturing segment. Other also includes the discontinued operations for Minergy Neenah. Effective September 27, 2006, we sold 100% of the membership interest in Minergy Neenah. The sale transaction is included in Income from Discontinued Operations, Net of Tax. Certain overheads reported for Minergy Neenah continue to exist following the sale and are reported in continuing operations. Certain other costs are directly attributable to the discontinued operations. Total assets in other includes: Minergy Neenah assets held for sale of $17.4 million and $24.4 million at December 31, 2005 and 2004, respectively.

(d) An elimination for intersegment revenues is included in Operating Revenues of $64.1 million, $36.3 million and $6.8 million for 2006, 2005 and 2004, respectively.

R -- RELATED PARTIES

We receive and/or provide certain services to other associated companies in which we have an equity investment.

American Transmission Company LLC: As of December 31, 2006, we have a 29.4% interest in ATC. We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance and project management work for ATC, which are reimbursed to us by ATC. Under our PTF plan, we are required to pay the cost of needed transmission infrastructure upgrades. ATC will reimburse us for these costs when the units are placed into service. At December 31, 2006 and 2005, we had a receivable of $27.2 million and $19.4 million, respectively, for these items.

Guardian: In April 2006, we sold our one third ownership interest in Guardian. As such, the tables below reflect activity through April 2006 with respect to Guardian. We have committed to purchase 650,000 Dth per day of capacity (approximately 87% of the pipeline's total capacity) under the terms of a 10 year transportation agreement expiring December 2022.

Nuclear Management Company: At December 31, 2006, NMC, which operates Point Beach, was owned by our affiliate, WEC Nuclear Corporation, and the affiliates of two other unaffiliated investor-owned utilities in the region. Wisconsin Electric pays NMC a plant operating charge. In December 2006, we announced our intention to sell Point Beach to an affiliate of FPL. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us), the operating licenses for Point Beach will transfer from NMC to the buyer and our relationship with NMC will be terminated.

We provided and received services from the following associated companies during 2006, 2005 and 2004:

Equity Investee	2006	2005	2004
		(Millions of Dollars)	
Services Provided			
-ATC	$ 16.6	$ 20.9	$ 21.6
Services Received			
-ATC	$149.4	$130.1	$115.5
-NMC	$ 65.2	$ 61.2	$ 58.1
-Guardian	$ 11.8	$ 34.0	$ 33.6

At December 31, 2006 and 2005 our consolidated balance sheets included receivable and payable balances with the following associated companies:

Equity Investee	2006	2005
	(Millions of Dollars)	
Services Provided		
-ATC	$ 1.2	$ 1.3
Services Received		
-ATC	$12.5	$10.6
-NMC	$ 5.7	$ 2.5
-Guardian	$ -	$ 3.0

S -- COMMITMENTS AND CONTINGENCIES

Capital Expenditures: We have made certain commitments in connection with 2007 capital expenditures. During 2007, we estimate that total capital expenditures will be approximately $1.4 billion.

Operating Leases: We enter into long-term purchase power contracts to meet a portion of our anticipated increase in future electric energy supply needs. These contracts expire at various times through 2013. Certain of these contracts were deemed to qualify as operating leases. In addition, we have various other operating leases including leases for vehicles and coal cars.

Future minimum payments for the next five years and thereafter for our operating lease contracts are as follows:

	(Millions of Dollars)
2007	$51.6
2008	35.7
2009	22.5
2010	20.5
2011	20.7
Thereafter	32.9
Total	$183.9

Divested Assets: Pursuant to the terms of the sale agreement for Minergy Neenah, we have agreed to customary indemnification provisions related to post-closing obligations and other matters. Our maximum aggregate exposure under the indemnification provisions is $0.3 million.

Pursuant to the terms of the sale agreement for Calumet, Wisvest has agreed to customary indemnification provisions related to environmental conditions and other matters. Except for retention of the full exposure to indemnify Tenaska for environmental claims related to certain property no longer leased or owned by Wisvest or any of its subsidiaries, Wisvest's maximum aggregate exposure under the indemnification provisions is $35 million. Pursuant to the terms of the agreement, we have guaranteed post-closing obligations under the agreement, including indemnity obligations.

Pursuant to the terms of the sales agreement for WICOR Wisconsin Energy agreed to customary indemnification provisions related to certain environmental, asbestos, and product liability matters associated with the manufacturing business. In addition, the amount of cash taxes and future deferred income tax benefits are subject to a number of factors including appraisals of the fair value of Wisconsin Gas assets and applicable tax laws. Any changes in the estimates of taxes and indemnification matters will be recorded as an adjustment to the gain on sale and reported in discontinued operations in the period the adjustment is determined. We have established reserves related to these customary indemnification and tax matters.

Environmental Matters: We periodically review our exposure for environmental remediation costs as evidence becomes available indicating that our liability has changed. Given current information, including the following, we believe that future costs in excess of the amounts accrued and/or disclosed on all presently known and quantifiable environmental contingencies will not be material to our financial position or results of operations.

We have a program of comprehensive environmental remediation planning for former manufactured gas plant sites and coal-ash disposal sites. We perform ongoing assessments of manufactured gas plant sites and related disposal sites used by Wisconsin Electric and Wisconsin Gas, and coal ash disposal/landfill sites used by Wisconsin Electric, as discussed below. We are working with the WDNR in our investigation and remediation planning. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

Manufactured Gas Plant Sites: We have identified several sites at which Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. We have substantially completed planned remediation activities at some of those sites and certain other sites are subject to ongoing monitoring. Remediation at additional sites is currently being performed, and other sites are being investigated or monitored. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon ongoing analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from $25 to $50 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of December 31, 2006, we have established reserves of $30.5 million related to future remediation costs.

The PSCW has allowed Wisconsin utilities, including Wisconsin Electric and Wisconsin Gas, to defer the costs spent on the remediation of manufactured gas plant sites, and has allowed for these costs to be recovered in rates over five years. Accordingly, we have recorded a regulatory asset for remediation costs.

Ash Landfill Sites: Wisconsin Electric aggressively seeks environmentally acceptable, beneficial uses for its coal combustion by-products. However, these coal-ash by-products have been, and to a small degree, continue to be disposed in company-owned, licensed landfills. Some early designed and constructed landfills may allow the release of low levels of constituents resulting in the need for various levels of monitoring or adjusting. Where Wisconsin Electric has become aware of these conditions, efforts have been expended to define the nature and extent of any release, and work has been performed to address these conditions. The costs of these efforts are recovered under the fuel clause for Wisconsin Electric and are expensed as incurred. During 2006, 2005 and 2004, Wisconsin Electric incurred $0.5 million, $0.1 million and $1.8 million, respectively, in coal-ash remediation expenses. As of December 31, 2006, we have no reserves established related to ash landfill sites.

EPA - Proposed Consent Decree: In April 2003, Wisconsin Electric and the EPA announced that a consent decree had been reached that resolved all issues related to a request for information that had been issued by the EPA. Under the consent decree, Wisconsin Electric agreed to significantly reduce its air emissions from its coal-fired generating facilities. The reductions are expected to be achieved by 2013 through a combination of installing new pollution control equipment, upgrading existing equipment and retiring certain older units. Through December 31, 2006, we have spent approximately $355.0 million associated with implementing the EPA agreement and the ultimate capital cost of implementing this agreement is estimated to be $1 billion through the year 2013.

The consent decree, amended to include the State of Michigan, has been filed with a federal court for approval. Various intervenor groups have commented on the consent decree and we believe that the briefings and subsequent discovery is complete. At this time, we are unable to predict the timing or the ultimate resolution of the federal court's consideration; however, we do not believe that the ultimate resolution of this matter will have a material impact on our financial position or results of operations.

Deloitte.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2006 and 2005, and the related consolidated statements of income, common equity and cash flows for each of the three years in the period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

February 22, 2007

Member of
Deloitte Touche Tohmatsu

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Wisconsin Energy Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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 maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides 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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2006 of the Company and our report dated February 22, 2007 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

February 22, 2007

Member of
Deloitte Touche Tohmatsu

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of Wisconsin Energy Corporation's and subsidiaries internal control over financial reporting based on the framework in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in Internal Control - Integrated Framework, our management concluded that Wisconsin Energy Corporation's and subsidiaries internal control over financial reporting was effective as of December 31, 2006.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of 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.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of our financial statements has issued an attestation report on management's assessment of the effectiveness of Wisconsin Energy Corporation's and subsidiaries internal control over financial reporting as of December 31, 2006. Deloitte & Touche's report is included in this report.

Changes in Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting during the fourth quarter of 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

WISCONSIN ENERGY CORPORATION

CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

Financial	2006	2005	2004	2003	2002
Year Ended December 31					
Net income - Continuing Operations (Millions)	$ 312.5	$ 303.6	$ 219.6	$ 201.3	$ 135.9
Earnings per share - Continuing Operations					
Basic	$ 2.67	$ 2.59	$ 1.87	$ 1.72	$ 1.18
Diluted	$ 2.64	$ 2.56	$ 1.84	$ 1.70	$ 1.17
Dividends per share of common stock	$ 0.92	$ 0.88	$ 0.83	$ 0.80	$ 0.80
Common Stock Price - High During Year	$ 48.70	$ 40.83	$ 34.60	$ 33.68	$ 26.48
Common Stock Price - Low During Year	$ 38.16	$ 33.35	$ 29.50	$ 22.56	$ 20.17
Operating revenues (Millions)					
Utility energy	$ 3,979.0	$ 3,793.0	$ 3,375.4	$ 3,263.9	$ 2,852.1
Non-utility energy	69.1	40.0	19.9	12.3	165.0
Other including eliminations	(51.7)	(17.5)	10.8	5.9	15.6
Total operating revenues	$ 3,996.4	$ 3,815.5	$ 3,406.1	$ 3,282.1	$ 3,032.7
At December 31 (Millions)					
Total assets	$ 11,130.2	$ 10,462.0	$ 9,565.4	$ 10,014.5	$ 9,465.9
Long-term debt (including current maturities), capital lease obligations and mandatorily redeemable trust preferred securities	$ 3,370.1	$ 3,527.0	$ 3,340.5	$ 3,736.7	$ 3,266.6

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

(Millions of Dollars, Except Per Share Amounts) (a)

	March		June	
Three Months Ended	2006	2005	2006	2005
Operating revenues	$ 1,247.0	$ 1,094.7	$ 814.4	$ 788.5
Operating income	191.6	166.8	107.1	89.9
Income from Continuing Operations	104.4	90.0	59.7	56.8
Income (loss) from Discontinued Operations	1.3	(0.1)	3.2	5.2
Total Net Income	$ 105.7	$ 89.9	$ 62.9	$ 62.0
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.89	$ 0.77	$ 0.51	$ 0.49
Discontinued operations	0.01	-	0.03	0.04
Total earnings per share (basic)	$ 0.90	$ 0.77	$ 0.54	$ 0.53
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.88	$ 0.76	$ 0.50	$ 0.48
Discontinued operations	0.01	-	0.03	0.04
Total earnings per share (diluted)	$ 0.89	$ 0.76	$ 0.53	$ 0.52

	September		December	
Three Months Ended	2006	2005	2006	2005
Operating revenues	$ 839.8	$ 797.3	$ 1,095.2	$ 1,135.0
Operating income	131.2	128.4	138.6	177.8
Income from Continuing Operations	70.8	65.8	77.6	91.0
Income (loss) from Discontinued Operations	-	0.4	(0.6)	(0.4)
Total Net Income	$ 70.8	$ 66.2	$ 77.0	$ 90.6
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.61	$ 0.57	$ 0.66	$ 0.77
Discontinued operations	-	-	-	-
Total earnings per share (basic)	$ 0.61	$ 0.57	$ 0.66	$ 0.77
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.60	$ 0.56	$ 0.65	$ 0.77
Discontinued operations	-	-	-	-
Total earnings per share (diluted)	$ 0.60	$ 0.56	$ 0.65	$ 0.77

(a) Quarterly results of operations are not directly comparable because of seasonal and other factors. See Management's Discussion and Analysis of Financial Condition and Results of Operations.

(b) Quarterly earnings per share may not total to the amounts reported for the year since the computation is based on the weighted average common shares outstanding during each quarter.

PERFORMANCE GRAPH

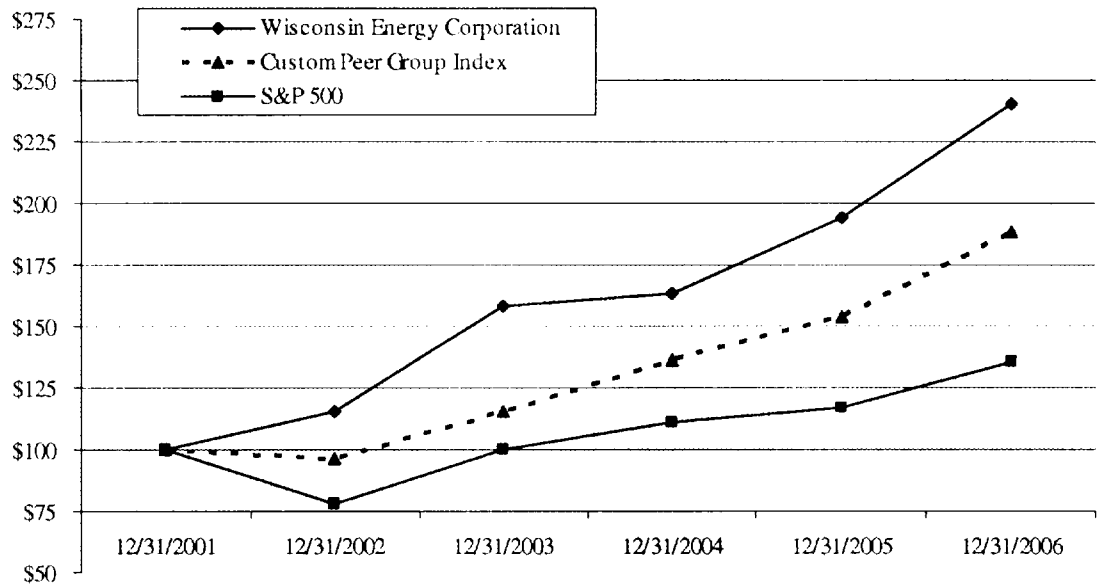
The performance graph below shows a comparison of the cumulative total return, assuming reinvestment of dividends, over the last five years had $100 been invested at the close of business on December 31, 2001, in each of:

- Wisconsin Energy common stock;
- a Custom Peer Group Index; and
- the Standard & Poor's 500 Index ("S&P 500").

We use the Custom Peer Group Index for peer comparison purposes because we believe the Index provides an accurate representation of our peers. The Custom Peer Group Index is a market-capitalization-weighted index consisting of 30 companies, including Wisconsin Energy. These companies are similar to us in terms of business model and long-term strategies.

The companies in the Custom Peer Group Index are Allegheny Energy, Inc.; Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; Avista Corporation; Consolidated Edison, Inc.; DTE Energy Company; Duke Energy Corp.; Energy East Corporation; Entergy Corporation; Exelon Corporation; FirstEnergy Corp.; FPL Group, Inc.; NiSource Inc.; Northeast Utilities; Nstar; OGE Energy Corp.; Pinnacle West Capital Corporation; Pepco Holdings, Inc.; Progress Energy Inc.; Public Service Enterprise Group Incorporated; Puget Energy, Inc.; SCANA Corporation; Sempra Energy; Sierra Pacific Resources; The Southern Company; Westar Energy, Inc.; Wisconsin Energy Corporation; WPS Resources Corporation (now known as Integrys Energy Group, Inc.); and Xcel Energy Inc. In 2006, Cinergy Corp. and Duke Energy Corp. merged. Cinergy Corp. was part of the Custom Peer Group, but was replaced by Duke Energy Corp. after the merger.

Five-Year Cumulative Return Chart



Value of Investment at Year-End

	12/31/01	12/31/02	12/31/03	12/31/04	12/31/05	12/31/06
Wisconsin Energy Corporation	$ 100	$ 115	$ 158	$ 163	$ 194	$ 241
Custom Peer Group Index	$ 100	$ 96	$ 115	$ 136	$ 154	$ 188
S&P 500	$ 100	$ 78	$ 100	$ 111	$ 117	$ 135

NON-GAAP EARNINGS MEASURES

Adjusted earnings (non-GAAP earnings), which generally exclude nonoperational items as well as charges or credits that are not associated with the company's ongoing operations, are provided as a complement to earnings presented in accordance with GAAP. The excluded items are not indicative of the company's operating performance. Therefore, we believe that the presentation of adjusted earnings from continuing operations is relevant and useful to investors to understand Wisconsin Energy's operating performance. Management uses such measures internally to evaluate the company's performance and manage its operations.

EARNINGS RECONCILIATION (UNAUDITED)

Earnings Reconciliation (Unaudited)

Year Ended December 31	2006	2005	2004
Adjusted Diluted Earnings Per Share-Continuing Operations	$2.58	2.42	2.13
Debt Redemption Costs	-	-	(0.13)
State Tax Benefits	0.05	0.14	-
Voluntary Severance Program	-	-	(0.16)
Sale of Guardian	0.01	-	-
Diluted Earnings Per Share-Continuing Operations	$2.64	$2.56	$1.84

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

NUMBER OF COMMON STOCKHOLDERS

As of December 31, 2006, based upon the number of Wisconsin Energy Corporation stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 54,000 registered stockholders.

COMMON STOCK LISTING AND TRADING

Our common stock is listed on the New York Stock Exchange. The ticker symbol is "WEC". Daily trading prices and volume can be found in the "NYSE Composite" section of most major newspapers, usually abbreviated as WI Engy.

DIVIDENDS AND COMMON STOCK PRICES

Common Stock Dividends of Wisconsin Energy: Cash dividends on our common stock, as declared by the Board of Directors, are normally paid on or about the first day of March, June, September and December of each year. We review our dividend policy on a regular basis. Subject to any regulatory restrictions or other limitations on the payment of dividends, future dividends will be at the discretion of the Board of Directors and will depend upon, among other factors, earnings, financial condition and other requirements. For information regarding restrictions on the ability of our subsidiaries to pay us dividends see Note J -- Common Equity in the Notes to Consolidated Financial Statements.

On January 18, 2007, our Board of Directors announced that it increased our common stock quarterly dividend rate by 8.7%, to $0.25 per share. With the increase, the new dividend is equivalent to an annual rate of $1.00 per share. The Board has established a goal of increasing the annual dividend at a rate of approximately half of the expected rate of growth in earnings per share, subject to the factors referred to above.

Range of Wisconsin Energy Common Stock Prices and Dividends:

	2006			2005		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$42.35	$38.92	$0.23	$36.12	$33.35	$0.22
Second	$40.91	$38.16	0.23	$39.31	$34.20	0.22
Third	$43.79	$39.75	0.23	$40.48	$37.32	0.22
Fourth	$48.70	$43.25	0.23	$40.83	$36.49	0.22
Year	$48.70	$38.16	$0.92	$40.83	$33.35	$0.88

BOARD OF DIRECTORS

John F. Ahearne
Director since 1994.
Director of the ethics program of the Sigma Xi Center for Sigma Xi, The Scientific Research Society, an organization that publishes American Scientist, provides grants to graduate students and conducts national meetings on scientific issues.

John F. Bergstrom
Director since 1987.
Chairman and Chief Executive Officer of Bergstrom Corporation, which owns and operates numerous automobile sales and leasing companies.

Barbara L. Bowles
Director since 1998.
Vice Chair of Profit Investment Management and Chairman of The Kenwood Group, Inc., investment advisory firms.

Patricia W. Chadwick
Director since 2006.
President of Ravengate Partners LLC, which provides businesses and not-for-profit institutions with advice about the financial markets.

Robert A. Cornog
Director since 1993.
Retired Chairman of the Board, President and Chief Executive Officer of Snap-on Incorporated, a developer, manufacturer and distributor of professional hand and power tools, diagnostic and shop equipment and tool storage products.

Curt S. Culver
Director since 2004.
Chairman and Chief Executive Officer of MGIC Investment Corporation and Mortgage Guaranty Insurance Corporation, a private mortgage insurance company.

Thomas J. Fischer
Director since 2005.
Principal of Fischer Financial Consulting LLC, which provides consulting on corporate financial, accounting and governance matters.

Gale E. Klappa
Director since 2003.
Chairman of the Board, President and Chief Executive Officer of Wisconsin Energy Corporation.

Ulice Payne, Jr.
Director since 2003.
Managing Member of Addison-Clifton, LLC, which provides advisory services on global trade compliance.

Frederick P. Stratton, Jr.
Director since 1987.
Chairman Emeritus of Briggs & Stratton Corporation, a manufacturer of small gasoline engines.

OFFICERS

Gale E. Klappa[1] – Chairman of the Board, President and Chief Executive Officer.

James C. Fleming[1] – Executive Vice President and General Counsel.

Frederick D. Kuester[1] – Executive Vice President.

Allen L. Leverett[1] – Executive Vice President and Chief Financial Officer.

Larry Salustro[1][2] – Executive Vice President.

James R. Klauser – Senior Vice President.

Kristine A. Rappé[1] – Senior Vice President and Chief Administrative Officer.

Darnell K. DeMasters – Vice President – Federal Policy.

Stephen P. Dickson[1] – Vice President and Controller.

Anne K. Klisurich – Vice President and Corporate Secretary.

Kristine M. Krause – Vice President – Environmental.

Walter J. Kunicki – Vice President.

Jeffrey P. West – Vice President and Treasurer.

Richard J. White – Vice President.

Arthur A. Zintek – Vice President.

Keith H. Ecke – Assistant Corporate Secretary.

David L. Hughes – Assistant Treasurer.

Ralph W. Kane[2] – Assistant Vice President – Tax.

James A. Schubilske – Assistant Treasurer.

[1] Executive Officers of Wisconsin Energy Corporation as of December 31, 2006. Charles R. Cole, Senior Vice President of Wisconsin Electric Power Company and Wisconsin Gas LLC, is also an executive officer of Wisconsin Energy Corporation.
[2] Mr. Salustro and Mr. Kane retired from Wisconsin Energy Corporation effective February 28, 2007 and March 16, 2007, respectively.