XCEL ENERGY INC
Form 424B3
May 20, 2003

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File Number 333-103258

Xcel Energy Inc.

800 Nicollet Mall, Suite 3000

Minneapolis, Minnesota 55402-2023
(612) 330-5500

$230,000,000

7 1/2% Senior Convertible Notes

due 2007
and

Shares of Common Stock issuable upon conversion of the Notes.

We sold the notes in a private offering on November 21, 2002. Selling security holders may use this prospectus to resell their notes and the shares of common stock issuable upon conversion of their notes. The notes mature on November 21, 2007. The notes are convertible, at the option of the holder, at any time on or prior to maturity into shares of our common stock. The notes are convertible at a conversion rate of approximately 81.1359 shares of our common stock per $1,000 principal amount of notes, which is equal to a conversion price of $12.33 per share, subject to adjustment as described in the prospectus.

We will pay interest on the notes on May 21 and November 21 of each year, beginning on May 21, 2003. The notes will mature on November 21, 2007. Holders of the notes may require us to purchase some or all of the notes for cash upon a change of control, as described in this prospectus, at a price equal to 100% of the principal amount of the notes tendered plus accrued and unpaid interest.

We will make additional payments of interest, referred to in this prospectus as protection payments, on the notes in an amount equal to any portion of our per share dividends on our common stock that exceeds $0.1875 per quarter that would have been payable to the holders of the notes if such holders had converted their notes on the record date for such dividend. Holders of the notes will not be entitled to any protection payment if the dividend triggering the protection payment causes an adjustment of the conversion rate.

The notes are unsecured and unsubordinated obligations and rank on parity in right of payment with all our existing and future unsecured and unsubordinated indebtedness. As of December 31, 2002, we had approximately $600 million of long-term debt outstanding in addition to the notes excluding long-term debt of our subsidiaries. There are currently no outstanding debt obligations junior to the notes. We are structured as a holding company and conduct substantially all of our business through our subsidiaries. The notes are effectively subordinate to all existing and future indebtedness and other liabilities of our subsidiaries.

The notes issued in the initial private placement are eligible for trading in the PORTAL System. We do not intend to list the notes on any other securities exchange or automated quotation system. Our common stock is traded on the New York Stock Exchange under the symbol XEL.

As of December 31, 2002, our subsidiaries had approximately $20.7 billion of indebtedness and other liabilities outstanding.

Investing in the notes involves risks. You should consider carefully the risk factors described under the caption Risk Factors beginning on page 8 of this prospectus before investing in the notes.

Please read this prospectus carefully before investing and retain it for your future reference.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved these securities or passed upon the accuracy or adequacy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is May 14, 2003

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You should rely only on the information provided in this prospectus. We have not authorized anyone else to provide you with different information. This prospectus does not constitute an offer of these securities in any state where the offer is not permitted. You should not assume that the information in this prospectus is accurate as of any date other than the date on the front of this prospectus.

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INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains statements that are not historical fact and constitute forward-looking statements. When we use words like believes, expects, anticipates, intends, plans, estimates, may, should, or similar expressions, or when we discuss our strategy or plans, we are ma forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Our future results may differ materially from those expressed in these forward-looking statements. These statements are necessarily based upon various assumptions involving judgments with respect to the future and other risks, including, among others:

- general economic conditions, including the availability of credit, actions of rating agencies and their impact on our access to capital and the ability of us and our subsidiaries to obtain financing on favorable terms;
- business conditions in the energy industry;
- competitive factors, including the extent and timing of the entry of additional competition in the markets served by us and our subsidiaries;
- unusual weather;
- state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on the rate structures, and affect the speed and degree to which competition enters the electric and gas markets;
- the higher risk associated with our nonregulated business compared with our regulated businesses;
- currency translation and transaction adjustments;
- risks related to the financial condition of NRG Energy, Inc., one of our wholly-owned subsidiaries including NRG s ability to reach agreements with its lenders and creditors to restructure its debt;
- risks associated with the California power market;
- the effect on the U.S. economy as a consequence of war and acts of terrorism; and
- the other risk factors discussed under Risk Factors.

You are cautioned not to rely unduly on any forward-looking statements. These risks and uncertainties are discussed in more detail under Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations, Business, and Notes to Consolidated Financial Statements included elsewhere in this prospectus.

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PROSPECTUS SUMMARY

The following summary is qualified in its entirety by and should be read together with the more detailed information and financial statements included in this prospectus. Because this is a summary, it may not contain all the information that may be important to you. You should read the entire prospectus before making an investment decision. When used in this prospectus, the terms Xcel Energy, we, our and us refer to Xcel Energy Inc. and its consolidated subsidiaries, unless otherwise specified.

Our Business

We are a public utility holding company with six utility subsidiaries:

- Northern States Power Company, a Minnesota corporation (NSP-Minnesota), which serves approximately 1.3 million electric customers and approximately 430,000 gas customers in Minnesota, North Dakota and South Dakota;
- Public Service Company of Colorado, a Colorado corporation (PSCo), which serves approximately 1.3 million electric customers and approximately 1.2 million gas customers in Colorado;
- Southwestern Public Service Company, a New Mexico corporation (SPS), which serves approximately 390,000 electric customers in portions of Texas, New Mexico, Oklahoma and Kansas;
- Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin), which serves approximately 230,000 electric customers and approximately 90,000 gas customers in northern Wisconsin and Michigan;
- Cheyenne Light, Fuel and Power Company (Cheyenne), a Wyoming corporation, which serves approximately 37,000 electric customers and approximately 30,000 gas customers in and around Cheyenne, Wyoming; and
- Black Mountain Gas Company (BMG), an Arizona corporation, which serves approximately 9,300 customers in Arizona.

Our regulated businesses also include WestGas InterState Inc. (WGI), an interstate natural gas pipeline. Prior to January 2003, our regulated businesses included Viking Gas Transmission Company (Viking).

We also own or have an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc. As a result of the exchange of shares of Xcel Energy for publicly held shares of NRG, which was completed in June 2002, NRG is now an indirect wholly-owned subsidiary of ours. NRG is a global energy company, primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products.

In addition to NRG, our nonregulated subsidiaries include:

- Utility Engineering (UE), which is involved in engineering, construction and design;
- Seren Innovations, Inc. (Seren), which is involved in broadband telecommunications services;
- e prime, inc. (e prime), which is involved in natural gas marketing and trading,
- Planergy International Inc. (Planergy), which is involved in energy management consulting and demand-side management services;
- Eloigne Company (Eloigne), which is involved in acquisition of rental housing projects that qualify for low-income housing tax credits; and
- Xcel Energy International (XEI), an international independent power producer.

We are a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). We were incorporated in 1909 under the laws of Minnesota as Northern States Power

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Company. On August 18, 2000, we merged with New Century Energies, Inc. (NCE) and our name was changed from Northern States Power Company to Xcel Energy Inc.

Our principal executive offices are located at 800 Nicollet Mall, Suite 3000, Minneapolis, Minnesota 55402, and our telephone number at that location is (612) 330-5500.

Recent Developments

On November 7, 2002, our subsidiary, Xcel Energy Market Holdings Inc., reached an agreement to sell its wholly-owned subsidiary, Viking and Viking s ownership interest in Guardian Pipeline, L.L.C. (Guardian) to a subsidiary of Northern Border Partners, L.P. (NBP). The sale was completed on January 17, 2003 and Xcel Energy received net proceeds of $124 million.

On November 8, 2002, we issued $100 million principal amount of 8% senior convertible notes (the Prior Notes) pursuant to a Securities Purchase Agreement with Citadel Equity Fund Ltd., Citadel Credit Trading Ltd. and Jackson Investment Fund Ltd. (together, the Purchasers). A portion of the proceeds of our initial issue and sale of the notes offered pursuant to this prospectus were used to redeem the Prior Notes on November 25, 2002. Upon redemption of the Prior Notes, we entered into an agreement with the Purchasers granting them the right, exercisable at any time and from time to time through November 24, 2003, to purchase notes in a private placement that are identical (other than issuance date) to the notes offered pursuant to this prospectus in an aggregate principal amount equal to $57,500,000.

On November 21, 2002, we issued the notes covered by this prospectus to Merrill, Lynch, Pierce, Fenner and Smith Incorporated and Lazard Frères & Co. L.L.C. in a private transaction. We received net proceeds from the sale of the notes, after deducting the initial purchasers discount and our offering expenses of approximately $220 million. As described above, a portion of the net proceeds from the sale of the notes were used to redeem the Prior Notes. The remaining net proceeds have and will be used for other general corporate purposes, including working capital.

On January 22, 2003, we entered into a nine month credit facility with King Street Capital, L.P. and Perry Principals Investments LLC, pursuant to which we may borrow up to $100 million at an interest rate of 9% per annum. There are currently no amounts outstanding under this facility.

On November 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG in the United States Bankruptcy Court for the District of Minnesota (Minnesota Bankruptcy Court). Under provisions of federal law, NRG has the full authority to continue to operate its business as if the involuntary petition had not been filed unless and until a court hearing on the validity of the involuntary petition is resolved adversely to NRG. NRG responded to the involuntary petition, contesting the petitioners claims and filing a motion to dismiss the case.

NRG and its counsel have been involved in negotiations with the petitioners and their counsel. As a result of these negotiations, NRG and the petitioners reached an agreement and compromise regarding their respective claims against each other (Settlement Agreement). In February 2003, the Settlement Agreement was executed, pursuant to which NRG agreed to pay the petitioners an aggregate settlement in the amount of $12 million.

On February 28, 2003, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a petition alleging that they hold unsecured, non-contingent claims against NRG in a joint amount of $100 million.

On March 26, 2003, our board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against us, including claims related to the support and capital subscription agreement between us and NRG dated May 29, 2002 (the Support Agreement). The settlement is subject to a variety of conditions as set forth below, including definitive documentation. The principal terms of the settlement as of the date of this prospectus were as follows:

We would pay up to $752 million to NRG to settle all claims of NRG, and the claims of NRG against us, including all claims under the Support Agreement.

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$350 million would be paid at or shortly following the consummation of a restructuring of NRG s debt through a bankruptcy proceeding. It is expected that this payment would be made prior to year-end 2003. $50 million would be paid on January 1, 2004, and all or any part of such payment could be made, at our election, in our common stock. Up to $352 million would be paid on April 30, 2004, except to the extent that we had not received at such time tax refunds equal to $352 million associated with the loss on our investment in NRG. To the extent we had not received such refunds, the April 30 payment would be due on May 30, 2004.

$390 million of our payments are contingent on receiving releases from NRG creditors. To the extent we do not receive a release from an NRG creditor, our obligation to make $390 million of the payments would be reduced based on the amount of the creditor s claim against NRG. As noted below, however, the entire settlement is contingent upon us receiving releases from at least 85 percent of the claims in various NRG creditor groups. As a result, it is not expected that our payment obligations would be reduced by more than approximately $60 million. Any reduction would come from our payment due on April 30, 2004.

Upon the consummation of NRG s debt restructuring through a bankruptcy proceeding, our exposure on any guaranties or other credit support obligations incurred by us for the benefit of NRG or any subsidiary would be terminated and any cash collateral posted by us would be returned. The current amount of such cash collateral is approximately $11.5 million.

As part of the settlement with us, any intercompany claims of us against NRG or any subsidiary arising from the provision of intercompany goods or services or the honoring of any guaranty will be paid in full in cash in the ordinary course except that the agreed amount of such intercompany claims arising or accrued as of January 31, 2003 will be reduced from approximately $32 million as asserted by us to $10 million. The $10 million agreed amount is to be paid upon the effective date of the NRG plan of reorganization, with an unsecured promissory note of NRG in the principal amount of $10 million.

NRG and its direct and indirect subsidiaries would not be reconsolidated with us or any of our other affiliates for tax purposes at any time after their June 2002 re-affiliation or treated as a party to or otherwise entitled to the benefits of any tax sharing agreement with us. Likewise, NRG would not be entitled to any tax benefits associated with the tax loss we expect to incur in connection with the write down of our investment in NRG.

On May 12, 2003, the Minnesota Bankruptcy Court granted NRG s motion to dismiss the involuntary chapter 11 petition against NRG.

On May 14, 2003, NRG and certain of NRG s U.S. affiliates filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. Neither we nor any of our other subsidiaries were included in the filing. NRG s plan of reorganization filed with the U.S. Bankruptcy Court for the Southern District of New York incorporates the terms of an overall settlement among NRG, us and NRG s major creditor constituencies that provides for payments by us to NRG, and that NRG will pay in turn to its creditors, of up to $752 million.

A plan support agreement reflecting the settlement has been signed by us, holders of approximately 40% of NRG s long-term notes and bonds along with two NRG banks who serve as co-chairs of the global steering committee for the NRG bank lenders. This agreement will become fully effective upon execution by holders of approximately an additional ten percent in principal amount of NRG s long-term notes and bonds and by a majority of NRG bank lenders representing at least two-thirds in principal amount of NRG s bank debt. We expect the requisite signatures will be obtained promptly.

The terms of the settlement with NRG s major creditors are basically the same as discussed above. $350 million would be paid at or shortly following the effective date of the NRG plan of reorganization. It is expected that this payment would be made prior to year-end 2003. An additional $50 million would be paid on January 1, 2004, and all or any part of such payment could be made, at our election, in our common stock. Up to $352 million would be paid in the second quarter of 2004.

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Consummation of the settlement is contingent upon, among other things, the following:

(i) The effective date of the NRG plan of reorganization occurring on or prior to December 15, 2003;

(ii) The final plan of reorganization approved by the Bankruptcy Court and related documents containing terms satisfactory to us, NRG and various groups of the NRG creditors;

(iii) The receipt of releases in our favor from holders of at least 85 percent of the claims represented by NRG s creditors; and

(iv) Our receipt of all necessary regulatory and other approvals.

Since many of these conditions are not within our control, we cannot state with certainty that the settlement will be effectuated. Nevertheless, our management is optimistic at this time that the settlement will be implemented.

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The Offering

Issuer	Xcel Energy Inc.
Notes Offered	$230,000,000 principal amount of 7 1/2% Convertible Senior Notes due 2007 (including $30,000,000 pursuant to the overallotment option exercised by the initial purchasers in full).
Maturity	November 21, 2007
Interest Payment Dates	7 1/2% per annum on the principal amount, payable semiannually on May 21 and November 21, beginning on May 21, 2003.
Dividend Protection	We will make additional payments of interest, referred to in this prospectus as protection payments, on the notes in an amount equal to any portion of our per share dividends on our common stock that exceeds $0.1875 per quarter that would have been payable to the holders of the notes if such holders had converted their notes on the record date for such dividend. Holders of the notes will not be entitled to any protection payment if the dividend triggering the protection payment causes an adjustment to the conversion rate.
Conversion Rights	The notes are convertible, at the option of the holder, at any time on or prior to maturity into shares of our common stock at a conversion price of $12.33 per share, which is equal to a conversion rate of approximately 81.1359 shares of common stock per $1,000 principal amount of notes. The conversion rate is subject to adjustment. See Description of the Notes Conversion Rights.
Ranking	The notes are unsecured and unsubordinated obligations and rank on a parity in right of payment with all our existing and future unsecured and unsubordinated indebtedness. The indenture under which the notes are issued does not prevent us or our subsidiaries from incurring additional indebtedness, which may be secured by some or all of our assets, or other obligations. As of December 31, 2002, we had no secured indebtedness and our unsecured and unsubordinated indebtedness had been approximately $830 million. We are structured as a holding company and conduct substantially all of our business operations through our subsidiaries. The notes are effectively subordinated to all existing and future indebtedness and other liabilities and commitments of our subsidiaries. As of December 31, 2002, our subsidiaries had aggregate indebtedness and other liabilities of approximately $20.7 billion.
Change of Control	Upon a change of control event, each holder of the notes may require us to repurchase some or all of its notes for cash at a repurchase price equal to 100% of the principal amount of the notes plus accrued and unpaid interest. See Description of the Notes Change of Control Permits Purchase of Notes at the Option of the Holder.
Use of Proceeds	We will not receive any proceeds from the sale by any selling security holder of the notes or the common stock issuable upon conversion of the notes. See Use of Proceeds.
DTC Eligibility	The notes were issued in book-entry form and are represented by permanent global certificates without coupons deposited with a

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	custodian for and registered in the name of a nominee of The Depository Trust Company in New York, New York. Beneficial interests in the notes are shown on, and transfers will be effected only through, records maintained by The Depository Trust Company and its direct and indirect participants, and any such interest may not be exchanged for certificated securities, except in limited circumstances. See Description of the Notes Form, Denomination and Registration.
Trading	The notes issued in the initial private placement are eligible for trading in the PORTAL System. We do not intend to list the notes on any other national securities exchange or automated quotation system. Our common stock is traded on the New York Stock Exchange under the symbol XEL.
Risk Factors	See Risk Factors and the other information in this prospectus before deciding to invest in the notes.

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Summary Historical Financial Data

The following tables present our summary consolidated historical financial data. The data presented in these tables are from Selected Consolidated Financial Data, included elsewhere in this prospectus. You should read that section for a further explanation of the consolidated financial data summarized here. You should also read the summary consolidated financial data presented below in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations, and our audited consolidated financial statements and related notes and other financial information contained in this prospectus. The historical financial information may not be indicative of our future performance.

	Year ended December 31,		
	2002(1)	2001	2000
	(Thousands of dollars)		
Consolidated Statement of Operations Data:			
Operating revenue	$ 9,524,372	$ 11,333,422	$ 9,223,466
Operating (loss) income	$ (1,432,333)	$ 1,858,147	$ 1,479,199
Interest charges and financing costs	$ 918,080	$ 766,776	$ 652,973
Net (loss) income	$ (2,217,991)	$ 794,966	$ 526,828

	December, 2002(2)
	(Thousands of dollars)
Consolidated Balance Sheet Data:	
Total assets	$ 27,257,842
Short-term debt (including current maturities)(3)	$ 9,298,224
Long-term debt(3)	$ 6,550,248
Total debt	$ 15,848,472
Minority interest	$ 34,762
Mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000
Preferred stockholders equity	$ 105,320
Common stockholders equity	$ 4,664,984
Total capitalization (includes short-term debt and minority interests)	$ 21,147,538

(1) Results for 2002 include two significant items that are described further in the notes to our consolidated financial statements: (a) impairment charges and disposal losses (excluding discontinued operations) related to NRG s long-lived assets and equity investments, which reduced operating income by $2.7 billion and net income by $2.6 billion; and (b) income tax benefits related to our investment in NRG, which increased net income by $706 million.

(2) Actual capitalization amounts are as reported in our consolidated Statements of Capitalization, which include amounts reclassified to discontinued operations of NRG. The components of such discontinued operations are segregated on the balance sheet, outside of apparent capitalization components. As a result, $445.7 million of short-term debt is reported as current liabilities held for sale and $0.1 million of long-term debt is noncurrent liabilities held for sale.

(3) Based on the defaults under certain NRG debt agreements, and NRG s lenders ability to call such debt within twelve months of December 31, 2002, the majority of NRG s long-term debt has been reclassified to current as of that date.

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Summary Pro Forma Financial Data

As discussed in the Recent Developments section, on May 14, 2003 NRG filed for bankruptcy protection. This bankruptcy filing will change our accounting for NRG from consolidated reporting to the equity method. The following pro-forma financial information reflects adjustments to report NRG on the equity method for the year ended December 31, 2002. See Unaudited Consolidated Pro-forma Financial Information on pages F-85 et seq. for additional information on the pro-forma adjustments made, and a reconciliation of historical financial data to pro-forma amounts.

	Year ended December 31, 2002(1)
	(Thousands of dollars)
Consolidated Statement of Operations Data:	
Operating revenue	$ 7,243,223
Operating loss	$ 1,155,683
Interest charges and financing costs	$ 424,124
Net loss	$ (2,217,991)

	December, 2002(2)
	(Thousands of dollars)
Consolidated Balance Sheet Data:	
Total assets	$ 16,347,781
Short-term debt (including current maturities)	$ 1,074,922
Long-term debt	$ 5,357,618
Total debt	$ 6,432,540
Minority interest	$ 4,922
Mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000
Preferred stockholders equity	$ 105,320
Common stockholders equity	$ 4,664,984
Total capitalization (includes short-term debt and minority interests)	$ 11,701,766

(1) Individual revenue and expense items exclude the results of NRG (a loss of $3.5 billion), which are reported under the equity method as a single loss item, Equity in Losses of NRG.

(2) Individual asset and liability amounts exclude NRG amounts, which are reported under the equity method as a single current liability item, NRG Losses in Excess of Investment.

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RISK FACTORS

You should carefully consider the risks described below as well as all of the information set forth in this prospectus before purchasing the notes.

The risks described in this section are those that we consider to be the most significant to your decision whether to invest in the notes. If any of the events described below occurs, our business financial condition or results could be materially harmed. In addition, we may not be able to make payments on the notes, and this could result in your losing all or part of your investment.

Risks Related to Our Ownership of NRG

Our subsidiary, NRG, is in default under most of its debt obligations and has filed a voluntary petition for protection under the bankruptcy laws. The creditors of NRG and its subsidiaries could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of NRG or its subsidiaries. These claims, if successful, would have a material adverse effect on our financial condition and liquidity, and on our ability to make payments on the notes.

At December 31, 2002, NRG had failed to make scheduled payments on interest and/or principal on approximately $4 billion of its recourse debt and is in default under the related debt instruments. These missed payments also have resulted in cross-defaults of numerous other non-recourse and limited recourse debt instruments of NRG. In addition, on November 6, 2002, lenders accelerated the approximately $1.1 billion of debt under a construction revolver financing facility, thereby rendering the debt immediately due and payable. Further, on November 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG in the United States Bankruptcy Court for the District of Minnesota (Minnesota Bankruptcy Court). Under the provisions of federal law, NRG has full authority to continue to operate its business as if the involuntary petition had not been filed unless and until a court hearing on the validity of the involuntary petition is resolved adversely to NRG. NRG responded to the involuntary petition, contesting the petitioners claims and filing a motion to dismiss the case.

NRG and its counsel have been involved in negotiations with the petitioners and their counsel. As a result of these negotiations, NRG and the petitioners reached an agreement and compromise regarding their respective claims against each other (Settlement Agreement). In February 2003, the Settlement Agreement was executed, pursuant to which NRG agreed to pay the petitioners an aggregate settlement in the amount of $12 million.

On February 28, 2003, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a petition alleging that they hold unsecured, non-contingent claims against NRG in a joint amount of $100 million.

In addition to the missed debt payments, a significant amount of NRG s debt and other obligations contain terms which require that they be supported with letters of credit or cash collateral following a ratings downgrade. As a result of the downgrades that NRG has experienced since July 26, 2002, NRG estimates that it is in default of its obligations to post collateral ranging from $1.1 billion to $1.3 billion, principally to fund equity guarantees associated with its construction revolver financing facility, to fund debt service reserves and other guarantees related to NRG projects, and to fund trading operations.

On March 26, 2003, our board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against us, including claims related to the support and capital subscription agreement between us and NRG dated May 29, 2002 (the Support Agreement). The settlement is subject to a variety of conditions, including definitive documentation. Under the terms of the settlement which is described in more detail elsewhere in this prospectus, we would pay up to $752 million to NRG to settle all claims of NRG, and the claims of NRG against us, including all claims under the Support Agreement.

On May 12, 2003, the Minnesota Bankruptcy Court granted NRG s motion to dismiss the involuntary chapter 11 petition against NRG.

On May 14, 2003, NRG and certain of NRG s U.S. affiliates filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. Neither we nor any of our other subsidiaries were included in the filing. NRG s plan of reorganization filed with the U.S. Bankruptcy Court for the Southern District of New York incorporates the terms of an overall settlement among NRG, us and NRG s major creditor constituencies that provides for payments by us to NRG, and that NRG will pay in turn to its creditors, of up to $752 million.

A plan support agreement reflecting the settlement has been signed by us, holders of approximately 40% of NRG s long-term notes and bonds along with two NRG banks who serve as co-chairs of the global steering committee for the NRG bank lenders. This agreement will become fully effective upon execution by holders of approximately an additional ten percent in principal amount of NRG s long-term notes and bonds and by a majority of NRG bank lenders representing at least two-thirds in principal amount of NRG s bank debt. We expect the requisite signatures will be obtained promptly. The term of the settlement with NRG s major creditors are basically the same as previously reported. For additional information regarding the settlement, see our discussion in Recent Developments above.

Because many of the conditions to the settlement are not within our control, the settlement may not be effectuated.

Pending the resolution of NRG credit contingencies and the timing of possible asset sales, a portion of NRG s long-term debt obligations have been classified as current liabilities on our consolidated balance sheet due to lenders having the ability to accelerate such debt within twelve months of the balance sheet date. In the event that NRG is unable to effect a restructuring of its debt and other obligations and is unable to obtain adequate financing on acceptable terms, there would be substantial doubt as to NRG s ability to continue as a going concern. In any event, it is unlikely that we ultimately will own any equity interest in NRG. As of December 31, 2002, our proforma investment in NRG, calculated as if NRG were deconsolidated at that date, was a negative $625 million. As of December 31, 2002, the net equity of NRG Energy as reported was a deficit of approximately $696 million.

In the NRG bankruptcy proceeding, NRG or its creditors could seek to substantively consolidate us with NRG. The equitable doctrine of substantive consolidation would permit a bankruptcy court to disregard the separateness of related entities; such as NRG and us, and consolidate and pool the entities assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. Substantive consolidation is an equitable remedy in bankruptcy that results in the pooling of assets and liabilities of the debtor and one or more of its debtor affiliates or, in very rare circumstances, non-debtor affiliates, solely for the purposes of the bankruptcy case, including treatment under a reorganization plan. The practice of substantive consolidation is not expressly authorized under the Bankruptcy Code and there are no definitive rules as to when a court will order substantive consolidation. Courts agree, however, that substantial consolidation should be invoked sparingly. A court s decision whether to order substantive consolidation turns primarily on the facts of the case. Circumstances that courts have generally considered in determining whether to substantively consolidate the assets and liabilities of a debtor and one or more of its affiliated entities in cases under the Bankruptcy Code include: (a) whether such entities operate independently of one another; (b) whether corporate or other applicable organizational formalities are observed in the operation of such entities; (c) whether the assets of such entities are kept separate and whether records are kept that permit the segregation of the assets and liabilities of such entities; (d) whether such entities hold themselves out to the public as separate entities; (e) whether such entities have maintained separate financial statements; (f) whether such entities have made intercompany guarantees on loans; (g) whether such entities share common officers, directors or employees; (h) whether the creditors have relied on the financial condition of an entity separately from the financial condition of the entity proposed to be consolidated in extending credit; (i) whether the consolidation of, or the failure to consolidate, the assets and liabilities of such entities will result in unfairness to creditors; and (j) whether consolidation of such entities will adversely impact the chances of a successful reorganization. If NRG or its creditors were to assert claims of substantive consolidation, or piercing the corporate veil, alter ego or related theories, in an NRG bankruptcy proceeding, the bankruptcy court could resolve the issue in a manner adverse to us. One of the creditors of an NRG project already has included claims against NRG and us. If a bankruptcy court were

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to allow substantive consolidation of us with NRG, it would have a material adverse effect on us and on our ability to make payments on our obligations, including the notes, and could ultimately cause us to seek to restructure under the protection of the bankruptcy laws.

If our assets are substantively consolidated with those of NRG, or if we otherwise incur significant liabilities relating to NRG, we may not have sufficient resources to satisfy those claims, and it would adversely affect our ability to make payments on the notes.

The bankruptcy court may substantively consolidate us with NRG and make our assets available to satisfy NRG s obligations.

Even without substantive consolidation, however, we have certain other potential exposures to claims relating to NRG. In May 2002, we entered into a Support Agreement pursuant to which we agreed to provide up to $300 million to NRG under certain circumstances. As discussed above, we have entered into a settlement with NRG and various NRG credit constituencies pursuant to which we have agreed to pay up to $752 million to settle all claims of NRG against us, including under the Support Agreement. We may be required to provide NRG with these funds.

We have also provided various guarantees and bond indemnities supporting certain of NRG s obligations, guaranteeing the payment or performance under specified agreements or transactions of NRG. As a result, our exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of our guarantees limit our exposure to a maximum amount stated in the guarantees. As of December 31, 2002, the maximum amount stated in our guarantees of obligations of NRG was approximately $219.5 million. Our aggregate exposure on guarantees of obligations of NRG was approximately $96.3 million as of December 31, 2002.

Even without substantive consolidation, we may also have additional potential exposure to certain liabilities relating to employee benefit plans maintained for the benefit of the employees of NRG:

Eligible current or former NRG employees participate in one of our qualified defined benefit pension plans, with the result that our plan is liable for past and future accruals for these employees. To the extent NRG is unable to contribute amounts necessary to fund these accruals, we would be required to do so. We expect to agree to make a $2 million funding contribution due by NRG to our plan in March 2003 and seek reimbursement from NRG for the payment, although it is unlikely that we would obtain such reimbursement.

Some current or former NRG employees participate in non-qualified deferred compensation plans that we or other subsidiaries, including NRG, maintain. To the extent NRG fails to pay benefits accrued by its current or former employees under these plans, such employees may seek payment from us. If we are found liable for such payment, it could be material.

Certain NRG current or former employees also participate in various welfare plans, including retiree medical and life plans, maintained by us. We have also provided guarantees for specified NRG severance and employment payments. Benefits that we may be required to pay NRG current or former employees pursuant to these arrangements could, in the aggregate, be material if NRG were unable to pay them when due.

NRG maintains a long-term incentive plan under which options for 2,914,839 of our shares are outstanding. Such options, which have a weighted average exercise price of $29.80, would become fully exercisable if a change of control (as defined in the plan) of NRG were to occur during or following bankruptcy proceedings. Of these options outstanding, none currently have an in-the-money spread.

NRG participates in a multiemployer pension plan covered by Title IV of the Employee Retirement Income Security Act of 1974, as amended (ERISA), with respect to certain employees covered by collective bargaining agreements. If NRG were to withdraw from this plan in a complete or partial withdrawal while it was a member of our controlled group within the meaning of ERISA (generally, subsidiaries of which we own directly or indirectly at least 80%), we would be liable under ERISA for any portion of the resulting withdrawal liability imposed under Title IV of ERISA that NRG is unable to pay. If such withdrawal were to occur now, our withdrawal liability may be material.

In addition, we may incur liability for certain tax obligations of NRG. Under regulations issued by the U.S. Department of the Treasury, each member of a consolidated group during any part of a consolidated federal income tax return year is severally liable for the tax obligation of the entire consolidated group for that year. NRG was a member of our consolidated group before March 2001 and is eligible for re-inclusion in our consolidated group as of June 2002. It is likely, though not certain, that we will decide not to reconsolidate NRG for income tax purposes for 2002. If the IRS determines that NRG owes additional taxes and NRG does not pay them, the IRS would look to one or more members of the consolidated group, including us, for taxes owed by NRG for tax periods when NRG was a member of the consolidated group. If the IRS looked to us to pay taxes not paid by NRG, we would exercise any legal rights that are available for recovery of the payment from NRG, including in any NRG bankruptcy proceeding. Amounts that we could be required to pay to the IRS could be material and we may not be able to recover such amounts from NRG.

We may not have access to adequate funds in the event that we are substantively consolidated with NRG or we incur other significant liabilities relating to NRG. If these events were to occur, it would adversely affect our ability to make payments on the notes and you could risk the loss of your entire investment.

Recent and ongoing lawsuits relating to our ownership of NRG could impair our profitability and liquidity and could divert the attention of our management.

On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of our common stock between January 31, 2001 and July 26, 2002, was filed in the United States District Court in Minnesota. The complaint named Xcel Energy; Wayne H. Brunetti, chairman, president and chief executive officer; Edward J. McIntyre, former vice president and chief financial officer; and James J. Howard, former chairman, as defendants. Among other things, the complaint alleged violations of Section 10(b) of the Securities Exchange Act and Rule 10b-5 related to allegedly false and misleading disclosures concerning various issues, including round trip energy trades, the existence of cross-default provisions in our and NRG s credit agreements with lenders, NRG s liquidity and credit status, the supposed risks to our credit rating and the status of our internal controls to monitor trading of its power. Since the filing of the lawsuit on July 31, 2002, several additional lawsuits were filed with similar allegations, one of which added claims on behalf a purported class of purchasers of two series of NRG Senior Notes issued by NRG in January 2001. The cases have all been consolidated, and a consolidated amended complaint has been filed. The amended complaint charges false and misleading disclosures concerning round trip energy trades and the existence of provisions in our credit agreements with lenders for cross-defaults in the event of a default by NRG; it adds as additional defendants Gary R. Johnson, General Counsel, Richard C. Kelly, president of Xcel Energy Enterprises, two former executive officers of NRG (David H. Peterson, Leonard A. Bluhm) and one current executive officer of NRG (William T. Pieper) and a former independent director of NRG (Luella G. Goldberg); and it adds claims of false and misleading disclosures (also regarding round trip trades and the cross-defaults provisions) under Section 11 of the Securities Act. On August 15, 2002, a shareholder derivative action was filed in the same court as the class actions described above purportedly on our behalf, against our directors and certain present and former officers, citing essentially the same circumstances as the class actions and asserting breach of fiduciary duty. Subsequently, two additional derivative actions were filed in the state trial court for Hennepin County, Minnesota, against essentially the same defendants, focusing on alleged wrongful energy trading activities and asserting breach of fiduciary duty for failure to establish and maintain adequate accounting controls, abuse of control and gross mismanagement. In addition, complaints have been filed against us, certain of our present and former officers and directors and the members of our board of directors in the United States District Court for the District of Colorado under the Employee Retirement Income Security Act by participants in our 401(k) and ESOP plan, alleging breach of fiduciary duty in allowing or encouraging purchase, contribution and/or retention of our common stock in the plans, and misleading statements and omissions in that regard, and purporting to represent classes from as early as September 23, 1999 forward. If any one or combination of these cases results in a substantial monetary judgment against us or is settled on unfavorable terms, our profitability and liquidity could be materially adversely affected.

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Defaults at additional NRG projects could cause us to recognize significant additional losses and write-downs.

Substantially all of NRG s operations are conducted by project subsidiaries and project affiliates. NRG s cash flow and ability to service corporate-level indebtedness when due are dependent upon receipt of cash dividends and distributions or other transfers from NRG s subsidiaries and project affiliates. The debt agreements of NRG s subsidiaries and project affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to NRG. As of December 31, 2002, certain of NRG s subsidiaries and project affiliates are restricted from making cash payments to NRG: among others, Loy Yang, Killingholme, Energy Center Kladno, LSP Energy (Batesville), NRG South Central and NRG Northeast Generating do not currently meet the minimum debt service coverage ratios required for these projects to make payments to NRG. Crockett Cogeneration is also limited in its ability to make distributions to NRG and its other partners.

Many of the debt agreements of NRG s subsidiaries and project affiliates require the funding of debt service reserve accounts. Prior to the NRG downgrades, certain debt service reserve account funding requirements were satisfied by provision of a guarantee from NRG. Following the downgrade of NRG, those guarantees no longer qualified as acceptable credit support and the accounts were required to be funded with cash by NRG. The accounts were not funded with cash from NRG, and, after allowing for applicable cure periods, events of default were triggered under such project financings that allow the lenders to accelerate the project debt. NRG South Central Generating, NRG McClain, NRG MidAtlantic, Flinders, NRG Northeast Generating and Enfield are precluded from making payments to NRG due to unfunded debt service reserve accounts. During January 2003, ownership of the Killingholme and Brazos Valley projects was transferred to their lenders and NRG no longer has an interest in those projects.

Additional asset impairments may be recorded by NRG in periods subsequent to December 31, 2002, given the changing business conditions for NRG and the resolution of its plan of reorganization. We are unable at this time to determine the possible magnitude of any additional NRG asset impairments, but they could be material.

For additional information regarding our ownership of NRG and its potential implications on us, see Notes 4 and 18 to our consolidated financial statements.

Risks related to our Liquidity and Access to the Capital Markets

Our credit ratings have been recently lowered and could be further lowered in the future. If this were to occur, our access to capital would be negatively affected and the value of the notes could decline.

Our credit ratings and access to the capital markets have been significantly and negatively affected recently, and may be further affected in the future. As of December 31, 2002, our senior unsecured debt was rated BBB by Standard & Poor s, Baa3 (negative outlook) by Moody s and BB+, with negative outlook, by Fitch. As a result, our ability to access needed capital and bank credit has been limited, and our cost of capital has increased materially. Any further downgrade of our debt securities would increase our cost of capital and impair our access to the capital markets. This could adversely affect our financial condition and results of operations.

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On June 24, 2002, Standard & Poor s lowered the short-term rating on our commercial paper to A-3 from A-2 and on July 30, 2002, Fitch withdrew our commercial paper rating. Our commercial paper is currently not rated by Moody s. Consequently, we do not currently have access to the commercial paper market and refinanced our outstanding commercial paper as it matured with borrowings under our credit facilities. As of December 31, 2002, and after giving effect to the repayment of the $400 million credit facility at maturity on November 8, 2002, we had no commercial paper outstanding and had borrowings of approximately $400 million under our five-year credit facility, which matures in November 2005.

Our cost of new borrowings to replace our commercial paper is greater than the historical cost of our commercial paper. As a result of our loss of access to the commercial paper market and the current lack of additional capacity under our credit facility, we are more dependent upon accessing the capital markets. Access to the capital markets on favorable terms will be affected by our credit ratings (and the ratings of our affiliated companies) and prevailing conditions in the capital markets.

Our current ratings or those of our affiliates, including NRG, may not remain in effect for any given period of time and a rating may be lowered or withdrawn entirely by a rating agency. In particular, under the current rating methodology used by Standard & Poor s, our ratings could be changed to reflect a change in credit ratings of any of our affiliates, including NRG. Further adverse developments related to NRG s liquidity and its debt and other obligations described above, and the actions we take to address that situation, could have an adverse effect on our credit ratings and therefore our liquidity. Any lowering of the rating of the notes offered hereby would likely reduce the value of the notes.

We have provided various guarantees and bond indemnities supporting certain of our subsidiaries by guaranteeing the payment or performance by such subsidiaries of specified agreements or transactions. Our exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. The majority of our guarantees limit our exposure to a maximum amount that is stated in the guarantees. As of December 31, 2002, we had guarantees outstanding with a maximum stated amount of approximately $1,509 million and actual current aggregate exposure of approximately $446 million, which amount may vary over time.

On November 21, 2002 Moody s rated the notes Baa3 (negative outlook). If either Standard & Poor s or Moody s were subsequently to downgrade our credit rating below investment grade, we may be required to provide credit enhancement in the form of cash collateral, letters of credit or other security to satisfy part or potentially all of these exposures.

Any such downgrading of our ratings would increase our cost of capital, impair our access to the capital markets and adversely affect our liquidity position.

Our reduced access to sources of liquidity may increase our cost of capital and our dependence on capital markets.

Historically, we have relied on bank lines of credit, the commercial paper market and dividends from our regulated utility subsidiaries to meet our cash requirements, including dividend payments to our shareholders, and the short-term liquidity requirements of our business. Given the recent events at NRG discussed above and the recent downgrades in our short-term ratings, we do not have access to the commercial paper market.

In addition, our $400 million revolving credit facility expired in November 2002, and we were not able to renew this facility on favorable terms. Consequently, we repaid the facility from funds from a new financing and from available cash. Our inability to obtain bank financing on favorable terms will limit our ability to contribute equity or make loans to our subsidiaries, including our regulated utilities, and may cause us to seek alternative sources of funds to meet temporary cash needs.

Furthermore, until the issues related to NRG are resolved, our access to the capital markets is likely to be constrained. Access to the capital markets and our cost of capital will be affected by our credit ratings (and the ratings of our affiliated companies) and prevailing conditions in the capital markets. If we are unable to access the capital markets on favorable terms, our ability to fund our operations and required capital expenditures and other investments may be adversely affected.

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Our utility subsidiaries also rely on accessing the capital markets to support their capital expenditure programs and other capital requirements to maintain and build their utility infrastructure and comply with future requirements such as installing emission-control equipment. The ability of our utility subsidiaries to access the capital markets also has been negatively impacted by events at NRG.

We must rely on cash from our subsidiaries to make debt payments.

We are a holding company and thus our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to service our indebtedness, including the notes, depends upon the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due pursuant to the notes or to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary s ability to pay dividends to us depends on any statutory and/or contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets.

As discussed above, our utility subsidiaries are regulated by various state utility commissions which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions attempt to impose restrictions on the ability of our utility subsidiaries to pay dividends to us, it could adversely affect our ability to make payments on the notes or otherwise meet our financial obligations.

We are subject to regulatory restrictions on accessing capital.

We are a public utility holding company registered with the SEC under PUHCA. PUHCA contains limitations on the ability of registered holding companies and certain of their subsidiaries to issue securities. Such registered holding companies and subsidiaries may not issue securities unless authorized by an exemptive rule or order of the SEC.

Because the exemptions available to us are limited, we sought and received authority from the SEC under PUHCA for various financing arrangements. One of the conditions of our original financing order was that our ratio of common equity to total capitalization, on a consolidated basis, be at least 30 percent. During the quarter ended September 30, 2002, we were required to record significant asset impairment losses from sales or divestitures of NRG assets and businesses, from NRG s cancelling or deferring the funding of certain projects under construction, and from NRG s deciding not to contribute additional funds to certain projects already operating. As a result, our common equity ratio fell below 30 percent.

In anticipation of falling below the 30 percent level, we obtained authorization from the SEC under PUHCA to engage in certain financing transactions and intrasystem loans through March 31, 2003, so long as our ratio of common equity to total capitalization, on an as adjusted basis, is at least 24 percent. As of September 30, 2002, our common equity ratio, as adjusted, was at least 24 percent. Financings authorized by the SEC included the issuance of debt (including convertible debt) to refinance or replace a $400 million credit facility that expired on November 8, 2002, issuance of $483 million of stock (less amounts of long-term debt issued as part of the refinancing of the $400 million credit facility) and the renewal of guarantees for trading obligations of NRG s power marketing subsidiary. The SEC reserved jurisdiction over additional securities issuances by us through June 30, 2003, while our common equity ratio is below 30 percent. After June 30, 2003, our common equity ratio must be at least 30 percent in order to engage in financing transactions without additional approval of the SEC.

On December 20, 2002, we filed a revised request with the SEC seeking additional financing authorization to conduct our business as proposed during 2003. We are seeking an increase of $500 million in the amount of long-term debt and common equity we are authorized to issue from $2.0 billion to $2.5 billion. In addition, we proposed that our common equity, as reflected on our most recent Form 10-K or Form 10-Q and as adjusted to reflect subsequent events that affect capitalization, will be at least 30 percent of total consolidated capitalization, provided that in any event that we do not satisfy the 30 percent common equity standard, we may issue common stock. We further asked the SEC to reserve jurisdiction over the

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authorization for us and our subsidiaries to engage in any other financing transactions authorized under current SEC orders and in the instant request at a time that we do not satisfy the 30 percent common equity standard. We also requested that the SEC permit us to pay up to $260 million of dividends out of capital and unearned surplus in the event we cease to have retained earnings. The amount of dividends that we can pay is limited by PUHCA, in that we may not pay dividends out of capital or unearned surplus without approval of the SEC. See discussion of dividend restrictions in Note 12 to the consolidated financial statements.

It is possible that we may be required to recognize further losses at NRG and that our common equity ratio may fall below the 24 percent level. As of December 31, 2002, our common equity ratio was below 24 percent. In addition, it is anticipated that for at least some period of time following March 31, 2003, our common equity ratio will be below 30 percent. If that occurs and we are unable to obtain additional relief from the SEC, we may not be able to issue securities, which could have a material adverse effect on our ability to make payments on the notes and otherwise meet our capital and other needs.

For additional information regarding our liquidity and capital resources, and the effect that the recent reductions in our credit ratings has had on our access to capital, see Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

Risks Associated with Our Business

There may be changes in the regulatory environment that impair our ability to recover costs from our customers.

We are subject to comprehensive regulation by several federal and state utility regulatory agencies, which significantly influences our operating environment and our ability to recover our costs from utility customers. The utility commissions in the states where our utility subsidiaries operate regulate many aspects of our utility operations including siting and construction of facilities, customer service and the rates that we can charge customers.

In light of the recent credit and liquidity events regarding NRG, we face enhanced scrutiny from our state regulators. On August 8, 2002, the MPUC asked for additional information related to the impact of NRG s financial circumstances on NSP-Minnesota. Subsequent to that date, several newspaper articles alleged concern about the reporting of service quality data and NSP-Minnesota s overall maintenance practices. In an order dated October 22, 2002, the MPUC opened an investigation into the accuracy of NSP-Minnesota s reliability records and to allow for further review of its maintenance and other service quality measures. The Minnesota Department of Commerce and Office of Attorney General have begun an investigation of these issues. There is no scheduled date for completion of these investigations. These investigations, and any attendant remedial actions, may materially and adversely affect the financial position and results of operations of NSP-Minnesota.

The events relating to NRG could also negatively impact the positions taken by the Colorado Public Utilities Commission (CPUC) in PSCo s pending and future rate proceedings, which could result in reduced recovery of our costs. In May 2002, PSCo filed a combined general retail electric, gas and thermal energy base rate case with the Colorado Public Utilities Commission (CPUC) to address increased costs for providing energy to Colorado customers. On April 4, 2003, a comprehensive settlement agreement between PSCo and all but one of the intervenors was executed and filed with the CPUC, which addressed all significant issues in the rate case. In summary, the settlement agreement, among other things, provides for:

- base rate decreases of approximately $33 million for natural gas and $230,000 for electricity, including an annual reduction to electric depreciation expense of approximately $20 million, effective July 1, 2003;

- an interim adjustment clause (IAC) that recovers 100 percent of prudently incurred 2003 electric fuel and purchased energy expense above the expense recovered through electric base rates. This clause is projected to recover energy costs totaling approximately $216 million in 2003. The IAC originally went into effect on Jan. 1, 2003. The IAC rate was increased on May 1, 2003 by $93 million to recover the total anticipated energy costs for 2003;

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- a new electric commodity adjustment clause (ECA) for 2004-2006, with an $11.25 million cap on any cost sharing over or under an allowed ECA formula rate;
- an authorized return on equity of 10.75 percent for electricity and 11.0 percent for natural gas and thermal energy.

Hearings on one settlement agreement were held in late April 2003. Management believes the CPUC will approve the settlement agreement and issue a final rate order during the second quarter, with new rates effective as discussed above. PSCo will now move to the phase II, rate design, portion of the case.

As a result of the energy crisis in California and the financial troubles at a number of energy companies, including the financial challenges of NRG, the regulatory environments in which we operate have received an increased amount of public attention. The profitability of our utility operations is dependent on our ability to recover costs related to providing energy and utility services to our customers. It is possible that there could be changes in the regulatory environment that would impair our ability to recover costs historically absorbed by our customers. State utility commissions generally possess broad powers to ensure that the needs of the utility customers are being met. We may be asked to ensure that our ratepayers are not harmed as a result of the credit and liquidity events at NRG. The state utility commissions also may seek to impose restrictions on the ability of our utility subsidiaries to pay dividends to us. If successful, this could materially and adversely affect our ability to meet our financial obligations, including making payments on the notes.

As discussed above, our system also is subject to the jurisdiction of the SEC under PUHCA, which imposes a number of restrictions on the operations of registered holding company systems. These restrictions include, subject to certain exceptions, a requirement that the SEC approve securities issuances, payments of dividends out of capital or unearned surplus, sales and acquisitions of utility assets or of securities of utility companies and acquisitions of other businesses. PUHCA also generally limits the operations of a registered holding company like us to a single integrated public utility system, plus additional energy-related businesses. PUHCA rules require that transactions between affiliated companies in a registered holding company system be performed at cost, with limited exceptions.

The Federal Energy Regulatory Commission has jurisdiction over wholesale rates for electric transmission service and electric energy sold in interstate commerce, hydro facility licensing and certain other activities of our utility subsidiaries. Federal, state and local agencies also have jurisdiction over many of our other activities.

We are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations and hence could materially and adversely affect our ability to meet our financial obligations, including making payments on the notes.

We are subject to commodity price risk, credit risk and other risks associated with energy markets.

We are exposed to market and credit risks in our generation, retail distribution and energy trading operations. To minimize the risk of market price and volume fluctuations, we enter into financial derivative instrument contracts to hedge purchase and sale commitments, fuel requirements and inventories of natural gas, distillate fuel oil, electricity and coal, and emission allowances. However, financial derivative instrument contracts do not eliminate the risk. Specifically, such risks include commodity price changes, market supply shortages, credit risk and interest rate changes. The impact of these variables could result in our inability to fulfill contractual obligations, significantly higher energy or fuel costs relative to corresponding sales contracts or increased interest expense.

Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

We mark our energy trading portfolio to estimated fair market value on a daily basis (mark-to-market accounting), which causes earnings variability. Market prices are utilized in determining the value of electric

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energy, natural gas and related derivative commodity instruments. For longer-term positions, which are limited to a maximum of eighteen months, and certain short-term positions for which market prices are not available, models based on forward price curves are utilized. These models incorporate estimates and assumptions as to a variety of factors such as pricing relationships between various energy commodities and geographic locations. Actual experience can vary significantly from these estimates and assumptions.

We may be subject to enhanced scrutiny and potential liabilities as a result of our trading operations.

On May 8, 2002, in response to disclosure by Enron Corporation of certain trading strategies used in 2000 and 2001 that may have violated market rules, the FERC ordered all sellers of wholesale electricity and/or ancillary services to the California Independent System Operator or Power Exchange, including us, to respond to data requests, including requests about the use of certain trading strategies. On May 22, 2002, we reported to the FERC that we had not engaged directly in the trading strategies identified in the May 8th inquiry. On May 21, 2002, the FERC supplemented the May 8th request by ordering all sellers of wholesale electricity and/or ancillary services in the United States portion of the Western Systems Coordinating Council during 2000 and 2001 to report whether they had engaged in activities referred to as wash, round trip or sell/buyback trading. On May 31, 2002, we reported that we had not engaged in so-called round trip electricity trading identified in the May 21st inquiry.

On May 13, 2002, independently and not in direct response to any regulatory inquiry, we reported that PSCo had engaged in transactions in 1999 and 2000 with the trading arm of Reliant Resources, Inc. (Reliant) in which PSCo bought power from Reliant and simultaneously sold the same quantity back to Reliant. For doing this, PSCo normally received a small profit. PSCo made a total pretax profit of approximately $110,000 on these transactions. These transactions included one trade with Reliant in which PSCo simultaneously bought and sold power at the same price without realizing any profit. In this transaction, PSCo agreed to buy from Reliant 15,000 megawatts per hour, during the off-peak hours of the months of November and December 1999. Collectively, these sales with Reliant consisted of approximately 10 million megawatt hours in 1999 and 1.8 million megawatt hours in 2000 and represented approximately 55 percent of our trading volumes for 1999 and approximately 15 percent of our trading volumes for 2000. The purpose of the non-profit transaction was in expectation of entering into additional future for-profit transactions, such as the ones described above. PSCo engaged in these transactions with Reliant for the proper commercial objective of making a profit. PSCo did not enter into these transactions to inflate volumes or revenues and, at the time the transactions occurred, the transactions were reported net in PSCo s financial statements.

We also have received a subpoena from the SEC for documents concerning round trip trades in electricity and natural gas with Reliant Resources, Inc. for the period from January 1, 1999 to the present. The SEC subpoena is issued pursuant to a formal order of private investigation that does not name us. Based upon accounts in the public press, we believe that similar subpoenas in the same investigation have been served on other industry participants. We are cooperating with the regulators and taking steps to assure satisfactory compliance with the subpoenas.

If it is determined that we acted improperly in connection with these trading activities, we could be subject to a range of potential sanctions, including civil penalties and loss of market-based trading authority.

In addition, a number of actions have been filed in state and federal courts relating to power sales in California and other Western markets from May 2000 through June 2001. Xcel Energy and PSCo have been named in the California litigation and it is possible that we could be brought into the additional litigation, or named in future proceedings. There are also actions pending at FERC regarding these and similar issues. We cannot assure you that we will not have to pay refunds or other damages as a result of these proceedings. Any such refunds or damages could have an adverse effect on our financial results.

Pursuant to a formal order of investigation, on June 17, 2002 the Commodity Futures Trading Commission (CFTC) issued broad subpoenas to us on behalf of our affiliates, including NRG, calling for production, among other things, of all documents related to natural gas and electricity trading (the June 17, 2002 subpoenas). Since that time, we have produced documents and other materials in response to

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numerous more specific requests under the June 17, 2002 subpoenas. Certain of these requests and our responses have concerned so-called round-trip trades. By a subpoena dated January 29, 2003 and related letter requests (the January 29, 2003 subpoena), the CFTC has requested that we produce all documents related to all data submittals and documents provided to energy industry publications. We have produced documents and other materials in response to the January 29, 2003 subpoena, including a report identifying instances where our e prime subsidiary reported natural gas transactions to an industry publication in a manner inconsistent with the publication s instructions. We believe this reporting did not affect the financial accounting treatment of any transaction recorded in e prime s books and records. Also beginning on January 29, 2003, the CFTC has sought testimony from twenty current and former employees, and may seek additional testimony from other employees and executives, concerning the reporting of energy transactions to industry publications. A number of energy companies have stated in documents filed with FERC that employees reported fictitious natural gas transactions to industry publications. Various other energy companies are also subject to a recent order by FERC placing requirements on natural gas marketers related to reporting. We and NRG are cooperating in the CFTC investigation, but cannot predict the outcome of any investigation.

We received a Notice of Violation from the United States Environmental Protection Agency alleging violations of the New Source Review requirements of the Clean Air Act at two of our stations in Colorado and we continue to respond to information requests related to several of our plants in Minnesota. The ultimate financial impact to us is uncertain at this time.

On July 1, 2002, we received a Notice of Violation (NOV) from the United States Environmental Protection Agency (EPA) alleging violations of the New Source Review (NSR) requirements of the Clean Air Act at PSCo s Comanche and Pawnee Stations in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid- to late-1990s were non-routine major modifications and should have required a permit under the NSR process. Although we believe we acted in full compliance with the Clean Air Act and NSR process, we cannot assure you that we will not be required to install additional emission control equipment at the facilities, which would require substantial capital expenditures, and pay civil penalties. Civil penalties are limited to not more than $25,000 to $27,500 per day for each violation, commencing from the date the violation began. The ultimate financial impact to us is not determinable at this time.

The EPA also issued requests for information pursuant to the Clean Air Act to our subsidiary NSP-Minnesota. In 2001, NSP-Minnesota responded to EPA s initial information requests related to its plants in Minnesota. On May 22, 2002, EPA issued a follow-up information request to NSP-Minnesota seeking additional information regarding NSR compliance at its plants in Minnesota. NSP-Minnesota has responded to the follow-up request.

Our subsidiary, PSCo, has received a notice from the Internal Revenue Service (the IRS) proposing to disallow certain interest expense deductions that PSCo claimed in 1993 through 1997. Should the IRS ultimately prevail on this issue, our liquidity position and financial results could be materially adversely affected.

One of PSCo s wholly owned subsidiaries, PSR Investments, Inc. (PSRI), owns and manages, among other things, life insurance policies on some of PSCo s employees known as corporate-owned life insurance (COLI) policies. From time to time, PSCo made borrowings against the cash values of these COLI policies and deducted the interest expense on these borrowings. The IRS issued a Notice of Proposed Adjustment to PSCo proposing to disallow interest expense deductions PSCo had taken in tax years 1993 through 1997. In late 2001, PSCo received a technical advice memorandum from the IRS National Office that communicated a position adverse to PSRI. Consequently, we expect the IRS to continue disallowing the interest deductions and seeking to impose an interest charge on the resulting underpayment of taxes.

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After consultation with tax counsel, we believe that the IRS position is not supported by the tax law. Based on this assessment, PSCo continues to believe that the deduction of interest expense on the COLI policy loans is in full compliance with the tax law. For this reason and following consultation with our auditors, we have determined not to record any provision or reserve for income taxes or interest charges in connection with this matter. In addition, PSCo has continued to claim deductions for interest expense related to COLI policy loans on its income tax returns for taxable years after 1997, and intends to continue to challenge the IRS s proposed disallowance.

The total disallowance of interest expense deductions for the period of 1993 through 1997 is approximately $175 million. Additional interest expense deductions for the period 1998 through 2002 are estimated to total approximately $317 million. Should the IRS ultimately prevail on this issue, tax and interest payable through December 31, 2002 would reduce earnings by an estimated $214 million (after tax). Because we are continuing to claim deductions for interest expenses related to these COLI policy loans, the tax and interest ultimately owed by us, should the IRS and state tax agencies ultimately prevail, will continue to increase over time.

Should the IRS ultimately prevail on the COLI loan policy issue, our liquidity position and financial results could be materially adversely affected.

Increased competition resulting from restructuring efforts could have a significant financial impact on us and our utility subsidiaries and consequently decrease our revenue.

Retail competition and the unbundling of regulated energy and gas service could have a significant financial impact on us and our subsidiaries due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. The restructuring may have a significant impact on our financial position, results of operations and cash flows. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our financial position, results of operations or cash flows. We believe that the prices our utility subsidiaries charge for electricity and gas and the quality and reliability of their service currently place them in a position to compete effectively in the energy market.

For additional information regarding the regulatory environment in which we operate and certain other matters regarding our business discussed above, see Notes 1, 15, 18, 19 and 20 to our consolidated financial statements.

Risks Related to the Notes

The notes are effectively subordinated to all existing and future indebtedness and liabilities of our subsidiaries.

As a stockholder, rather than a creditor of our subsidiaries, our right and the rights of our creditors to participate in the assets of any of our subsidiaries upon any liquidation or reorganization of that subsidiary will rank behind the claims of that subsidiary s creditors, including trade creditors (except to the extent we have a claim as a creditor of such subsidiary). As a result, the notes are effectively subordinated to all existing and future indebtedness and other liabilities, including trade payables, of our subsidiaries.

As of December 31, 2002, our subsidiaries had outstanding indebtedness and other liabilities of approximately $20.7 billion. Some of these liabilities are secured by the assets of these subsidiaries. We and our subsidiaries may incur additional debt. The indenture governing the notes does not contain any restriction on us or our subsidiaries incurring additional debt.

An active trading market for the notes may not develop.

There is no existing trading market for the notes. We do not plan to apply for listing of any notes sold pursuant to this prospectus on any securities exchange or for inclusion of such notes in any automated quotation system. If the notes are traded after their initial issuance, they may trade at a discount, depending on the prevailing interest rates, the market for similar securities, the price of our common stock, our

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performance and other factors. We do not know whether an active trading market will develop for the notes. To the extent that an active trading market does not develop, the price at which you may be able to sell the notes, if at all, may be less than the price you pay for them.

Certain provisions of law, as well as provisions in our bylaws and shareholder rights plan, may make it more difficult for others to obtain control of us, even though some shareholders might consider this favorable.

We are a Minnesota corporation and certain anti-takeover provisions of Minnesota law apply to us and create various impediments to the acquisition of control of us or to the consummation of certain business combinations with us. In addition, our bylaws and shareholder rights plan contain provisions which may make it more difficult to remove incumbent directors or effect certain business combinations with us without the approval of our board of directors. See Description of Capital Stock. Finally, certain federal and state utility regulatory statutes may also make it difficult for another party to acquire a controlling interest in us. These provisions of law and of our corporate documents, individually or in the aggregate, could discourage a future takeover attempt which individual shareholders might deem to be in their best interests or in which shareholders would receive a premium for their shares over current prices.

We may enter into acquisitions, changes of control, refinancings or other recapitalizations or highly leveraged transactions that could increase the amount of debt outstanding, affect our capital structure or credit quality, or otherwise adversely affect the notes.

We may decide to enter into acquisitions, changes of control, refinancings of our current debt or other recapitalizations or highly leveraged transactions that could increase the amount of debt outstanding, affect our capital structure or credit quality, or otherwise adversely affect investors such as holders of the notes. Holders of the notes covered by this prospectus are not protected in the event of a highly leveraged transaction or a change of control except that a change of control permits the repurchase of notes at the option of the holder.

We may issue additional shares of our common stock that could dilute the value of our common stock issuable upon conversion of the notes.

We may be required to issue additional shares of our common stock that may dilute the value of our common stock and may adversely affect the market price our common stock.

On March 13, 2001, NRG completed the sale of 11.5 million equity units, consisting of a corporate unit comprising a $25 principal amount of NRG s senior debentures and an obligation to acquire shares of NRG common stock no later than May 18, 2004. Initially the equity units were convertible by the holder into NRG common stock. Following the exchange offer and subsequent short form merger pursuant to which we acquired the outstanding publicly-held stock of NRG on June 3, 2002, the equity units may be converted by the holder into our common stock. The maximum number of shares to be issued by us upon conversion of the equity units is 5,323,925 (subject to adjustment for specified events arising from stock splits and combinations, stock dividends and other actions that modify our capital structure).

We and some of our subsidiaries have incentive compensation plans under which stock options and other performance incentives are awarded to key employees. As of December 31, 2002, stock options for 16,981,207 shares of common stock were outstanding, of which options for 8,992,632 shares of common stock were exercisable. The exercise price for the options ranges from $11.50 to $63.60. In addition, certain employees also may be awarded restricted stock under our incentive plans. We hold restricted stock until restrictions lapse, generally ratably over a three year period. We granted 50,083 restricted shares in 2002, 21,774 restricted shares in 2001, 58,690 restricted shares in 2000 and 52,688 restricted shares in 1999.

Our ability to pay dividends on our common stock may be restricted by regulatory requirements.

Under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. Due to 2002 losses incurred by NRG, retained earnings of

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Xcel Energy were a deficit of $101 million at December 31, 2002 and, accordingly, dividends cannot be declared until earnings in 2003 are sufficient to eliminate this deficit or Xcel Energy is granted relief under the PUHCA. Xcel Energy has requested authorization from the SEC to pay dividends out of paid-in capital up to $260 million until September 30, 2003. It is not known when or if the SEC will act on this request. See Note 12 to the consolidated financial statements for a discussion of factors affecting our payment of dividends.

Fluctuations in the market price of our common stock could adversely affect the trading price of the notes.

The market price of our common stock has fluctuated recently. In addition, the stock market in recent years has experienced significant price and volume fluctuations that have often been unrelated to the operating performance of companies. The market price of our common stock may continue to fluctuate in the future. Negative fluctuations in the market price of our common stock could adversely impact the trading price of the notes.

RATIO OF EARNINGS TO FIXED CHARGES

	Year ended December 31,				
	2002(1)	2001	2000	1999	1998
Ratio of Earnings to Fixed Charges(2)	(1.8)	2.1	1.9	2.4	3.0

(1) Earnings as defined in the ratio for the twelve months ended December 31, 2002 were reduced by NRG asset impairment charges of $3.1 billion. The fixed charges exceeded earnings, as defined for this ratio, by $2.9 billion in 2002.

(2) For purposes of computing the ratio of earnings to fixed charges:

earnings consist of net income plus fixed charges, federal and state income taxes, deferred income taxes and investment tax credits and less undistributed equity in earnings of unconsolidated investees, and

fixed charges consist of interest on long-term debt, other interest charges, distributions on redeemable preferred securities of subsidiary trusts and amortization of debt discount, premium and expense.

USE OF PROCEEDS

We will not receive any proceeds from the sale by any selling security holder of the notes or the common stock issuable upon conversion of the notes. See Selling Security Holders.

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PRICE RANGE OF COMMON STOCK AND DIVIDEND HISTORY

Our common stock is currently listed on the New York Stock Exchange under the symbol XEL. The following table sets forth the intra-day high and low prices for transactions involving our common stock for each calendar quarter, as reported on the New York Stock Exchange Composite Tape, and related dividends paid per common share during such periods.

	High	Low	Dividend
2003:			
First Quarter	$ 12.97	$ 10.59	N/A
2002:			
Fourth Quarter	$ 11.60	$ 7.40	$ 0.1875
Third Quarter	$ 17.20	$ 5.12	$ 0.1875
Second Quarter	$ 26.49	$ 13.91	$ 0.3750
First Quarter	$ 28.49	$ 22.26	$ 0.3750
2001:			
Fourth Quarter	$ 29.77	$ 25.30	$ 0.3750
Third Quarter	$ 29.51	$ 25.00	$ 0.3750
Second Quarter	$ 31.85	$ 27.39	$ 0.3750
First Quarter	$ 30.35	$ 24.19	$ 0.3750
2000:			
Fourth Quarter	$ 30.00	$ 24.63	$ 0.3750
Third Quarter	$ 27.56	$ 20.13	$ 0.3750
Second Quarter	$ 23.81	$ 19.50	$ 0.3675
First Quarter	$ 20.56	$ 16.13	$ 0.3625

On May 9, 2003 the last reported sale price of our common stock on the New York Stock Exchange was $13.81 per share. As of December 31, 2002, there were approximately 128,000 holders of our common stock.

Historically, we have paid quarterly dividends to our shareholders. For each quarter in 2001 and for the first two quarters of 2002, we paid dividends to our shareholders of $0.375 per share. In the third and fourth quarters of 2002 we paid dividends of $0.1875 per share. In making such decision, the board of directors considered several factors, including the goal of funding customer growth in our core business through internal cash flow and reducing our reliance on debt and equity financings. The board of directors also compared our dividend to its utility earnings and to the dividend payout of comparable utilities. Dividends on our common stock are paid as declared by our board of directors. Under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. Retained earnings were $115 million at December 31, 2002 based on preliminary results. We requested authorization from the SEC to pay dividends out of paid-in capital up to $260 million until September 30, 2003.

Our Articles of Incorporation place restrictions on the amount of common stock dividends we can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if our capitalization ratio (on a holding company basis only, i.e., not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to the (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, our capitalization ratio at December 31, 2002 was 85 percent. Although, we have preferred stock outstanding, the restrictions do not place any effective limit on our ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of our common stock.

Historical stock price information for periods prior to August 19, 2000 is information for the common stock of Northern States Power Company (which was listed on the New York Stock Exchange under the symbol NSP), the predecessor of Xcel Energy. Xcel Energy was formed on August 18, 2000 by the merger of Northern States Power Company with New Century Energies, Inc.

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CAPITALIZATION

The following table sets forth our consolidated capitalization as of December 31, 2002. We will not receive any proceeds from the sale by any selling security holders of the notes or the common stock issuable upon conversion of the notes. You should read the information in this table together with the detailed information and financial statements appearing in this prospectus and with Selected Consolidated Financial Data included elsewhere in this prospectus.

	As of December 31, 2002(1)	
	(Thousands of Dollars)	% of Capitalization
Short-term debt, including current maturities	$ 9,298,224	43.97%
Minority interest	34,762	0.16%
Long-term debt	6,550,248	30.97%
Mandatorily redeemable preferred securities of subsidiary trusts	494,000	2.34%
Preferred stockholders equity	105,320	0.5%
Common stockholders equity	4,664,984	22.06%
Total capitalization (including short-term debt and minority interest)	$ 21,147,538	100.0%

(1) Actual capitalization amounts are as reported in our Consolidated Statements of Capitalization, which include amounts reclassified to discontinued operations of NRG. The components of such discontinued operations are segregated on the balance sheet, outside of apparent capitalization components. As a result, $445.7 million of short-term debt is reported as current liabilities held for sale and $0.1 million of long-term debt is noncurrent liabilities held for sale.

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SELECTED CONSOLIDATED FINANCIAL DATA

The following selected consolidated financial data as of December 31, 2002 and 2001, and for the years ended December 31, 2002, 2001, 2000, 1999 and 1998 have been derived from our audited consolidated financial statements and the related notes. The information set forth below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations, our audited consolidated financial statements and related notes and other financial information contained in this prospectus. The historical financial information may not be indicative of our future performance.

	Year Ended December 31,				
	2002(1)	2001	2000	1999	1998
	(In millions, except per share data)				
Consolidated Statement of Operations Data:					
Operating revenue(2)	$ 9,524	$ 11,333	$ 9,223	$ 6,883	$ 6,606
Operating expense(2)	10,957	9,475	7,744	5,679	5,412
Operating income (loss)	$ (1,433)	$ 1,858	$ 1,479	$ 1,204	$ 1,194
Interest income and other nonoperating income net of other expenses	44	46	16	3	49
Interest charges and financing costs	918	766	653	453	383
Income taxes (benefits)	(628)	331	299	180	240
Minority interest (income) expense	(17)	68	30	3	
(Loss) income from continuing operations	$ (1,661)	738	514	571	620
(Loss) income from discontinued operations, net of tax	(557)	47	32		4
Extraordinary items, net of tax		10	(19)		
Net (loss) income	(2,218)	795	527	571	624
Dividends on preferred stock	4	4	4	5	5
(Loss) earnings available for common shareholders	$ (2,222)	$ 791	$ 523	$ 566	$ 619
Earnings per share diluted:					
(Loss) income before extraordinary items	(4.36)	2.13	1.51	1.70	1.91
Discontinued Operations	(1.46)	0.14	0.09		
Extraordinary items		0.03	(0.06)		
Total	$ (5.82)	$ 2.30	$ 1.54	$ 1.70	$ 1.91

(1) Results for 2002 include two significant items that are described further in the notes to our consolidated financial statements: (a) impairment charges and disposal losses (excluding discontinued operations) related to NRG s long-lived assets and equity investments, which increased operating expenses and reduced operating income for the year ended December 31, 2002 by $2.7 billion; reduced, net income and earnings available for common shareholders for the year ended December 31, 2002 by $2.6 billion; and reduced earnings per share for the year ended December 31, 2002 by $6.80; and (b) income tax benefits related to our investment in NRG, which increased income from continuing operations and net income for the year ended December 31, 2002 by $706 million, and increased earnings per share from continuing operations and total earnings per share for the year ended December 31, 2002 by $1.85.

(2) Operating revenues and expenses for 1998 through 2001 include reclassifications to conform to the 2002 presentation. These reclassifications related to reporting to electric and natural gas trading revenues and costs on a net basis, and to presenting the results of discontinued operations separately. These reclassifications had no effect on net income or earnings per share.

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	December 31, 2002	December 31, 2001
	(In millions)	
Consolidated Balance Sheet Data:		
Current assets	$ 3,737	$ 3,330
Net Property, plant and equipment, at cost	18,816	19,781
Other assets	4,705	5,642
Total assets	$ 27,258	$ 28,754
Current portion of long-term debt(1)	7,756	393
Short-term debt	1,542	2,225
Other current liabilities	3,051	2,851
Total current liabilities	12,349	55,469
Deferred credits and other liabilities	3,060	4,321
Minority interest	35	615
Long-term debt(1)	6,550	11,556
Mandatorily redeemable preferred securities of subsidiary trusts	494	494
Preferred stockholders equity	105	105
Common stockholders equity	4,665	6,195
Total liabilities and equity	$ 27,258	$ 28,754

(1) Based on the defaults under certain NRG debt agreements, and NRG s lenders ability to call such debt within twelve months of December 31, 2002, the majority of NRG s long-term debt has been reclassified to current as of that date.

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SELECTED PRO FORMA CONSOLIDATED FINANCIAL DATA

The following selected pro forma consolidated financial data as of and for the year ended December 31, 2002 have been derived from our audited consolidated financial statements and the related notes. The information set forth below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations, our audited consolidated financial statements and related notes, our pro-forma financial information and related notes, and other financial information contained in this prospectus. The historical financial information may not be indicative of our future performance.

	Year Ended December 31, 2002(1)
	(In millions, except per share data)
Consolidated Statement of Operations Data:	
Operating revenue	$ 7,243
Operating expense	6,087
Operating income (loss)	$ 1,156
Interest income and other nonoperating income net of other expenses	40
Equity in losses of NRG	(3,464)
Interest charges and financing costs	424
Income taxes (benefits)	(462)
Minority interest (income) expense	(12)
Net loss	(2,218)
Dividends on preferred stock	4
Loss available for common shareholders	$ (2,222)
Earnings per share diluted	$ 5.82

(1) Individual revenue and expense items exclude the results of NRG (a loss of $3.5 billion), which are reported under the equity method as a single loss item, Equity in Losses of NRG.

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	December 31, 2002(2)
	(In millions)
Consolidated Balance Sheet Data:	
Current assets	$ 2,286
Net Property, plant and equipment, at cost	11,973
Other assets	2,089
Total assets	$ 16,348
Current portion of long-term debt	563
Short-term debt	512
NRG losses in excess of investment	634
Other current liabilities	1,513
Total current liabilities	3,222
Deferred credits and other liabilities	2,499
Minority interest	5
Long-term debt	5,358
Mandatorily redeemable preferred securities of subsidiary trusts	494
Preferred stockholders equity	105
Common stockholders equity	4,665
Total liabilities and equity	$ 16,348

(2) Individual asset and liability amounts exclude NRG amounts, which are reported under the equity method as a single current liability item, NRG Losses in Excess of Investment.

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MANAGEMENT S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with Summary Consolidated Financial Data, Selected Consolidated Financial Data and our financial statements and related notes appearing elsewhere in this prospectus. This discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. See Information Regarding Forward-Looking Statements. The actual results may differ materially from those anticipated in these forward-looking statements as a result of a number of factors including, but not limited to, those set forth under Information Regarding Forward Looking Statements and Risk Factors in this prospectus.

On August 18, 2000, New Century Energies, Inc. (NCE) and Northern States Power Co. (NSP) merged and formed Xcel Energy Inc. (Xcel Energy). Xcel Energy, a Minnesota corporation, is a registered holding company under the Public Utility Holding Company Act of 1935 (PUHCA). As part of the merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed subsidiary of Xcel Energy named Northern States Power Co. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. As a stock-for-stock exchange for shareholders of both companies, the merger was accounted for as a pooling-of-interests and, accordingly, amounts reported for periods prior to the merger have been restated for comparability with post-merger results.

We directly own six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are Northern States Power Co., a Minnesota corporation (NSP-Minnesota); Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); Southwestern Public Service Co. (SPS); Black Mountain Gas Co. (BMG), which is in the process of being sold pending regulatory approval; and Cheyenne Light, Fuel and Power Co. (Cheyenne). They serve customers in portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. During 2002, our regulated businesses also included Viking Gas Transmission Co. (Viking), which was sold on January 17, 2003, and WestGas InterState Inc. (WGI), both interstate natural gas pipeline companies.

We also own or have an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc. (NRG), an independent power producer. We owned 100 percent of NRG at the beginning of 2000. About 18 percent of NRG was sold to the public in an initial public offering in the second quarter of 2000, leaving us with an 82-percent interest at December 31, 2000. In March 2001, another 8 percent of NRG was sold to the public, leaving us with an interest of about 74 percent at December 31, 2001. On June 3, 2002, we acquired the 26 percent of NRG held by the public so that we again held 100 percent ownership at December 31, 2002. NRG is facing extreme financial difficulties and has filed a voluntary petition for bankruptcy under Chapter 11 of the U.S. Bankruptcy Code. See Notes 2, 3, 4 and 7 to the consolidated financial statements filed with this prospectus.

In addition to NRG, our nonregulated subsidiaries include Utility Engineering Corp. (engineering, construction and design), Seren Innovations, Inc. (broadband telecommunications services), e prime inc. (natural gas marketing and trading), Planergy International, Inc. (enterprise energy management solutions), Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits) and Xcel Energy International Inc. (an international independent power producer).

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on our financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and notes included in this prospectus. All note references refer to the notes to the consolidated financial statements.

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Results of Operations

Our earnings per share for the past three years were as follows:

	Contribution to Earnings per Share		
	2002	2001	2000
Continuing Operations Before Extraordinary Items:			
Regulated utility	$ 1.59	$ 1.90	$ 1.20
NRG (including impairments and restructuring charges)	(7.58)	0.44	0.37
Other nonregulated and holding company (including tax benefits related to investment in NRG in 2002)	1.63	(0.21)	(0.06)
Income (loss)from continuing operations	(4.36)	2.13	1.51
Discontinued operations NRG (see Note 3)	(1.46)	0.14	0.09
Extraordinary items Regulated utility (see Note 15)		0.03	(0.06)
Total earnings (loss) per share diluted	$ (5.82)	$ 2.30	$ 1.54

Additional information on earnings contributions by operating segments are as follows:

	Contribution to Earnings per Share		
	2002	2001	2000
Regulated utility (including extraordinary items):			
Electric utility	$ 1.33	$ 1.66	$ 1.03
Gas utility	0.26	0.24	0.17
Total regulated utility	1.59	1.90	1.20
NRG (including discontinued operations) (see Note 3)	(9.04)	0.58	0.46
Other nonregulated and holding company:			
Tax benefit related to investment in NRG	1.85	0.00	0.00
Other (see Note 21 for components)	(0.22)	(0.18)	(0.12)
Total earnings (loss) per share diluted	$ (5.82)	$ 2.30	$ 1.54

For more information on significant factors that had an impact on earnings, see below.

Significant Factors that Impacted 2002 Results

*Special Charges Regulated Utility*Regulated utility earnings from continuing operations were reduced by approximately 2 cents per share in 2002 due to a $5-million regulatory recovery adjustment for SPS and $9 million in employee separation costs associated with a restaffing initiative early in the year for utility and service company operations. See Note 2 to the consolidated financial statements for further discussion of these items, which are reported as Special Charges in operating expenses.

*Impairment and Financial Restructuring Charges NRG*NRG s losses from both continuing and discontinued operations were affected by charges recorded in 2002. Continuing operations included losses of approximately $7.07 per share in 2002 for asset impairment and disposal losses, and for other charges related mainly to its financial restructuring. These costs are reported as Special Charges and Writedowns and Disposal Losses from Investments in operating expenses, and are discussed further in Note 2 to the consolidated financial statements. In addition, discontinued operations included losses of approximately $1.56 per share for asset impairments and disposal losses, and are discussed further in Note 3 to the consolidated financial statements.

During 2002, NRG experienced credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. These events led to impairment reviews of a number of NRG assets, which resulted in material write-downs in 2002. In addition to impairments of projects operating or under development, certain NRG projects were determined to be held for sale, and estimated losses on disposal for such projects were also recorded. These impairment charges, some of which related to equity investments, have reduced our earnings for 2002 as follows: $6.29 of Special Charges in continuing operations, $0.51 of Losses on Disposal of Investments in continuing operations, and $1.57 of impairment charges included in discontinued operations. As reported previously, there is substantial doubt as to NRG s ability to continue as a going concern, and NRG will likely be the subject of a bankruptcy proceeding.

NRG also expensed approximately $111 million in 2002 for incremental costs related to its financial restructuring and business realignment. These costs, which reduced 2002 earnings by 27 cents per share, include expenses for financial and legal advisors, contract termination costs, employee separation and other incremental costs incurred during the financial restructuring period. These costs also include a charge related to NRG s NEO landfill gas generation operations for the estimated impact of a dispute settlement with NRG s partner on the NEO project, Fortistar. Most of these costs were paid in 2002. See Note 2 to the consolidated financial statements for discussion of accrued financial restructuring cost activity related to NRG.

Tax Benefit NRG Investment As discussed in Note 11, it was determined in 2002 that NRG was no longer likely to be included in our consolidated income tax group. Approximately $706 million has been recognized at one of our nonregulated intermediate holding companies for the estimated tax benefits related to our investment in NRG, based on the difference between book and tax bases of such investment. This estimated tax benefit increased 2002 annual results by $1.85 per share.

Other Nonregulated & Holding Companies Nonregulated and holding company earnings for 2002 were reduced by losses of approximately 6 cents per share for the combined effects of unusual items that occurred during the year. As discussed later, Xcel International recorded impairment losses for Argentina assets of 3 cents per share and disposal losses for Yorkshire Power of 2 cents per share, Planergy recorded gains from contract sales of 2 cents per share, losses were incurred on holding company debt of 2 cents per share, and incremental costs related to NRG financial restructuring activities of 1 cent per share were incurred at the holding company level.

Significant Factors that Impacted 2001 Results

Regulated utility earnings were reduced by a net 1 cent per share from the combined effects of four unusual items that occurred during the year. Three of the items affected continuing operations, reducing earnings by 4 cents per share. The remaining item increased income from extraordinary items by 3 cents per share.

Conservation Incentive Recovery Regulated utility earnings from continuing operations in 2001 were increased by 7 cents per share due to a Minnesota Public Utilities Commission (MPUC) decision. In June 2001, the MPUC approved a plan allowing recovery of 1998 incentives associated with state-mandated programs for energy conservation. As a result, the previously recorded liabilities of approximately $41 million, including carrying charges, for potential refunds to customers were no longer required. The plan approved by the MPUC increased revenue by approximately $34 million and increased allowance for funds used during construction by approximately $7 million, increasing earnings by 7 cents per share for the second quarter of 2001. Based on the new MPUC policy and less uncertainty regarding conservation incentives to be approved, conservation incentives are being recorded on a current basis beginning in 2001.

*Special Charges Postemployment Benefits and Restaffing Costs*Regulated utility earnings from continuing operations in 2001 were decreased by 4 cents per share due to a Colorado Supreme Court decision that resulted in a pretax write-off of $23 million of a regulatory asset related to deferred postemployment benefit costs at PSCo.

Also, regulated utility earnings from continuing operations were reduced by approximately 7 cents per share in 2001 due to $39 million of employee separation costs associated with a restaffing initiative late in the year for utility and service company operations. See Note 2 to the consolidated financial statements for further discussion of these items, which are reported as Special Charges in operating expenses.

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Extraordinary Items Electric Utility Restructuring In 2001, extraordinary income of $18 million before tax, or 3 cents per share, was recorded related to the regulated utility business to reflect the impacts of industry restructuring developments for SPS. This represents a reversal of a portion of the 2000 extraordinary loss discussed later. For more information on SPS extraordinary items, see Note 15 to the Consolidated Financial Statements.

Significant Factors that Impacted 2000 Results

*Special Charges Merger Costs*During 2000, we expensed pretax special charges of $241 million, or 52 cents per share, for costs related to the merger between NSP and NCE. Of these special charges, approximately 44 cents per share were associated with the costs of merging regulated utility operations and 8 cents per share were associated with merger impacts on nonregulated and holding company activities other than NRG. See Note 2 to the consolidated financial statements for more information on these merger-related costs reported as Special Charges.

Extraordinary Items Electric Utility Restructuring In 2000, extraordinary losses of approximately $28 million before tax, or 6 cents per share, were recorded related to the regulated utility business for the expected discontinuation of regulatory accounting for SPS generation business. For more information on SPS extraordinary items, see Note 15 to the consolidated financial statements.

Statement of Operations

Electric Utility and Commodity Trading Margins Electric fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Due to fuel cost recovery mechanisms for retail customers in several states, most fluctuations in energy costs do not materially affect electric utility margin. However, the fuel clause cost recovery in Colorado does not allow for complete recovery of all variable production expense, and cost changes can affect earnings. Electric utility margins reflect the impact of sharing energy costs and savings relative to a target cost per delivered kilowatt-hour and certain trading margins under the incentive cost adjustment (ICA) ratemaking mechanism in Colorado. In addition to the ICA, Colorado has other adjustment clauses that allow certain costs to be recovered from retail customers.

We have three distinct forms of wholesale sales: short-term wholesale, electric commodity trading and natural gas commodity trading. Short-term wholesale refers to electric sales for resale, which are associated with energy produced from our generation assets or energy and capacity purchased to serve native load. Electric and natural gas commodity trading refers to the sales for resale activity of purchasing and reselling electric and natural gas energy to the wholesale market.

Our commodity trading operations are conducted by NSP-Minnesota (electric), PSCo (electric) and e prime (natural gas). Margins from electric trading activity, conducted at NSP-Minnesota and PSCo, are partially redistributed to our other operating utilities, pursuant to a joint operating agreement (JOA) approved by the Federal Energy Regulatory Commission (FERC). Trading margins reflect the impact of sharing certain trading margins under the ICA. Trading revenues, as discussed in Note 1 to the consolidated financial statements, are reported net (i.e., margins) in the consolidated statements of operations. Trading revenue and costs associated with NRG s operations are included in nonregulated margins. The

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following table details the revenue and margin for base electric utility, short-term wholesale and electric and natural gas trading activities.

	Base Electric Utility	Short-Term Wholesale	Electric Commodity Trading	Natural Gas Commodity Trading	Intercompany Eliminations	Consolidated Totals
			(Millions of dollars)			
2002						
Electric utility revenue	$ 5,232	$ 203	$	$	$	$ 5,435
Electric fuel and purchased power utility	(2,029)	(170)				(2,199)
Electric and natural gas trading revenue gross			1,529	1,898	(71)	3,356
Electric and natural gas trading costs			(1,527)	(1,892)	71	(3,348)
Gross margin before operating expenses	$ 3,203	$ 33	$ 2	$ 6	$	$ 3,244
Margin as a percentage of revenue	61.2%	16.3%	0.1%	0.3%		36.9%
2001						
Electric utility revenue	$ 5,607	$ 788	$	$	$	$ 6,395
Electric fuel and purchased power utility	(2,559)	(613)				(3,172)
Electric and natural gas trading revenue gross			1,337	1,938	(88)	3,187
Electric and natural gas trading costs			(1,268)	(1,918)	88	(3,098)
Gross margin before operating expenses	$ 3,048	$ 175	$ 69	$ 20	$	$ 3,312
Margin as a percentage of revenue	54.4%	22.2%	5.2%	1.0%		34.6%
2000						
Electric utility revenue	$ 5,107	$ 567	$	$	$	$ 5,674
Electric fuel and purchased power utility	(2,106)	(475)				(2,581)
Electric and natural gas trading revenue gross			819	1,297	(54)	2,062
Electric and natural gas trading costs			(788)	(1,287)	54	(2,021)
Gross margin before operating expenses	$ 3,001	$ 92	$ 31	$ 10	$	$ 3,134
Margin as a percentage of revenue	58.8%	16.2%	3.8%	0.8%	%	40.5%

2002 Comparison to 2001 Base electric utility revenue decreased $375 million, while electric utility margins, primarily retail, increased approximately $155 million in 2002, compared with 2001. Base electric revenues decreased largely due to decreased recovery of fuel and purchased power costs driven by declining fuel costs in 2002. The higher base electric margins in the year reflect lower unrecovered costs, due in part to resetting the base-cost recovery at PSCo in January 2002. In 2001, PSCo s allowed recovery was approximately $78 million less than its actual costs, while in 2002 its allowed recovery was approximately $29 million more than its actual cost. For the year, higher accrued conservation revenues, sales growth and more favorable temperatures also contributed to the higher electric margins and partially offset the lower base electric revenue. Lower wholesale capacity sales in Texas, as well as the impact of the conservation incentive adjustment in Minnesota in 2001, as discussed previously, partially offset the increased margins and contributed to the lower revenues.

Short-term wholesale margins consist of asset-based trading activity. Electric and natural gas commodity trading activity margins consist of non-asset-based trading activity. Short-term wholesale and electric and natural gas commodity trading sales margins decreased an aggregate of approximately $223 million in 2002, compared with 2001. The decrease in short-term wholesale and electric commodity trading margin reflects lower power prices and less favorable market conditions. The decrease in natural gas commodity trading margin reflects reduced market opportunities.

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2001 Comparison to 2000 Base electric utility revenue increased by approximately $500 million, or 9.8 percent, in 2001. Base electric utility margin increased by approximately $47 million, or 1.6 percent, in 2001. These revenue and margin increases were due to sales growth, weather conditions in 2001 and the recovery of conservation incentives in Minnesota. Increased conservation incentives, including the resolution of the 1998 dispute, as discussed previously, and accrued 2001 incentives, increased revenue and margin by $49 million. More favorable weather during 2001 increased revenue by approximately $23 million and margin by approximately $13 million. These increases were partially offset by increases in fuel and purchased power costs, which are not completely recoverable from customers in Colorado due to various cost-sharing mechanisms. Revenue and margin also were reduced in 2001 by approximately $30 million due to rate reductions in various jurisdictions agreed to as part of the merger approval process, compared with $10 million in 2000.

Short-term wholesale revenue increased by approximately $221 million, or 39.0 percent, in 2001. Short-term wholesale margin increased $83 million, or 90.2 percent, in 2001. These increases are due to the expansion of our wholesale marketing operations and favorable market conditions for the first six months of 2001, including strong prices in the western markets, particularly before the establishment of price caps and other market changes.

Electric and natural gas commodity trading margins, including proprietary electric trading (i.e., not in electricity produced by our own generating plants) and natural gas trading, increased approximately $48 million for the year ended December 31, 2001, compared with the same period in 2000. The increase reflects an expansion of our trading operations and favorable market conditions, including strong prices in the western markets, particularly before the establishment of pricing caps and other market changes.

Natural Gas Utility Margins The following table details the changes in natural gas utility revenue and margin. The cost of natural gas tends to vary with changing sales requirements and the unit cost of natural gas purchases. However, due to purchased natural gas cost recovery mechanisms for retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin.

	2002	2001	2000
		(Millions of dollars)	
Natural gas utility revenue	$ 1,398	$ 2,053	$ 1,469
Cost of natural gas purchased and transported	(852)	(1,518)	(948)
Gas utility margin	$ 546	$ 535	$ 521

2002 Comparison to 2001 Natural gas utility revenue decreased by $655 million, while natural gas margins increased by $11 million. Natural gas revenue decreased largely due to decreases in the cost of natural gas, which are generally passed through to customers. Natural utility gas margin increased due primarily to more favorable temperatures and sales growth.

2001 Comparison to 2000 Natural gas utility revenue increased by approximately $584 million, or 39.8 percent, for 2001, primarily due to increases in the cost of natural gas, which are largely passed on to customers and recovered through various rate adjustment clauses in most of the jurisdictions in which we operate. Natural gas utility margin increased by approximately $14 million, or 2.7 percent, for 2001 due to sales growth and a rate increase in Colorado. These natural gas revenue and margin increases were partially offset by the impact of warmer temperatures in 2001, which decreased natural gas revenue by approximately $38 million and natural gas margin by approximately $16 million.

Nonregulated Operating Margins The following table details the changes in nonregulated revenue and margin included in continuing operations.

	2002	2001	2000
		(Millions of dollars)	
Nonregulated and other revenue	$ 2,611	$ 2,580	$ 1,856
Earnings from equity investments	72	217	183
Nonregulated cost of goods sold	(1,361)	(1,319)	(877)
Nonregulated margin	$ 1,322	$ 1,478	$ 1,162

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2002 Comparison to 2001 Nonregulated revenue from continuing operations increased slightly in 2002, reflecting growth from the full-year impact of NRG s 2001 generating facility acquisitions but partially offset by lower market prices. Nonregulated margin from continuing operations decreased in 2002, due to decreased equity earnings. Earnings from equity investments for 2002 decreased compared with 2001, primarily due to decreased equity earnings from NRG s West Coast Power project, which experienced less favorable long-term contracts and higher uncollectible receivables.

2001 Comparison to 2000 Nonregulated revenue and margin from continuing operations increased in 2001, largely due to NRG s acquisition of generating facilities, increased demand for electricity, market dynamics, strong performance from existing assets and higher market prices for electricity. Earnings from equity investments for 2001 increased compared with 2000, primarily due to increased equity earnings from NRG projects, which offset lower equity earnings from Yorkshire Power. As a result of a sales agreement to sell most of our investment in Yorkshire Power, we did not record any equity earnings from Yorkshire Power after January 2001.

Non-Fuel Operating Expense and Other Items Other utility operating and maintenance expense for 2002 decreased by approximately $4 million, or 0.3 percent. The decreased costs reflect lower incentive compensation and other employee benefit costs, as well as lower staffing levels in corporate areas. These decreases were substantially offset by higher plant outage and property insurance costs, in addition to inflationary factors such as market wage increases.

Other utility operating and maintenance expense for 2001 increased by approximately $60 million, or 4.1 percent, compared with 2000. The change is largely due to increased plant outages, higher nuclear operating costs, bad debt reserves reflecting higher energy prices, increased costs due to customer growth and higher performance-based incentive costs.

Other nonregulated operating and maintenance expenses for continuing operations increased $111 million in 2002 and increased $143 million in 2001. These expenses are included in the results for each nonregulated subsidiary, as discussed later.

Depreciation and amortization expense increased $131 million, or 14.5 percent, in 2002 and $140 million, or 18.2 percent, in 2001, primarily due to acquisitions of generating facilities by NRG and additions to utility plant. Higher NRG depreciation expense accounted for $87 million of the increase in 2002.

Interest income was higher in 2002 and 2001 due to higher cash balances at NRG in both years and to interest on affiliate loans in 2001.

Other income was higher in 2002 and 2001 due mainly to a gain on the sale of nonregulated property and PSCo assets.

Other expense increased in 2002 due largely to variations in currency exchange losses at NRG.

Interest expense increased $152 million, or 20.8 percent, in 2002 and $114 million, or 18.5 percent, in 2001, primarily due to increased debt of NRG. In addition, long-term debt was refinanced at higher interest rates during 2002. Higher NRG interest expense accounted for $105 million of the increase in 2002.

Income tax expense decreased by approximately $959 million in 2002, compared with 2001. Nearly all of this decrease relates to NRG s 2002 losses and the change in tax filing status for NRG effective in the third quarter of 2002, as discussed in Note 11 to the consolidated financial statements. NRG is now in a tax operating loss carryforward position and is no longer assumed to be part of our consolidated tax group. The effective tax rate for continuing operations, excluding minority interest and before extraordinary items, was 27.3 percent for the year ended December 31, 2002, and 28.8 percent for the same period in 2001. The decrease in the effective rate between years reflects a nominal tax rate at NRG, due to their loss carryforward position. Partially offsetting the NRG tax rate decrease is the impact of a one-time adjustment to recognize tax benefits from our investment in NRG, as discussed in Note 11 to the consolidated financial statements. The effective tax rate for the regulated utility business and operations other than NRG was significantly lower in 2002, compared with 2001, due to the benefit recorded on the investment in NRG and the changes in the items listed in the rate reconciliation in Note 11.

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Weather our earnings can be significantly affected by weather. Unseasonably hot summers or cold winters increase electric and natural gas sales, but also can increase expenses, which may not be fully recoverable. Unseasonably mild weather reduces electric and natural gas sales, but may not reduce expenses, which affects overall results. The following summarizes the estimated impact on the earnings of our utility subsidiaries due to temperature variations from historical averages:

weather in 2002 increased earnings by an estimated 6 cents per share;

weather in 2001 had minimal impact on earnings per share; and

weather in 2000 increased earnings by an estimated 1 cent per share.

NRG Results

	Contribution to Xcel Energy s Earnings per Share		
	2002	**2001**	**2000**
Continuing NRG operations:			
Operations before tax credits, special charges and disposal losses	$ (0.54)	$ 0.49	$ 0.35
Tax credits		0.14	0.10
Special charges-asset impairments (Note 2)	(6.29)		
Special charges-financial restructuring and NEO (Note 2)	(0.27)		
Write-downs and disposal losses from equity investments (Note 2)	(0.51)		
Income (loss) from continuing NRG operations	(7.61)	0.63	0.45
Discontinued NRG operations (Note 3)	(1.46)	0.14	0.09
Total NRG earnings (loss) per share	(9.07)	0.77	0.54
Minority shareholder interest	0.03	(0.19)	(0.08)
NRG contribution to Xcel Energy	$ (9.04)	$ 0.58	$ 0.46

NRG Continuing Operations and Tax Credits As previously stated, NRG is facing extreme financial difficulties, and has filed for protection under the bankruptcy laws. During 2002, NRG s continuing operations, excluding impacts of asset impairments and disposals and restructuring costs, experienced significant losses compared with 2001. The 2002 losses are primarily attributable to NRG s North American operations, which experienced significant reductions in domestic energy and capacity sales and an overall decrease in power pool prices and related spark spreads. During 2002, an additional reserve for uncollectible receivables in California was established by West Coast Power, which reduced NRG s equity earnings by approximately $29 million, after tax. West Coast Power s 2002 income was also lower than 2001 due to less-favorable contracts and reductions in sales of energy and capacity. In addition, increased administrative costs, depreciation and interest expense from completed construction costs also contributed to the less-than-favorable results for NRG in 2002. Partially off-setting these earnings reductions was the recognition, in the fourth quarter of 2002, of approximately $51 million of additional revenues related to the contractual termination related to NRG s Indian River project.

On a stand-alone basis, NRG does not have the ability to recognize all tax benefits that may ultimately accrue from its losses incurred in 2002, thus increasing the overall loss from continuing operations. In addition to losing the ability to recognize all tax benefits for operating losses, NRG in 2002 also lost the ability to utilize tax credits generated by its energy projects. These lower tax credits account for a portion of the decreased earnings contribution of NRG compared with results in 2001 and 2000, which included income related to recognition of tax credits.

NRG s earnings for 2001 increased primarily due to new acquisitions in Europe and North America, as well as a full year of operation in 2001 of acquisitions made in the fourth quarter of 2000. In addition, NRG s 2001 earnings reflected a reduction in the overall effective tax rate and mark-to-market gains related to SFAS No. 133 Accounting for Derivative Instruments and Hedging Activity. The overall reduction in tax rates in 2001 was primarily due to higher energy credits, the implementation of state tax planning strategies and a higher percentage of NRG s overall earnings derived from foreign projects in lower tax jurisdictions.

NRG Special Charges Impairments and Financial Restructuring As discussed previously, both the continuing and discontinued operations of NRG in 2002 included material losses for asset impairments and estimated disposal losses. Also, NRG recorded other special charges in 2002, mainly for incremental costs related to its financial restructuring and business realignment. See Notes 2 and 3 to the consolidated financial statements for further discussion of NRG s special charges and discontinued operations, respectively.

Other Nonregulated Subsidiaries and Holding Company Results

	Contribution to Xcel Energy s Earnings per Share		
	2002	**2001**	**2000**
Xcel International	$ (0.05)	$ (0.02)	$ 0.09
Eloigne Company	0.02	0.03	0.02
Seren Innovations	(0.07)	(0.08)	(0.07)
Planergy International	0.00	(0.04)	(0.08)
e prime	0.00	0.02	(0.02)
Financing costs and preferred dividends	(0.11)	(0.11)	(0.07)
Other nonregulated/ holding company results	(0.01)	0.02	0.01
Subtotal nonregulated/ holding co. excluding tax benefit	(0.22)	(0.18)	(0.12)
Tax benefit from investment in NRG (Note 11)	1.85		
Total nonregulated/ holding company earnings per share	$ 1.63	$ (0.18)	$ (0.12)

Xcel International Xcel International is currently comprised primarily of power generation projects in Argentina, and previously included an investment in Yorkshire Power.

In December 2002, a subsidiary of Xcel Argentina decided it would no longer fund one of its power projects in Argentina and defaulted on its loan agreements. The default is not material to us. However, this decision resulted in the shutdown of the Argentina plant facility, pending financing of a necessary maintenance outage. Updated cash flow projections for the plant were insufficient to provide recovery of Xcel International s investment. An impairment write-down of approximately $13 million, or 3 cents per share, was recorded in 2002.

In August 2002, we announced we had sold our 5.25-percent interest in Yorkshire Power Group Limited for $33 million to CE Electric UK. The sale of the 5.25-percent interest resulted in an after-tax loss of $8.3 million, or 2 cents per share, in 2002. The loss is included in write-downs and disposal losses from investments on the Consolidated Statements of Operations. We and American Electric Power Co. initially each held a 50-percent interest in Yorkshire, a UK retail electricity and natural gas supplier and electricity distributor, before selling 94.75 percent of Yorkshire to Innogy Holdings plc in April 2001. As a result of this sales agreement, we did not record any equity earnings from Yorkshire Power after January 2001. For more information, see Note 3 to the consolidated financial statements.

Eloigne Company Eloigne invests in affordable housing that qualifies for Internal Revenue Service tax credits. Eloigne s earnings contribution declined slightly in 2002 as tax credits on mature affordable housing projects began to decline. The actual decline in Eloigne s net income in 2002, compared with 2001, was only $716,000, with 2002 earnings representing 2.1 cents per share and 2001 earnings representing 2.5 cents per share.

Seren Innovations Seren operates a combination cable television, telephone and high-speed Internet access system in St. Cloud, Minn., and Contra Costa County, California. Operation of its broadband communications network has resulted in losses. Seren projects improvement in its operating results with positive cash flow anticipated in 2005, upon completion of its build-out phase, and a positive earnings contribution anticipated in 2008.

Planergy International Planergy, a wholly owned subsidiary of us, provides energy management services. Planergy s results for 2002 improved, largely due to gains from the sale of a portfolio of energy management contracts, which increased earnings by nearly 2 cents per share.

Planergy s results for 2000 were reduced by special charges of 4 cents per share for the write-offs of goodwill and project development costs.

e prime e prime s results for the year ended December 31, 2001, reflect the favorable structure of its contractual portfolio, including natural gas storage and transportation positions, structured products and proprietary trading in natural gas markets. e prime s earnings were lower in 2002, and higher in 2001, due to varying natural gas commodity trading margins, as discussed previously.

e prime s results for 2000 were reduced by special charges of 2 cents per share for contractual obligations and other costs associated with post-merger changes in the strategic operations and related revaluations of e prime s energy marketing business.

Financing Costs and Preferred Dividends Nonregulated results include interest expense and preferred dividends, which are incurred at the our and intermediate holding company levels, and are not directly assigned to individual subsidiaries.

In November 2002, we issued temporary financing, which included detachable options for the purchase of our notes, which are convertible to our common stock. This temporary financing was replaced with longer-term holding company financing in late November 2002. Costs incurred to redeem the temporary financing included a redemption premium of $7.4 million, $5.2 million of debt discount associated with the detachable option and other issuance costs, which increased financing costs and reduced 2002 earnings by 2 cents per share.

Other Certain costs related to NRG s restructuring are being incurred at the holding company level. Approximately $5 million of such costs were incurred in 2002, which reduced earnings by approximately 1 cent per share.

Other nonregulated results for 2000, which include the activity of several nonregulated subsidiaries, were reduced by merger-related special charges of 2 cents per share. These special charges include $10 million in asset write-downs and losses resulting from various other nonregulated business ventures that are no longer being pursued after the Xcel Energy merger.

Factors Affecting Results of Operations

Our utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions. In addition, our nonregulated businesses have adversely affected our earnings in 2002. The historical and future trends of our operating results have been, and are expected to be, affected by the following factors:

Impact of NRG Financial Difficulties NRG is experiencing severe financial difficulties, resulting primarily from declining credit ratings and lower prices for power. These financial difficulties have caused NRG to miss several scheduled payments of interest and principal on its bonds and incur approximately $3.1 billion in asset impairment charges. In addition, as a result of being downgraded, NRG was required to post cash collateral ranging from $1.1 billion to $1.3 billion. NRG has been unable to post this cash collateral and, as a result, is in default on various obligations. Furthermore, in November 2002, lenders to NRG accelerated approximately $1.1 billion of NRG s debt, rendering the debt immediately due and payable. In February 2003, lenders to NRG accelerated an additional $1 billion of debt. NRG does not contemplate making any principal or interest payments on its corporate-level debt pending the restructuring of its obligations and is in default under various debt instruments. As a consequence of the defaults, the lenders are able to seek to enforce their remedies, if they so choose, and that would likely lead to a bankruptcy filing by NRG. On May 14, 2003, NRG filed a voluntary petition for bankruptcy under Chapter 11 of the U.S. Bankruptcy Code.

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plan. See further discussion of potential NRG bankruptcy and financial restructuring under Liquidity and Capital Resources and in Notes 4 and 18 to the consolidated financial statements.

Subsequent to its credit downgrade in July 2002, NRG experienced losses as follows in 2002:

	Third Quarter	Fourth Quarter
	(Millions of dollars)	
Net losses from NRG:		
Special Charges asset impairments	$ (2,466)	$ (79)
Special Charges financial restructuring and other costs	(34)	(21)
Write-downs and losses on equity method investments	(118)	(74)
Other income (loss) from continuing operations, including income tax effects	140	(176)
NRG loss from continuing operations	(2,478)	(350)
Discontinued operations asset impairments	(600)	
Discontinued operations other	23	9
Net NRG loss for period	$ (3,055)	$ (341)

These NRG losses have reduced our retained earnings to a deficit as of December 31, 2002. NRG is expected to continue to experience material losses into 2003, pending a successful financial restructuring and increased power prices. NRG s losses in 2003 may include further asset impairments, losses from asset disposals, and financial restructuring costs as NRG continues its financial restructuring and decisions are made to realign NRG s business operations and divest operating assets. In addition, the impact of any settlement with NRG s creditors regarding the financial restructuring of NRG may also impact our operating results and retained earnings, by material amounts which will not be determinable until settlement terms are reached. See Note 4 to the financial statements for a discussion of a preliminary settlement with NRG s creditors. As discussed later, we are unable without SEC approval under PUHCA to declare dividends on our common stock until consolidated retained earnings are positive, and continuing NRG financial impacts may continue to limit our ability to declare and pay dividends.

There may be additional impacts on our financial condition and results of operations as a result of NRG s bankruptcy filing. See the Xcel Energy Impacts under the Other Liquidity and Capital Resource Considerations section later in Management s Discussion and Analysis, and Note 4 to the financial statements, for further discussion of the possible effects of the NRG bankruptcy filing on us.

General Economic Conditions The slower United States economy, and the global economy to a lesser extent, may have a significant impact on our operating results. Current economic conditions have resulted in a decline in the forward price curve for energy and decreased commodity-trading margins. In addition, certain operating costs, such as insurance and security, have increased due to the economy, terrorist activity and the threat of war. Management cannot predict the impact of a continued economic slowdown, fluctuating energy prices, war or the threat of war.

However, we could experience a material adverse impact to our results of operations, future growth or ability to raise capital from a weakened economy or war.

Sales Growth In addition to weather impacts, customer sales levels in our regulated utility businesses can vary with economic conditions, customer usage patterns and other factors. Weather-normalized sales growth for retail electric utility customers was estimated to be 1.8 percent in 2002 compared with 2001, and 1.0 percent in 2001 compared with 2000. Weather-normalized sales growth for firm gas utility customers was estimated to be approximately the same in 2002 compared with 2001, and 2.6 percent in 2001 compared with 2000. We are projecting that 2003 weather-normalized sales growth in 2003 compared with 2002 will be 1.5 to 2.0 percent for retail electric utility customers and 2.5 to 3.0 percent for firm gas utility customers.

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Utility Industry Changes The structure of the electric and natural gas utility industry has been subject to change. Merger and acquisition activity over the past few years has been significant as utilities combine to capture economies of scale or establish a strategic niche in preparing for the future. Some regulated utilities are divesting generation assets. All utilities are required to provide nondiscriminatory access to the use of their transmission systems.

In December 2001, the FERC approved Midwest Independent Transmission System Operator, Inc. (MISO) as the Midwest independent system operator responsible for operating the wholesale electric transmission system. Accordingly, in compliance with the FERC s Order No. 2000, we turned over operational control of our transmission system to the MISO in January 2002.

Some states had begun to allow retail customers to choose their electricity supplier, and many other states were considering retail access proposals. However, the experience of the state of California in instituting competition, as well as the bankruptcy filing of Enron, have caused indefinite delays in most industry restructuring.

We cannot predict the outcome of restructuring proceedings in the electric utility jurisdictions we serve at this time. The resolution of these matters may have a significant impact on our financial position, results of operations and cash flows.

California Power Market NRG operates in the wholesale power market in California. See Note 18 to the consolidated financial statements for a description of lawsuits against NRG and other power producers and marketers involving the California electricity markets. We and NRG have fully reserved for our uncollected receivables related to the California power market.

Critical Accounting Policies Preparation of consolidated financial statements and related disclosures in compliance with generally accepted accounting principles (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 consolidated financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the consolidated 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, and that require management s most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Accounting Policy	Judgments/ Uncertainties Affecting Application	See Additional Discussion At
Asset Valuation NRG Seren Argentina	Regional economic conditions affecting asset operation, market prices and related cash flows Foreign currency valuation changes Regulatory and political environments and requirements Levels of future market penetration and customer growth	Management s Discussion and Analysis: Results of Operations Management s Discussion and Analysis: Factors Affecting Results of Operations Impacts of NRG Financial Difficulties Impact of Other Nonregulated Investments Notes to Consolidated Financial Statements Notes 2, 3 and 18

Accounting Policy	Judgments/ Uncertainties Affecting Application	See Additional Discussion At
NRG Financial Restructuring	Terms negotiated to settle NRG s obligations to its creditors Ownership interest in and control of NRG, and related ability to continue consolidating NRG as a subsidiary Impacts of court decisions in future bankruptcy proceedings, including any obligations of Xcel Energy	Management s Discussion and Analysis: Liquidity and Capital Resources NRG Financial Issues Xcel Energy Impacts Notes to Consolidated Financial Statements Notes 4 and 18
Income Tax Accruals	Application of tax statutes and regulations to transactions Anticipated future decisions of tax authorities Ability of tax authority decisions/ positions to withstand legal challenges and appeals Ability to realize tax benefits through carrybacks to prior periods or carryovers to future periods	Management s Discussion and Analysis: Factors Affecting Results of Operations Tax Matters Notes to Consolidated Financial Statements Notes 1, 11 and 18
Benefit Plan Accounting	Future rate of return on pension and other plan assets, including impacts of any changes to investment portfolio composition Interest rates used in valuing benefit obligation Actuarial period selected to recognize deferred investment gains and losses	Management s Discussion and Analysis: Factors Affecting Results of Operations Pension Plan Costs and Assumptions Notes to Consolidated Financial Statements Notes 1 and 13
Regulatory Mechanisms and Cost Recovery	External regulator decisions, requirements and regulatory environment Anticipated future regulatory decisions and their impact Impact of deregulation and competition on ratemaking process and ability to recover costs	Management s Discussion and Analysis: Factors Affecting Results of Operations Utility Industry Changes and Restructuring Notes to Consolidated Financial Statements Notes 1, 18 and 20

Accounting Policy	Judgments/ Uncertainties Affecting Application	See Additional Discussion At
Environmental Issues	Approved methods for cleanup Responsible party determination Governmental regulations and standards Results of ongoing research and development regarding environmental impacts	Management s Discussion and Analysis: Factors Affecting Results of Operations Environmental Matters Notes to Consolidated Financial Statements Notes 1 and 18
Uncollectible Receivables	Economic conditions affecting customers, suppliers and market prices Regulatory environment and impact of cost recovery constraints on customer financial condition Outcome of litigation and regulatory proceedings	Management s Discussion and Analysis: Factors Affecting Results of Operations California Power Market Notes to Consolidated Financial Statements Notes 1 and 18
Nuclear Plant Decommissioning and Cost Recovery	Costs of future decommissioning Availability of facilities for waste disposal Approved methods for waste disposal Useful lives of nuclear power plants Future recovery of plant investment and decommissioning costs	Notes to Consolidated Financial Statements Notes 1, 18 and 19

Pension Plan Costs and Assumptions Our pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension investment assets will earn in the future, and the interest rate used to discount future pension benefit payments to a present value obligation for financial reporting. In addition, the actuarial calculation uses an asset smoothing methodology to reduce volatility of varying investment performance over time. Note 13 to the consolidated financial statements discusses the rate of return and discount rate used in the calculation of pension costs and obligations in the accompanying financial statements.

Pension costs have been increasing in recent years, and are expected to increase further over the next several years, due to lower than expected investment returns experienced and decreases in interest rates used to discount benefit obligations. Investment returns in 2000 and 2001 were below the assumed level of 9.5 percent, and interest rates have declined from the 7.5 percent to 8 percent levels used in 1999 and 2000 cost determinations to 7.25 percent used in 2002. We continually review our pension assumptions, and in 2003 expect to change the investment return assumption to 9.25 percent and the discount rate assumption to 6.75 percent.

We base our investment return assumption on expected long-term performance for each of the investment types included in our pension asset portfolio. These include equity investments, such as corporate common stocks; fixed-income investments, such as corporate bonds and U.S. Treasury securities and non-traditional investments, such as timber or real estate partnerships. In reaching a return assumption, we consider the actual historical returns achieved by our asset portfolio over the past 20-year or longer period, as well as the long-term return levels projected and recommended by investment experts in the marketplace. The historical weighted average annual return for the past 20 years for our portfolio of pension investments is 12.6 percent, in excess of the current assumption level. The pension cost determinations assume the continued current mix of investment types over the long-term. The target and 2002 mix of assets among these portfolio components is discussed in Note 13 to the consolidated financial statements. Our portfolio is heavily weighted toward equity securities, and includes non-traditional investments that can provide a higher than average return. However, as is the experience in recent years, a higher weighting in equity investments can increase the volatility in the return levels actually achieved by pension assets in any year. We lowered the 2003 pension investment return assumptions to reflect changing expectations of investment experts in the marketplace.

The investment gains or losses resulting from the difference between the expected pension returns assumed on smoothed or market-related asset levels and actual returns earned is deferred in the year the difference arises and recognized over the subsequent five-year period. This gain or loss recognition occurs by using a five-year moving-average value of pension assets to measure expected asset returns in the cost determination process, and by amortizing deferred investment gains or losses over the subsequent five-year period. Based on the use of average market-related asset values, and considering the expected recognition of past investment gains and losses over the next five years, achieving the assumed rate of asset return of 9.25 percent in each future year and holding other assumptions constant, we currently project that the pension costs recognized by us for financial reporting purposes will increase from a credit, or negative expense, of $84 million in 2002 to a credit of $45 million in 2003, a credit of $20 million in 2004, and a net expense of $20 million in 2005. Pension costs are currently a credit due to the recognized investment asset returns exceeding the other pension cost components, such as benefits earned for current service and interest costs for the effects of the passage of time on discounted obligations.

We base our discount rate assumption on benchmark interest rates quoted by an established credit rating agency, Moody s Investors Service (Moody s), and have consistently benchmarked the interest rate used to derive the discount rate to the movements in long-term corporate bond indices for bonds rated AAA through BAA by Moody s, which have a period to maturity comparable to our projected benefit obligations. At December 31, 2002, the annualized Moody s Aa index rate, roughly in the middle of the AAA and BAA range, was 6.63 percent, which when rounded to the nearest quarter-percent rate, as is our policy, resulted in our 6.75 percent pension discount rate at year-end 2002. This rate was used to value the actuarial benefit obligations at that date, and will be used in 2003 pension cost determinations.

If we were to use alternative assumptions for pension cost determinations, a 1 percent change would result in the following impacts on the estimated pension costs recognized by us for financial reporting purposes:

a 1 percent higher rate of return, 10.25 percent, would decrease 2003 pension costs by $22 million

a 1 percent lower rate of return, 8.25 percent, would increase 2003 pension costs by $22 million

a 1 percent higher discount rate, 7.75 percent, would decrease 2003 pension costs by $8 million

a 1 percent lower discount rate, 5.75 percent, would increase 2003 pension costs by $12 million

Alternative assumptions would also change the expected future cash funding requirements for the pension plans. Cash funding requirements can be impacted by changes to actuarial assumptions, actual asset levels and other pertinent calculations prescribed by the funding requirements of income tax and other pension-related regulations. These regulations did not require cash funding in recent years for our pension plans, and do not require funding in 2003. Assuming future asset return levels equal the actuarial assumption of 9.25 percent for the years 2003-2005, then under current funding regulations we project that no cash funding would be required for 2004, $35 million in funding would be required for 2005, and $54 million in funding would be required for 2006. Actual performance can affect these funding requirements significantly. If the actual return level is 0 percent in 2003 and 2004, which assumes a continued downturn in the financial markets, and 9.25 percent in 2005, then the 2004 cash-funding requirement would still be zero. However, the

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2005 funding requirement would increase to $60 million, and 2006 funding required would be $70 million. Current funding regulations are under legislative review in 2003, and if not retained in their current form, could change these funding requirements materially.

Regulation We are a registered holding company under the PUHCA. As a result, we, our utility subsidiaries and certain of our nonutility subsidiaries are subject to extensive regulation by the SEC under the PUHCA with respect to issuances and sales of securities, acquisitions and sales of certain utility properties and intra-system sales of certain goods and services. In addition, the PUHCA generally limits the ability of registered holding companies to acquire additional public utility systems and to acquire and retain businesses unrelated to the utility operations of the holding company. See further discussion of financing restrictions under Liquidity and Capital Resources.

The electric and natural gas rates charged to customers of our utility subsidiaries are approved by the FERC and the regulatory commissions in the states in which they operate. The rates are generally designed to recover plant investment, operating costs and an allowed return on investment. We request changes in rates for utility services through filings with the governing commissions. Because comprehensive rate changes are requested infrequently in some states, changes in operating costs can affect our financial results. In addition to changes in operating costs, other factors affecting rate filings are sales growth, conservation and demand-side management efforts and the cost of capital.

Most of the retail rate schedules for our utility subsidiaries provide for periodic adjustments to billings and revenues to allow for recovery of changes in the cost of fuel for electric generation, purchased energy, purchased natural gas and, in Minnesota and Colorado, conservation and energy management program costs. In Minnesota and Colorado, changes in electric capacity costs are not recovered through these rate adjustment mechanisms. For Wisconsin electric operations, where automatic cost-of-energy adjustment clauses are not allowed, the biennial retail rate review process and an interim fuel-cost hearing process provide the opportunity for rate recovery of changes in electric fuel and purchased energy costs in lieu of a cost-of-energy adjustment clause. In Colorado, PSCo has an ICA mechanism that allows for an equal sharing among customers and shareholders of certain fuel and energy costs and certain gains and losses on trading margins.

Regulated public utilities are allowed to record as regulatory assets certain costs that are expected to be recovered from customers in future periods and to record as regulatory liabilities certain income items that are expected to be refunded to customers in future periods. In contrast, nonregulated enterprises would expense these costs and recognize the income in the current period. If restructuring or other changes in the regulatory environment occur, we may no longer be eligible to apply this accounting treatment, and may be required to eliminate such regulatory assets and liabilities from our balance sheet. Such changes could have a material adverse effect on our results of operations in the period the write-off is recorded.

At December 31, 2002, we reported on our balance sheet regulatory assets of approximately $404 million and regulatory liabilities of approximately $297 million that would be recognized in the statement of operations in the absence of regulation. In addition to a potential write-off of regulatory assets and liabilities, restructuring and competition may require recognition of certain stranded costs not recoverable under market pricing. We currently do not expect to write off any stranded costs unless market price levels change or cost levels increase above market price levels. See Notes 1 and 20 to the consolidated financial statements for further discussion of regulatory deferrals.

Merger Rate Agreements As part of the merger approval process, we agreed to reduce our rates in several jurisdictions. The discussion below summarizes the rate reductions in Colorado, Minnesota, Texas and New Mexico.

As part of the merger approval process in Colorado, PSCo agreed to:

- reduce its retail electric rates by an annual rate of $11 million for the period of August 2000 through July 2002;

- file a combined electric and natural gas rate case in 2002, with new rates effective January 2003;

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- cap merger costs associated with the electric operations at $30 million and amortize the merger costs for ratemaking purposes through 2002;
- extend its ICA mechanism through December 31, 2002 with an increase in the ICA base rate from $12.78 per megawatt hour to a rate based on 2001 actual costs;
- continue the electric performance-based regulatory plan (PBRP) and the electric quality service plan (QSP) currently in effect through 2006, with modifications to cap electric earnings at a 10.5-percent return on equity for 2002, to reflect no earnings sharing in 2003 since new base rates would have recently been established, and to increase potential bill credits if quality standards are not met; and
- develop a QSP for the natural gas operations to be effective for calendar years 2002 through 2007.

As part of the merger approval process in Minnesota, NSP-Minnesota agreed to:

- reduce its Minnesota electric rates by $10 million annually through 2005;
- not increase its electric rates through 2005, except under limited circumstances;
- not seek recovery of certain merger costs from customers; and
- meet various quality standards.

As part of the merger approval process in Texas, SPS agreed to:

- guarantee annual merger savings credits of approximately $4.8 million and amortize merger costs through 2005;
- retain the current fuel-recovery mechanism to pass along fuel cost savings to retail customers; and
- comply with various service quality and reliability standards, covering service installations and upgrades, light replacements, customer service call centers and electric service reliability.

As part of the merger approval process in New Mexico, SPS agreed to:

- guarantee annual merger savings credits of approximately $780,000 and amortize merger costs through December 2004;
- share net nonfuel operating and maintenance savings equally among retail customers and shareholders;
- retain the current fuel recovery mechanism to pass along fuel cost savings to retail customers; and
- not pass along any negative rate impacts of the merger.

PSCo Performance-Based Regulatory Plan The Colorado Public Utilities Commission (CPUC) established an electric PBRP under which PSCo operates. The major components of this regulatory plan include:

- an annual electric earnings test with the sharing between customers and shareholders of earnings in excess of the following limits:
  - all earnings above 10.50-percent return on equity for 2002
  - no earnings sharing for 2003
  - an annual electric earnings test with the sharing of earnings in excess of the return on equity set in the 2002 rate case for 2004 through 2006
- an electric QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to electric reliability and customer service through 2006;

a gas QSP that provides for bill credits to customers if PSCo does not achieve certain performance targets relating to gas leak repair time and customer service through 2007; and

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an ICA that provides for the sharing of energy costs and savings relative to an annual baseline cost per kilowatt-hour generated or purchased. According to the terms of the merger rate agreement in Colorado, the annual baseline cost will be reset in 2002, based on a 2001 test year. Pursuant to a stipulation approved by the CPUC, the ICA remains in effect through March 31, 2005, to recover allowed ICA costs from 2001 and 2002. The recovery of fuel and purchased energy expense beginning Jan. 1, 2003, will be decided in the PSCo 2002 general rate case. In the interim period until the conclusion of the general rate case, 2003 fuel and purchased energy expense is recovered through the interim adjustment clause (IAC).

PSCo regularly monitors and records as necessary an estimated customer refund obligation under the earnings test. In April of each year following the measurement period, PSCo files its proposed rate adjustment under the PBRP. The CPUC conducts proceedings to review and approve these rate adjustments annually. During 2002, PSCo filed that its electric department earnings were below the 11-percent return on equity threshold. PSCo has estimated no customer refund obligation for 2002 under the earnings test, the electric QSP or the gas QSP. PSCo has estimated no customer refund obligation for 2001 under the earnings test. The 2001 earnings test filing has not been approved. A hearing is scheduled for May 2003.

PSCo 2002 General Rate Case In May 2002, PSCo filed a combined general retail electric, natural gas and thermal energy base rate case with the CPUC to address increased costs for providing services to Colorado customers. This filing was required as part of the Xcel Energy merger stipulation and agreement previously approved by the CPUC. Among other things, the case includes establishing an electric energy recovery mechanism, elimination of the qualifying facilities capacity cost adjustment (QFCCA), new depreciation rates and recovery of additional plant investment. PSCo requested an increase to its authorized rate of return on equity to 12 percent for electricity and 12.25 percent for natural gas. In early 2003, PSCo filed its rebuttal testimony in this rate case. At this point in the rate proceeding, PSCo is now requesting an overall annual increase to electric revenue of approximately $233 million. This is based on a $186-million increase for fuel and purchased energy expense and a $47-million electric base rate increase. PSCo is requesting an annual base rate decrease in natural gas revenue of approximately $21 million. The rebuttal case incorporates several adjustments to the original filing, including lower depreciation expense, higher fuel and energy expense and various corrections to the original filing.

Intervenors, including the CPUC staff and the Colorado Office of Consumer Council (OCC) have filed testimony requesting both electric and natural gas base rate decreases and increases in fuel and energy revenues that are less than the amounts requested by PSCo. On Feb. 19, 2003, the CPUC postponed the scheduled hearings for 30 days to allow parties to pursue a comprehensive settlement of all issues in this proceeding. PSCo filed a joint motion on March 14, 2003 extending the filing date of the settlement agreement until April 1, 2003. New rates are expected to be effective during the second quarter of 2003. A final decision on the recovery of fuel and energy costs will be applied retroactive to January 1, 2003. Until such time, PSCo is billing customers under the IAC, assuming 100-percent pass-through cost recovery.

Tax Matters As discussed further in Note 18, the Internal Revenue Service (IRS) issued a Notice of Proposed Adjustment proposing to disallow interest expense deductions taken in tax years 1993 through 1997 related to corporate-owned life insurance (COLI) policy loans of PSR Investments, Inc. (PSRI), a wholly owned subsidiary of PSCo. Late in 2001, we received a technical advice memorandum from the IRS national office, which communicated a position adverse to PSRI. Consequently, the IRS examination division has disallowed the interest expense deductions for the tax years 1993 through 1997. After consultation with tax counsel, it is our position that the tax law does not support the IRS determination. Although the ultimate resolution of this matter is uncertain, management continues to believe it will successfully resolve this matter without a material adverse impact on our results of operations. However, defense of PSCo s position may require significant cash outlays on a temporary basis, if refund litigation is pursued in United States District Court.

The total disallowance of interest expense deductions for the period of 1993 through 1997 is approximately $175 million. Additional interest expense deductions for the period 1998 through 2002 are estimated to total approximately $317 million. Should the IRS ultimately prevail on this issue, tax and interest payable through December 31, 2002, would reduce earnings by an estimated $214 million, after tax. If COLI interest expense deductions were no longer available, annual earnings for 2003 would be reduced by an estimated $33 million, after tax, prospectively, which represents 8 cents per share using 2003 share levels.

Environmental Matters Our environmental costs include payments for nuclear plant decommissioning, storage and ultimate disposal of spent nuclear fuel, disposal of hazardous materials and wastes, remediation of contaminated sites and monitoring of discharges to the environment. A trend of greater environmental awareness and increasingly stringent regulation has caused, and may continue to cause, slightly higher operating expenses and capital expenditures for environmental compliance.

In addition to nuclear decommissioning and spent nuclear fuel disposal expenses, costs charged to our operating expenses for environmental monitoring and disposal of hazardous materials and wastes were approximately:

$149 million in 2002

$146 million in 2001

$144 million in 2000

We expect to expense an average of approximately $177 million per year from 2003 through 2007 for similar costs. However, the precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are currently unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates is not certain.

Capital expenditures on environmental improvements at our regulated facilities, which include the cost of constructing spent nuclear fuel storage casks, were approximately:

$108 million in 2002

$136 million in 2001

$57 million in 2000

Our regulated utilities expect to incur approximately $44 million in capital expenditures for compliance with environmental regulations in 2003 and approximately $948 million during the period from 2003 through 2007. Most of the costs are related to modifications to reduce the emissions of NSP-Minnesota s generating plants located in the Minneapolis-St. Paul metropolitan area. See Notes 18 and 19 to the Consolidated Financial Statements for further discussion of our environmental contingencies.

NRG expects to incur as much as $145 million in capital expenditures over the next five years to address conditions that existed when it acquired facilities, and to comply with new regulations.

Impact of Other Nonregulated Investments Our investments in nonregulated operations have had a significant impact on our results of operations. We do not expect to continue investing in nonregulated domestic and international power production projects through NRG, but may continue investing in natural gas marketing and trading through e prime and construction projects through Utility Engineering. Our nonregulated businesses may carry a higher level of risk than its traditional utility businesses due to a number of factors, including:

competition, operating risks, dependence on certain suppliers and customers, and domestic and foreign environmental and energy regulations;

partnership and government actions and foreign government, political, economic and currency risks; and

development risks, including uncertainties prior to final legal closing.

Our earnings from nonregulated subsidiaries, other than NRG, also include investments in international projects, primarily in Argentina, through Xcel Energy International, and broadband communications systems through Seren. Management currently intends to hold and operate these investments, but is evaluating their

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strategic fit in our business portfolio. As of December 31, 2002, our investment in Seren was approximately $255 million. Seren had capitalized $290 million for plant in service and had incurred another $21 million for construction work in progress for these systems at December 31, 2002. Xcel Energy International s gross investment in Argentina, excluding unrealized currency translation losses of approximately $62 million, was $112 million at December 31, 2002. Given the political and economic climate in Argentina, we continue to closely monitor the investment for asset impairment. Currently, management believes that no impairment exists in addition to what was recognized in 2002, as previously discussed.

Some of our nonregulated subsidiaries have project investments, as listed in Note 14 to the consolidated financial statements, consisting of minority interests, which may limit the financial risk, but also limit the ability to control the development or operation of the projects. In addition, significant expenses may be incurred for projects pursued by our subsidiaries that do not materialize. The aggregate effect of these factors creates the potential for volatility in the nonregulated component of our earnings. Accordingly, the historical operating results of our nonregulated businesses may not necessarily be indicative of future operating results.

Inflation Inflation at its current level is not expected to materially affect our prices or returns to shareholders. Since late 2001, the Argentine peso has been significantly devalued due to the inflationary Argentine economy. We will continue to experience related currency translation adjustments through Xcel Energy International.

Pending Accounting Changes

SFAS No. 143 In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143 Accounting for Asset Retirement Obligations. This statement will require us to record our future nuclear plant decommissioning obligations as a liability at fair value with a corresponding increase to the carrying value of the related long-lived asset. The liability will be increased to its present value each period, and the capitalized cost will be depreciated over the useful life of the related long-lived asset. If at the end of the asset s life the recorded liability differs from the actual obligations paid, SFAS No. 143 requires that a gain or loss be recognized at that time. However, rate-regulated entities may recognize a regulatory asset or liability instead, if the criteria for SFAS No. 71 Accounting for the Effects of Certain Types of Regulation are met.

We currently follow industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in accumulated depreciation. At December 31, 2002, we recorded and recovered in rates $662 million of decommissioning obligations and had estimated discounted decommissioning cost obligations of $1.1 billion based on approvals from the various state commissions, which used a single scenario. However, with the adoption of SFAS No. 143, a probabilistic view of several decommissioning scenarios were used, resulting in an estimated discounted decommissioning cost obligation of $1.6 billion.

We adopted SFAS No. 143 as required on January 1, 2003. In current estimates for adoption, the initial value of the liability, including cumulative accretion expense through that date, would be approximately $869 million. This liability would be established by reclassifying accumulated depreciation of $573 million and by recording two long-term assets totaling $296 million. A gross capitalized asset of $130 million would be recorded and would be offset by accumulated depreciation of $89 million. In addition, a regulatory asset of approximately $166 million would be recorded for the cumulative effect adjustment related to unrecognized depreciation and accretion under the new standard. Management expects that the entire transition amount would be recoverable in rates over time and, therefore, would support this regulatory asset upon adoption of SFAS No. 143.

We have completed a detailed assessment of the specific applicability and implications of SFAS No. 143 for obligations other than nuclear decommissioning. Other assets that may have potential asset retirement obligations include ash ponds, any generating plant with a Part 30 license and electric and natural gas transmission and distribution assets on property under easement agreements. Easements are generally perpetual and require retirement action only upon abandonment or cessation of use of the property for the specified purpose. The liability is not estimable because we intend to utilize these properties indefinitely. The asset retirement obligations for the ash ponds and generating plants cannot be reasonably estimated due to an indeterminate life for the assets associated with the ponds and uncertain retirement dates for the generating plants. Since the time period for retirement is unknown, no liability would be recorded. When a retirement date is certain, a liability will be recorded.

SFAS No. 143 will also affect our accrued plant removal costs for other generation, transmission and distribution facilities for its utility subsidiaries. Although SFAS No. 143 does not recognize the future accrual of removal costs as a GAAP liability, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates over time, we have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Accordingly, we have an estimated regulatory liability accrued in accumulated depreciation for future removal costs of the following amounts at December 31, 2002:

	(Millions of Dollars)
NSP-Minnesota	$ 304
NSP-Wisconsin	70
PSCo.	329
SPS	97
Cheyenne	9
Total Xcel Energy	$ 809

SFAS No. 145 In April 2002, the FASB issued SFAS No. 145 Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections, which supercedes previous guidance for the reporting of gains and losses from extinguishment of debt and accounting for leases, among other things. Adoption of SFAS No. 145 may affect the recognition of impacts from NRG s financial improvement and restructuring plan, if existing debt agreements are ultimately renegotiated while NRG is still a consolidated subsidiary of us. Other impacts of SFAS No. 145 are not expected to be material to us.

SFAS No. 146 In June 2002, the FASB issued SFAS No. 146 Accounting for Exit or Disposal Activities, addressing recognition, measurement and reporting of costs associated with exit and disposal activities, including restructuring activities. SFAS No. 146 may have an impact on the timing of recognition of costs related to the implementation of the NRG financial improvement and restructuring plan; however, such impact is not expected to be material.

SFAS No. 148 In December 2002, the FASB issued SFAS No. 148 Accounting for Stock-Based Compensation Transition and Disclosure, amending FASB Statement No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation, and requiring disclosure in both annual and interim consolidated financial statements about the method used and the effect of the method used on results. We continue to account for our stock-based compensation plans under Accounting Principles Board (APB) Opinion No. 25 Accounting for Stock Issued to Employees and does not plan at this time to adopt the voluntary provisions of SFAS No. 148.

Emerging Issues Tax Force (EITF) Nos. 02-03 and 98-10 See Note 1 to the consolidated financial statements regarding reporting changes made in 2002 for the presentation of trading results and pending changes related to accounting for the impacts of trading operations in 2003.

FASB Interpretation No. 45 (FIN No. 45) In November 2002, the FASB issued FIN No. 45 Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others . The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor s fiscal year-end. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. The interpretation addresses the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under guarantees. The interpretation also clarifies the requirements related to the recognition of a liability by a guarantor at the inception of the guarantee for the obligations the guarantor has undertaken in issuing the guarantee.

FASB Interpretation No. 46 (FIN No. 46) In January 2003, the FASB issued FIN No. 46 requiring an enterprise s consolidated financial statements to include subsidiaries in which the enterprise has a controlling financial interest. Historically, that requirement has been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise s consolidated financial statements do not include the consolidations of variable interest entities with which it has similar relationships but no majority voting interest. Under FIN No. 46, the voting interest approach is not effective in identifying controlling financial interest. As a result, we expect that we will have to consolidate our affordable housing investments made through Eloigne, which currently are accounted for under the equity method.

As of December 31, 2002, the assets of these entities were approximately $155 million and long-term liabilities were approximately $87 million. Currently, investments of $62 million are reflected as a component of investments in unconsolidated affiliates in the December 31, 2002, Consolidated Balance Sheet. FIN No. 46 requires that for entities to be consolidated, the entities assets be initially recorded at their carrying amounts at the date the new requirement first applies. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value as of the first date the new requirements apply. Any difference between the net consolidated amounts added to our balance sheet and the amount of any previously recognized interest in the newly consolidated entity should be recognized in earnings as the cumulative effect adjustment of an accounting change. Had we adopted FIN No. 46 requirements early in 2002, there would have been no material impact to net income. We plan to adopt FIN No. 46 when required in the third quarter of 2003.

Derivatives, Risk Management and Market Risk

Business and Operational Risk We and our subsidiaries are exposed to commodity price risk in our generation, retail distribution and energy trading operations. In certain jurisdictions, purchased energy expenses and natural gas costs are recovered on a dollar-for-dollar basis. However, in other jurisdictions, we and our subsidiaries have limited exposure to market price risk for the purchase and sale of electric energy and natural gas. In such jurisdictions, electric energy and natural gas expenses are recovered based on fixed price limits or under established sharing mechanisms.

We manage commodity price risk by entering into purchase and sales commitments for electric power and natural gas, long-term contracts for coal supplies and fuel oil, and derivative instruments. Our risk management policy allows us to manage the market price risk within each rate regulated operation to the extent such exposure exists. Management is limited under the policy to enter into only transactions that manage market price risk where the rate regulation jurisdiction does not already provide for dollar-for-dollar recovery. One exception to this policy exists in which we use various physical contracts and derivative instruments to reduce the cost of natural gas and electricity we provide to our retail customers even though the regulatory jurisdiction may provide dollar-for-dollar recovery of actual costs. In these instances, the use of derivative instruments and physical contracts is done consistently with the local jurisdictional cost recovery mechanism.

We and our subsidiaries are exposed to market price risk for the sale of electric energy and the purchase of fuel resources, including coal, natural gas and fuel oil used to generate the electric energy within its nonregulated operations. We manage this market price risk by entering into firm power sales agreements for approximately 55 to 75 percent of our electric capacity and energy from each generation facility, using contracts with terms ranging from one to 25 years. In addition, we manage the market price risk covering the fuel resource requirements to provide the electric energy by entering into purchase commitments and derivative instruments for coal, natural gas and fuel oil as needed to meet fixed-priced electric energy requirements. Our risk management policy allows the company to manage market price risks, and provides guidelines for the level of price risk exposure that is acceptable within our operations.

We are exposed to market price risk for the sale of electric energy and the purchase of fuel resources used to generate the electric energy from the company s equity method investments that own electric operations. We manage this market price risk through involvement with the management committee or board of directors of each of these ventures. Our risk management policy does not cover the activities conducted by the ventures. However, other policies are adopted by the ventures as necessary and mandated by the equity owners.

Interest Rate Risk We and our subsidiaries are exposed to fluctuations in interest rates when entering into variable rate debt obligations to fund certain power projects being developed or purchased. Exposure to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put- or call-options. These contracts reduce exposure to the volatility of cash flows for interest and result in primarily fixed rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Our risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

At December 31, 2002 and 2001, a 100 basis point change in the benchmark rate on our variable debt would impact net income by approximately $52.2 million and $29.9 million, respectively. See Note 16 to the consolidated financial statements for a discussion of our and our subsidiaries interest rate swaps.

Currency Exchange Risk We and our subsidiaries have certain investments in foreign countries, creating exposure to foreign currency exchange risk. The foreign currency exchange risk includes the risk relative to the recovery of our net investment in a project, as well as the risk relative to the earnings and cash flows generated from such operations. We manage exposure to changes in foreign currency by entering into derivative instruments as determined by management. Our risk management policy provides for this risk management activity.

As discussed in Note 21 to the consolidated financial statements, we have substantial investments in foreign projects, through NRG and other subsidiaries, creating exposure to currency translation risk. Cumulative translation adjustments, included in the consolidated statement of stockholders Equity as Accumulated Other Comprehensive Income, experienced to date have been material and may continue to occur at levels significant to the company s financial position. As of December 31, 2002, NRG had two foreign currency exchange contracts with notional amounts of $3.0 million. If the contracts had been discontinued on December 31, 2002, NRG would have owed the counterparties approximately $0.3 million.

Trading Risk We and our subsidiaries conduct various trading operations and power marketing activities, including the purchase and sale of electric capacity and energy and natural gas. The trading operations are conducted both in the United States and Europe with primary focus on specific market regions where trading knowledge and experience have been obtained. Our risk management policy allows management to conduct the trading activity within approved guidelines and limitations as approved by the company s risk management committee, which is made up of management personnel not involved in the trading operations.

The fair value of our trading contracts as of December 31, 2002, is as follows:

	Total Fair Value (Millions of Dollars)
Fair value of trading contracts outstanding at Jan. 1, 2002	$ 90.1
Contracts realized or settled during 2002	(139.5)
Fair value of trading contract additions and changes during the year	87.8
Fair value of contracts outstanding at December 31, 2002*	$ 38.4

* Amounts do not include the impact of ratepayer sharing in Colorado.

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The future maturities of our trading contracts are as follows:

Source of Fair Value	Maturity Less than 1 Year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity Greater than 5 years	Total Fair Value
			(Millions of dollars)		
Prices actively quoted	$ 12.7	$ (7.1)	$	$ (1.9)	$ 3.7
Prices based on models and other valuation methods (including prices quoted from external sources)	61.7	52.6	(23.0)	(56.6)	34.7

Our trading operations and power marketing activities measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, using an industry standard methodology know as Value-at-Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time, with a given confidence interval under normal market conditions. We utilize the variance/ covariance approach in calculating VaR. The VaR model employs a 95-percent confidence interval level based on historical price movement, lognormal price distribution assumption and various holding periods varying from two to five days.

As of December 31, 2002, the calculated VaRs were:

Operations	Year Ended Dec. 31, 2002	During 2002 Average	High	Low
		(Millions of Dollars)		
Electric Commodity Trading	0.29	0.62	3.39	0.01
Natural Gas Commodity Trading	0.11	0.35	1.09	0.09
Natural Gas Retail Marketing	0.54	0.47	0.92	0.32
NRG Power Marketing(a)	118.60	76.20	124.40	42.00

(a) NRG VaR is an undiversified VaR.

As of December 31, 2001, the calculated VaRs were:

Operations	Year Ended Dec. 31, 2002	During 2002 Average	High	Low
		(Millions of Dollars)		
Electric Commodity Trading	0.52	1.71	7.37	0.16
Natural Gas Commodity Trading	0.16	0.15	0.52	0.01
Natural Gas Retail Marketing	0.69	0.39	0.94	0.13
NRG Power Marketing	71.70	78.80	126.60	58.60

In 2001, we changed our holding period for measuring VaR from electricity trading activity from 21 days to two to five days. Our revised holding periods are generally consistent with current industry standard practice.

Credit Risk In addition to the risks discussed previously, we and our subsidiaries are exposed to credit risk in our risk management activities. Credit risk relates to the risk of loss resulting from the non-performance by a counterparty of its contractual obligations. As we continue to expand our natural gas and power marketing and trading activities, exposure to credit risk and counterparty default may increase. We and our subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

We and our subsidiaries conduct standard credit reviews for all counterparties. We employ additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. The credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

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Liquidity and Capital Resources

Cash Flows

	2002	2001	2000
	(Millions of dollars)		
Net cash provided by operating activities	$ 1,715	$ 1,584	$ 1,408

Cash provided by operating activities increased during 2002, compared with 2001, primarily due to NRG s efforts to conserve cash by deferring the payment of interest payments and managing its cash flows more closely. NRG s accrued interest costs rose by nearly $200 million in 2002 compared to year-end 2001 levels. In addition, regulated utility operating cash flows increased in 2002 due to lower 2002 receivables and unbilled revenues, reflecting collections of higher year-end 2001 amounts. Cash provided by operating activities increased during 2001, compared with 2000, primarily due to the higher net income, depreciation and improved working capital.

	2002	2001	2000
	(Millions of dollars)		
Net cash used in investing activities	$ (2,718)	$ (5,168)	$ (3,347)

Cash used in investing activities decreased during 2002, compared with 2001, primarily due to lower levels of nonregulated capital expenditures as a result of NRG terminating its acquisition program due to its financial difficulties. Such nonregulated expenditures decreased $2.8 billion in 2002 due mainly to NRG asset acquisitions in 2001 that did not recur in 2002. Cash used in investing activities increased during 2001, compared with 2000, primarily due to increased levels of nonregulated capital expenditures and asset acquisitions, primarily at NRG. The increase was partially offset by our sale of most of our investment in Yorkshire Power.

	2002	2001	2000
	(Millions of dollars)		
Net cash provided by financing activities	$ 1,580	$ 3,713	$ 2,016

Cash provided by financing activities decreased during 2002, compared with 2001, primarily due to lower NRG capital requirements and constraints on NRG s ability to access the capital market due to its financial difficulties, as discussed previously. NRG s cash provided from financing activities declined by $2.7 billion in 2002, compared with 2001. Cash provided by financing activities increased during 2001, compared with 2000, primarily due to increased short-term borrowings and net long-term debt issuances, mainly to fund NRG acquisitions.

See discussion of trends, commitments and uncertainties with the potential for future impact on cash flow and liquidity under Capital Sources.

Capital Requirements

Utility Capital Expenditures, Nonregulated Investments and Long-term Debt Obligations The estimated cost of our and our subsidiaries capital expenditure programs, excluding NRG, and other capital requirements for the years 2003, 2004 and 2005 are shown in the table below.

	2003	2004	2005
	(Millions of dollars)		
Electric utility	$ 700	$ 840	$ 950
Natural Gas utility	110	110	110
Common utility	90	50	40
Total utility	900	1,000	1,100
Other nonregulated (excluding NRG)	32	23	15
Total capital expenditures	932	1,023	1,115
Sinking funds and debt maturities	563	169	223
Total capital requirements	$ 1,495	$ 1,192	$ 1,338

The capital expenditure forecast for 2004 includes new steam generators at the Prairie Island nuclear plant. These expenditures will not occur unless the Minnesota Legislature grants additional spent fuel storage at Prairie Island during 2003. The capital expenditure forecast also includes the early stages of the costs related to modifications to reduce the emissions of NSP-Minnesota s generating plants located in the Minneapolis and St. Paul metropolitan area. This project is expected to cost approximately $1.1 billion with major construction starting in 2005 and finishing in 2009.

Our capital expenditure programs are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting our long-term energy needs. In addition, our ongoing evaluation of merger, acquisition and divestiture opportunities to support corporate strategies, address restructuring requirements and comply with future requirements to install emission-control equipment may impact actual capital requirements. For more information, see Notes 4 and 18 to the consolidated financial statements.

Our investment in exempt wholesale generators and foreign utility companies, which includes NRG and other subsidiaries of us, is currently limited to 100 percent of consolidated retained earnings, as a result of the PUHCA restrictions. At December 31, 2002, such investments exceeded consolidated retained earnings.

NRG Energy is required to provide financial guarantees of up to approximately $8 million, for closure and ongoing monitoring costs of some sites to which it sends coal ash and other waste, by April 30, 2003.

NRG Capital Expenditures Management expects NRG s capital expenditures,which include refurbishments and environmental compliance, to total approximately $475 million to $525 million in the years 2003 through 2007. NRG anticipates funding its ongoing capital requirements through committed debt facilities, operating cash flows and existing cash. NRG s capital expenditure program is subject to continuing review and modification. The timing and actual amount of expenditures may differ significantly based upon plant operating history, unexpected plant outages, changes in the regulatory environment and the availability of cash. The pending financial restructuring or bankruptcy filings of NRG may affect the timing and magnitude of capital resources available to NRG and, accordingly, the level of capital expenditures NRG can fund.

Contractual Obligations and Other Commitments We have a variety of contractual obligations and other commercial commitments that represent prospective requirements in addition to our capital expenditure programs. The following is a summarized table of contractual obligations. See additional discussion in the Consolidated Statements of Capitalization and Notes 5, 6, 7, 16 and 18 to the consolidated financial statements.

Contractual Obligations	Total	Payments Due by Period: Less than 1 year	1-3 years	4-5 years	After 5 years
		(Thousands of dollars)			
Long-term debt	$ 14,311,689	$ 7,756,903	$ 547,796	$ 1,137,934	$ 4,869,056
Capital lease obligations	688,421	34,422	67,771	66,386	519,842
Operating leases(a)	386,215	66,155	125,031	108,534	86,495
Unconditional purchase obligations	11,240,364	1,317,293	2,214,974	1,817,770	5,890,327
Other long-term obligations	699,248	42,597	64,517	34,594	557,540
Short-term debt	1,541,963	1,541,963			
Total contractual cash obligations	$ 28,867,900	$ 10,759,333	$ 3,020,089	$ 3,165,218	$ 11,923,260

(a) Under some leases, we would have to sell or purchase the property that we lease if we chose to terminate before the scheduled lease expiration date. Most of our railcar, vehicle and equipment, and aircraft leases have these terms. We would then own the equipment and could continue to use it in the normal course of business or sell the equipment. At December 31, 2002, the amount that we would have to pay if we chose to terminate these leases was approximately $160 million.

Common Stock Dividends Future dividend levels will be dependent upon the statutory limitations discussed below, as well as our results of operations, financial position, cash flows and other factors, and will be evaluated by our board of directors.

Under the PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. Due to 2002 losses incurred by NRG, our retained earnings were a deficit of $101 million at December 31, 2002. We did not declare a dividend on our common stock during the first quarter of 2003. We have requested authorization from the SEC to pay dividends out of paid-in capital up to $260 million until September 30, 2003. It is not known when or if the SEC will act on this request. As explained below, we have reached a preliminary settlement agreement with the various NRG creditors. Also, we could be required to cease including NRG as a consolidated subsidiary for financial reporting purposes, if NRG were to seek protection under the bankruptcy laws and we ceased to have control over NRG. In the event the tentative settlement is effectuated and we are required to cease including NRG as a consolidated subsidiary in our financial statements, the financial impact of these events are expected to positively impact retained earnings and may be sufficient to eliminate the negative retained earnings balance, absent additional charges at NRG. We cannot predict the precise financial impact of these items at this time. For this reason, we will continue seeking authorization from the SEC so we are able to pay dividends notwithstanding negative retained earnings. We intend to make every effort to pay the full common stock dividend of 75 cents per share during 2003.

Our Articles of Incorporation place restrictions on the amount of common stock dividends we can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if our capitalization ratio (on a holding company basis only, *i.e.*, not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (1) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, our capitalization ratio at December 31, 2002, was 85 percent. Therefore, the restrictions do not place any effective limit on our ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of our common stock.

Capital Sources

We expect to meet future financing requirements by periodically issuing long-term debt, short-term debt, common stock and preferred securities to maintain desired capitalization ratios. As a result of our registration as a holding company under the PUHCA, we are required to maintain a common equity ratio of 30 percent or higher in its consolidated capital structure.

On November 7, 2002, the SEC issued an order authorizing us to engage in certain financing transactions through March 31, 2003, so long as our common equity ratio, as reported in our most recent Form 10-K, or Form 10-Q and as adjusted for pending subsequent items that affect capitalization, was at least 24 percent of our total capitalization. Financings authorized by the SEC included the issuance of debt, including convertible debt, to refinance or replace our $400-million credit facility that expired on November 8, 2002, issuance of $450 million of common stock, less any amounts issued as part of the refinancing of the $400-million credit facility, and the renewal of guarantees for various trading obligations of NRG s power marketing subsidiary. The SEC reserved authorizing additional securities issuances by us through June 30, 2003, while our common equity ratio is below 30 percent.

For this purpose, common equity, including minority interest, at December 31, 2002, was 23 percent of total capitalization. As a result, we may experience constraints on available capital sources that may be affected by factors including earnings levels, project acquisitions and the financing actions of our subsidiaries. In the event NRG were to seek protection under bankruptcy laws and we ceased to have control over NRG, NRG would no longer be a consolidated subsidiary of us for financial reporting purposes and our common equity ratio under the SEC s method of calculation would exceed 30 percent.

In December 2002, we filed a request for additional financing authorization with the SEC. We requested an increase from $2.0 billion to $2.5 billion in the aggregate amount of securities that we may issue during the period through September 30, 2003. In addition, the request proposed that common equity will be at least 30 percent of total consolidated capitalization, provided that in any event that the 30-percent common equity requirement is not met, we may issue common stock. The notice period expired with no comments. SEC action on the request is pending. As a result, we at the present time cannot finance, either on a short-term or long-term basis, without SEC approval unless our common equity is at least 30 percent of total capitalization.

With approval of the request currently pending before the SEC, further described below, management believes it will have adequate authority under SEC orders and regulations to conduct business as proposed during 2003 and will seek additional authorization when necessary.

Short-Term Funding Sources Historically, we have a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for utility construction expenditures and nonregulated project investments. Another significant short-term funding need is the dividend payment requirement, as discussed previously in Common Stock Dividends.

Operating cash flow as a source of short-term funding is reasonably likely to be affected by such operating factors as weather, regulatory requirements, including rate recovery of costs, environmental regulation compliance and industry deregulation, changes in the trends for energy prices and supply, and operational uncertainties that are difficult to predict. See further discussion of such factors under Statement of Operations Analysis and Factors Affecting Results of Operations.

Short-term borrowing as a source of funding is affected by regulatory actions and access to reasonably priced capital markets. This varies based on financial performance and existing debt levels. These factors are evaluated by credit rating agencies that review our and our subsidiary operations on an ongoing basis. NRG s credit situation has affected our credit ratings and access to short-term funding. As a result of a decline in our credit ratings, we have been unable to utilize the commercial paper market to satisfy any short-term funding needs. For additional information on our short-term borrowing arrangements, see Note 5 to the consolidated financial statements.

Access to reasonably priced capital markets is also dependent in part on credit agency reviews. In the past year, our credit ratings and those of our subsidiaries have been adversely affected by NRG s credit contingencies, despite what management believes is a reasonable separation of NRG s operations and credit risk from our utility operations and corporate financing activities. These ratings reflect the views of Moody s and Standard & Poor s. A security rating is not a recommendation to buy, sell or hold securities and is subject

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to revision or withdrawal at any time by the rating company. As of April 14, 2003, the following represents the credit ratings assigned to various Xcel Energy companies:

Company	Credit Type	Moody s*	Standard & Poor s
Xcel Energy	Senior Unsecured Debt	Baa3	BBB-
Xcel Energy	Commercial Paper	NP	A3
NSP-Minnesota	Senior Unsecured Debt	Baa1	BBB-
NSP-Minnesota	Senior Secured Debt	A3	BBB+
NSP-Minnesota	Commercial Paper	P2	A3
NSP-Wisconsin	Senior Unsecured Debt	Baa1	BBB
NSP-Wisconsin	Senior Secured Debt	A3	BBB+
PSCo	Senior Unsecured Debt	Baa2	BBB-
PSCo	Senior Secured Debt	Baa1	BBB+
PSCo	Commercial Paper	P2	A3
SPS	Senior Unsecured Debt	Baa1	BBB
SPS	Commercial Paper	P2	A3
NRG	Corporate Credit Rating	Caa3**	D**

* Negative credit watch/negative outlook

** Below investment grade

Moody s and Standard & Poor s each provide long-term and short term credit ratings. Both rating agencies distinguish between investment grade and non-investment grade ratings, and within these two categories between superior, excellent, good and adequate, which are conside investment grade, and may be adequate, vulnerable, extremely vulnerable and default , which are considered non-investment grade. Moody s issues its ratings in the form of letter combinations ranging from Aaa through D, with Baa3 being the lowest investment grade rating and Ba1 being the highest non-investment grade rating. Standard & Poor s provides its ratings in form of letter combinations ranging from AAA through D, with BBB- being the lowest investment grade rating and BB+ being the highest non-investment grade rating. Furthermore, Standard & Poor s provides short-term ratings ranging from A-1, which is considered strong, to D, which stands for default. Moody s provides three short-term ratings ranging from P-1, which stands for a superior rating, to P-3, which stands for an acceptable rating.

NRG s access to short-term capital is currently non-existent outside of bankruptcy. The downgrade of NRG s credit ratings below investment grade in July 2002 has resulted in cash collateral requirements, as discussed previously and in Notes 4 and 7 to the consolidated financial statements. In addition, lower credit ratings will increase the relative cost of NRG s capital financing compared to historical levels, assuming NRG could obtain such financing.

In June 2002, our access to commercial paper markets was reduced due to lowered credit ratings, shown previously. We typically use sources of financing, both short- and long-term, other than commercial paper to fulfill our cash needs and manage our capital structure.

NRG Capital Sources NRG has generally financed the acquisition and development of its projects under financing arrangements to be repaid solely from each of its project s cash flows, which are typically secured by the plant s physical assets and equity interests in the project company. As discussed above, NRG s credit situation has significantly affected its credit ratings and has virtually eliminated its access to short-term funding. See credit ratings in previous table. NRG anticipates funding its ongoing capital requirements through committed debt facilities, operating cash flows, and existing cash.

NRG s operating cash flows have been affected by lower operating margins as a result of low power prices since mid-2001. Seasonal variations in demand and market volatility in prices are not unusual in the independent power sector, and NRG does normally experience higher margins in peak summer periods and lower margins in non-peak periods. NRG has also incurred significant amounts of debt to finance its acquisitions in the past several years, and the servicing of interest and principal repayments from such financing is largely dependent on domestic project cash flows. Management has concluded that the forecasted free cash flow available to NRG after servicing project-level obligations will be insufficient to service recourse debt obligations at NRG.

Substantially all of NRG s operations are conducted by project subsidiaries and project affiliates. NRG s cash flow and ability to service corporate-level indebtedness when due is dependent upon receipt of cash dividends and distributions or other transfers from NRG s projects and other subsidiaries. NRG has generally financed the acquisition and development of its projects under financing arrangements to be repaid solely from each of its project s cash flows, which are typically secured by the plant s physical assets and equity interests in the project company. In August 2002, NRG suspended substantially all of its acquisition and development activities indefinitely, pending a comprehensive restructuring of NRG. The debt agreements of NRG s subsidiaries and project affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to NRG. As of December 31, 2002, Loy Yang, Energy Center Kladno, LSP Energy (Batesville), NRG South Central, and NRG Northeast Generating do not currently meet the minimum debt service coverage ratios required for these projects to make payments to NRG. In addition, NRG s subsidiaries, including LSP Kendall, NRG McClain, NRG Mid-Atlantic, NRG South Central and NRG Northeast Generating are in default on their various debt instruments, resulting in dividend payment restrictions.

For additional information on NRG s defaults on short-term and long-term borrowing arrangements, see Note 7 to the consolidated financial statements.

Registration Statements Our Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of December 31, 2002, we had approximately 399 million shares of common stock outstanding. In addition, our Articles of Incorporation authorize the issuance of 7 million shares of $100 par value preferred stock. On December 31, 2002, we had approximately 1 million shares of preferred stock outstanding. Registered securities available for issuance are as follows:

In February 2002, we filed a $1-billion shelf registration with the SEC. We may issue debt securities, common stock and rights to purchase common stock under this shelf registration. We have approximately $482.5 million remaining under this registration, which we can only issue when our common equity exceeds 30 percent of our total capitalization absent SEC approval under PUHCA.

In April 2001, NSP-Minnesota filed a $600-million, long-term debt shelf registration with the SEC. NSP-Minnesota has approximately $415 million remaining under this registration.

In June 2001, NRG filed a shelf registration with the SEC to sell up to $2 billion in debt securities, common and preferred stock, warrants and other securities. NRG has approximately $1.5 billion remaining under this shelf registration. However, NRG s access to capital markets is severely constrained and the registration no longer represents access to financing sources.

In March 2003, PSCo issued $250 million of 4.875 percent, First Collateral Trust Bonds due in 2013. The bonds were issued in a private placement to qualified institutional buyers and were not registered under the Securities Act of 1933. Pursuant to a registration rights agreement, PSCo has an obligation to file a registration statement for an exchange offer for these bonds.

In April 14, 2003, PSCo filed a registration statement on Form S-3 with the SEC, registering $500 million of new secured first collateral trust bonds or unsecured senior debt securities. The registration statement also constitutes a post-effective amendment to PSCo s registration statement on Form S-3 filed with the SEC in June 1999 under which $300 million of unsecured senior debt securities remain unsold.

Other Liquidity and Capital Resource Considerations

NRG Financial Issues and Bankruptcy Historically, NRG has obtained cash from operations, issuance of debt and equity securities, borrowings under credit facilities, capital contributions from us, reimbursement by us of tax benefits pursuant to a tax-sharing agreement and proceeds from non-recourse project financings. NRG has used these funds to finance operations, service debt obligations, fund the acquisition, development and construction of generation facilities, finance capital expenditures and meet other cash and liquidity needs.

As discussed previously, substantially all of NRG s operations are conducted by project subsidiaries and project affiliates. NRG s cash flow and ability to service corporate-level indebtedness when due is dependent upon receipt of cash dividends and distributions or other transfers from NRG s projects and other subsidiaries. The debt agreements of NRG s subsidiaries and project affiliates generally restrict their ability to pay dividends, make distributions or otherwise transfer funds to NRG. As of December 31, 2002, Loy Yang, Killingholme, Energy Center Kladno, LSP Energy (Batesville), NRG South Central and NRG Northeast Generating do not currently meet the minimum debt service coverage ratios required for these projects to make payments to NRG.

Killingholme, NRG South Central and NRG Northeast Generating are in default on their credit agreements. NRG believes the situations at Energy Center Kladno, Loy Yang and Batesville do not create an event of default and will not allow the lenders to accelerate the project financings.

In all of these cases, NRG s corporate-level financial obligations to project lenders is limited to no more than six-months debt service.

As previously discussed, NRG s operating cash flows have been affected by lower operating margins as a result of low power prices since mid-2001. Seasonal variations in demand and market volatility in prices are not unusual in the independent power sector, and NRG does normally experience higher margins in peak summer periods and lower margins in non-peak periods. NRG has also incurred significant amounts of debt to finance its acquisitions in the past several years, and the servicing of interest and principal repayments from such financing is largely dependent on domestic project cash flows. NRG s management has concluded that the forecasted free cash flow available to NRG after servicing project-level obligations will be insufficient to service recourse debt obligations.

Since mid-2002, as discussed previously, NRG has experienced severe financial difficulties, resulting primarily from declining credit ratings and lower prices for power. These financial difficulties have caused NRG to, among other things, miss several scheduled payments of interest and principal on its bonds and incur an approximately $3-billion asset impairment charge. The asset impairment charge relates to write-offs for anticipated losses on sales of several projects as well as anticipated losses for projects for which NRG has stopped funding. In addition, as a result of having its credit ratings downgraded, NRG is in default of obligations to post cash collateral of approximately $1 billion. Furthermore, on November 6, 2002, lenders to NRG accelerated approximately $1.1 billion of NRG s debt under the construction revolver financing facility, rendering the debt immediately due and payable. In addition, on February 27, 2003, lenders to NRG accelerated approximately $1.0 billion of NRG Energy s debt under the corporate revolver financing facility, rendering the debt immediately due and payable. NRG continues to work with its lenders and bondholders on a comprehensive restructuring plan. NRG does not contemplate making any principal or interest payments on its corporate-level debt pending the restructuring of its obligations. Consequently, NRG is, and expects to continue to be, in default under various debt instruments.

In addition to the collateral requirements, NRG must continue to meet its ongoing operational and construction funding requirements. Since NRG s credit rating downgrade, its cost of borrowing has increased and it has not been able to access the capital markets. NRG believes that its current funding requirements under its already reduced construction program may be unsustainable given its inability to raise money in the capital markets and the uncertainties involved in obtaining additional equity funding from us. NRG and we have retained financial advisors to help work through these liquidity issues.

As discussed above, NRG is not making any payments of principal or interest on its corporate-level debt, and neither NRG nor any subsidiary is making payment of principal or interest on publicly held bonds. This failure to pay, coupled with past and anticipated proceeds from the sales of projects, has provided NRG with adequate liquidity to meet its day-to-day operating costs. Through January 31, 2003, NRG completed a number of transactions, which resulted in net cash proceeds to NRG after debt pay-downs and after financial advisor fees of approximately $350 million. As discussed in more detail above under the caption Recent Developments, NRG has filed a voluntary petition for bankruptcy under the U.S. Bankruptcy Code.

Xcel Energy Impacts During 2002, we provided NRG with $500 million of cash infusions. In May 2002, we and NRG entered into a support and capital subscription agreement (Support Agreement) pursuant to which we agreed, under certain circumstances, to provide an additional $300 million to NRG.

We have not, to date, provided funds to NRG under this agreement. See discussion of preliminary settlement with NRG s creditors below and at Note 4 to the financial statements.

Many companies in the regulated utility industry, with which the independent power industry is closely linked, are also restructuring or reviewing their strategies. Several of these companies are discontinuing going forward with unregulated investments, seeking to divest of their unregulated subsidiaries or attempting to have their regulated subsidiaries acquire their unregulated subsidiaries. This may lead to an increased competition between the regulated utilities and the unregulated power producers within certain markets. In such instances, NRG may compete with regulated utilities in the influence of market designs and rulemaking.

On March 26, 2003, our board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against us, including claims related to the Support Agreement. The settlement is subject to a variety of conditions as set forth below, including definitive documentation. As described in Note 4 to the consolidated financial statements, the settlement would require us to pay up to $752 million over 13 months. We would expect to fund those payments with cash from tax savings. The principal terms of the settlement as of the date of this report were as follows:

We would pay up to $752 million to NRG to settle all claims of NRG, and the claims of NRG against us, including all claims under the Support Agreement.

$350 million would be paid at or shortly following the consummation of a restructuring of NRG s debt through a bankruptcy proceeding. It is expected that this payment would be made prior to year-end 2003. $50 million would be paid on January 1, 2004, and all or any part of such payment could be made, at our election, in our common stock. Up to $352 million would be paid on April 30, 2004, except to the extent that we had not received at such time tax refunds equal to $352 million associated with the loss on our investment in NRG. To the extent we had not received such refunds, the April 30 payment would be due on May 30, 2004.

$390 million of our payments are contingent on receiving releases from NRG creditors. To the extent we do not receive a release from an NRG creditor, our obligation to make $390 million of the payments would be reduced based on the amount of the creditor s claim against NRG. As noted below, however, the entire settlement is contingent upon us receiving releases from at least 85 percent of the claims in various NRG creditor groups. As a result, it is not expected that our payment obligations would be reduced by more than approximately $60 million. Any reduction would come from the our payment due on April 30, 2004.

Upon the consummation of NRG s debt restructuring through a bankruptcy proceeding, our exposure on any guarantees or other credit support obligations incurred by us for the benefit of NRG or any subsidiary would be terminated and any cash collateral posted by us would be returned to us. The current amount of such cash collateral is approximately $11.5 million.

As part of the settlement with us, any intercompany claims of us against NRG or any subsidiary arising from the provision of intercompany goods or services or the honoring of any guarantee will be paid in full in cash in the ordinary course except that the agreed amount of such intercompany claims arising or accrued as of January 31, 2003 will be reduced from approximately $32 million as asserted by us to $10 million. The $10 million agreed amount is to be paid upon the effective date of the NRG plan of reorganization, with an unsecured promissory note of NRG in the principal amount of $10 million.

NRG and its direct and indirect subsidiaries would not be reconsolidated with us or any of our other affiliates for tax purposes at any time after their June 2002 re-affiliation or treated as a party to or otherwise entitled to the benefits of any tax sharing agreement with us. Likewise, NRG would not be entitled to any tax benefits associated with the tax loss we expect to incur in connection with the write down of our investment in NRG.

On May 14, 2003, NRG and certain of NRG s U.S. affiliates filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. Neither we nor any of our other subsidiaries were included in the filing. NRG s plan of reorganization filed with the U.S. Bankruptcy Court for the Southern District of New York incorporates the terms of an overall settlement among NRG, us and NRG s major creditor constituencies that provides for payments by us to NRG, and that NRG will pay in turn to its creditors, of up to $752 million.

A plan support agreement reflecting the settlement has been signed by us, holders of approximately 40% of NRG s long-term notes and bonds along with two NRG banks who serve as co-chairs of the global steering committee for the NRG bank lenders. This agreement will become fully effective upon execution by holders of approximately an additional ten percent in principal amount of NRG s long-term notes and bonds and by a majority of NRG bank lenders representing at least two-thirds in principal amount of NRG s bank debt. We expect the requisite signatures will be obtained promptly.

The terms of the settlement with NRG s major creditors are basically the same as discussed above. $350 million would be paid at or shortly following the effective date of the NRG plan of reorganization. It is expected that this payment would be made prior to year-end 2003. An additional $50 million would be paid on January 1, 2004, and all or any part of such payment could be made, at our election, in our common stock. Up to $352 million would be paid in the second quarter of 2004.

Consummation of the settlement is contingent upon, among other things, the following:

(i) The effective date of the NRG plan of reorganization occurring on or prior to December 15, 2003;

(ii) The final plan of reorganization approved by the Bankruptcy Court and related documents containing terms satisfactory to us, NRG and various groups of the NRG creditors;

(iii) The receipt of releases in our favor from holders of at least 85 percent of the claims represented by NRG s creditors; and

(iv) Our receipt of all necessary regulatory and other approvals.

Since many of these conditions are not within our control, we cannot state with certainty that the settlement will be effectuated. Nevertheless, our management is optimistic at this time that the settlement will be implemented.

Based on the foreseeable effects of a settlement agreement with the major NRG noteholders and bank lenders and the tax effect of an expected write-off of our investment in NRG, we would recognize the expected tax benefits of the write-off as of December 31, 2002. The tax benefit has been estimated at approximately $706 million. This benefit is based on the tax basis of our investment in NRG.

We expect to claim a worthless stock deduction in 2003 on our investment. This would result in us having a net operating loss for the year. Under current law, this 2003 net operating loss could be carried back two years for federal purposes. We expect to file for a tax refund of approximately $355 million in first quarter 2004. This is refund based on a two-year carryback. However, under the Bush administration s new dividend tax proposal, the carryback could be one year, which would reduce the refund to $125 million.

As to the remaining $351 million of expected tax benefits, we expect to eliminate or reduce estimated quarterly income tax payments, beginning in 2003. The amount of cash freed up by the reduction in estimated tax payments would depend on our taxable income.

While it is an exception rather than the rule, especially where one of the companies involved is not in bankruptcy, the equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities; to consolidate and pool the entities assets and liabilities; and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. In the event the settlement described above is not effectuated, we believe that any effort to substantively consolidate us with NRG would be without merit. However, it is possible that NRG or its creditors would attempt to advance such claims, or other claims under piercing the corporate veil, alter ego or related theories, should an NRG bankruptcy proceeding commence, particularly in the absence of a prenegotiated plan of reorganization, and we cannot be certain how a bankruptcy court would resolve these issues. One of the creditors of the NRG project Pike, as discussed in Note 18 to the consolidated financial statements, has already filed involuntary bankruptcy proceedings against that project and has included claims against both NRG and us. Also, as discussed in Note 18 to the consolidated financial statements, a group of former executives of NRG have commenced an involuntary bankruptcy proceeding against NRG related to the payments of certain benefits and deferred compensation amounts claimed to be due them. If a bankruptcy court were to allow substantive consolidation of us and NRG, it would have a material adverse effect on us.

The accompanying consolidated financial statements do not reflect any conditions or matters that would arise if NRG were in bankruptcy.

Following NRG s bankruptcy filing NRG will no longer be included in our consolidated financial statements. Such de-consolidation of NRG would encompass a change in our accounting for NRG to the equity method, under which we would continue to record our interest in NRG s income or losses until our investment in NRG (under the equity method) reached the level of obligations that we had either guaranteed on behalf of NRG or was otherwise committed to in the form of financial assistance to NRG. Prior to completion of a bankruptcy proceeding, a prenegotiated plan of reorganization or other settlement reached with NRG s creditors would be the determining factors in assessing whether a commitment to provide financial assistance to NRG existed at the time of de-consolidation.

At December 31, 2002, our pro forma investment in NRG, calculated under the equity method if applied at that date, was a negative $625 million. If the amount of guarantees or other financial assistance committed to NRG by us exceeded that level after de-consolidation of NRG, then NRG s losses would continue to be included in our results until the amount of negative investment in NRG reaches the amount of guarantees and financial assistance committed to by us. As of December 31, 2002, the estimated guarantee exposure that we had provided on behalf of NRG of $96 million, as discussed in Note 16, and potential financial assistance was committed in the form of a support and capital subscription agreement pursuant to which we agreed, under certain circumstances, to provide an additional $300 million contribution to NRG if the financial restructuring plan discussed earlier is approved by NRG s creditors. Additional commitments for financial assistance to NRG could be created in 2003 as we, NRG and NRG s creditors continue to negotiate terms of a possible prenegotiated plan of reorganization to resolve NRG s financial difficulties.

In addition to the effects of NRG s losses, our operating results and retained earnings in 2003 could also be affected by the tax effects of any guarantees or financial commitments to NRG, if such income tax benefits were considered likely of realization in the foreseeable future. The income tax benefits recorded in 2002 related to our investment in NRG, as discussed in Note 11 to the consolidated financial statements, includes only the tax benefits related to cash and stock investments already made in NRG at December 31, 2002. Additional tax benefits could be recorded in 2003 at the time that such benefits are considered likely of realization, when the payment of guarantees and other financial assistance to NRG become probable.

As noted above, the bankruptcy filing by NRG will have several effects on our financial condition and results of operations. Management anticipates that NRG would no longer be included in our consolidated financial statements, prospectively from the date of the bankruptcy filing by NRG. Such de-consolidation of NRG would encompass a change in our accounting for NRG to the equity method, thus all of NRG s assets and liabilities would be presented in a single line on our balance sheet at that point. This would reduce our debt leverage ratios and increase our equity ratio as a percent of total capitalization to above 30 percent, thereby reinstating our financing authority under PUHCA. In addition, the revenues and expenses of NRG would be reported on a net basis as equity income or losses. Losses would be subject to certain limitations. Also, the operating, investing and financing cash flows of NRG would not be included in ours except to the extent cash flowed between us and NRG. Finally, there may be tax effects for guarantees or financial

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commitments made by us to NRG related to the bankruptcy or other resolution of NRG s financial difficulties. See Note 4 to the consolidated financial statements for further discussion of these possible effects of an NRG bankruptcy filing on us.

We believe that the ultimate resolution of NRG s financial difficulties and going-concern uncertainty will not affect our ability to continue as a going concern. We are not dependent on cash flows from NRG, nor are we contingently liable to creditors of NRG in an amount material to our liquidity. We believe that our cash flows from regulated utility operations and anticipated financing capabilities will be sufficient to fund our non-NRG-related operating, investing and financing requirements. Beyond these sources of liquidity, we believe we will have adequate access to additional debt and equity financing that is not conditioned upon the outcome of NRG s financial restructuring plan.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

During 2000, 2001 and 2002, there were no disagreements with our independent public accountants on accounting principles or practices, financial statement disclosures, or auditing scope or procedures.

On March 27, 2002, the Audit Committee of our Board of Directors recommended, and our Board approved, the decision to engage Deloitte & Touche LLP, subject to completion of their customary acceptance procedures, as our new principal independent accountants for 2002. Accordingly, on March 27, 2002, our management informed Arthur Andersen LLP that the firm would no longer be engaged as our principal independent accountants. The reports of Arthur Andersen LLP on our financial statements for the year ended December 31, 2001 or 2000 did not contain an adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principles. Further, during 2000, 2001 and 2002, there have been no reportable events (as defined in Commission Regulation S-K Item 304(a)(1)(v)).

Arthur Andersen LLP furnished us with a letter addressed to the SEC stating that it agreed with the above statements.

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BUSINESS

Company Overview

On August 18, 2000, NCE and NSP merged (the Merger) and formed Xcel Energy Inc., a Minnesota corporation. We are a registered holding company under PUHCA. As part of the Merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed subsidiary of ours named Northern States Power Company. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. As a stock-for-stock exchange for shareholders of both companies, the Merger was accounted for as a pooling-of-interests and accordingly, amounts reported for periods prior to the Merger have been restated for comparability with post-Merger results.

We directly own six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo, SPS, Cheyenne and BMG. Their service territories include portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Our regulated businesses also include Viking, which we sold on January 17, 2003, and WGI, both interstate natural gas pipeline companies.

We also own or have an interest in a number of nonregulated businesses, the largest of which is NRG. As a result of the exchange of shares of Xcel Energy for publicly held shares of NRG, which was completed in June 2002, NRG is now an indirect wholly-owned subsidiary of ours. NRG is a global energy company, primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products. As discussed previously, NRG is currently experiencing severe financial difficulties and has sold or is in the process of selling a significant amount of its assets.

In addition to NRG, our nonregulated subsidiaries include:

- UE, which is involved in engineering, construction and design;
- Seren, which is involved in broadband telecommunications services;
- e prime inc., which is involved in natural gas marketing and trading;
- Planergy, which is involved in enterprise energy management solutions;
- Eloigne, which is involved in investments in rental housing projects that qualify for low-income housing tax credits; and
- XEI, an international independent power producer.

We were incorporated under the laws of Minnesota in 1909. Our executive offices are located at 800 Nicollet Mall, Minneapolis, Minnesota 55402.

For information on our nonregulated subsidiaries, see Nonregulated Subsidiaries below. For information regarding our segments and foreign revenues, see Note 21 to the consolidated financial statements.

NSP-Minnesota

NSP-Minnesota was incorporated in 2000 under the laws of Minnesota. NSP-Minnesota is an operating utility engaged in the generation, transmission and distribution of electricity and the transportation, storage and distribution of natural gas. NSP-Minnesota provides generation, transmission and distribution of electricity in Minnesota, North Dakota and South Dakota. NSP-Minnesota also purchases, distributes and sells natural gas to retail customers and transports customer-owned gas in Minnesota, North Dakota and South Dakota. NSP-Minnesota provides retail electric utility service to approximately 1.3 million customers and gas utility service to approximately 430,000 customers.

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NSP-Minnesota owns the following direct subsidiaries: United Power and Land Co., which holds real estate; NSP Nuclear Corp., which holds NSP-Minnesota s interest in the Nuclear Management Co.; and NSP Financing I, a special purpose business trust.

NSP-Wisconsin

NSP-Wisconsin was incorporated in 1901 under the laws of Wisconsin. NSP-Wisconsin is an operating utility engaged in the generation, transmission and distribution of electricity to approximately 230,000 retail customers in northwestern Wisconsin and in the western portion of the Upper Peninsula of Michigan. NSP-Wisconsin is also engaged in the distribution and sale of natural gas in the same service territory to approximately 90,000 customers in Wisconsin and Michigan.

NSP-Wisconsin owns the following direct subsidiaries: Chippewa and Flambeau Improvement Co., which operates hydro reserves; Clearwater Investments Inc., which owns interests in affordable housing; and NSP Lands, Inc., which holds real estate.

PSCo

PSCo was incorporated in 1924 under the laws of Colorado. PSCo is an operating utility engaged principally in the generation, purchase, transmission, distribution and sale of electricity and the purchase, transportation, distribution and sale of natural gas. PSCo serves approximately 1.3 million electric customers and approximately 1.2 million gas customers in Colorado.

PSCo owns the following direct subsidiaries: 1480 Welton, Inc., which owns certain real estate interests of PSCo; PSR Investments, Inc., which owns and manages permanent life insurance policies on certain employees; Green and Clear Lakes Company, which owns water rights and PSCo Capital Trust I, a special purpose financing trust. PSCo also holds controlling interests in several other relatively small ditch and water companies whose capital requirements are not significant. PS Colorado Credit Corp., a finance company that was owned by PSCo and financed certain of PSCo s current assets was dissolved in 2002.

SPS

SPS was incorporated in 1921 under the laws of New Mexico. SPS is an operating utility engaged primarily in the generation, transmission, distribution and sale of electricity. SPS serves approximately 390,000 electric customers in portions of Texas, New Mexico, Oklahoma and Kansas. The wholesale customers served by SPS comprise approximately 36 percent of the total kilowatt-hour sales.

SPS owns a direct subsidiary, SPS Capital I, which is a special purpose financing trust.

Other Regulated Subsidiaries

Cheyenne was incorporated in 1900 under the laws of Wyoming. Cheyenne is an operating utility engaged in the purchase, transmission, distribution and sale of electricity and natural gas primarily serving approximately 37,000 electric customers and 30,000 natural gas customers in and around Cheyenne, Wyoming.

BMG was incorporated in 1999 under the laws of Arizona. BMG is a natural gas and propane distribution company, located in Cave Creek, Arizona, with approximately 9,300 customers. We have entered into an agreement to sell BMG. The sale is subject to the receipt of several regulatory approvals.

Viking, acquired in 1993, owns and operates an interstate natural gas pipeline serving portions of Minnesota, Wisconsin and North Dakota. Viking operates exclusively as a transporter of natural gas for third-party shippers under authority granted by the FERC. On January 17, 2003, we completed the sale of Viking, including its ownership interest in Guardian, to a subsidiary of NBP.

WGI was incorporated in 1990 under the laws of Colorado. WGI is a natural gas transmission company engaged in transporting natural gas from Chalk Bluffs, Colorado, to Cheyenne, Wyoming.

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Utility Regulation

Ratemaking Principles

Our system is subject to the jurisdiction of the SEC under PUHCA. The rules and regulations under PUHCA generally limit the operations of a registered holding company to a single integrated public utility system, plus additional energy-related businesses. PUHCA rules require that transactions between affiliated companies in a registered holding company system be performed at cost, with limited exceptions. See additional discussion of PUHCA requirements under Management s Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting Results of Operations and Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources.

FERC has jurisdiction over rates for electric transmission service in interstate commerce and wholesale electric energy sold in interstate commerce, hydro facility licensing and certain other activities of our utility subsidiaries. Federal, state and local agencies also have jurisdiction over many of our other activities.

We are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. We strive to comply with all rules and regulations issued by the various agencies.

NSP-Minnesota

Retail rates, services and other aspects of NSP-Minnesota s operations are subject to the jurisdiction of the MPUC, the North Dakota Public Service Commission (NDPSC) and the South Dakota Public Utilities Commission (SDPUC) within their respective states. The MPUC also possesses regulatory authority over aspects of NSP-Minnesota s financial activities, including security issuances, certain property transfers, mergers with other utilities and transactions between NSP-Minnesota and its affiliates. In addition, the MPUC reviews and approves NSP-Minnesota s electric resource plans and gas supply plans for meeting customers future energy needs. The MPUC also certifies the need for generating plants greater than 50 megawatts and transmission lines greater than 100 kilovolts. NSP-Minnesota has received authorization from the FERC to act as a power marketer.

The Minnesota Environmental Quality Board (MEQB) is empowered to select and designate sites for new power plants with a capacity of 50 megawatts or more and wind energy conversion plants with a capacity of five megawatts or more. It also designates routes for electric transmission lines with a capacity of 100 kilovolts or more. No power plant or transmission line may be constructed in Minnesota except on a site or route designated by the MEQB.

NSP-Wisconsin

NSP-Wisconsin is subject to regulation of similar scope by the Public Service Commission of Wisconsin (PSCW) and the Michigan Public Service Commission (MPSC). In addition, each of the state commissions certifies the need for new generating plants and electric and retail gas transmission lines of designated capacities to be located within the respective states before the facilities may be sited and built.

The PSCW has a biennial filing requirement. By June of each odd-numbered year, NSP-Wisconsin must submit a rate filing for the two-year period beginning the following January. The filing procedure and review generally allow the PSCW sufficient time to issue an order effective with the start of the test year.

PSCo

PSCo is subject to the jurisdiction of the CPUC with respect to its facilities, rates, accounts, services and issuance of securities. PSCo is subject to the jurisdiction of the FERC with respect to its wholesale electric operations and accounting practices and policies. PSCo has received authorization from the FERC to act as a power marketer. Also, PSCo holds a FERC certificate that allows it to transport natural gas in interstate commerce without PSCo becoming subject to full FERC jurisdiction.

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SPS

The PUCT has jurisdiction over SPS Texas operations as an electric utility and over its retail rates and services. The municipalities in which SPS operates in Texas have original jurisdiction over SPS rates in those communities. The New Mexico Public Regulatory Commission (NMPRC) has jurisdiction over the issuance of securities and accounting. The NMPRC, the Oklahoma Corporation Commission and the Kansas Corporation Commission have jurisdiction with respect to retail rates and services in their respective states. The FERC has jurisdiction over SPS rates for wholesale sales for resale and the transmission of electricity in interstate commerce. SPS has received authorization from the FERC to make wholesale electricity sales under market-based prices.

Cheyenne

Cheyenne is subject to the jurisdiction of the Wyoming Public Service Commission with respect to its facilities, votes, accounts, services and issuances of securities.

Other

Viking and WGI are subject to the FERC jurisdiction and each holds a FERC certificate, which allows them to transport natural gas in interstate commerce pursuant to the provisions of the Natural Gas Act. BMG is subject to the regulation of the Arizona Corporation Commission (ACC).

Fuel, Purchased Gas and Resource Adjustment Clauses

NSP-Minnesota

NSP-Minnesota s retail electric rate schedules provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy. NSP-Minnesota is permitted to recover financial instrument costs through a fuel clause adjustment, a mechanism that allows NSP-Minnesota to bill customers for the cost of fuel used to generate electricity at its plants and energy purchased from other suppliers. Changes in capacity charges are not recovered through the fuel clause. NSP-Minnesota s electric wholesale customers do not have a fuel clause provision in their contracts. Instead, the contracts have an escalation factor.

Gas rate schedules for NSP-Minnesota include a purchased gas adjustment (PGA) clause that provides for rate adjustments for changes in the current unit cost of purchased gas compared with the last costs included in rates. The PGA factors in Minnesota are calculated for the current month based on the estimated purchased gas costs for that month. The MPUC has the authority to disallow certain costs if it finds the utility was not prudent in its procurement activities.

NSP-Minnesota is required by Minnesota law to spend a minimum of 2 percent of Minnesota electric revenue and 0.5 percent of Minnesota gas revenue on conservation improvement programs (CIP). These costs are recovered through an annual recovery mechanism for electric and gas conservation and energy management program expenditures. NSP-Minnesota is required to request a new cost recovery level annually.

NSP-Wisconsin

NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, it has a procedure that compares actual monthly and anticipated annual fuel costs with those costs that were included in the latest retail electric rates. If the comparison results in a difference outside a prescribed range, the PSCW may hold hearings limited to fuel costs and revise rates (upward or downward). Any revised rates would be effective until the next rate case. The adjustment approved is calculated on an annual basis, but applied prospectively. Most of NSP-Wisconsin s wholesale electric rate schedules provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy.

NSP-Wisconsin has a gas cost recovery mechanism to recover the actual cost of natural gas.

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NSP-Wisconsin s gas and retail electric rate schedules for Michigan customers include gas cost recovery factors and power supply cost recovery factors, which are based on 12-month projections. After each 12-month period, a reconciliation is submitted whereby over-collections are refunded and any under-collections are collected from the customers over the subsequent 12-month period.

PSCo

PSCo currently had or currently has seven adjustment clauses that recover fuel, purchased energy and resource costs: the ICA, the interim adjustment clause (IAC), the air quality improvement rider (AQIR), the gas cost adjustment (GCA), the steam cost adjustment (SCA), the demand side management cost adjustment (DSMCA) and the qualifying facilities capacity cost adjustment (QFCCA). These adjustment clauses allow certain costs to be passed through to retail customers. For certain adjustment mechanisms, PSCo is required to file applications with the CPUC for approval in advance of the proposed effective dates.

The ICA allowed for an equal sharing between customers and shareholders of certain fuel and purchased energy cost increases for fuel and purchased energy costs incurred prior to December 31, 2002. The IAC recovers fuel and energy costs incurred during 2003 until the conclusion of the 2002 general rate case, at which time the fuel and purchased energy cost recovery from January 1, 2003 onward shall be recalculated in accord with the fuel and purchased energy cost recovery mechanism approved by the Commission in the PSCo 2002 general rate case. The AQIR recovers over a fifteen year period the incremental cost (including fuel and purchased energy) incurred by PSCo as a result of voluntary investments in air quality improvement. PSCo, through its SCA, is allowed to recover the difference between its actual cost of fuel and the amount of these costs recovered under its base rates. The SCA rate is revised annually to coincide with changes in fuel costs. The QFCCA provides for recovery of purchased capacity costs from certain QF projects not otherwise reflected in base electric rates. The QFCCA will expire at the conclusion of PSCo s general rate case will expire at the conclusion of the 2002 general rate case. Through its GCA, PSCo is allowed to recover its actual costs of purchased gas. The GCA rate is revised at least annually to coincide with changes in purchased gas costs. Purchased gas costs and revenues received to recover gas costs are compared on a monthly basis and differences are deferred. In 2002, PSCo requested to modify the GCA to allow for monthly changes in gas rates. A final decision on this proceeding is expected in 2003.

The DSMCA clause currently permits PSCo to recover DSM costs over five years while non-labor incremental expenses and carrying costs associated with deferred DSM costs are recovered on an annual basis. PSCo also has implemented a low-income energy assistance program. The costs of this energy conservation and weatherization program for low-income customers are recovered through the DSMCA.

SPS

Fuel and purchased power costs are recoverable in Texas through a fixed fuel factor, which is part of SPS rates. If it appears that SPS will materially over-recover or under-recover these costs, the factor may be revised upon application by SPS or action by the PUCT. The rule requires refunding and surcharging under/over-recovery amounts, including interest, when they exceed 4 percent of the utility s annual fuel and purchased power costs, as allowed by the PUCT, if this condition is expected to continue. PUCT regulations require periodic examination of SPS fuel and purchased power costs, the efficiency of the use of such fuel and purchased power, fuel acquisition and management policies and purchase power commitments. Under the PUCT s regulations, SPS is required to file an application for the PUCT to retrospectively review at least every three years the operations of SPS electric generation and fuel management activities.

The NMPRC regulations provide for a fuel and purchased power cost adjustment clause for SPS New Mexico retail jurisdiction. SPS files monthly and annual reports of its fuel and purchased power costs with the NMPRC, which include the current over/under fuel collection calculation, plus interest. In January 2002, the NMPRC authorized SPS to implement a monthly adjustment factor on an interim basis beginning with the February 2002 billing cycle.

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Cheyenne

All electric demand and purchased power costs are recoverable through an energy adjustment clause. Differences in costs incurred from costs recovered in rates are deferred and recovered through prospective adjustments to rates. However, rate changes for cost recovery require WPSC approval before going into effect. Historically, customers have been provided carrying costs on overcollected costs, but Cheyenne has not been allowed to collect carrying charges for under recovered costs.

Other Regulatory Mechanisms and Requirements

NSP-Minnesota

In December 2000, the NDPSC approved our PLUS performance-based regulation proposal for its electric operations in the state. The plan established operating and service performance standards in the areas of system reliability, customer satisfaction, price and worker safety. NSP Minnesota s performance determines the range of allowed return on equity for its North Dakota electric operations. The plan will generate refunds or surcharges when earnings fall outside of the allowed return on equity range. The PLUS plan will remain in effect through 2005.

PSCo

The CPUC established an electric performance-based regulatory plan (PBRP) under which PSCo operates. See further discussion above under Management s Discussion and Analysis of Financial Condition and Results of Operation.

SPS

Prior to June 2001, SPS operated under an earnings test in Texas, which required excess earnings to be returned to the customers. In May 2000, SPS filed its 1999 earnings report with the PUCT, indicating no excess earnings. In September 2000, the PUCT staff and the Office of Public Utility Counsel filed with the PUCT a notice of disagreement, indicating adjustments to SPS calculations, which would result in excess earnings. During 2000, SPS recorded an estimated obligation of approximately $11.4 million for 1999 and 2000. In February 2001, the PUCT ruled on the disputed issues in the 1999 report and found that SPS had excess earnings of $11.7 million. This decision was appealed by SPS to the District Court. On December 11, 2001, SPS entered into an overall settlement of all earnings issues for 1999 through 2001, which reduced the excess earnings for 1999 to $7.3 million and found that there were no excess earnings for 2000 or through June 2001. The settlement also provided that the remaining excess earnings for 1999 could be used to offset approved transition costs that SPS was seeking to recover. The PUCT approved the overall settlement on January 10, 2002.

Pending Regulatory Matters

Xcel Energy

Temporary Modification of PUHCA Equity Ratio Limit In accordance with an SEC order under PUHCA granting our general financing authority, we must maintain common stockholders equity at a level at least equal to 30 percent of total capitalization in order to issue securities or guarantees. On November 7, 2002, the SEC issued an order authorizing us to engage in certain financing transactions through March 31, 2003 so long as our common equity ratio, as reported in our most recent Form 10-K, or Form 10-Q and as adjusted for pending subsequent items that affect capitalization, was at least 24 percent of our total capitalization. At September 30, 2002, and as adjusted for pending subsequent items that affect capitalization, our common equity ratio was at least 24 percent. Financings authorized by the SEC included the issuance of debt (including convertible debt) to refinance or replace our $400-million credit facility that expired on November 8, 2002, issuance of $483 million of stock (less any amounts issued as part of the refinancing of the $400-million credit facility) and the renewal of guarantees for various trading obligations of NRG s power marketing subsidiary. The SEC reserved authorizing additional securities issuances by us through June 30, 2003 while our common equity ratio is below 30 percent. In the event NRG were to seek protection under bankruptcy laws and we ceased to have control over NRG, NRG would cease to be a consolidated subsidiary of us for financial reporting purposes and our common equity ratio under the SEC s method of calculation would exceed 30 percent.

On December 20, 2002, we filed a request with the SEC seeking additional financing authorization to conduct our business as proposed during 2003. We are seeking an increase in the amount of long-term debt and common equity we are authorized to issue. In addition, we proposed that our common equity, as reflected on our most recent Form 10-K or Form 10-Q and as adjusted to reflect subsequent events that affect capitalization, will be at least 30 percent of total consolidated capitalization, provided that in any event that we do not satisfy the 30 percent common equity standard, we may issue common stock. We further asked the SEC to reserve jurisdiction over the authorization of us and our subsidiaries to engage in any other financing transactions authorized under current SEC orders and in the instant request at a time that we do not satisfy the 30 percent common equity standard. We believe that, assuming approval of the authority currently sought, we will have adequate authority, including financing authority, under SEC orders and regulations for us and our subsidiaries to conduct our businesses as proposed during 2003 and will seek additional authorization when necessary.

Investigations into Trading Practices On May 8, 2002, in response to disclosure by Enron of certain trading strategies used in 2000 and 2001, which may have violated market rules, the FERC ordered all sellers of wholesale electricity and/or ancillary services to the California Independent System Operator or Power Exchange, including us, PSCo and NRG, to respond to data requests, including requests for admissions with respect to certain trading strategies in which the companies may have engaged. On May 22, 2002, we reported to the FERC that we have not engaged directly in the trading strategies identified in the May 8th inquiry.

However, in that submission we reported that at times during 2000 and 2001, PSCo did sell energy to another energy company that may then have resold the electricity for delivery into California as part of an overstated electricity load in schedules submitted to the California Independent System Operator. During that period, the regulated operations of PSCo made sales to the other electricity provider of approximately 8,000 megawatt-hours in the California intra-day market, which resulted in revenues to us of approximately $1.5 million. We cannot determine from our records what part of such sales was associated with such possible over-schedules. Subsequently, in the California Refund Proceeding, as discussed later, PSCo informed the FERC that evidence that was adduced by certain California litigants appears to indicate that the PSCo trader involved in these transactions did not believe that they involved overstated schedules, and that we accordingly may have over reported transactions in that submission.

On May 21, 2002, the FERC supplemented the May 8th request by ordering all sellers off wholesale electricity and/or ancillary services in the United States portion of the Western Systems Coordinating Council during 2000 and 2001 to report whether they had engaged in activities referred to as wash, round trip or sell/ buyback trading. On May 31, 2002, we reported that we had not engaged in so-called round trip electricity trading identified in the May 21st inquiry.

On May 13, 2002, independently and not in direct response to any regulatory inquiry, we reported that PSCo had engaged in transactions in 1999 and 2000 with the trading arm of Reliant Resources, Inc. (Reliant) in which PSCo bought power from Reliant and simultaneously sold the same quantity back to Reliant. For doing this, PSCo normally received a small profit. PSCo made a total pretax profit of approximately $110,000 on these transactions. These transactions included one trade with Reliant in which PSCo simultaneously bought and sold power at the same price without realizing any profit. In this transaction, PSCo agreed to buy from Reliant 15,000 megawatts per hour, during the off-peak hours of the months of November and December 1999. Collectively, these sales with Reliant consisted of approximately 10 million megawatt hours in 1999 and 1.8 million megawatt hours in 2000 and represented approximately 55 percent of our trading volumes for 1999 and approximately 15 percent of our trading volumes for 2000. The purpose of the non-profit transaction was in expectation of entering into additional future for-profit transactions, such as the ones described above. PSCo engaged in these transactions with Reliant for the proper commercial objective of making a profit. PSCo did not enter into these transactions to inflate volumes or revenues and, at the time the transactions occurred, the transactions were reported net in PSCo s financial statements.

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On March 26, 2003, the FERC at its open meeting discussed this investigation and stated its intent to issue show cause orders to thirty identified market participants, requesting that these entities explain why their conduct did not constitute impermissible gaming under applicable tariffs and why they should not have to disgorge unjust profits or be subjected to other remedies. PSCo was not identified as one of these market participants. However, it was indicated that NRG would be asked to show cause why its prices from May to October, 2000, did not constitute economic withholding and inflated bidding and why it should not be required to disgorge unjust profits or be subjected to other remedies.

As discussed later, we and PSCo have received subpoenas from the Commodities Future Trading Commission for disclosure related to these round trip trades and other trading in electricity and natural gas for the period from January 1, 1999 to the present involving us or any of our subsidiaries.

We also have received a subpoena from the SEC for documents concerning round trip trades in electricity and natural gas with Reliant for the period from January 1, 1999 to the present. The SEC subpoena is issued pursuant to a formal order of private investigation that does not name us. Based upon accounts in the public press, we believe that similar subpoenas in the same investigation have been served on other industry participants. We are cooperating with the regulators and taking steps to assure satisfactory compliance with the subpoenas.

Section 206 Investigation Against All Wholesale Electric Sellers In November 2001, the FERC issued an order under Section 206 of the Federal Power Act initiating a generic investigation proceeding against all jurisdictional electric suppliers making sales in interstate commerce at market-based rates. NSP-Minnesota, PSCo, SPS and certain NRG affiliates previously received FERC authorization to make wholesale sales at market-based rates, and have been engaged in such sales subject to rates on file at the FERC. The order proposed that all wholesale electric sales at market-based rates conducted starting 60 days after publication of the FERC order in the Federal Register would be subject to refund conditioned on factors determined by the FERC.

In December 2001, the FERC issued a supplemental order delaying the effective date of the subject to refund condition, but subject to further investigation and proceedings. Numerous parties filed comments in January 2002, and reply comments were filed in February of that year. Further, the FERC staff convened a conference in this proceeding in February 2002. The FERC has not yet acted on the matter.

California Refund Proceeding A number of parties purchasing energy in markets operated by the California Independent System Operator (California ISO) or the California Power Exchange (PX) have asserted prices paid for such energy were unjust and unreasonable and that refunds should be made in connection with sales in those markets for the period October 2, 2000 through June 20, 2001. PSCo and NRG supplied energy to these markets during the referenced period and have been an active participant in the proceedings. The FERC ordered an investigation into the California ISO and PX spot markets and concluded that the electric market structure and market rules for wholesale sales of energy in California were flawed and have caused unjust and unreasonable rates for short-term energy under certain conditions. The FERC ordered modifications to the market structure and rules in California and established an administrative law judge (ALJ) to make findings with respect to, among other things, the amount of refunds owed by each supplier based on the difference between what was charged and what would have been charged in a more functional market, i.e., the market clearing price, which in turn is based on the unit providing energy in an hour with the highest incremental cost. The initial proceeding related to California s demand for $8.9 billion in refunds from power sellers. The ALJ subsequently stated that after assessing a refund of $1.8 billion for power prices, power suppliers were owed $1.2 billion because the State was holding funds owed to suppliers. Because of the low volume of sales that PSCo had into California after this date, PSCo s exposure is estimated at approximately $1.2 million, which is offset by amounts owed by the California ISO to PSCo in excess of that amount. The purchasing parties have appealed this decision. They have also asserted that the refund effective date should be set at an earlier date. The FERC has allowed the purchasing parties to request additional information regarding the market participants uses of certain strategies and the effect those strategies may have had on the market. The purchasing parties have filed a pleading at the FERC in which

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they claim that use of these strategies justifies an earlier refund effective date. An earlier effective date could increase PSCo s exposure to approximately $15 million.

On March 26, 2003, FERC at its open meeting discussed and voted on a draft order in this proceeding. Based on the discussion of the draft order, it would appear that the FERC is going to use different gas costs to determine the applicable market clearing prices for the refund period. The effect of this change will be to increase PSCo s and other sellers refund exposure. However, it does not appear from the discussion that the FERC will move back the applicable refund effective date. It may be expected that California litigants will request rehearing of this aspect of the order after it is issued.

Commodity Futures Trading Commission Investigation Pursuant to a formal order of investigation, on June 17, 2002 the Commodity Futures Trading Commission (CFTC) issued broad subpoenas to us on behalf of our affiliates, including NRG, calling for production, among other things, of all documents related to natural gas and electricity trading (the June 17, 2002 subpoenas). Since that time, we have produced documents and other materials in response to numerous more specific requests under the June 17, 2002 subpoenas. Certain of these requests and our responses have concerned so-called round-trip trades. By a subpoena dated January 29, 2003 and related letter requests (the January 29, 2003 subpoena), the CFTC has requested that we produce all documents related to all data submittals and documents provided to energy industry publications. We have produced documents and other materials in response to the January 29, 2003 subpoena, including a report identifying instances where our e prime subsidiary reported natural gas transactions to an industry publication in a manner inconsistent with the publication s instructions. We believe this reporting did not affect the financial accounting treatment of any transaction recorded in e prime s books and records. Also beginning on January 29, 2003, the CFTC has sought testimony from twenty current and former employees, and may notify us of its intention to seek additional testimony from numerous employees and executives, concerning the reporting of energy transactions to industry publications. A number of energy companies have stated in documents filed with FERC that employees reported fictitious natural gas transactions to industry publications. Various other energy companies are also subject to a recent order by FERC placing requirements on natural gas marketers related to reporting. We and NRG are cooperating in the CFTC investigation, but cannot predict the outcome of any investigation.

FERC Transmission Inquiry The FERC has begun a formal, non-public inquiry relating to the treatment by public utility companies of affiliates in generator interconnection and other transmission matters. In connection with the inquiry, the FERC has asked us and our subsidiaries for certain information and documents. We and our subsidiaries are complying with the request.

PUHCA Regulation See discussion of pending issues under PUHCA regulation at Management s Discussion and Analysis Liquidity and Capital Resources.

NSP-Minnesota

Minnesota Financial and Service Quality Investigation On August 8, 2002, the MPUC asked for additional information related to the impact of NRG s financial circumstances on NSP-Minnesota. Subsequent to that date, several newspaper articles alleged concerns about the reporting of service quality data and NSP-Minnesota s overall maintenance practices. In an order dated October 22, 2002, the MPUC directed the Minnesota Department of Commerce and the Office of the Attorney General Residential Utilities Division to investigate the accuracy of NSP-Minnesota s reliability records and to allow for further review of its maintenance and other service quality measures. There is no scheduled date for completion of this inquiry. The October 22, 2002 order requires a number of reporting requirements regarding financial information, and to work with interested parties on various issues to ensure NSP-Minnesota s commitments are fulfilled. The October 22, 2002 order references the NSP-Minnesota commitment (made at the time of the NSP/NCE Merger) to not seek a rate increase until 2006 unless certain exceptions are met. In addition, among other requirements, the order imposes restrictions on NSP-Minnesota s ability to encumber utility

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property, provide intercompany loans and the method by which NSP-Minnesota can calculate its cost of capital in present and future filings before the MPUC. On January 3, 2003, the MPUC subsequently issued an order bifurcating the financial aspect of this proceeding from the state agency s inquiry into the NSP-Minnesota s service quality reporting and allowing the agencies to continue to investigate other allegations in existing dockets. As a result, these two matters will proceed under separate dockets. On March 10, 2003, the DOC and OAG submitted a progress report to the MPUC drafted by the state agencies auditor. The report documents alleged instances of record keeping inconsistencies and misstatements and concludes it would be nearly impossible to establish the magnitude of misstatements in the record keeping system. In submitting the progress report, the state agencies noted, however, that the total outage duration stated would need to increase by nearly 33 million minutes to violate state-imposed standards. NSP-Minnesota vigorously disputes the method, findings and conclusions of the report.

Minnesota Emissions Reduction Program On July 26, 2002, NSP-Minnesota filed for approval by the MPUC a proposal to invest in existing NSP-Minnesota generation facilities (AS King, High Bridge, Riverside) to reduce emissions under the terms of legislation adopted by the 2001 Minnesota Legislature. The proposal includes the installation of state-of-the-area pollution control equipment as the AS King plant and conversion to natural gas at the High Bridge and Riverside plants. Under the terms of the statute, the filing concurrently seeks approval of a rate recovery mechanism for the costs of the proposal, estimated to be a total of $1.1 billion with major expenditures anticipated to begin in 2005 and continuing through 2009. The rate recovery would be through an annual automatic adjustment mechanism authorized by 2001 legislation, outside a general rate case, and is proposed to be effective at the expiration of the NSP-Minnesota merger rate freeze, which extends through 2005 unless certain exemptions are triggered. The rate recovery proposed by NSP-Minnesota would allow recovery of financing costs of capital expenditures prior to the in-service date of each plant. The proposal is pending comments by interested parties. Other regulatory approvals, such as environmental permitting, are needed before the proposal can be implemented. On December 30, 2002, the Minnesota Pollution Control Agency issued a report to the MPUC in which it found that the NSP-Minnesota emission reduction proposal is appropriate and complies with the requirement of the 2001 legislation. The MPUC must now act on the proposal.

Renewable Cost Recovery Tariff In April 2002, NSP-Minnesota also filed for MPUC authorization to recover in retail rates the costs of electric transmission facilities constructed to provide transmission service for renewable energy. The rate recovery would be through an automatic adjustment mechanism authorized by 2001 legislation, outside a general rate case. In January 2003, the MPUC issued an order approving the tariff subject to certain modifications.

Electric Transmission Construction In December 2001, NSP-Minnesota filed for certificates of need authorizing construction of various high voltage transmission facilities to provide generator outlet for up to 825 megawatts of wind generation. The projected cost is approximately $160 million. On January 30, 2003, the MPUC voted to issue certificates of need supporting NSP-Minnesota s preferred transmission construction plan. The certificates of need were issued with conditions that require NSP-Minnesota to purchase wind powered electric generating capacity to match the increased transmission capacity created by the certified lines.

Filings will be made with the Minnesota Environmental Quality Board (MEQB) to decide routing issues associated with the transmission plan. MEQB decisions are expected by the end of 2003 and early 2004. Construction is expected to be complete in the spring of 2007.

Time-of-Use Pilot Project As required by MPUC Orders, MSP-Minnesota has been working to develop a time-of-use pilot project that would attempt to measure customer response and conservation potential of such a program. This pilot project explores providing customers with pricing signals and information that could better inform customer choices about their use of electricity based on its costs. NSP-Minnesota has petitioned the MPUC for recovery of program costs. 2002 program costs are approximately $2 million. The Department of Commerce has supported deferred accounting to provide for recovery of prudent, otherwise unrecovered and appropriate costs, subject to a normal prudence review process. The

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Office of the Attorney General has argued that cost recovery should be denied for several reasons. An MPUC hearing on these issues is likely in the first half of 2003.

Merger Agreement As part of the NCE and NSP merger approval process in Minnesota, NSP-Minnesota agreed to:

- Reduce its Minnesota electric rates by $10 million annually through 2005;
- Not increase its electric rates through 2005, except under limited circumstances;
- Not seek recovery of certain merger costs from customers; and
- Meet various quality standards.

NSP-Wisconsin

Retail Electric Fuel Rates In August 2002, NSP-Wisconsin filed an application with the PSCW, requesting a decrease in Wisconsin retail electric rates for fuel costs. The amount of the proposed rate decrease is approximately $6.3 million on an annual basis. The reasons for the decrease include moderate weather, lower than forecast market power costs, and optimal plant availability. On August 7, 2002, the PSCW issued an order approving the fuel rate credit. The rate credit was effective on August 12, 2002.

On October 9, 2002, NSP-Wisconsin filed an application with the PSCW requesting another decrease in Wisconsin retail electric rates for fuel costs. The incremental amount of the second proposed rate decrease was approximately $5 million on an annual basis. The reasons for the additional decrease include continued moderate weather, lower than forecast market power costs, and optimal plant availability. On October 16, 2002, the PSCW issued an order approving the revised fuel rate credit, effective October 19, 2002.

On October 22, 2002, NSP-Wisconsin filed an application with the PSCW requesting the establishment of a new fuel monitoring range and fuel recovery factor for 2003. On January 30, 2003, the PSCW issued an order authorizing a new fuel monitoring range for 2003 and a new fuel recovery factor effective February 3, 2003. This results in an annual revenue increase of approximately $5 million from the fuel credit factor the PSCW approved October 16, 2002.

Michigan Transfer Pricing On October 3, 2002, the Michigan Public Service Commission denied NSP-Wisconsin s request for a waiver of the section of the Michigan Electric Code of Conduct (Michigan Code) dealing with transfer pricing policy. The Michigan Code requires the price of goods and services provided by an affiliate to NSP-Wisconsin be at the lower of market price or cost plus 10 percent, and the price of goods and services provided by NSP-Wisconsin to an affiliate be at the higher of cost or market price. NSP-Wisconsin requested the waiver based on its belief that the Michigan Code conflicts with SEC requirements to price goods and services provided between affiliates at cost. In November 2002, NSP-Wisconsin filed a request for reconsideration of the October 3, 2002 order. During its January 31, 2003 meeting, the Michigan Public Service Commission considered NSP-Wisconsin s rehearing request and granted the Company s request for waiver from this section of the Michigan Code. In its decision, the Michigan Public Service Commission indicated that it should grant the waiver to avoid placing NSP-Wisconsin in a position where it may be unable to comply with the Michigan Code and the pricing standards enforced by the SEC.

PSCo

Merger Agreements Under the Stipulation and Agreement approved by the CPUC in connection with the Merger, PSCo agreed to:

- file a combined electric, gas and steam rate case in 2002 with new rates effective in January 2003;
- extend its ICA mechanism for one more year through December 31, 2002 with an increase in the ICA base rate from $12.78 per megawatt hour to a rate based on the 2001 actual costs;

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continue the electric Performance Based Regulatory Plan and the electric Quality Service Plan through 2006 with an electric department earnings cap of 10.5 percent return on equity for 2002 and no earnings sharing for 2003;

develop a gas Quality of Service Plan for calendar year 2002 through 2007 performance;

reduce electric rates annually by $11 million for the period August 2000 to July 2002; and

cap merger costs associated with electric operations at $30 million and amortize such costs through 2002.

Incentive Cost Adjustment PSCo s 2001 calendar year energy costs under the ICA were approximately $19 per megawatt-hour, compared with the $12.78 per megawatt-hour rate that was billed to customers. The sharing of certain energy wholesale trading margins mitigated the significant under-recovery of energy costs for 2001. In early 2002, PSCo filed to increase the ICA rate earlier than originally agreed in the merger stipulation and agreement to mitigate future cost deferrals and to recover the projected ICA energy costs of $148 million for calendar year 2002. On May 10, 2002, the CPUC approved a settlement agreement between PSCo and other parties to increase the recovery of energy costs to $14.88 per megawatt-hour ($12.78 through base electric rates and $2.10 through the ICA), providing for recovery of the deferred costs as of December 31, 2001, and the projected 2002 costs over a 34-month period from June 1, 2002 through March 31, 2005. On March 5, 2003, PSCo filed to reduce the ICA rate to $2.07 per megawatt hour.

PSCo s costs for 2002 were approximately $17 per megawatt-hour or approximately $56 million less than the energy costs for the 2001 test year. Under the ICA mechanism, retail customers and PSCo share this difference equally. A CPUC proceeding to review and approve the incurred and recoverable 2001 costs under the ICA is in process. A review of the 2002 recoverable ICA costs will be conducted in a separate future proceeding. The results of these rate proceedings could impact the cost recovery and sharing amounts recorded under the ICA for 2001 and 2002.

On May 31, 2002, PSCo filed with the CPUC seeking to change its electric base rates and seeking to increase the recovery of fuel and purchased power expense by $113 million annually through a mechanism called the Electric Commodity Adjustment (ECA). The ICA, filed in January 2003, resulted in an annual increase in fuel and purchased expense recovery revenue of $123 million predicated on calendar year 2003 forecasted sales for PSCo retail. Finally, on February 12, 2003 PSCo filed supplemental rebuttal testimony revising its original ECA request made on May 31, 2002. In this filing, PSCo is seeking ECA rates that would increase the annual level of recovery at May 31, 2002. Since $123 million of the requested $186 million is already in effect, the net increase requested on February 12, 2003 is $63 million.

There are four factors accounting for the change from $113 million requested in the May 31, 2002 filing and the $186 million requested in the February 12, 2003 filing. Specifically, the February 12, 2003 filing contains: (1) a revision in ECA costs caused by a renegotiated purchased power contract; (2) a revised 2003 sales forecast; (3) an updated forecast of natural gas costs used as a fuel source in electric generating stations; and (4) a correction for transformation and line losses made to the level of kilowatt-hours used in deriving the proposed level of annual ECA costs.

2002 General Rate Case In May 2002, PSCo filed a combined general retail electric, gas and thermal energy base rate case with the CPUC to address increased costs for providing energy to Colorado customers. This filing is required as part of the Xcel Energy Merger Stipulation and Agreement approved by the CPUC. The case included setting the electric energy recovery mechanism, elimination of the QFCCA, new depreciation rates and recovery of additional plant investment. PSCo also asked to increase our authorized rate of return on equity set at 12 percent for electricity and 12.25 percent for natural gas. In February 2003, PSCo filed its rebuttal testimony, which revised the requested net increase. PSCo then requested to increase electric revenue by approximately $233 million annually. This is based on $186 million for fuel and purchased power and $47 million for the cost of electric service. PSCo also requested a decrease in natural gas revenue by approximately $21 million. On April 4, 2003, a comprehensive settlement agreement between the PSCo and all intervenors was executed and filed with the CPUC, which addressed all significant issues in the rate case.

Hearings are scheduled for late April 2003. Management believes the CPUC will approve the settlement agreement at that time and issue a final rate order during the second quarter, with new rates effective as discussed above.

Gas Cost Prudence Review In May 2002, the staff of the CPUC filed testimony in PSCo s gas cost prudence review case, recommending $6.1 million in disallowances of gas costs for the July 2000 through June 2001 gas purchase year. Hearings were held before an administrative law judge (ALJ) in July 2002. On February 10, 2003, the ALJ issued his recommended decision rejecting the proposed disallowances and approving PSCo s gas costs for the subject gas purchase year as prudently incurred. The decision is subject to Commission.

Gas Rate Reduction In September 2002, PSCo filed a request with the CPUC for a $65 million reduction in the natural gas cost component of our rates in Colorado. The gas cost adjustment would reduce overall customer bills starting October 1, 2002. The CPUC approved the requested decrease by order issued September 27, 2002

Gas Rate Adjustment In March 2003, PSCo filed a request with the CPUC for a $95.6 million gas cost adjustment increase through September 2003, to reflect an increase in current and forecasted costs for natural gas. The CPUC approved the requested increase by order issued March 20, 2003. The cost adjustment will not result in any additional gas margin for PSCo, as the increase reflects additional costs for purchasing natural gas on behalf of its customers. Natural gas costs are passed on to customers on a dollar-per-dollar basis.

PSCo Fuel Clause Investigation Certain wholesale power customers of PSCo have filed complaints with the FERC alleging PSCo has been improperly collecting certain fuel and purchased energy costs through the wholesale fuel cost adjustment clause included in their rates. The FERC consolidated the complaints and set them for hearing and settlement judge procedures. In November 2002, the Chief Judge terminated settlement procedures after settlement was not reached. The investigation is currently in the discovery process and hearings are set for August 2003.

Home Builders Association of Metropolitan Denver Home Builders Association of Metropolitan Denver (HBA) filed a formal complaint with the CPUC on February 23, 2001, requesting an award of reparations for excessive charges related to construction payments under PSCo s gas extension tariff as a result of PSCo s alleged failure to file revisions to its published construction allowances since 1996. HBA seeks an award of $13.6 million, including interest on behalf of all of PSCo s gas extension applicants since Oct. 1, 1996. HBA also seeks recovery of its attorney s fees.

Hearings were held before an ALJ on August 29, 2001, and September 24, 2001. On January 15, 2002, the ALJ issued a recommended decision dismissing HBA s complaint. The ALJ found that HBA failed to show that there have been any excessive charges, as required under the reparations statute, resulting from PSCo s failure to comply with its tariff. The ALJ held that HBA s claim for reparations: (i) was barred by the filed rate doctrine (since PSCo at all times applied the approved construction allowances set forth in its tariff), (ii) would require the CPUC to violate the prohibition against retroactive ratemaking and (iii) was based on speculation as to what the CPUC would do had PSCo made the filings in prior years to change its construction allowances. The ALJ also denied HBA s request for costs and attorney s fees. HBA filed exceptions to the ALJ s recommended decision. On June 19, 2002, the CPUC issued an order granting in part HBA s exceptions to the ALJ s recommended decision and remanding the case back to the ALJ for further proceedings. The CPUC reversed the ALJ s legal conclusion that the filed rate doctrine and prohibition against retroactive ratemaking bars HBA s claim for reparations under the circumstances of this case. The CPUC remanded the case back to the ALJ for a determination of whether and to what extent reparations should be awarded, considering certain enumerated issues.

A full-day hearing on remand was held on January 10, 2003. Simultaneous briefs were filed on February 5, 2003. Reply briefs were filed on February 12, 2003. The ALJ decision on remand is pending.

Pacific Northwest Power Market A complaint has been filed at the FERC requesting that the agency set for investigation, pursuant to Section 206 of the Federal Power Act, the justness and reasonableness of the rates of wholesale sellers in the spot markets in the Pacific Northwest, including PSCo. The FERC decided to hold a preliminary evidentiary hearing to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001. Such hearing was held before an administrative law judge of the FERC in August 2001. The administrative law judge recommended that the FERC conclude that the rates charged were not unjust and unreasonable, and accordingly, that there should be no refunds. PSCo believes that the findings should be upheld at the FERC. However, the matter is still pending before the FERC, and the ultimate outcome cannot be determined.

On March 26, 2003, the FERC at its open meeting discussed this proceeding. While the action that the FERC plans to take cannot be definitively ascertained from that discussion, it appears that the FERC may conduct further proceedings to determine whether spot-market bilateral sales in the Pacific Northwest should be subject to refund.

SPS

SPS Texas Fuel Reconciliation, Fuel Factor and Fuel Surcharge Application In June 2002, SPS filed an application for the PUCT to retrospectively review the operations of the utility s electric generation and fuel management activities. In this application, SPS filed its reconciliation for electric generation and fuel management activities, totaling approximately $608 million, for the period from January 2000 through December 2001. This proceeding is ongoing, and intervenor and PUCT staff filed testimony. Intervenors proposed that revenues from certain wholesale transactions be credited to Texas retail customers. SPS opposed this proposed revenue treatment. Hearings were scheduled for March 2003. On March 14, the parties submitted to the Administrative Law Judges a stipulation settling the proceeding. The stipulation resolves all issues regarding SPS s fuel costs and wholesale trading activities through December 2001. SPS will withdraw, without prejudice, its request to share in 10 percent of margins from certain wholesale non-firm sales. SPS had proposed to recover $1.1 million from Texas customers for the proposed sharing of wholesale non-firm sales margins. The company had not recorded these proposed revenues pending the outcome in this proceeding. The parties agreed that SPS would reduce its December 2001 fuel under-recovery balances by $5.8 million. Taking into account the withdrawal of proposed margin sharing of wholesale non-firm sales, the net impacts to SPS s deferred fuel expense balances, before tax, is $4.7 million. On May 2, 2003, the PUCT issued its order approving the settlement and the reconciliation of SPS fuel costs through December 2001.

SPS has reported to the PUCT that it has under-collected its fuel costs under the current Texas retail fixed fuel factors. Taking into account the stipulation in the fuel cost reconciliation proceeding, SPS has under-collected through February 2003 by $16.2 million. In March 2003, SPS filed an application seeking to surcharge Texas retail customer bills from June 2003 through January 2004 to collect the $16.2 million in deferred expenses. SPS is in the process of preparing a filing with the PUCT to recover in customer rates current fuel costs under its fixed fuel cost recovery factors in accordance with state statutes and PUCT regulations. On April 3, 2003, SPS withdrew its application for a fuel surcharge due to credit in fuel expense received from SPS s coal fuel supplier, TUCO, Inc. TUCO, SPS s coal supplier had been involved in negotiations to resolve a lawsuit pending in the 251st District Court of Potter County, Texas, known as *TUCO, Inc. v. Thunder Basin Coal Company and Atlantic Richfield Company*. TUCO and Thunder Basis were able to reach an agreement on all issues. As a result of the settlement a credit to fuel expense alleviated the need for this surcharge docket.

Texas Fuel Factor Increase and Fuel Surcharge Application In May 2003, and as a result of increased natural gas costs to power SPS s power plants, SPS filed a request with the PUCT to increase the Texas retail fixed fuel factors and implement a fuel surcharge. The increase fixed fuel factors will increase annual fuel revenues by $60.2 million. The fuel surcharge is to collect $13.2 million in prior under-collected fuel costs. The application is now pending before the PUCT.

SPS New Mexico Fuel Factor On December 17, 2001, SPS filed an application with the NMPRC seeking approval of continued use of its fuel and purchased power cost adjustment using a monthly adjustment factor, authorization to implement the proposed monthly factor on an interim basis and approval of the

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reconciliation of its fuel and purchase power adjustment clause collections for the period October 1999 through September 2001. In January 2002, the NMPRC authorized SPS to implement a monthly adjustment factor on an interim basis beginning with the February 2002 billing cycle. Hearings were completed in May 2002. SPS continuation and reconciliation portion of the file is pending before the NMPRC.

Golden Spread Electric Cooperative, Inc. In October 2001, Golden Spread Electric Cooperative, Inc. (Golden Spread) filed a complaint and request for investigation against SPS before the FERC. Golden Spread alleged SPS had violated provisions of a Commitment and Dispatch Service Agreement pursuant to which SPS conducts joint dispatch of SPS and Golden Spread resources. SPS filed a counter complaint against Golden Spread in which it has alleged that Golden Spread has failed to adhere to certain requirements of the Commitment and Dispatch Service Agreement. In April 2003, a definitive settlement agreement with Golden Spread was reached. The settlement provides for the payment to Golden Spread of $5 million for prior periods. Such payment will likely be recoverable by customers under the various fuel clause mechanisms.

Merger Agreement As a part of the NCE and NSP merger approval process in Texas, SPS agreed to:

guarantee annual merger savings credits of approximately $4.8 million and amortize merger costs through 2005;

retain the current fuel recovery mechanism to pass along fuel cost savings to retail customers; and

comply with various service quality and reliability standards, covering service installations and upgrades, light replacements, customer service call centers and electric service reliability.

As part of the merger approval process in New Mexico, SPS agreed to:

guarantee annual merger savings credits of approximately $780,000 and amortize merger costs through December 2004;

share net non-fuel operating and maintenance savings equally among retail customers and shareholders;

retain the current fuel recovery mechanism to pass along fuel cost savings to retail customers; and

not pass along any negative rate impacts of the merger.

SPS Texas Transition to Competition Cost Recovery Application In December 2001, SPS filed an application with the PUCT to recover $20.3 million in costs from the Texas retail customers associated with the transition to competition. These costs were incurred to position SPS for retail competition, which was eventually delayed for SPS. The filing was amended in March 2002 to reduce the recoverable costs by $7.3 million, which was associated with over-earnings recognized for the 1999 annual report. The PUCT approved SPS using the 1999 annual report over-earnings to offset the claims for reimbursement of transition to competition costs. This reduced the requested net collection in Texas to $13.0 million. In April 2002, a unanimous settlement agreement was reached. Final approval by the PUCT was received in May 2002. The stipulation provides for the recovery of $5.9 million through an incremental cost recovery rider and the capitalization of $1.9 million for metering equipment. Based on the settlement agreement, SPS wrote off pretax restructuring costs of approximately $5 million in the first quarter of 2002. Recovery of the $5.9 million began in July 2002.

New Mexico Renewable Energy Requirements In December 2002, the NMPRC adopted new regulations requiring investor-owned utilities operating in New Mexico to promote the use of renewable energy technologies by procuring at least ten percent of their New Mexico retail energy requirements from renewable resources by no later than 2011.

NRG

Connecticut Light & Power-NRG On December 5, 2001, NRG and Connecticut Light and Power (CL&P) filed a request with the Connecticut Department of Public Utility Control (DPUC) for an increase in the standard offer rate paid to energy suppliers. The increase was requested to cover higher costs related to recent environmental legislation and anticipated higher charges for transmission service. The increase would have contributed approximately $5 million of net income per month to NRG. On June 17, 2002, the DPUC ruled the parties were not entitled to the requested increase.

In July 2002, NRG reached a tentative agreement with CL&P that would result in increased compensation to NRG, as supplier of CL&P s wholesale supply agreement. As part of the agreement, NRG has committed to keeping power generation units in service at its Devon and Norwalk Harbor generating stations as well as at its Cos Cob remote jet sites for the remainder of the wholesale supply agreement. CL&P filed an emergency petition with the DPUC asking for approval of a shift of wholesale supply agreement revenues, effective August 1, 2002, through December 31, 2003, that would reallocate 0.7 cents per kilowatt-hour in the wholesale price paid to existing suppliers. On July 26, 2002, the DPUC denied the request of CL&P for an emergency letter ruling. NRG expects to continue negotiations for receipt of capacity payments for critical generating units in Connecticut.

On August 9, 2002, NRG announced it had finalized an agreement with ISO-New England to keep three units at its Devon station in service. Under the terms of the agreement, units seven and eight will remain available until ISO-New England gives a 60-day notice that one or both are no longer needed for reliability. Unit 10 may be deactivated on or after October 1, 2002. The agreement expires on September 30, 2003. The agreement provides for increased capacity payments and notice of termination. It also allows NRG sufficient compensation to continue operating through the end of the agreement.

Cheyenne

Cheyenne Purchased Power Costs In March 2001, Cheyenne requested an increase in retail electric rates to provide for recovery of increasing power costs. As a result of the significant increase in electric energy costs since late February 2001, Cheyenne under recovered its costs under its electric cost adjustment (ECA) mechanism. On May 25, 2001, the WPSC approved a Stipulation Agreement between Cheyenne and intervenors in connection with a proposed increase in rates charged to Cheyenne s retail customers to recover increased power costs.

The Stipulation provides for an ECA rate structure with a fixed energy supply rate for Cheyenne s customers through 2003; the continuation of the ECA with certain modifications, including the amortization through December 2005 of unrecovered costs incurred during 2001 up to the agreed upon fixed supply rates; and agreement that Cheyenne s energy supply needs will be provided, in whole or in part, by PSCo in accordance with wholesale tariff rates to be approved by the FERC. The estimated retail rate increases under the Stipulation would provide recovery of an additional $18 million (in comparison to prior rate levels) through the remainder of 2001 and a total of $28 million for each of the years 2002 and 2003. In 2004 and 2005, Cheyenne will return to requesting recovery of its actual costs incurred plus the outstanding balance of any deferral from earlier years. New cost levels consistent with the Stipulation Agreement has been reflected in Cheyenne s expenses, and in deferred costs based on current ECA recovery levels, with an effective date of June 1, 2001, and retroactive adjustments back to the date of the increase in costs on February 25, 2001.

For more information on regulatory matters, see Management s Discussion and Analysis of Financial Condition and Results of Operations.

Electric Utility Operations

Competition and Industry Restructuring

Retail competition and the unbundling of regulated energy service could have a significant financial impact on us and our subsidiaries, due to an impairment of assets, a loss of retail customers, lower profit margins and increased costs of capital. The total impacts of restructuring may have a significant financial impact on our financial position, results of operations and cash flows and our utility subsidiaries cannot predict when they will be subject to changes in legislation or regulation, nor can they predict the impacts of such changes on their financial position, results of operations or cash flows. We believe that the prices our utility subsidiaries charge for electricity and the quality and reliability of their service currently place them in a position to compete effectively in the energy market.

Retail Business Competition The retail electric business faces increasing some competition as industrial and large commercial customers have some ability to own or operate facilities to generate their own electric energy. In addition, customers may have the option of substituting other fuels, such as natural gas for heating, cooling and manufacturing purposes, or the option of relocating their facilities to a lower cost environment. While each of our utility subsidiaries face these challenges, these subsidiaries believe their rates are competitive with currently available alternatives. Our utility subsidiaries are taking actions to lower operating costs and are working with their customers to analyze energy efficiency and load management programs in order to better position our utility subsidiaries to more effectively operate in a competitive environment.

Wholesale Business Competition The wholesale electric business faces increasing competition in the supply of bulk power, due to federal and state initiatives to provide open access to utility transmission systems. Under current FERC rules, utilities are required to provide wholesale open-access transmission services and to unbundle wholesale merchant and transmission operations. Our utility subsidiaries are operating under a joint tariff in compliance with these rules. To date, these provisions have not had a material impact on the operations of our utility subsidiaries.

Utility Industry Changes and Restructuring The structure of the electric and natural gas utility industry continues to change. Merger and acquisition activity over the past few years has been significant as utilities combine to capture economies of scale or establish a strategic niche in preparing for the future. Some regulated utilities are divesting generation assets. All utilities are required to provide nondiscriminatory access to the use of their transmission systems.

Some states have begun to allow retail customers to choose their electricity supplier, and many other states are considering retail access proposals. However, the experience of the state of California in instituting competition, as well as the bankruptcy filing of Enron, have caused delays in industry restructuring.

Major issues that must be addressed include mitigation of market power, divestiture of generation capacity, transmission constraints, legal separation, refinancing of securities, modification of mortgage indentures, implementation of procedures to govern affiliate transactions, investments in information technology and the pricing of unbundled services, all of which have significant financial implications. We cannot predict the outcome of restructuring proceedings in the electric utility jurisdictions it serves at this time. The resolution of these matters may have a significant impact on our financial position, results of operations and cash flows. For more information on the delay of restructuring for SPS in Texas and New Mexico, see Note 15 to the consolidated financial statements.

FERC Restructuring During 2001 and 2002, the FERC issued several industry-wide orders impacting (or potentially impacting) our operating companies and NRG. In addition, our utility subsidiaries submitted proposals to the FERC that could impact future operations, costs and revenues.

Section 206 Investigation Against All Wholesale Electric Sellers In November 2001, the FERC issued an order under Section 206 of the Federal Power Act initiating a generic investigation proceeding against all jurisdictional electric suppliers making sales in interstate commerce at market based rates. NSP-Minnesota, PSCo, SPS and certain NRG affiliates had previously received FERC authorization to make wholesale sales at market based rates, and have been engaged in such sales subject to rates on file at the FERC. The order proposed that all wholesale electric sales at market based rates conducted starting 60 days after publication of the FERC order in the Federal Register would be subject to refund conditioned on factors determined by the FERC.

Several parties filed requests for rehearing, arguing the November 2001 order was vague and would require the affected utilities to conditionally report future revenues and earnings. In late November 2001, the FERC issued a notice delaying the effective date of the subject to refund condition, but subject to further investigation and proceedings. Comments were filed by numerous parties in January, 2002 and reply comments were filed in February of that year. Further, the FERC Staff convened a conference in this proceeding in February of 2002. The FERC has not yet acted on the matter.

MISO Begins Operations In compliance with a condition in the January 2000 FERC order approving the Merger, NSP-Minnesota and NSP-Wisconsin entered into agreements to join the MISO in August 2000. In December 2000, the FERC approved the MISO as the first approved regional transmission organization (RTO) in the U.S., pursuant to FERC Order 2000. On February 1, 2002, the MISO began interim operations, including regional transmission tariff administration services for the NSP-Minnesota and NSP-Wisconsin electric transmission systems. NSP-Minnesota and NSP-Wisconsin have received all required regulatory approvals to transfer functional control of their high voltage (100 kV and above) transmission systems to the MISO when the MISO is fully operational. The MISO will then control the operations of these facilities and the facilities of neighboring electric utilities. The MISO also submitted an application to the FERC for approval of the business combination of the MISO and the SPP. However, in March 2003, MISO and SPP mutually terminated their planned combination.

In October 2001, the FERC issued an order in the separate proceeding to establish the initial MISO regional transmission tariff rates, ruling that all transmission services (with limited exceptions) in the MISO region must be subject to the MISO regional tariff and administrative surcharges to prevent discrimination between wholesale transmission service users. The FERC order unilaterally modified the agreement with the MISO signed in August 2000. The FERC order increased wholesale transmission costs to NSP-Minnesota and NSP-Wisconsin by up to $9 million per year.

TRANSLink Transmission Company LLC In September 2001, our operating companies joined a proposal with several other electric utilities in the U.S. Mid-continent region to form TRANSLink Transmission Company LLC (TRANSLink), an independent transmission company (ITC) which would own and/or operate electric high voltage transmission facilities within a FERC-approved RTO. Initially, the applicants propose that the high voltage transmission systems of NSP-Minnesota and NSP-Wisconsin be under the functional control of TRANSLink under an operating agreement between the utilities and TRANSLink, which would then be a member of the Midwest ISO RTO. The electric transmission facilities of SPS would participate upon the merger of the MISO and SPP. PSCo would also be operated by TRANSLink, but would not initially be part of an RTO because no FERC-approved RTO is operational in the western United States at this time.

TRANSLink would pay our operating companies a fee for use of their transmission systems, determined on a regulated cost of service basis, and would collect its administrative costs through transmission rate surcharges. The TRANSLink participants argue that RTO participation through the TRANSLink ITC would comply with FERC Order 2000 at a lower cost than RTO participation as vertically integrated utilities. Under the proposal, TRANSLink will be responsible for planning, managing and operating both local and regional transmission assets. TRANSLink will also construct and own new transmission system additions. TRANSLink will collect the revenue for the use of our transmission assets through a FERC-approved, regulated cost-of-service tariff and will collect its administrative costs through transmission rate surcharges. Transmission service pricing will continue to be regulated by the FERC, but construction and permitting approvals will continue to rest with regulators in the states served by TRANSLink.

In May 2002, the participants formed TRANSLink Development Company, LLC, which is responsible for pursuing the actions necessary to complete the regulatory approval of TRANSLink Transmission Company, LLC.

In April 2002, the FERC gave conditional approval for the applicants to transfer ownership or operations of their transmission systems to TRANSLink and to form TRANSLink as an independent transmission company operating under the umbrella RTO organization of MISO. The FERC conditioned TRANSLink s approval on the resubmission of its tariff as a separate rate schedule to be administered by the MISO. TRANSLink Development Company made this rate filing in October 2002. In October 2002, TRANSLink Development also entered into a definitive agreement with the MISO, whereby TRANSLink will contract with the MISO for certain required RTO functions and services. On November 1, 2002, the FERC issued its order supporting the approval of the formation of TRANSLink. The FERC also clarified several issues

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covered in its April 2002 order. In December 2002, the FERC approved the TRANSLink rate schedule subject to refund, and required TRANSLink to engage in settlement discussions on several items. TRANSLink anticipates resolving these issues during the first quarter. In January 2003, the FERC also approved TRANSLink s contractual relationship with the Midwest Independent System Operator. This contract delineates the role that TRANSLink will have within the TRO. Finally, in January 2003, TRANSLink also identified its nine member independent Board of Directors. The establishment of an independent board is required to satisfy Order 2000 obligations. Several state approvals also would be required to implement the proposal, as well as SEC approval. State applications were made in late 2002 and early 2003. Subject to receipt of required regulatory approvals, TRANSLink is expected to begin operations in the third quarter or fourth quarter of 2003.

Standards of Conduct Rulemaking In October 2001, the FERC issued proposed rules which would substantially increase the functional separation requirements under existing FERC rules (Orders No. 497 and 889) between the regulated electric and natural gas transmission functions of the Xcel Energy operating companies and West Gas Interstate, and the wholesale electric and natural gas marketing functions of PSCo, NSP-Minnesota, NRG and e prime. The proposed rules, if adopted, would require substantially increased functional separation, causing a loss of integration efficiencies and thus higher costs. In December 2001, we and numerous other parties filed comments opposing the proposed rules. In May 2002, the FERC Staff issued a reaction paper, generally rejecting the comments of parties opposed to the proposed rules. No final rule has been issued.

Standard Market Design Rulemaking In July 2002 the FERC issued a Notice of Proposed Rulemaking on Standard Market Design rulemaking for regulated utilities. If implemented as proposed, the Rulemaking will substantially change how wholesale markets operate throughout the United States. The proposed expands the FERC s intent to unbundle transmission operations from integrated utilities and ensure robust competition in wholesale markets. The rule contemplates that all wholesale and retail customers will be on a single network transmission service tariff. The rule also contemplates the implementation of a bid based system for buying and selling energy in wholesale markets. The market will be administered by RTOs or Independent Transmission Providers. RTOs will also be responsible for putting together regional plans that identify opportunities to construct new transmission, generation or demand side programs to reduce transmission constraints and meet regional energy requirements. Finally, the Rule envisions the development of Regional Market Monitors responsible for ensuring that individual participants do not exercise unlawful market power. Comments to the rules were filed in the fourth quarter of 2002, with replies and further comment scheduled for the first quarter of 2003. The FERC anticipated that the final rules would be in place in 2003 and the contemplated market changes will take place in 2003 and 2004 but recent FERC actions indicate the schedule for the final order may be delayed.

NSP-Minnesota

Minnesota Restructuring In 2001, the Legislature passed an energy security bill that includes provisions that are intended to streamline the siting process of new generation and transmission facilities. It also includes voluntary benchmarks for achieving renewable energy as a portion of the utility supply portfolio. There is unlikely to be any further action on restructuring in 2003.

North Dakota Restructuring In 1997, the North Dakota Legislature established by statute, an Electric Utility Competition Committee (EUC). The EUC was given six years to perform its research and submit its final report on restructuring, competition, and service territory reforms. To date, the committee has focused on the study of the state s current tax treatment of the electric utility industry, primarily in the transmission and distribution functions. The report presented to the legislative council in early 2001 did not include recommendations to change the current tax structure. However, the legislature, without recommendation from the EUC, overhauled the application of the coal severance and coal conversion taxes primarily to improve the competitive status of North Dakota lignite for generation. During 2002, the committee continued its review and is expected to present legislation to the legislative assembly in January 2003. No legislation resulted from the review.

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NSP-Wisconsin

Wisconsin Restructuring The state of Wisconsin continued its incremental approach to industry restructuring by passing legislation in 2001 that reduced the wholesale gross receipts tax on the sale of electricity by 50 percent starting in 2003. This legislation eliminates the double taxation on wholesale sales from non-utility generators, and should encourage the development of merchant plants by making sales from independent power producers more competitive. Additional legislation was passed that enables regulated utilities to enter into leased generation contracts with unregulated generation affiliates. The new legislation provides utilities a new financing mechanism and option to meet their customers energy needs. In 2002, the PSCW approved the first power plant proposal utilizing the new leased generation contract arrangement. While industry-restructuring changes continue in Wisconsin, the movement towards retail customer choice has virtually stopped.

Michigan Restructuring Since January 1, 2002, NSP-Wisconsin has been providing its Michigan electric customers with the opportunity to select an alternative electric energy provider. This action was required by Michigan s Customer Choice and Electricity Reliability Act, which became law in June 2002. NSP-Wisconsin developed and successfully implemented internal procedures, and obtained MPSC approval for these procedures to meet the January 1, 2002 deadline. Key elements of internal procedures include the development of retail open access tariffs and unbundled billing, environmental and fuel disclosure information, and a code of conduct compliance plan.

PSCo

Colorado Restructuring During 1998, a bill was passed in Colorado that established an advisory panel to conduct an evaluation of electric industry restructuring and customer choice. During 1999, this panel concluded that Colorado would not significantly benefit from opening its markets to retail competition. There was no legislative action with respect to restructuring in Colorado during the 2000, 2001 or 2002 legislative sessions. No legislative action is expected in 2003.

SPS

New Mexico Restructuring In March 2001, the state of New Mexico enacted legislation that delayed customer choice until 2007 and amended the Electric Utility Restructuring Act of 1999. SPS has requested recovery of its costs incurred to prepare for customer choice in New Mexico of approximately $5.1 million. A decision on this and other matters is pending before the NMPRC. SPS expects to receive regulatory recovery of these costs through a rate rider in the next New Mexico rate case filed.

Texas Restructuring In June 2001, the Governor of Texas signed legislation postponing the deregulation and restructuring of SPS until at least 2007. This legislation amended the 1999 legislation, Senate Bill No. 7 (SB-7), which provided for retail electric competition beginning January 2002. Under the newly-adopted legislation, prior PUCT orders issued in connection with the restructuring of SPS will be considered null and void. SPS restructuring and rate unbundling proceedings in Texas have been terminated. In addition, under the new legislation, SPS is entitled to recover all reasonable and necessary expenditures made or incurred before September 1, 2001, to comply with SB-7. SPS filed an application with the PUCT, requesting a rate rider to recover these costs incurred preparing for customer choice of approximately $20.3 million. These costs were incurred to position SPS for retail competition, which was eventually delayed for SPS. The filing was amended in March 2002 to reduce the recoverable costs by $7.3 million, which were associated with over-earnings for the calendar year 1999. The PUCT approved SPS using the 1999 over-earnings to offset the claims for reimbursement of transition to competition costs. This reduced the requested net collection in Texas to $13.0 million. In April 2002, a unanimous settlement agreement was reached. Final approval by the PUCT was received in May 2002. The stipulation provides for the recovery of $5.9 million through an incremental cost recovery rider and the capitalization of $1.9 million for metering equipment. Based on the settlement agreement, SPS wrote off pretax restructuring costs of approximately $5 million in the first quarter of 2002. Recovery of the $5.9 million began in July 2002.

For more information on restructuring in Texas and New Mexico, see Note 15 to the consolidated financial statements.

Kansas Restructuring During the 2001 legislative session, several restructuring-related bills were introduced for consideration by the state legislature, but to date, there is no restructuring mandate in Kansas.

Oklahoma Restructuring The Electric Restructuring Act of 1997 was enacted in Oklahoma during 1997. This legislation directed a series of studies to define the orderly transition to consumer choice of electric energy supplier by July 1, 2002. In 2001, Senate Bill 440 was signed into law to formally delay electric restructuring until restructuring issues could be studied further and new enabling legislation could be enacted. Senate Bill 440 established the Electric Restructuring Advisory Committee and directed the committee to complete an interim report on the state s transmission infrastructure needs by December 31, 2001. The Advisory Committee submitted this report to the Governor and Legislature on December 31, 2001. During 2002, there was no action taken by the Legislature as a result of this report. Oklahoma continues to delay retail competition.

Other

Wyoming Restructuring There were no electric industry restructuring legislation proposals introduced in the legislature during 2000, 2001 or 2002.

Capacity and Demand

Assuming normal weather during 2003, system peak demand and the net dependable system capacity for our electric utility subsidiaries are projected below. The electric production and transmission system of NSP-Minnesota and NSP-Wisconsin are managed as an integrated system (referred to as the NSP System). The system peak demand for each of the last three years and the forecast for 2003 are listed below.

System Peak Demand Forecast

Operating Company	2000	2001	2002	2003 Forecast
		(in megawatts)		
NSP System	7,936	8,344	8,259	8,090
PSCo	5,406	5,644	5,872	5,947
SPS	3,870	4,080	4,018	4,052

The peak demand for the NSP System, PSCo and SPS all typically occur in the summer. The 2002 system peak demand for the NSP System occurred on July 30, 2002. The 2002 system peak demand for PSCo occurred on July 18, 2002. The 2002 system peak demand for SPS occurred on August 1, 2002.

Energy Sources

Our utility subsidiaries expect to use the following resources to meet their net dependable system capacity requirements:

our electric generating stations;

purchases from other utilities, independent power producers and power marketers;

demand-side management options; and

phased expansion of existing generation at select power plants.

Purchased Power

Our electric utility subsidiaries have contractual arrangements to purchase power from other utilities and nonregulated energy suppliers. Capacity, typically measured in kilowatts or megawatts, is the measure of the rate at which a particular generating source produces electricity. Energy, typically measured in kilowatt-

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hours or megawatt-hours, is a measure of the amount of electricity produced from a particular generating source over a period of time. Purchase power contracts typically require a periodic payment to receive the capacity from a particular generating source and a charge for the associated energy actually purchased from such generating source.

Our utility subsidiaries also make short-term and non-firm purchases to replace generation from company-owned units that is unavailable due to maintenance and unplanned outages, to provide each utility s reserve obligation, to obtain energy at a lower cost than that which could be produced by other resource options, including company-owned generation and/or long-term purchase power contracts, and for various other operating requirements.

NSP System Resource Plan

In December 2002, NSP-Minnesota filed its Resource Plan with the Minnesota Public Utilities Commission (MPUC) for 2003 to 2017. The plan describes how we intend to meet the energy needs of the NSP System. The Plan contains conservation programs to reduce NSP System s peak demand and conserve overall electricity use, an approximate schedule of power purchase solicitations to meet increasing demand, and programs and plans to maintain the reliable operations of existing resources. In summary, the Plan includes the following elements:

- forecasts 1.7 percent annual growth in the NSP System s energy and peak demand requirements;
- outlines NSP System s demand side management and conservation programs;
- identifies various pending legislative and regulatory procedures affecting over half of the generating capacity necessary to meet the demand for electricity;
- proposes additional power purchase solicitations to meet growing demand for electricity; and
- updates the status of spent nuclear fuel at the Prairie Island plant and at the Monticello plant and describes the alternatives to replace nuclear generation if the two plants must be replaced as the result of spent nuclear fuel storage limitations.

The MPUC will receive comments on the Plan in the coming months and act to approve, modify, or reject the Plan late in the year. NSP-Minnesota has requested that the Minnesota Legislature address the issues of spent nuclear fuel storage limitations and their effect on the future of nuclear generation in Minnesota in the 2003 legislative session. The MPUC has suspended the procedure schedule pending completion of the legislative session.

PSCo Resource Plan

PSCo estimates it will purchase approximately 31 percent of its total electric system energy input for 2003. Approximately 44 percent of the total system capacity for the summer 2003 system peak demand for PSCo will be provided by purchased power.

To meet the demand and energy needs of the rapidly growing economy in Colorado, PSCo completed a solicitation process that will add approximately 1,800 megawatts of resources to its system over the 2002-2005 time period.

Purchased Transmission Services

Our utility subsidiaries have contractual arrangements with regional transmission service providers to deliver power and energy to the subsidiaries native load customers (retail and wholesale load obligations with terms of more than one year). Point-to-point transmission services typically include a charge for the specific amount of transmission capacity being reserved, although some agreements may base charges on the amount of metered energy delivered. Network transmission services include a charge for the metered demand at the delivery point at the time of the provider s monthly transmission system peak, usually calculated as a 12-month rolling average.

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Fuel Supply and Costs

The following tables present the delivered cost per million British thermal units (Mmbtu) of each significant category of fuel consumed for electric generation, the percentage of total fuel requirements represented by each category of fuel and the total weighted average cost of all fuels during such years.

	Coal*		Nuclear		
NSP System generating plants:	Cost	Percent	Cost	Percent	Average Fuel Cost
2002	$ 0.96	59%	$ 0.46	38%	$ 0.81
2001	$ 0.96	62%	$ 0.47	35%	$ 0.86
2000	$ 1.11	60%	$ 0.45	36%	$ 0.91

* Includes refuse-derived fuel and wood

	Coal		Gas		
PSCo generating plants:	Cost	Percent	Cost	Percent	Average Fuel Cost
2002	$ 0.91	79%	$ 2.25	21%	$ 1.19
2001	$ 0.86	84%	$ 4.27	16%	$ 1.41
2000	$ 0.91	87%	$ 3.97	13%	$ 1.30

	Coal		Gas		
SPS generating plants:	Cost	Percent	Cost	Percent	Average Fuel Cost
2002	$ 1.33	74%	$ 3.27	26%	$ 1.84
2001	$ 1.40	69%	$ 4.35	31%	$ 2.31
2000	$ 1.45	70%	$ 4.23	30%	$ 2.28

NSP-Minnesota and NSP-Wisconsin

NSP-Minnesota and NSP-Wisconsin normally maintain between 30 and 45 days of coal inventory at each plant site. Estimated coal requirements at NSP-Minnesota s major coal-fired generating plants are approximately 12 million tons per year. NSP-Minnesota and NSP-Wisconsin have long-term contracts providing for the delivery of up to 100 percent of 2003 coal requirements and up to 58 percent of their 2004 requirements. Coal delivery may be subject to short-term interruptions or reductions due to transportation problems, weather and availability of equipment.

NSP-Minnesota and NSP-Wisconsin expect that all of the coal they burn in 2003 will have a sulfur content of less than 1 percent. NSP-Minnesota and NSP-Wisconsin have contracts for a maximum of 38.4 million tons of low-sulfur coal for the next five years. The contracts are with two Montana coal suppliers and three Wyoming suppliers with expiration dates ranging between 2003 and 2007. NSP-Minnesota and NSP-Wisconsin could purchase approximately 42 percent of coal requirements in 2004 if spot prices are more favorable than contracted prices.

NSP-Minnesota and NSP-Wisconsin s current fuel oil inventory is adequate and they have access to meet anticipated 2003 requirements and they also have access to the spot market to buy more oil as needed. NSP-Minnesota and NSP-Wisconsin use both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for power plants are procured under short- and intermediate-term contracts to provide an adequate supply of fuel.

To operate NSP-Minnesota s nuclear generating plants, NSP-Minnesota secures contracts for uranium concentrates, uranium conversion, uranium enrichment and fuel fabrication. The contract strategy involves a portfolio of spot purchases and medium- and long-term contracts for uranium, conversion and enrichment. Current contracts are flexible and cover 100 percent of uranium, conversion and enrichment requirements through the year 2005. These contracts expire at varying times between 2003 and 2006. The overlapping nature of contract commitments will allow NSP-Minnesota to maintain 50 percent to 100 percent coverage beyond 2002. NSP-Minnesota expects sufficient uranium, conversion and enrichment to be available for the total fuel requirements of its nuclear generating plants. Fuel fabrication is 100 percent committed through 2004 and 30 percent committed through 2010.

PSCo

PSCo s primary fuel for its steam electric generating stations is low-sulfur western coal. PSCo s coal requirements are purchased primarily under long-term contracts with suppliers operating in Colorado and Wyoming. During 2002, PSCo s coal requirements for existing plants were approximately 10.1 million tons, a substantial portion of which was supplied pursuant to long-term supply contracts. Coal supply inventories at December 31, 2002, were approximately 47 days usage, based on the average burn rate for all of PSCo s coal-fired plants.

PSCo operates the Hayden Station, and has partial ownership in the Craig Station, in Colorado. All of Hayden Station s coal requirements are supplied under a long-term agreement. Approximately 75 percent of PSCo s Craig Station coal requirements are supplied under two long-term agreements. Any remaining Craig Station requirements for PSCo are supplied through spot coal purchases.

PSCo has secured more than 75 percent of Cameo Station s coal requirements for 2003. Any remaining requirements may be purchased from this contract or the spot market. PSCo has contracted for coal supplies to supply approximately 100 percent of the Cherokee and Valmont Stations projected requirements in 2003.

PSCo has long-term coal supply agreements for the Pawnee and Comanche Stations projected requirements. Under the long-term agreements, the supplier has dedicated specific coal reserves at the contractually defined mines to meet the contract quantity obligations. In addition, PSCo has a coal supply agreement to supply approximately 85 percent of Arapahoe Station s projected requirements for 2003. Any remaining Arapahoe Station requirements will be procured through spot purchases.

PSCo uses both firm and interruptible natural gas and standby oil in combustion turbines and certain boilers. Natural gas supplies for PSCo s power plants are procured under short and intermediate-term contracts to provide an adequate supply of fuel.

SPS

SPS purchases all of its coal requirements for Harrington and Tolk electric generating stations from TUCO Inc., in the form of crushed, ready-to-burn coal delivered to SPS plant bunkers. For the Harrington station the coal supply contract expires in 2016 and the coal-handling agreement expires in 2004. For the Tolk station, the coal supply contract expires in 2017 and the coal-handling agreement expires in 2005. At December 31, 2002, coal inventories at the Harrington and Tolk sites were approximately 44 and 53 days supply, respectively. TUCO has a long-term coal supply agreement to supply approximately 100 percent of the projected requirements for 2003 for Harrington Station and Tolk Station. TUCO has long-term contracts for the supply of coal in sufficient quantities to meet the primary needs of the Tolk station.

SPS has a number of short and intermediate contracts with natural gas suppliers operating in gas fields with long life expectancies in or near its service area. SPS also utilizes firm and interruptible transportation to minimize fuel costs during volatile market conditions and to provide reliability of supply. SPS maintains sufficient gas supplies under short and intermediate-term contracts to meet all power plant requirements; however, due to flexible contract terms, approximately 57 percent of SPS gas requirements during 2002 were purchased under spot agreements.

Trading Operations

We and our subsidiaries conduct various trading operations including the purchase and sale of electric capacity and energy. We use these trading operations to capture arbitrage opportunities created by regional pricing differentials, supply and demand imbalances, and changes in fuel prices. Participation in short-term wholesale energy markets provides market intelligence and information that supports the energy management of each utility subsidiary. We reduce commodity price and credit risks by using physical and financial instruments to minimize commodity price and credit risk and hedge supplies and purchases. Optimizing the utility subsidiaries physical assets by engaging in short-term sales and purchase commitments results in lowering the cost of supply for our native customers and the capturing of additional margins from non-traditional customers. We and our subsidiaries also use these trading operations to capture arbitrage opportunities created by regional pricing differentials, supply and demand imbalances and changes in fuel prices.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. Monticello began operation in 1971 and is licensed to operate until 2010. Prairie Island units 1 and 2 began operation in 1973 and 1974 and are licensed to operate until 2013 and 2014, respectively.

Nuclear power plant operation produces gaseous, liquid and solid radioactive wastes. The discharge and handling of such wastes are controlled by federal regulation. High-level radioactive waste includes used nuclear fuel. Low-level radioactive waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that has become contaminated through use in the plant.

Federal law places responsibility on each state for disposal of its low-level radioactive waste. Low-level radioactive waste from NSP-Minnesota s Monticello and Prairie Island nuclear plants is currently disposed of at the Barnwell facility, located in South Carolina (all classes of low-level waste), and the Clive facility, located in Utah (class A low-level waste only). Chem Nuclear is the owner and operator of the Barnwell facility, which has been given authorization by South Carolina to accept low-level radioactive waste from out of state. Envirocare, Inc. operates the Clive facility. NSP-Minnesota and Barnwell currently operate under an annual contract, while NSP-Minnesota uses the Envirocare facility through various low-level waste processors. NSP-Minnesota has low-level storage capacity available on-site at Prairie Island and Monticello that would allow both plants to continue to operate until the end of their licensed life, if off-site low-level disposal facilities were not available to NSP-Minnesota.

The federal government has the responsibility to dispose of, or permanently store, domestic spent nuclear fuel and other high-level radioactive wastes. The Nuclear Waste Policy Act requires the United States Department of Energy (DOE) to implement a program for nuclear waste management. This includes the siting, licensing, construction and operation of a repository for domestically produced spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive wastes at a permanent storage or disposal facility by 1998. None of NSP-Minnesota s spent nuclear fuel has yet been accepted by the DOE for disposal. See Legal Proceedings and Note 19 to the consolidated financial statements for further discussion of this matter.

NSP-Minnesota has on-site storage for spent nuclear fuel at its Monticello and Prairie Island nuclear plants. The Prairie Island plant is licensed by the federal Nuclear Regulatory Commission (NRC) to store up to 48 casks of spent fuel at the plant. In 1994, the Minnesota Legislature adopted a limit on dry cask storage of 17 casks for the entire state. The 17 casks, which stand outside the Prairie Island plant, are now full, and under the current configuration the storage pool within the plant would be full by 2007. Prairie Island cannot operate beyond 2007 unless the existing spent fuel is moved or the storage capacity is increased. Because the 17-cask limit is a statewide limit, the Monticello plant cannot, under current state law, store spent fuel in dry casks. Monticello s on-site storage pool is expected to be full in 2010. Monticello cannot operate beyond 2010 unless the existing spent fuel is moved or the storage capacity is increased.

NSP-Minnesota is part of a consortium of private parties working to establish a private facility for interim storage of spent nuclear fuel. In 1997, Private Fuel Storage, LLC (PFS) filed a license application with the NRC for a temporary storage site for spent nuclear fuel on the Skull Valley Indian Reservation in Utah. The NRC license review process includes formal evidentiary hearings before an Atomic Safety and Licensing Board (ASLB) and opportunities for public input. Evidentiary hearings were held in 2000 and 2002, Most of the issues raised by opponents of the project have been favorably resolved or dismissed. On March 10, 2003, the ASLB ruled that the likelihood of certain aircraft crashes into the proposed facility was sufficiently credible that it would have to be addressed before the facility could be licensed and set forth a potential process for addressing this concern. PFS is currently evaluating this decision and awaiting ASLB decisions on

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the remaining five major issues expected in a few weeks. Due to uncertainty regarding NRC and other regulatory and governmental approvals, it is possible that this interim storage may be delayed or not available at all.

If the Prairie Island plant is to continue operating beyond 2007, legislative authorization of additional storage space is needed. If additional storage space for continued operations is not authorized, legislation may be needed to ensure timely implementation of a replacement alternative.

NSP-Minnesota has developed viable replacement power options, including purchasing new coal or natural gas generation, and also reviewed the feasibility of supplementing new natural gas generation with additional wind turbines. These options have been presented to the 2003 Legislature. Each option involves trade-offs between cost, emissions and operational impacts.

Due to the investment decisions required to be made in conjunction with the continued efficient operation of the nuclear plants, as well as the time and cost involved to develop alternatives to the existing nuclear power generation, NSP-Minnesota believes a decision is necessary in 2003 by the Minnesota Legislature whether the state will allow the continued use of nuclear power in the future. Prairie Island will only be able to continue operating beyond 2007 with legislative authorization of additional storage space.

In February 2001, NSP-Minnesota signed a contract with Steam Generating Team Ltd. to perform engineering and construction services for the installation of replacement steam generators at the Prairie Island nuclear power plant. NSP-Minnesota is evaluating the economics of replacing two steam generators on unit 1 at the plant. NSP-Minnesota is taking steps to preserve the replacement option for as early as 2004. The total cost of replacing the steam generators is estimated to be approximately $132 million.

The NRC is engaged in various ongoing studies and rulemaking activities that may impose additional requirements upon commercial nuclear power plants. Management is unable to predict any new requirements or their impact on NSP-Minnesota s facilities and operations.

Nuclear Management Company

During 1999, NSP-Minnesota, Wisconsin Electric Power Co., Wisconsin Public Service Corp. and Alliant Energy established the Nuclear Management Company (NMC). Consumers Power joined the NMC during 2000, and transferred operating authority for the Palisades nuclear plant to the NMC in 2001. The five affiliated companies own eight nuclear units on six sites, with total generation capacity exceeding 4,500 megawatts. We are currently a 20 percent owner of the NMC.

The NRC has approved requests by the NMC s affiliated utilities to transfer operating authority for their nuclear plants to the NMC, formally establishing the NMC as an operating company. The NMC manages the operations and maintenance at the plants, and is responsible for physical security. NMC responsibilities also include oversight of on-site dry storage facilities for used nuclear fuel at the Prairie Island nuclear plant. Utility plant owners, including us, continue to own the plants, control all energy produced by the plants and retain responsibility for nuclear liability insurance and decommissioning costs. Existing personnel continue to provide day-to-day plant operations, with the additional benefit of sharing ideas and operating experience from all NMC-operated plants for improved safety, reliability and operational performance.

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For further discussion of nuclear issues, see Note 18 and Note 19 to the audited consolidated financial statements.

Electric Operating Statistics (Xcel Energy)

	Year Ended Dec. 31		
	2002	**2001**	**2000**
Electric sales (millions of Kwh):			
Residential	23,302	22,113	22,101
Commercial and industrial	57,815	57,755	57,409
Public authorities and other	1,143	1,103	1,184
Total retail	82,260	80,971	80,694
Sales for resale	23,256	26,104	26,284
Total energy sold	105,516	107,075	106,978
Number of customers at end of period:			
Residential	2,756,565	2,722,832	2,691,505
Commercial and industrial	394,620	387,579	380,784
Public authorities and other	81,341	100,819	98,715
Total retail	3,232,526	3,211,230	3,171,004
Wholesale	309	305	220
Total customers	3,232,835	3,211,535	3,171,224

Gas Utility Operations

Competition and Industry Restructuring

In the early 1990 s, the FERC issued Order No. 636, which mandated the unbundling of interstate natural gas pipeline services sales, transportation, storage and ancillary services. The implementation of Order No. 636 has resulted in additional competitive pressure on all local distribution companies (LDC) to keep gas supply and transmission prices for their large customers competitive. Customers have greater ability to buy gas directly from suppliers and arrange their own pipeline and LDC transportation service. Changes in regulatory policies and market forces have shifted the industry from traditional bundled gas sales service to an unbundled transportation and market based commodity service.

The natural gas delivery or transportation business has remained competitive as industrial and large commercial customers have the ability to bypass the local gas utility through the construction of interconnections directly with, and the purchase of gas directly from, interstate pipelines, thereby avoiding the delivery charges added by the local gas utility.

As LDCs NSP-Minnesota, NSP-Wisconsin and PSCo provide unbundled transportation service to large customers. Transportation service does not have an adverse effect on earnings because the sales and transportation rates have been designed to make them economically indifferent to whether gas has been sold and transported or merely transported. However, some transportation customers may have greater opportunities or incentives to physically bypass the LDC distribution system.

The Colorado Legislature passed legislation in 1999 that provides the CPUC the authority and responsibility to approve voluntary unbundling plans submitted by Colorado gas utilities in the future. PSCo has not filed a plan to further unbundle its gas service to all residential and commercial customers and continues to evaluate its business opportunities for doing so.

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Capability and Demand

NSP-Minnesota and NSP-Wisconsin

We categorize our gas supply requirements as firm or interruptible (customers with an alternate energy supply). The maximum daily sendout (firm and interruptible) for the combined system of NSP-Minnesota and NSP-Wisconsin was 722,992 MMBtu for 2001, which occurred on February 1, 2001 and 650,641 MMBtu for 2002, which occurred on January 2, 2002.

NSP-Minnesota and NSP-Wisconsin purchase gas from independent suppliers. The gas is delivered under gas transportation agreements with interstate pipelines. These agreements provide for firm deliverable pipeline capacity of approximately 604,000 MMBtu/day. In addition, NSP-Minnesota and NSP-Wisconsin have contracted with providers of underground natural gas storage services. These storage agreements provide storage for approximately 15 percent of winter season and 23 percent of peak daily, firm requirements of NSP-Minnesota and NSP-Wisconsin.

NSP-Minnesota and NSP-Wisconsin also own and operate two liquefied natural gas (LNG) plants with a storage capacity of 2.5 Billion cubic feet (Bcf) equivalent and four propane-air plants with a storage capacity of 1.4 Bcf equivalent to help meet its peak requirements. These peak-shaving facilities have production capacity equivalent to 246,000 MMBtu of natural gas per day, or approximately 32 percent of peak day firm requirements. LNG and propane-air plants provide a cost-effective alternative to annual fixed pipeline transportation charges to meet the peaks caused by firm space heating demand on extremely cold winter days and can be used to minimize daily imbalance fees on interstate pipelines.

NSP-Minnesota and NSP-Wisconsin are required to file for a change in gas supply contract levels to meet peak demand, to redistribute demand costs among classes, or exchange one form of demand for another. In October 2001, the MPUC approved NSP s 2000-2001 entitlement levels, NSP-Minnesota s 2001-2002 entitlement levels were approved on April 3, 2002, which allow NSP-Minnesota to recover the demand entitlement costs associated with the increase in transportation and storage levels in its monthly PGA. NSP-Minnesota s filing for approval of its 2001-2002 entitlement levels is pending MPUC action. NSP-Wisconsin s winter 2002-2003 supply plan was approved by the PSCW in October 2002.

PSCo and Cheyenne

PSCo and Cheyenne project peak day gas supply requirements for firm sales and backup transportation (transportation customers contracting for firm supply backup) to be approximately 1,756,000 MMBtu. In addition, firm transportation customers hold 451,000 MMBtu of capacity without supply backup. Total firm delivery obligations for PSCo and Cheyenne are 2,206,870 MMBtu per day. The maximum daily deliveries for both companies for 2002 (firm and interruptible services) were 1,652,459 MMBtu on February 25, 2002.

PSCo and Cheyenne purchase gas from independent suppliers. The gas supplies are delivered to the respective delivery systems through a combination of transportation agreements with interstate pipelines and deliveries by suppliers directly to each company. These agreements provide for firm deliverable pipeline capacity of approximately 1,220,000 MMBtu/day, which includes 797,000 MMBtu of supplies held under third-party underground storage agreements. In addition, PSCo operates three company-owned underground storage facilities, which provide about 38,000 MMBtu of gas supplies on a peak day. The balance of the quantities required to meet firm peak day sales obligations are primarily purchased at the companies city gate meter stations and a small amount received directly from wellhead sources.

PSCo has received approval to close one if its three storage facilities, Leyden Storage Field. The field s 110,000 MMBtu peak day capacity was replaced with additional third-party storage and transportation capacity.

PSCo is required by CPUC regulations to file a gas purchase plan by June of each year projecting and describing the quantities of gas supplies, upstream services and the costs of those supplies and services for the period beginning July 1 through June 30 of the following year. PSCo is also required to file a gas purchase report by October of each year reporting actual quantities and costs incurred for gas supplies and upstream services for the 12-month period ending the previous June 30.

Gas Supply and Costs

Our gas utilities actively seek gas supply, transportation and storage alternatives to yield a diversified portfolio that provides increased flexibility, decreased interruption and financial risk, and economical rates. This diversification involves numerous domestic and Canadian supply sources, with varied contract lengths.

The following table summarizes the average cost per MMBtu of gas purchased for resale by our regulated retail gas distribution business.

	NSP-Minnesota	NSP-Wisconsin	PSCo	Cheyenne
2002	$ 3.98	$ 4.63	$ 3.17	$ 2.77
2001	$ 5.83	$ 5.11	$ 4.99	$ 5.03
2000	$ 4.56	$ 4.71	$ 4.48	$ 4.03

The cost of natural gas supply, transportation service and storage service is recovered through various cost recovery adjustment mechanisms.

NSP-Minnesota and NSP-Wisconsin

NSP-Minnesota and NSP-Wisconsin have firm gas transportation contracts with several pipelines, which expire in various years from 2003 through 2014. Approximately 80 percent of NSP-Minnesota and NSP-Wisconsin s retail gas customers are served from the Northern Natural pipeline system.

NSP-Minnesota and NSP-Wisconsin have certain gas supply and transportation agreements that include obligations for the purchase and/or delivery of specified volumes of gas or to make payments in lieu of delivery. At December 31, 2002, NSP-Minnesota and NSP-Wisconsin were committed to approximately $267.7 million in such obligations under these contracts, which expire in various years from 2003 through 2014.

NSP-Minnesota and NSP-Wisconsin purchase firm gas supply utilizing long-term and short-term agreements from approximately 37 domestic and Canadian suppliers under contracts. This diversity of suppliers and contract lengths allows NSP-Minnesota and NSP-Wisconsin to maintain competition from suppliers and minimize supply costs.

PSCo and Cheyenne

PSCo and Cheyenne have certain gas supply and transportation agreements that include obligations for the purchase and/or delivery of specified volumes of gas or to make payments in lieu of delivery. At December 31, 2002, PSCo and Cheyenne were committed to approximately $906.3 million in such obligations under these contracts, which expire in various years from 2003 through 2025.

PSCo and Cheyenne have attempted to maintain low-cost, reliable natural gas supplies by optimizing a balance of long-term and short-term gas purchases, firm transportation and gas storage contracts. PSCo and Cheyenne also utilize a mixture of fixed-price purchases and index-related purchases to provide a less volatile, yet market sensitive, price to their customers. During 2002, PSCo and Cheyenne purchased natural gas from approximately 44 suppliers.

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Viking

On November 7, 2002, we reached an agreement to sell our wholly owned subsidiary, Viking and Viking s share of Guardian Pipeline to Border Viking Company (Border) whose ultimate parent is Northern Border Partners L.P. The sale closed on January 17, 2003, and we received net proceeds of $124 million.

Gas Operating Statistics (Xcel Energy)

	Year Ended Dec. 31,		
	2002	**2001**	**2000**
Gas deliveries (thousands of Dth):			
Residential	144,038	136,568	137,989
Commercial and industrial	95,959	97,303	96,370
Total retail	239,997	233,871	234,359
Transportation and other	294,640	284,301	297,041
Total deliveries	534,637	518,172	531,400
Number of customers at end of period:			
Residential	1,574,489	1,531,589	1,483,114
Commercial and industrial	148,383	146,266	143,568
Total retail	1,722,872	1,677,855	1,626,682
Transportation and other	3,189	3,054	3,233
Total customers	1,726,061	1,680,909	1,629,915
Gas Revenues (thousands of dollars):			
Residential	$ 842,786	$ 1,233,205	$ 878,638
Commercial and Industrial	455,152	711,282	506,040
Total Retail	1,297,938	1,944,487	1,384,678
Transportation and other	99,862	108,164	84,202
Total Gas Revenues	$ 1,397,800	$ 2,052,651	$ 1,468,880

Nonregulated Subsidiaries

Through our non-utility subsidiaries, we invest and operate several nonregulated businesses in a variety of industries. The following is an overview of the significant nonregulated businesses.

NRG Energy, Inc.

NRG is a global energy company primarily engaged in the ownership and operation of power generation facilities and the sale of energy, capacity and related products.

At December 31, 2001, we indirectly owned approximately 74 percent of NRG. We owned 100 percent of NRG until the second quarter of 2000, when NRG completed its initial public offering and 82 percent until a secondary offering was completed in March 2001.

In response to tightening credit standards experienced by NRG and the independent power production sector, on February 15, 2002 we announced a financial improvement and restructuring plan for NRG. The announced plan included an initial step of acquiring 100 percent ownership of NRG through a tender offer and merger to exchange all outstanding shares of NRG common stock with our common shares. In addition, the plan included:

- financial support to NRG from us;
- marketing certain NRG generating assets for possible sale;
- canceling and deferring capital spending for NRG projects; and
- combining certain NRG functions with our system and organization in order to realize greater synergies and to reduce expenses.

In June 2002, we acquired 100 percent ownership of NRG through the acquisition of NRG minority common shares.

NRG has experienced significant growth in the past, especially the year 2001, expanding from 15,007 megawatts of net ownership interest in power generation facilities (including those under construction) as of December 31, 2000 to 24,357 megawatts of net ownership interests as of December 31, 2001. NRG has a well diversified portfolio in terms of location, fuel and dispatch mode. See a listing of NRG power generation facilities below.

On Nov. 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG in the United States Bankruptcy Court for the District of Minnesota (Minnesota Bankruptcy Court). Under provisions of federal law, NRG has the full authority to continue to operate its business as if the involuntary petition had not been filed unless and until a court hearing on the validity of the involuntary petition is resolved adversely to NRG. NRG responded to the involuntary petition, contesting the petitioners claims and filing a motion to dismiss the case. A hearing has been set for April 10, 2003 to consider the motion to dismiss. In their petition, the petitioners sought recover of severance and other benefits of approximately $28 million.

NRG and its counsel have been involved in negotiations with the petitioners and their counsel. As a result of these negotiations, NRG and the petitioners reached an agreement and compromise regarding their respective claims against each other (Settlement Agreement). In February 2003, the Settlement Agreement was executed, pursuant to which NRG agreed to pay the petitioners an aggregate settlement in the amount of $12 million.

On February 28, 2003, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a petition alleging that they hold unsecured, non-contingent claims against NRG in a joint amount of $100 million. The Minnesota Bankruptcy Court has discretion in reviewing and ruling on the motion to dismiss and the review and approval of the Settlement Agreement. There is a risk that the Minnesota Bankruptcy Court may, among other things, reject the Settlement Agreement or enter an order for relief under Chapter 11 of Title 11 of the Bankruptcy Code.

On March 26, 2003, our board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against us, including claims related to the support and capital subscription agreement between us and NRG dated May 29, 2002 (the Support Agreement). The settlement is subject to a variety of conditions as set forth below, including definitive documentation. The principal terms of the settlement as of the date of this prospecturs were as follows:

We would pay up to $752 million to NRG to settle all claims of NRG, and the claims of NRG against us, including all claims under the Support Agreement.

$350 million would be paid at or shortly following the consummation of a restructuring of NRG s debt through a bankruptcy proceeding. It is expected that this payment would be made prior to year-end 2003. $50 million would be paid on January 1, 2004, and all or any part of such payment could be made, at our election, in our common stock. Up to $352 million would be paid on April 30, 2004, except to the extent that we had not received at such time tax refunds equal to $352 million associated with the loss on our investment

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in NRG. To the extent we had not received such refunds, the April 30 payment would be due on May 30, 2004.

$390 million of our payments are contingent on receiving releases from NRG creditors. To the extent we do not receive a release from an NRG creditor, our obligation to make $390 million of the payments would be reduced based on the amount of the creditor s claim against NRG. As noted below, however, the entire settlement is contingent upon us receiving releases from at least 85 percent of the claims in various NRG creditor groups. As a result, it is not expected that our payment obligations would be reduced by more than approximately $60 million. Any reduction would come from our payment due on April 30, 2004.

Upon the consummation of NRG s debt restructuring through a bankruptcy proceeding, our exposure on any guaranties or other credit support obligations incurred by us for the benefit of NRG or any subsidiary would be terminated and any cash collateral posted by us would be returned to us. The current amount of such cash collateral is approximately $11.5 million.

As part of the settlement with us, any intercompany claims of us against NRG or any subsidiary arising from the provision of intercompany goods or services or the honoring of any guaranty will be paid in full in cash in the ordinary course except that the agreed amount of such intercompany claims arising or accrued as of January 31, 2003 will be reduced from approximately $55 million as asserted by us to $13 million. The $13 million agreed amount is to be paid upon the consummation of NRG s debt restructuring with $3 million in cash and an unsecured promissory note of NRG on market terms in the principal amount of $10 million.

NRG and its direct and indirect subsidiaries would not be reconsolidated with us or any of our other affiliates for tax purposes at any time after their June 2002 re-affiliation or treated as a party to or otherwise entitled to the benefits of any tax sharing agreement with us. Likewise, NRG would not be entitled to any tax benefits associated with the tax loss we expect to incur in connection with the write down of our investment in NRG.

Our obligations under the tentative settlement, including our obligations to make the payments set forth above, are contingent upon, among other things, the following:

- Definitive documentation, in form and substance satisfactory to the parties;
- Between 50 percent and 100 percent of the claims represented by various NRG facilities or creditor groups (the NRG Credit Facilities) having executed an agreement, in form and substance satisfactory to us, to support the settlement;
- Various stages of the implementation of the settlement occurring by dates currently being negotiated, with the consummation of the settlement to occur by September 30, 2003;
- The receipt of releases in our favor by at least 85 percent of the claims represented by the NRG Credit Facilities;
- The receipt by us of all necessary regulatory approvals; and
- No downgrade prior to consummation of the settlement of any of our credit ratings from the level of such ratings as of March 25, 2003.

On May 12, 2003, the Minnesota Bankruptcy Court granted NRG s motion to dismiss the involuntary chapter 11 petition against NRG.

On May 14, 2003, NRG and certain of NRG s U.S. affiliates filed voluntary petitions for reorganization under Chapter 11 of the U.S. Bankruptcy Code to restructure their debt. Neither we nor any of our other subsidiaries were included in the filing. NRG s plan of reorganization filed with the U.S. Bankruptcy Court for the Southern District of New York incorporates the terms of an overall settlement among NRG, us and NRG s major creditor constituencies that provides for payments by us to NRG, and that NRG will pay in turn to its creditors, of up to $752 million.

A plan support agreement reflecting the settlement has been signed by us, holders of approximately 40% of NRG s long-term notes and bonds along with two NRG banks who serve as co-chairs of the global steering committee for the NRG bank lenders. This agreement will become fully effective upon execution by holders of approximately an additional ten percent in principal amount of NRG s long-term notes and bonds and by a majority of NRG bank lenders representing at least two-thirds in principal amount of NRG s bank debt. We expect the requisite signatures will be obtained promptly. The term of the settlement with NRG s major creditors are basically the same as previously reported. See our discussion in Recent Developments above.

Since many of these conditions are not within our control, we cannot state with certainty that the settlement will be effectuated. Nevertheless, our management is optimistic at this time that the settlement will be implemented.

NRG is organized into four regionally-based divisions: NRG North America based in Minneapolis, Minnesota; NRG Europe, based in London, England; NRG Asia-Pacific based in Brisbane, Australia and NRG Latin America, based in Miami, Florida. Most of NRG s North American projects are grouped under regional holding companies corresponding to their domestic core market. NRG operates its United States generation facilities within each region as a separate operating unit within its power generation business. This regional portfolio structure allows NRG to coordinate the operations of its assets to take advantage of regional opportunities, reduce risks related to outages, whether planned or unplanned, and pursue expansion plans on a regional basis.

NRG s international power generation projects are managed as three distinct markets, Asia-Pacific, Europe and Other Americas.

At December 31, 2002, NRG had interests in power generation facilities with a total generating capacity of 46,346 megawatts. Of this amount, NRG has a net ownership of 28,770 megawatts. NRG also has interests in district heating and cooling systems and steam transmission operations. As of December 31, 2002, these thermal businesses had a steam and chilled water capacity equivalent to approximately 1,641 megawatts, of which NRG s net ownership interest is 1,514 megawatts.

Through January 31, 2003, NRG completed a number of transactions, which resulted in net cash proceeds to NRG after debt pay downs and after financial advisor fees of approximately $350 million.

In the second-quarter 2002, NRG announced the sale of its ownership interest in an Australian energy company, Energy Development Limited (EDL) and its 50 percent interest in Collinsville Power Station in Australia. These transactions reached financial close during the third-quarter of 2002 and the company received proceeds of approximately $45 million in exchange for its ownership interest in these two assets.

In the third-quarter, 2002, NRG announced the sale of its Csepel power generating facilities, its 44.5 percent interest in the ECKG power station and its interest in Entrade, an electricity trading business. These transactions reached financial close in the fourth quarter 2002 and the first quarter of 2003 and the company realized net cash proceeds of approximately $200 million.

In the fourth-quarter 2002 NRG closed several transactions resulting in net proceeds of approximately $105 Million. The transactions included the sale of 60 percent interest in Compania Electrica Central Bulo Bulo S.A. (Bulo Bulo), a Bolivian corporation; NRG s transfer of its indirect 50% interest in SRW Cogeneration LP (SRW), which owns a cogeneration facility in Orange County, Texas; and NRG s sale of its 57.7 percent interest in the Crockett Cogeneration Project and the sale of its 39.5 percent indirect partnership interest in the Mt. Poso Cogeneration Company, a California limited partnership (Mt. Poso), in California.

NRG Divestitures and Project Terminations

Conectiv In April 2002, NRG terminated its purchase agreement with a subsidiary of Conectiv to acquire 794 megawatts of generating capacity and other assets, including an additional 66 megawatts of the Conemaugh Generating Station and an additional 42 megawatts of the Keystone Generating Station. Canceling the acquisition will result in a $230 million reduction in NRG s capital spending for 2002. No incremental costs were incurred by NRG related to the termination of this agreement.

FirstEnergy Assets In 2001, NRG had signed purchase agreements to acquire or lease a portfolio of generating assets from FirstEnergy Corporation. Under the terms of the agreements, NRG had agreed to finance approximately $1.6 billion for four primarily coal-fueled generating stations.

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On August 8, 2002, FirstEnergy notified NRG that the purchase agreements related to FirstEnergy generating assets had been cancelled. FirstEnergy cited the reason for canceling the agreements as an alleged anticipatory breach of certain obligations in the agreements by NRG. FirstEnergy also notified NRG that it is reserving the right to pursue legal action against NRG and us for damages, based on the alleged anticipatory breach. On February 5, 2003, FirstEnergy submitted filings with the U.S. Bankruptcy Court in Minnesota seeking permission to file a demand for arbitration against NRG. On February 27, 2003, FirstEnergy gave NRG notice that it was commencing arbitration against NRG to determine whether NRG is liable to FirstEnergy for failure to close the transaction. NRG believes it has meritorious defenses against FirstEnergy s claim and intends to vigorously defend its position. No amount has been accrued for this contingency. Management is unable to predict the ultimate outcome of this matter, however, an adverse decision could be material to NRG s financial position and results of operations.

LSP Pike Energy, LLC In August 2002, The Shaw Group (Shaw) and NRG tentatively entered into an agreement to transfer NRG s interest in the assets in LSP Pike Energy, LLC (Pike), a 1,200-megawatt combined cycle gas turbine plant currently under construction in Mississippi, which is approximately one-third completed. The agreement was subject to approval by the NRG board of directors and lenders. To date, Pike, NRG and its lenders have not approved the agreement and are not expected to in the near future.

On October 17, 2002 Shaw filed an involuntary petition for liquidation of Pike under Chapter 7 of the U.S. Bankruptcy Code. Shaw also filed suit against us and NRG. The suit seeks recovery of approximately $130 million as a result of multiple breaches of contract. Pike and NRG expect to challenge the allegations vigorously and believe Shaw s claims regarding the Pike project do not give Shaw any recourse against NRG or us. The carrying value of Pike s assets has been reduced to zero as a result of the impairments reflected as Special Charges. See discussion in Note 2 to the consolidated financial statements. See also Note 3 to the consolidated financial statements for discussion of other NRG divestitures that are reported as discontinued operations or assets held for sale as of December 31, 2002.

NRG 2001 Business Developments

During 2001, NRG completed numerous acquisitions. NRG has generally financed the acquisition and development of projects under financing arrangements to be repaid solely from each of its project s cash flows, which are typically secured by the plant s physical assets and equity interests in the project company. These acquisitions were recorded using the purchase method of accounting. Accordingly, the purchase prices were allocated to assets acquired and liabilities assumed based on their estimated fair values at the date of acquisition. Operations of the acquired companies have been included in the operations of NRG since the date of the respective acquisitions.

In January 2001, NRG purchased from LS Power, LLC a 5,339 MW portfolio of operating projects and projects in construction and advanced development that are located primarily in the north central and south central United States. Each facility employs natural gas-fired, combined-cycle technology. Through December 31, 2005, NRG also has the opportunity to acquire ownership interests in an additional 3,000 MW of generation projects developed and offered for sale by LS Power and its partners.

In March 2001, NRG purchased from Cogentrix the remaining 430 MW, or 51.37% interest, in an 837 MW natural gas-fired combined-cycle plant in Batesville, Mississippi. NRG acquired a 48.63% interest in the plant in January 2001 from LS Power.

In June 2001, NRG purchased a 640 MW natural gas-fired power plant in Audrain County, Missouri from Duke Energy North America LLC.

In June 2001, NRG closed on the construction financing for the Brazos Valley generating facility, a 633 MW gas-fired power plant in Fort Bend County, Texas that NRG will build, operate and manage. At the time of the closing, NRG also became the 100% owner of the project by purchasing STEAG Power LLC s 50% interest in the project. During January 2003, NRG transferred its interest in the Brazos Valley project to its creditors.

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In June 2001, NRG purchased 1,081 MW of interests in power generation plants from a subsidiary of Conectiv. NRG acquired a 100% interest in the 784 MW coal-fired Indian River Generating Station located near Millsboro, Delaware, and in the 170 MW oil-fired Vienna Generating Station located in Vienna, Maryland. In addition, NRG acquired 64 MW of the 1,711 MW coal-fired Conemaugh Generating Station located approximately 60 miles east of Pittsburgh, Pennsylvania and 63 MW of the 1,711 MW coal-fired Keystone Generating Station located approximately 50 miles east of Pittsburgh, Pennsylvania.

In June 2001, NRG purchased a 389 MW gas-fired power plant and a 116 MW thermal power plant, both of which are located on Csepel Island in Budapest, Hungary, from PowerGen. In April 2001, NRG also purchased from PowerGen its interest in Saale Energie GmbH and its 33.3% interest in MIBRAG BV. By acquiring PowerGen s interest in Saale Energie, NRG increased its ownership interest in the 960 MW coal-fired Schkopau power station located near Halle, Germany from 200 MW to 400 MW.

By acquiring PowerGen s interest in MIBRAG, an integrated energy business in eastern Germany consisting primarily of two lignite mines and three power stations, and following MIBRAG s buy back of the shares NRG acquired from PowerGen, NRG increased its ownership of MIBRAG from 33.3% to 50%. The Washington Group International, Inc., owns the remaining 50% of MIBRAG.

In August 2001, NRG acquired from Indeck Energy Services, Inc. an approximately 2,255 MW portfolio of operating projects and projects in advanced development, that are located in Illinois and upstate New York.

In August 2001, NRG acquired Duke Energy s 77% interest in the approximately 520 MW natural-gas fired McClain Energy Generating Facility located near Oklahoma City, Oklahoma. The Oklahoma Municipal Power Authority owns the remaining 23% interest. The McClain facility commenced operations in June 2001.

In September 2001, NRG acquired a 50% interest in TermoRio SA, a 1,040 MW gas-fired cogeneration facility currently under construction in Rio de Janeiro State, Brazil, from Petroleos Brasileiros SA (Petrobras). Commercial operation of the facility is expected to begin in March 2004. NRG has the option to put its interest in the project back to Petrobras after March 2002 if by that time certain milestones have not been met, including final agreement on the terms of all project documents.

During fiscal year 2001, NRG also acquired other minor interests in projects in Taiwan, India, Peru and the State of Nevada.

The respective purchase prices have been allocated to the net assets of the acquired entities as follows:

	Year Ended Dec. 31, 2002	
Current assets:	$	307,654
Property plant and equipment		4,173,509
Non-current portion of notes receivable		736,041
Current portion of long term debt assumed		(61,268)
Other current liabilities		(99,666)
Long term debt assumed		(1,586,501)
Deferred income taxes		(149,988)
Other long term liabilities		(202,411)
Other non-current assets and liabilities		(181,473)
Total purchase price		2,935,897
Less Cash balances acquired (excluding restricted cash)		(122,780)
Net purchase price	$	2,813,117

In July 2001, NRG signed agreements to acquire from Edison Mission Energy a 50% interest in the 375 MW Commonwealth Atlantic gas and oil-fired generating station located near Chesapeake, Virginia, and

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a 50% interest in the 110 MW James River coal-fired generating facility in Hopewell, Virginia. NRG closed the acquisition of the Commonwealth Atlantic and James River generating facilities in January 2002, for $11.2 million and $6.5 million, respectively.

Terminated Asset Acquisitions

Conectiv In April 2002, NRG terminated its purchase agreement with a subsidiary of Conectiv to acquire 794 MW of generating capacity and other assets, including an additional 66 MW of the Conemaugh Generating Station and an additional 42 MW of the Keystone Generating Station. The purchase price for these assets was approximately $230 million. No incremental costs were incurred by NRG related to the termination of this agreement.

FirstEnergy In November 2001, NRG signed purchase agreements to acquire or lease a portfolio of generating assets from FirstEnergy Corporation. Under the terms of the agreements, NRG agreed to pay approximately $1.6 billion for four primarily coal-fueled generating stations.

On July 2, 2002, the Federal Energy Regulatory Commission (FERC) issued an order approving the transfer of FirstEnergy generating assets to NRG; however, the FERC conditioned the approval on NRG s assumption of FirstEnergy s obligations under a separate agreement between FirstEnergy and the City of Cleveland. These conditions required FirstEnergy to protect the City of Cleveland in the event the generating assets are taken out of service. On July 16, 2002, FERC clarified that the condition would require NRG to provide notice to the City of Cleveland and FirstEnergy if the generating assets were taken out of service and that other obligations remain with FirstEnergy.

On August 8, 2002, FirstEnergy notified NRG that the agreements regarding the transfer of generating assets from FirstEnergy to NRG had been cancelled. FirstEnergy cited the reason for canceling the agreements as an alleged anticipatory breach of certain obligations in the agreements by NRG. On February 27, 2003, FirstEnergy gave NRG notice that it was commencing arbitration against NRG to determine whether NRG is liable to FirstEnergy for failure to close the transaction. NRG believes it has meritorious defenses against FirstEnergy s claim and intends to vigorously defend its position. No amount has been accrued for this contingency. Management is unable to predict the ultimate outcome of this matter, however, an adverse decision could be material to NRG s financial position and results of operations.

e prime, inc.

e prime was incorporated in 1995 under the laws of Colorado. e prime provides energy related products and services, which include natural gas marketing and trading and energy consulting. In 1996, e prime received authorization from the FERC to act as a power marketer. Additionally, e prime owns Young Gas Storage Company, which owns a 47.5 percent general partnership interest in an underground gas storage facility in northeastern Colorado.

e prime s gas trading operations acquire assets and commodities and subsequently trade around those assets or commodity positions. e prime captures trading opportunities through price volatility driven by factors such as asset utilization, locational price differentials, weather, available supplies, credit, and customer actions. Trading margins are captured through the utilization of transmission, transportation, and storage assets, capitalization on regional price differences, and other factors.

Other Subsidiaries

Although not individually reportable segments, we also have a number of nonregulated subsidiaries in various lines of business. The most significant are discussed below.

Xcel Energy International

XEI was formed in 1997 to manage our international operations, outside of NRG. At December 31, 2002, XEI s primary investments included Yorkshire Power and Xcel Energy Argentina.

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In April 1997, XEI purchased a 50 percent interest in Yorkshire Power, a U.K. regional electricity company, for approximately $362 million. Yorkshire Electricity s main business is the supply and distribution and supply of electricity and the supply of gas to approximately 2 million customers. During April 2001, XEI sold the majority of its investment in Yorkshire Power to Innogy Holdings plc. We received approximately $366 million for the sale, which approximated the book value of our investment.

Yorkshire Power Group Sale In August 2002, we announced that we had sold our 5.25-percent interest in Yorkshire Power Group Limited for $33 million to CE Electric UK. Xcel Energy and American Electric Power Co. each held a 50-percent interest in Yorkshire, a UK retail electricity and gas supplier and electricity distributor, before selling 94.75 percent of Yorkshire to Innogy Holdings plc in April 2001. The sale of the 5.25-percent interest resulted in an after-tax loss of $8.3 million, or 2 cents per share, in the third quarter of 2002. The loss is included in write-downs and disposal losses from investments on the Statement of Income.

As of December 31, 2002, XEI s investment in Argentina was $112 million. In December 2002, a subsidiary of Xcel Energy decided it would no longer fund one of its power projects in Argentina. This decision resulted in the shutdown of the Argentina plant facility, pending financing of a necessary maintenance outage. Updated cash flow projections for the plant were insufficient to provide recovery of XEI s investment. An impairment write-down of approximately $13 million, or 3 cents per share, was recorded in the fourth quarter of 2002.

Utility Engineering

UE was incorporated in 1985 under the laws of Texas. UE is engaged in engineering, design, construction management and other miscellaneous services. UE currently has five wholly-owned subsidiaries Universal Utility Services LLC, Precision Resource Co., Quixx, Proto-Power and Applied Power Associates Inc. Universal Utility Services Co. provides cooling tower maintenance and repair, certain other industrial plant improvement services, and engineered maintenance of high-voltage plant electric equipment. Precision Resource Co. provides contract professional and technical resources for customers in the energy industrial sectors. Quixx was incorporated in 1985 under the laws of Texas. Quixx s primary business is investing in and developing cogeneration and energy-related projects. Quixx also holds water rights and certain other non-utility assets. Quixx financed the sale of heat pumps until December 1999.

Planergy International Inc.

Planergy was acquired in 1998. Planergy provides energy management, consulting, on-site generation, load curtailment, demand-side management, energy conservation and optimization, distributed generation and power quality services, as well as information management solutions to industrial, commercial and utility customers.

EMI began operations in 1993. EMI primarily offers retrofitting and upgrading facilities for greater energy efficiency on a national basis. In 1995, EMI acquired Energy Masters Corporation, a company that specializes in energy efficiency improvement services for commercial, industrial and institutional customers. In 1997, EMI acquired 100 percent of Energy Solutions International Inc., an energy management firm.

During 2000, Planergy and EMI, both wholly-owned subsidiaries of ours, were combined to form Planergy.

Seren Innovations, Inc.

Seren was formed in 1996 to pursue communications and data services businesses. Currently, Seren is constructing a combination cable television, telephone and high-speed internet access system in two locations: St. Cloud, Minnesota and Contra Costa County in the East Bay area of northern California. As of December 31, 2002, Xcel Energy s investment in Seren was approximately $255 million. Seren projects improvement in its operating results with positive cash flow anticipated in 2005 and earnings contribution in 2008.

Eloigne Company

Eloigne was established in 1993 and its principal business is the acquisition of rental housing projects that qualify for low-income housing tax credits under current federal tax law. As of December 31, 2002, approximately $83 million had been invested in Eloigne projects, including approximately $23 million in wholly owned properties and approximately $60 million in equity interests in jointly owned projects.

Completed and committed Eloigne projects as of December 31, 2002, are expected to generate tax credits of $76 million over the time period of 2003 through 2011.

Environmental Matters

Certain of our subsidiary facilities are regulated by federal and state environmental agencies. These agencies have jurisdiction over air emissions, water quality, wastewater discharges, solid wastes and hazardous substances. Various company activities require registrations, permits, licenses, inspections and approvals from these agencies. We have received all necessary authorizations for the construction and continued operation of its generation, transmission and distribution systems. Company facilities have been designed and constructed to operate in compliance with applicable environmental standards.

We and our subsidiaries strive to comply with all environmental regulations applicable to its operations. However, it is not possible at this time to determine when or to what extent additional facilities or modifications of existing or planned facilities will be required as a result of changes to environmental regulations, interpretations or enforcement policies or, generally, what effect future laws or regulations may have upon our operations. For more information on Environmental Contingencies, see Note 18 and Note 19 to the consolidated financial statements and Management s Discussion and Analysis of Financial Condition and Results of Operation Environmental Matters.

Capital Spending and Financing

For a discussion of expected capital expenditures and funding sources, see Management s Discussion and Analysis of Financial Condition and Results of Operation.

Properties

For a discussion and information concerning nonregulated properties, see Nonregulated Subsidiaries above.

Virtually all of the utility plant of NSP-Minnesota, NSP-Wisconsin and PSCo is subject to the lien of their first mortgage bond indentures.

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Electric utility generating stations:

NSP-Minnesota

Station and Unit	Fuel	Installed	Summer 2002 Net Dependable Capability (Mw)
Sherburne Becker, Minnesota			
Unit 1	Coal	1976	706
Unit 2	Coal	1977	689
Unit 3(a)	Coal	1987	507
Prairie Island Welch, Minnesota			
Unit 1	Nuclear	1973	522
Unit 2	Nuclear	1974	522
Monticello Monticello, Minnesota	Nuclear	1971	578
King Bayport, Minnesota	Coal	1968	529
Black Dog Burnsville, Minnesota			
2 Units	Coal	1955-1960	278
2 Units	Natural Gas	2002	260
High Bridge St. Paul, Minnesota			
2 Units	Coal	1956-1959	267
Riverside Minneapolis, Minnesota			
2 Units	Coal	1964-1987	374
Angus Anson Sioux Falls, S.D.			
2 Units	Natural Gas	1994	217
Inver Hills Inver Grove Heights, Minn.			
6 Units	Natural Gas	1972	306
Blue Lake Shakopee, Minn.			
4 Units	Natural Gas	1974	160
Other	Various	Various	323
		Total	6,238

(a) Based on NSP-Minnesota s ownership interest of 59 percent.

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NSP-Wisconsin

Station and Unit	Fuel	Installed	Summer 2002 Net Dependable Capability (Mw)
Combustion Turbine:			
Flambeau Station Park Falls, Wisconsin	Natural Gas/Oil	1969	12
Wheaton Eau Claire, Wisconsin			
6 Units	Natural Gas/Oil	1973	345
French Island La Crosse, Wisconsin			
2 Units	Oil	1974	142
Steam:			
Bay Front Ashland, Wisconsin			
3 Units	Coal/Wood/Natural Gas	1945-1960	76
French Island La Crosse, Wisconsin			
2 Units	Wood/RDF*	1940-1948	27
Hydro:			
19 Plants		Various	249
		Total	851

* RDF is refuse derived fuel, made from municipal solid waste.

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PSCo

Station and Unit	Fuel	Installed	Summer 2002 Net Dependable Capability (Mw)
Steam:			
Arapahoe Denver, Colorado			
2 Units	Coal	1950-1955	156
Cameo Grand Junction, Colorado			
2 Units	Coal	1957-1960	73
Cherokee Denver, Colorado			
4 Units	Coal	1957-1968	717
Comanche Pueblo, Colorado			
2 Units	Coal	1973-1975	660
Craig Craig, Colorado			
2 Units(a)	Coal	1979-1980(a)	83
Hayden Hayden, Colorado			
2 Units(b)	Coal	1965-1976(b)	237
Pawnee Brush, Colorado	Coal	1981	505
Valmont Boulder, Colorado	Coal	1964	186
Zuni Denver, Colorado			
3 Units	Natural Gas/Oil	1948-1954	107
Combustion Turbines:			
Fort St. Vrain Platteville, Colorado			
4 Units	Natural Gas	1972-2001	690
Various Locations			
6 Units	Natural Gas	Various	171
Hydro:			
Various Locations		Various	32
14 Units		1967	210
Cabin Creek Georgetown, Colorado			
Pumped Storage Wind:			
Ponnequin Weld County, Colorado		1999-2001	
Diesel Generators:			
Cherokee Denver, Colorado			
2 Units		1967	6
		Total	3,833

(a) Based on PSCo ownership interest of 9.72 percent

(b) Based on PSCo ownership interest of 75.5 percent of unit 1 and 37.4 percent of unit 2.

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SPS

Station and Unit	Fuel	Installed	Summer 2002 Net Dependable Capability (Mw)
Steam:			
Harrington Amarillo, Texas			
3 Units	Coal	1976-1980	1,066
Tolk Muleshoe, Texas			
2 Units	Coal	1982-1985	1,080
Jones Lubbock, Texas			
2 Units	Natural Gas	1971-1974	486
Plant X Earth, Texas			
4 Units	Natural Gas	1952-1964	442
Nichols Amarillo, Texas			
3 Units	Natural Gas	1960-1968	457
Cunningham Hobbs, New Mexico			
2 Units	Natural Gas	1957-1965	267
Maddox Hobbs, New Mexico	Natural Gas	1983	118
CZ-2 Pampa, Texas	Purchased Steam	1979	26
Moore County Amarillo, Texas	Natural Gas	1954	48
Gas Turbine:			
Carlsbad Carlsbad, Texas	Natural Gas	1977	13
CZ-1 Pampa, Texas	Hot Nitrogen	1965	13
Maddox Hobbs, New Mexico	Natural Gas	1983	65
Riverview Electric City, Texas	Natural Gas	1973	23
Cunningham Hobbs, New Mexico	Natural Gas	1998	220
Diesel:			
Tucumcari Tucumcari, New Mexico			
6 Units		1941-1968	
		Total	4,324

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at December 31, 2002:

Structure Miles	Cheyenne	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 kilovolt (kv)		2,919			
345 kv		5,653	1,312	529	2,735
230 kv		1,440		10,005	8,998
161 kv		298	1,331		
138 kv				92	
115 kv	113	6,162	1,528	4,789	8,837
less than 115 kv	2,781	78,316	31,063	57,346	15,477

Electric utility transmission and distribution substations at December 31, 2002:

Quantity of Substations	Cheyenne	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
	5	360	205	209	492

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Gas utility mains at December 31, 2002:

Miles	BMG	Cheyenne	NSP-Minnesota	NSP-Wisconsin	PSCo	Viking	WGI
Transmission			115		2,263	623	12
Distribution	415	673	8,608	1,929	18,114		

Listed below are descriptions of NRG s interests in facilities, operations and/or projects as of December 31, 2002.

Independent Power Production and Cogeneration Facilities

Name and Location of Facility	Purchaser/ Power Market	Net Owned Capacity (megawatts)	NRG s Percentage Ownership Interest	Fuel Type
East Region:				
Oswego, New York	Niagara Mohawk/ NYISO	1,700	100%	Oil/Gas
Huntley, New York	Niagara Mohawk/ NYISO	760	100%	Coal
Dunkirk, New York	Niagara Mohawk/ NYISO	600	100%	Coal
Arthur Kill, New York	NYISO	842	100%	Gas/Oil
Astoria Gas Turbines, New York	NYISO	614	100%	Gas/Oil
Ilion, New York	NYISO	60	100%	Gas/Oil
Somerset, Massachusetts	Eastern Utilities Associates	229	100%	Coal/Oil/Jet
Middletown, Connecticut	Connecticut Light & Power	856	100%	Oil/Gas/Jet
Montville, Connecticut	Connecticut Light & Power	498	100%	Oil/Gas
Devon, Connecticut	Connecticut Light & Power	401	100%	Gas/Oil/Jet
Norwalk Harbor	Connecticut Light & Power	353	100%	Oil
Connecticut Jet Power, Connecticut	Connecticut Light & Power	127	100%	Jet
Other 6 Projects	Various	68	Various	Various
Indian River, Delaware	Delmarva/PJM	784	100%	Coal/Oil
Dover, Delaware	PJM	106	100%	Gas/Coal
Vienna, Maryland	Delmarva/PJM	170	100%	Oil
Conemaugh, Pennsylvania	PJM	64	3.72%	Coal/Oil
Keystone, Pennsylvania	PJM	63	3.70%	Coal/Oil
Paxton Creek Cogeneration, Pennsylvania	Virginia Electric & Power	12	100%	Gas
Commonwealth Atlantic	PJM	188	50%	Coal/Oil
James River	PJM	55	50%	Coal/Oil
Central Region:				
Big Cajun II, Louisiana	Cooperative/SERC Entergy	1,498	86.04%	Coal
Big Cajun I, Louisiana	Cooperative/SERC Entergy	458	100%	Gas
Bayou Cove, Louisiana	SERC Entergy	320	100%	Gas
Sterlington, Louisiana	Louisiana Generating	202	100%	Gas
Batesville, Mississippi	SERC-TVA	837	100%	Gas
McClain, Oklahoma	SPP-Southern	400	77%	Gas
Mustang, Texas	Golden Spread Electric Coop	122	25%	Gas
Other 3 Projects	Various	45	Various	Various
Kendall, Illinois	MAIN	1,168	100%	Gas
Rockford I, Illinois	ComEd	342	100%	Gas

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Name and Location of Facility	Purchaser/ Power Market	Net Owned Capacity (megawatts)	NRG s Percentage Ownership Interest	Fuel Type
Rockford II, Illinois	MAIN	171	100%	Gas
Rocky Road Power, Illinois	MAIN	175	50%	Gas
Audrain, Missouri	MAIN/SERC-Entergy	640	100%	Gas
Other 2 projects	Various	42	Various	Various
West Coast Region:				
El Segundo Power, California	California DWR	510	50%	Gas
Encina, California	California DWR	483	50%	Gas/Oil
Long Beach Generating, California	California DWR	265	50%	Gas
San Diego Combustion Turbines, California	Cal ISO	127	50%	Gas/Oil
Saguaro Power Co., Nevada	Nevada Power	53	50%	Gas/Oil
Other North America:				
NEO Corporation, Various	Various	197	71.49%	Various
Energy Investors Funds, Various	Various	11	0.73%	Various
International Projects:				
Asia-Pacific:				
Lanco Kondapalli Power, India	APTRANSCO.	107	30%	Gas/Oil
Hsinchu, Taiwan	Industrials	102	60%	Gas
Australia:				
Flinders, South Australia	South Australian Pool	760	100%	Coal
Gladstone Power Station, Queensland	Enertrade/Boyne Smelters	630	37.50%	Coal
Loy Yang Power A, Victoria	Victorian Pool	507	25.37%	Coal
Europe:				
Killingholme Power A.UK	UK Electricity Grid	680	100%	Gas
Enfield Energy Centre, UK	UK Electricity Grid	99	25%	Gas/Oil
Schkopau Power Station, Germany	VEAG/Industrials	400	41.67%	Coal
MIBRAG mbH, Germany	ENVIA/ MIBRAG Mines	119	50%	Coal
ECK Generating, Czech Republic	STE/ Industrials	166	44.50%	Coal/Gas/Oil
CEEP Fund, Poland(3)	Industrials	5	7.56%	Gas/Coal
Other Americas:				
TermoRio, Brazil	Petrobras	520	50%	Gas/Oil
Itiquira Energetica, Brazil	COPEL/ Tradener	154	100%	Hydro
COBEE, Bolivia	Electropaz/ELF	217	98.90%	Hydro/Gas
Energia Pacasmayo, Peru	Electroperu/ Peruvian Grid	66	100%	Hydro/Oil
Cahua, Peru	Quimpac/ Industrials	45	100%	Hydro
Latin Power, Various	Various	52	6.75%	Various

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Thermal Energy Production and Transmission Facilities And Resource Recovery Facilities

Name and Location of Facility	Date of Acquisition	Net Owned Capacity(1)	NRG s Percentage Ownership Interest	Thermal Energy Purchaser / MSW Supplier
NRG Energy Center Minneapolis, Minnesota	1993	Steam: 1,403 mmBtu/hr. (411 MWt) Chilled water: 42,450 tons (149 MWt)	100%	Approximately 100 steam customers 40 chilled water customers
NRG Energy Center San Francisco, California	1999	Steam: 490 mmBtu/hr (144 MWt)	100%	Approximately 185 steam customers
NRG Energy Center Harrisburg, Pennsylvania	2000	Steam: 490 mmBtu/hr. (144 MWt) Chilled water: 1,800 tons (6 MWt)	100%	Approximately 295 steam customers and 2 chilled water customers
NRG Energy Center Pittsburgh, Pennsylvania	1999	Steam: 260 mmBtu/hr. (76 MWt) Chilled water: 12,580 tons (44 MWt)	100%	Approximately 30 steam and 30 chilled water customers
NRG Energy Center San Diego, California	1997	Chilled water: 8,000 tons (28 MWt)	100%	Approximately 20 chilled water customers
NRG Energy Center Rock-Tenn, Minnesota	1992	Steam: 430 mmBtu/hr (126 Mwt)	100%	Rock-Tenn Company
Camas Power Boiler, Washington	1997	Steam: 200 mmBtu/hr. (59 MWt)	100%	Georgia-Pacific Corp.
NRG Energy Center Dover, Delaware	2000	Steam: 190 mmBtu/hr. (56 MWt)	100%	Kraft Foods Inc
NRG Energy Center Washco, Minnesota	1992	Steam: 160 mmBtu/hr. (47 MWt)	100%	Anderson Corporation, Minnesota Correctional Facility
Energy Center Kladno, Czech Republic(2),(3)	1994	227 mmBtu/hr. (67 MWt)	44.40%	City of Kladno
Resource Recovery Facilities Newport, Minnesota	1993	MSW 1,500 tons/day	100%	Ramsey and Washington Counties
Elk River, Minnesota	2001	MSW: 1,275 tons/day	85%	Anoka, Hennepin, and Sherburne Counties; Tri-County Solid Waste Management Commission
Penobscot Energy Recovery, Maine	1997	MSW: 590 tons/day	85%	Bangor Hydroelectric Company

(1) Thermal production and transmission capacity is based on 1,000 Btu s per pound of steam production or transmission capacity. The unit mmbtu is equal to one million Btu s.

(2) Kaldno also is included in the Independent Power Production and Cogeneration Facilities table on the preceding page, under the name ECK Generating.

(3) Facilities held for sale.

In addition, NRG leases its corporate offices at 901 Marquette, Suite 2300, Minneapolis, Minnesota and various other office spaces.

The debt associated with many of the NRG facilities listed above is in default and could be subject to foreclosures by the lenders to such facilities. See Notes 2, 3, 4 and 7 to the consolidated financial statements.

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Employees

The number of our employees at December 31, 2002, is presented in the table below. Of the employees listed below, 7,449, or 50.9 percent, are covered under collective bargaining agreements.

NSP-Minnesota	2,963
NSP-Wisconsin	550
PSCo.	2,625
SPS	1,071
Xcel Energy Services Inc.	2,965
NRG	3,173
Other subsidiaries	1,295
Total	14,642

Legal Proceedings

In the normal course of business, various lawsuits and claims have arisen against us. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition for such matters.

Department of Energy Complaint On June 8, 1998, NSP-Minnesota filed a complaint in the Court of Federal Claims against the DOE requesting damages in excess of $1 billion for the DOE s partial breach of the Standard Contract. NSP-Minnesota requested damages consisting of the costs of storage of spent nuclear fuel at the Prairie Island nuclear generating plant, anticipated costs related to the Private Fuel Storage, LLC and costs relating to the 1994 state legislation limiting the number of casks that can be used to store spent nuclear fuel at Prairie Island. On April 6, 1999, the Court of Federal Claims dismissed NSP-Minnesota s complaint. On May 20, 1999, NSP-Minnesota appealed to the Court of Appeals for the Federal Circuit. On August 31, 2000, the Court of Appeals for the Federal Circuit reversed and remanded to the Court of Federal Claims. On December 26, 2000, NSP-Minnesota filed a motion with the Court of Federal Claims to amend its complaint and renew its motion for summary judgment on the DOE s liability. On July 31, 2001, the Court of Federal Claims granted NSP s motion for summary judgment on DOE s liability. On November 28, 2001, the DOE brought a motion of partial summary judgment on the schedule for acceptance of spent nuclear fuel and on November 27, 2001 the DOE s obligation to accept greater than Class C waste. These motions are pending. Limited discovery with respect to the schedule to the schedule issues has been conducted. A trial in NSP-Minnesota s suit against the DOE is not likely to occur before the second quarter of 2003.

Fortistar Litigation In July 1999, Fortistar Capital, Inc., a Delaware corporation, filed a complaint in District Court (Fourth Judicial District, Hennepin County) in Minnesota against NRG asserting claims for injunctive relief and for damages as a result of NRG s alleged breach of a confidentiality letter agreement with Fortistar relating to the Oswego facility in New York. NRG disputed Fortistar s allegations and asserted numerous counterclaims. In October 1999, NRG, through a wholly owned subsidiary, closed on the acquisition of the Oswego facility. In April and December 2000, NRG filed summary judgment motions to dispose of the litigation. A hearing on these motions was held in February 2001 and certain of Fortistar s claims were dismissed. On May 8, 2002, the parties resolved the litigation, pending final agreement on the terms of settlement. The settlement encompassed litigation with respect to the Oswego facility as well as litigation between the parties with respect to Minnesota Methane LLC. Because the conditions for settlement were not satisfied, the parties have renewed negotiations to explore alternative terms for reaching a settlement and are currently engaged in negotiation of a memorandum of understanding respecting the resolution of all disputes.

Stray Voltage On September 25, 2000, NSP-Wisconsin was served with a complaint in Eau Claire County Circuit Court on behalf of Claron and Janice Stubrud. The complaint alleged that stray voltage from NSP-Wisconsin s system harmed their dairy herd resulting in lost milk production, lost profits and income,

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property damage, and injury to their dairy herd. The complaint also alleged that NSP-Wisconsin acted willfully and wantonly, entitling plaintiffs to treble damages. The plaintiffs allege farm damages of approximately $3.8 million, $2.7 million of which represents prejudgement interest. On March 28, 2003, the trial court granted partial summary judgment to NSP-Wisconsin and dismissed plaintiffs claims for strict products liability, trespass, treble damages and prejudgment interest. Plaintiffs negligence and nuisance claims will proceed to trial in Eau Claire County in November 2003.

On November 13, 2001, Ralph Schmidt, Karline Schmidt, August C. Heeg Jr., and Joanne Heeg filed a complaint in Clark County, Wisconsin against Xcel Energy Services Inc. (XES), a wholly-owned subsidiary of ours. The complaint alleged that stray voltage harmed their dairy herd resulting in decreased milk production, lost profits and income, property damage and injury to their dairy herd. The plaintiffs also allege entitlement to treble damages. The Heeg plaintiffs allege compensatory damages of $1.9 million and pre-verdict interest of $6.1 million, for total damages of $8 million. The Schmidt plaintiffs allege compensatory damages of $1 million and pre-verdict interest of $1.2 million, for total damages of $2.2 million. No trial date has been set. At all relevant times, NSP-Wisconsin provided utility service to plaintiffs; therefore XES is seeking dismissal of XES and substitution of NSP-Wisconsin as the proper party defendant.

On March 1, 2002, NSP-Wisconsin was served with a lawsuit commenced by James and Grace Gumz and Michael and Susan Gumz in Marathon County Circuit Court, Wisconsin, alleging that electricity supplied by NSP-Wisconsin harmed their dairy herd and caused them personal injury. The Gumz s complaint alleges negligence, strict liability, nuisance, trespass, and statutory violations and seeks compensatory, punitive and treble damages. Plaintiffs allege compensatory damages of $1.7 million and pre-verdict interest of $1.8 million for total damages of $3.5 million. Trial has been set for March 2004.

French Island NSP-Wisconsin s French Island plant generates electricity by burning a mixture of wood waste and refuse derived fuel. The fuel is derived from municipal solid waste furnished under a contract with La Crosse County, Wisconsin. In October 2000, the EPA reversed a prior decision and found that the plant was subject to the federal large combustor regulations. Those regulations became effective on December 19, 2000. NSP-Wisconsin did not have adequate time to install the emission controls necessary to come into compliance with the large combustor regulations by the compliance date. As a result, on March 29, 2001, the EPA issued a finding of violation to NSP-Wisconsin. On April 2, 2001, a conservation group sent NSP-Wisconsin a notice of intent to sue under the citizen suit provisions of the Clean Air Act. NSP-Wisconsin could be fined up to $27,500 per day for each violation.

On July 27, 2001, the state of Wisconsin filed a lawsuit against NSP-Wisconsin in the Wisconsin Circuit Court for La Crosse County, contending that NSP-Wisconsin exceeded dioxin emission limits on numerous occasions between July 1995 and December 2000 at French Island. On September 3, 2002, the Wisconsin Circuit Court approved a settlement between NSP-Wisconsin and the state of Wisconsin. Under terms of that settlement, NSP-Wisconsin paid a penalty of approximately $168,000 and agreed to contribute $300,000 in installments through 2005 to help fund a household hazardous waste project in the LaCrosse area.

On August 15, 2001, NSP-Wisconsin received a Certificate of Authority to install control equipment necessary to bring the French Island plant into compliance with the large combustor regulations. NSP-Wisconsin began construction of the new air quality equipment on October 1, 2001. NSP-Wisconsin has reached an agreement in principle with La Crosse County through which La Crosse County will pay for the extra emissions equipment required to comply with the EPA regulation. Installation of the control equipment has been completed and source tests on one unit confirm that the unit is now in compliance with the state and federal dioxin standards. NSP-Wisconsin will test the remaining unit during the fourth quarter of 2002.

New York Department of Environmental Control Opacity Notice of Violation NRG became part of an opacity consent order as a result of acquiring the Niagara Mohawk assets. At the time of financial close, the consent order was being negotiated between Niagara Mohawk and the New York Department of Environmental Control (NYDEC). The consent order required Niagara Mohawk to pay a stipulated penalty for each opacity event. An opacity event is an event in time, usually six minutes or 20 minutes, when a plant s emissions do not meet minimum levels of air transparency. On January 14, 2002, the NYDEC issued NRG NOVs for opacity events, which had occurred since the time NRG assumed ownership of the Huntley,

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Dunkirk and Oswego Generating Stations. The NOVs alleged that a total of 7,231 events had occurred where the average opacity during the six-minute block of time had exceeded 20 percent. The NYDEC currently proposes a penalty associated with the NOVs at $900,000. Subsequently, the NYDEC has indicated that a consent order, not yet received by NRG, will seek a penalty in excess of that previously proposed. NRG expects to continue negotiations with NYDEC regarding the proposed consent orders, but cannot predict the outcome of those negotiations.

Light Rail Transit (LRT) On February 16, 2001, NSP-Minnesota filed a suit in the United States District Court in Minneapolis against the Minnesota Metropolitan Council, Minnesota Department of Transportation, State of Minnesota and the Federal Transit Administration (FTA) to prevent pave-over of NSP-Minnesota s underground facilities during construction of the LRT system. NSP-Minnesota also is seeking recovery of relocation expenses. State defendants countersued, seeking delay damages and a $330 million surety bond. On May 24, 2001, the District Court issued a preliminary injunction requiring NSP-Minnesota to commence the relocation project and to cooperate with defendants. NSP-Minnesota has complied with the preliminary injunction and utility line relocation has commenced. NSP-Minnesota is capitalizing its costs incurred as construction work in progress. In April 2002, Defendants brought motions for summary judgment before the federal district court. In September, 2002 the District Court granted the defendants motion for summary judgement. NSP is preparing its appeal to the Federal Court of Appeals for the Eighth District. In collateral matters regarding LRT construction, NSP-Minnesota has commenced a mandamus action in state court seeking an order requiring Defendants to commence condemnation proceedings concerning an underground substation, access to which is blocked by LRT. The state court denied the action for mandamus and NSP appealed to the Minnesota Court of Appeals.

California Ancillary Services On March 11, 2002, the Attorney General of California filed in federal court, United States District Court for the Northern District of California, a civil complaint against NRG, certain NRG affiliates, us, Dynegy, Inc. and Dynegy Power Marketing, Inc., alleging antitrust violations in the ancillary services market. The complaint alleges that the defendants repeatedly sold electricity generating capacity to the California Independent System Operator for use as a reserve and subsequently, and impermissibly, sold the same capacity into the spot market for wholesale power, unlawfully collecting millions of dollars. Similar complaints were filed against other power generators. The plaintiff seeks an injunction against further similar acts by the defendants, and also seeks restitution, disgorgement of all proceeds, including profits, gained from these sales, and certain civil penalties. On April 17, 2002, the defendants in these various cases removed all of them to the federal district court, which denied the Attorney General s motion to remand the cases to state court. That decision is on appeal to the Ninth Circuit Court. Meanwhile, the defendants motion to dismiss all the cases based on federal preemption and the filed rate doctrine is pending in the district court. A notice of bankruptcy filing regarding NRG has also been filed in this action, providing notice of the involuntary petition. On March 25, 2003, the federal district court dismissed the Attorney General s actions against NRG, certain NRG affiliates, Dynegy, Inc. and Dynegy Power Marketing, Inc. without prejudice.

Connecticut Light & Power Company Connecticut Light & Power Company (CL&P) filed a claim in United States District Court for the District of Connecticut for recovery of amounts it claims is owing for congestion charges under the terms of a contract with a subsidiary of NRG. CL&P has served and filed its motion for summary judgment and NRG has yet to respond. CL&P has offset approximately $30 million from amounts owed to NRG, claiming that it has the right to offset those amounts under the contract. NRG has counterclaimed seeking to recover those amounts, arguing that CL&P has no rights under the contract to offset them. NRG cannot estimate at this time the likelihood of an unfavorable outcome in this matter, or the overall exposure for congestion charges for the full term of the contract. CL&P has also sought joinder in the involuntary bankruptcy of NRG in Minnesota.

NRG Litigation In February 2002, individual stockholders of NRG filed nine separate, but similar, class action complaints in the Delaware Court of Chancery against us, NRG and the nine members of NRG s board of directors. A similar class action lawsuit filed in a Minnesota state court. Each of the actions challenged the offer and merger and contained various allegations of wrongdoing on the part of the defendants in connection with the offer and the merger. In April 2002 counsel for the parties to the consolidated action in the Delaware Court of Chancery and the Minnesota action entered into a memorandum of understanding setting forth an agreement in principle to settle the actions based on the increase by us of the exchange ratio in the offer and merger to 0.5000, but subject to confirmatory discovery, definitive documentation, and court approval. The Minnesota action has subsequently been dismissed without prejudice. As to the Delaware actions, the settlement has not been documented, approved or consummated, and in light of developments in the litigation that is described under the heading Securities Class Action Litigation below, it is uncertain whether the settlement will ever proceed.

NRG Involuntary Bankruptcy On November 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG in the United States Bankruptcy Court for the District of Minnesota (Minnesota bankruptcy Court). Under provisions of federal law, NRG has the full authority to continue to operate its business as if the involuntary petition had not been filed unless and until a court hearing on the validity of the involuntary petition is resolved adversely to NRG. NRG responded to the involuntary petition, contesting the petitioners claims and filing a motion to dismiss the case. A hearing has been set for April 10, 2003 to consider the motion to dismiss. In their petition, the petitioners sought recover of severance and other benefits of approximately $28 million.

NRG and its counsel have been involved in negotiations with the petitioners and their counsel. As a result of these negotiations, NRG and the petitioners reached an agreement and compromise regarding their respective claims against each other (Settlement Agreement). In February 2003, the Settlement Agreement was executed, pursuant to which NRG agreed to pay the petitioners an aggregate settlement in the amount of $12 million.

On February 28, 2003, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a petition alleging that they hold unsecured, non-contingent claims against NRG in a joint amount of $100 million. The Minnesota Bankruptcy Court has discretion in reviewing and ruling on the motion to dismiss and the review and approval of the Settlement Agreement. There is a risk that the Minnesota Bankruptcy Court may, among other things, reject the Settlement Agreement or enter an order for relief under Chapter 11 of Title 11 of the Bankruptcy Code.

PSCo Notice of Violation On November 3, 1999, the United States Department of Justice filed suit against a number of electric utilities for alleged violations of the Clean Air Act s NSR requirements related to the alleged modifications of electric generating stations located in the South and Midwest. Subsequently, the EPA also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities, including us, seeking to determine whether these utilities engaged in activities that may have been in violation of the NSR requirements. In 2001, we responded to the EPA s initial information requests related to our plants in Colorado.

On July 1, 2002, we received an NOV from the EPA alleging violations of the NSR requirements of the Clear Air Act at PSCo s Comanche and Pawnee Stations in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid-to-late 1990s should have required a permit under the NSR process. We believe we acted in full compliance with the Clean Air Act and NSR process. We believe that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. We also believe that the projects would be expressly authorized under the EPA s NSR policy announced by the EPA administrator on June 22, 2002. We disagree with the assertions contained in the NOV and intend to vigorously defend our position.

If the EPA is successful in any subsequent litigation regarding the issues set forth in the NOV or any matter arising as a result of its information requests, it could require us to install additional emission control equipment at the facilities and pay civil penalties. Civil penalties are limited to not more than $25,000 to $27,500 per day for each violation. The ultimate financial impact to us is not determinable at this time.

Securities Class Action Litigation On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of our common stock between January 31, 2001 and July 26, 2002, was filed in the United States District Court in Minnesota. The complaint named us; Wayne H. Brunetti, chairman, president and

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chief executive officer; Edward J. McIntyre, vice president and chief financial officer; and former chairman, James J. Howard as defendants. Among other things, the complaint alleged violations of Section 10b of the Securities Exchange Act and Rule 10b-5 related to allegedly false and misleading disclosures concerning various issues including round trip energy trades and the existence of cross-default provisions in our and our subsidiary, NRG s, credit agreements with lenders. After the filing of the lawsuit on July 31, 2002, several additional lawsuits were filed with similar allegations, one of which added claims on behalf of a purported class of purchasers of two series of NRG Senior Notes raised by NRG in January 2001. The cases have all been consolidated, and a consolidated amended complaint has been filed. The amended complaint charges false and misleading disclosures concerning round trip energy trades and the existence of provisions in our credit agreements with lenders for cross-defaults in the event of a default by NRG; it adds as additional defendants Gary R. Johnson, General Counsel, Richard C. Kelly, president of Xcel Energy Enterprises, two former executive officers of NRG (David H. Peterson, Leonard A. Bluhm) and one current executive officer of NRG (William T. Pieper) and a former independent director of NRG (Luella G. Goldberg); and it adds claims of false and misleading disclosures (also regarding round trip trades and the cross-default provisions) under Section 11 of the Securities Act. The defendants have not yet responded formally to the amended complaint, but deny any liability and maintain they have made disclosures fully compliant with applicable laws and reporting requirements.

Shareholder Derivative Litigation On August 15, 2002, a shareholder derivative action was filed in the United States District Court for the District of Minnesota, purportedly on behalf of the Xcel Energy, against the directors and certain present and former officers citing essentially the same circumstances as the class actions and asserting breach of fiduciary duty. This action has been consolidated for pre-trial purposes with the securities class actions. After its filing of this action, two additional derivative actions were filed in the state trial court for Hennepin County, Minnesota, against essentially the same defendants, focusing on allegedly wrongful energy trading activities and asserting breach of fiduciary duty for failure to establish adequate accounting controls, abuse of control, and gross mismanagement. In each of the derivative cases, the defendants have filed motions to dismiss the complaint for failure to make a proper pre-suit demand (or, in the federal court case, to make any pre-suit demand at all) upon our board of directors. The motion has not yet been ruled upon.

ERISA Class Litigation On September 23, 2002 and October 9, 2002, actions were filed in the United States District Court for the District of Colorado, purportedly on behalf of classes of employee participants in our (and our predecessors) 401(k)/ESOP plans from as early as September 23, 1999. The complaints in the actions, which name as defendants Xcel Energy, our directors, certain former directors, and certain of our present and former officers, allege violations of the Employee Retirement Income Security Act in the form of breach of fiduciary duty in allowing or encouraging the purchase, contribution and/or retention of our common stock in the plans and making misleading statements and omissions in that regard. The defendants have filed motions to dismiss the complaints, and separately have requested the Judicial Panel on Multidistrict Litigation to transfer the cases to the Minnesota federal court for purposes of coordination with the securities class actions and shareholder derivative action pending there. The motions have not yet been ruled upon.

Stone/Shaw Litigation On October 17, 2002, Stone & Webster, Inc. and Shaw Constructors, Inc. filed an action in the United States District Court for the Southern District of Mississippi against Xcel Energy; Wayne H. Brunetti, chairman, president and chief executive officer; Richard C. Kelly, president of Xcel Energy Enterprises; NRG and certain NRG subsidiaries. Stone/Show allege they had a contract with a single purpose NRG subsidiary for construction of a power generation facility, which was abandoned before completion, but after substantial sums had been spent by Stone/Shaw. They allege breach of contract, breach of an NRG guarantee, breach of fiduciary duty, tortious interference with contract, detrimental reliance, misrepresentation, conspiracy, aiding and abetting, and seek to impose alter ego liability on defendants other than the contracting NRG subsidiary through piercing the corporate veil. The defendants have filed motions to dismiss the complaint, which have not yet been ruled upon.

Threatened FirstEnergy Litigation As discussed in Note 18 to the consolidated financial statements, FirstEnergy terminated the purchase agreements pursuant to which NRG had agreed to purchase four

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generating stations for approximately $1.6 billion. FirstEnergy s cited rationale for terminating the agreements was an alleged anticipatory breach by NRG. FirstEnergy notified NRG that it is reserving the right to pursue legal action against NRG and us for damages. On February 5, 2003, FirstEnergy submitted filings with the U.S. Bankruptcy Court in Minnesota seeking permission to file a demand for arbitration against NRG. On February 27, 2003, FirstEnergy gave NRG notice that it was commencing arbitration against NRG to determine whether NRG is liable to FirstEnergy for failure to close the transaction. NRG believes it has meritorious defenses against FirstEnergy s claim and intends to vigorously defend its position. No amount has been accrued for this contingency. Management is unable to predict the ultimate outcome of this matter, however, an adverse decision could be material to NRG s financial position and results of operations.

Ashland Manufactured Gas Plant Site NSP-Wisconsin was named as one of three potentially responsible parties (PRP) for creosote and coal tar contamination at a site in Ashland, Wisconsin. The Ashland site includes property owned by NSP-Wisconsin and two other properties: an adjacent city lakeshore park area and a small area of Lake Superior s Chequemegon Bay adjoining the park.

Estimates of the ultimate cost to remediate the Ashland site vary from $4 million to $93 million, because different methods of remediation and different results are assumed in each. In the interim, NSP-Wisconsin has recorded a liability in the amount of $19 million for an estimate of its share of the cost of remediating the portion of the Ashland site that it owns, using information available to date and reasonably effective remedial methods.

The EPA and Wisconsin Department of Natural Resources have not yet selected the method of remediation to use at the site. On September 5, 2002, the Ashland site was placed on the National Priorities List (NPL). The NPL is intended primarily to guide the EPA in determining which sites require further investigation.

California Litigation Public Utility District No. 1 of Snohomish County, Washington, has filed a suit against Xcel Energy contending that various of its trading strategies, as reported to the FERC in response to that agency s investigation of trading strategies discussed above, violated the California Business and Professions Code. Public Utility District No. 1 of Snohomish County contends that the effect of those strategies was to increase amounts that it paid for wholesale power in the spot market in the Pacific Northwest. Xcel Energy and other defendants requested the case be dismissed in its entirety. In an order dated January 6, 2003, the District Court dismissed the County s claim. The plaintiff subsequently filed a notice of appeal on January 27, 2003.

In addition, the California Attorney General s Office has informed PSCo that it may raise claims against PSCo under the California Business and Professions Code with respect to the rates that PSCo has charged for wholesale sales and PSCo s reporting of those charges to the FERC. PSCo has had preliminary discussions with the California Attorney General s Office, and has expressed the view that FERC is the appropriate forum for the concerns that it has raised.

Home Builders Association of Metropolitan Denver (HBA) On February 23, 2001, HBA filed a formal complaint with the CPUC, requesting an award of reparations for excessive charges related to construction payments under PSCo s gas extension tariff as a result of PSCo s alleged failure to file revisions to its published construction allowances since 1996. HBA seeks an award of reparations on behalf of all of PSCo s gas extension applicants since October 1, 1996, in the amount of $13.6 million, including interest. HBA also seeks recovery of its attorneys fees.

Hearings were held before an administrative law judge (ALJ) on August 29 and September 24, 2001. On January 15, 2002, the ALJ issued his Recommended Decision dismissing HBA s complaint. The ALJ found that HBA failed to show that there have been any excessive charges, as required under the reparations statute, resulting from PSCo s failure to comply with its tariff. The ALJ held that HBA s claim for reparations (i) was barred by the filed rate doctrine (since PSCo at all times applied the approved construction allowances set forth in its tariff), (ii) would require the Commission to violate the prohibition against retroactive ratemaking, and (iii) was based on speculation as to what the Commission would do had PSCo made the filings in prior years to change its construction allowances. The ALJ also denied HBA s request for costs and attorneys fees. HBA filed exceptions to the ALJ s decision. On June 19, 2002, the CPUC issued an order granting in part HBA s exceptions to the ALJ s recommended decision and remanding the case back to the ALJ for further proceedings. The CPUC reversed the ALJ s legal conclusion that the filed rate doctrine and prohibition against retroactive ratemaking bars HBA s claim for reparations under the circumstances of this case. The CPUC remanded the case back to the ALJ for a determination of whether and to what extent due reparations should be awarded, considering certain enumerated issues.

A full-day hearing on remand was held on January 10, 2003. Simultaneous briefs were filed on February 5, 2003. Reply briefs are due February 12, 2003. The ALJ decision on remand is pending.

SchlumbergerSema, Inc. Under a 1996 Data Services Agreement (DSA), SchlumbergerSema, Inc. (SLB) provides automated meter reading, distribution automation, and other data services to NSP-Minnesota. In September 2002 NSP-Minnesota issued written notice that SLB has committed Events of Default under the DSA, including SLB s nonpayment of approximately $7.4 million for distribution automation assets. In November 2002 SLB demanded arbitration before the American Arbitration Association and asserted various claims against NSP-Minnesota totaling $24 million for NSP-Minnesota s alleged breach of an expansion contract and a meter purchasing contract. In the arbitration, NSP-Minnesota asserts counterclaims against SLB for SLB s failure to meet performance criteria, improper billing, failure to pay for use of NSP-owned property, and failure to pay $7.4 million for NSP-Minnesota distribution automation assets. NSP-Minnesota also seeks a declaratory judgment from the arbitrator that will terminate SLB s rights under the DSA. No arbitration date is set, but written discovery has commenced. The parties are scheduled to mediate their disputes on April 9, 2003.

Lamb County Electric Cooperative On July 24, 1995, Lamb County Electric Cooperative, Inc. (LCEC) petitioned the PUCT for a cease and desist order against SPS. LCEC alleged that SPS had been unlawfully providing service to oil field customers and their facilities in LCEC s singly-certificated area. SPS responded that it was lawfully entitled to serve oil field customers under grandfather rights granted it in the same order that granted LCEC its certificated area. Ultimately, the PUCT issued an order granting SPS motion for summary disposition, thus denying LCEC s petition. LCEC appealed the PUCT s order to the District Court, which upheld the order. LCEC then appealed to the Third Court of Appeals, which reversed the District Court judgment and remanded the case to the PUCT for an evidentiary hearing. The LCEC complaint was transferred to the State Office of Administrative Hearings (SOAH) for processing. On March 6, 2003, an ALJ issued a proposal for decision recommending that the cooperative s petition for a cease and desist order be denied on the basis that SPS is duly certificated to provide the service in the disputed oil fields. On April 17, 2003, the PUCT approved the SOAH ALJ s recommended proposal for decision and denied LCEC s petition for a cease and desist order. In related litigation, on Oct. 18, 1996, LCEC filed an action for damages based on its claim that SPS had been unlawfully providing service to oil field customers in its certified area. This case has remained dormant pending a final determination by the PUCT of the lawfulness of the service. Damages resulting from a decision adverse to us could be material.

For a discussion of other legal claims and environmental proceedings, see Note 18 to the consolidated financial statements. For a discussion of proceedings involving utility rates, see Business Pending Regulatory Matters.

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MANAGEMENT

The following table sets forth certain information about our directors and executive officers as of January 31, 2003.

Name	Age	Position
Wayne H. Brunetti	60	Chairman of the Board, President, Chief Executive Officer and Director
Richard C. Kelly	56	Vice President and Chief Financial Officer
Paul J. Bonavia	51	President Energy Markets
Cathy J. Hart	53	Vice President and Corporate Secretary
Gary R. Johnson	56	Vice President and General Counsel
Cynthia L. Lesher	54	Chief Administrative Officer
Raymond E. Gogel	52	Vice President and Chief Information Officer
Benjamin G.S. Fowke, III	44	Vice President and Treasurer
David E. Ripka	54	Vice President and Controller
James T. Petillo	58	President Energy Delivery
Patricia K. Vincent	44	President Retail Services
David M. Wilks	56	President Energy Supply
C. Coney Burgess	65	Director
David A. Christensen	67	Director
Roger R. Hemminghaus	66	Director
A. Barry Hirschfeld	60	Director
Douglas W. Leatherdale	66	Director
Albert F. Moreno	59	Director
A. Patricia Sampson	54	Director
Allan L. Schuman	68	Director
Rodney E. Slifer	68	Director
W. Thomas Stephens	60	Director
Dr. Margaret R. Preska	64	Director

Directors and Executive Officers

Wayne H. Brunetti is Chairman, President and Chief Executive Officer of Xcel Energy Inc. He has served as such since August 18, 2001 and as President and Chief Executive Officer upon the completion of our Merger on August 18, 2000. Mr. Brunetti has been a Director of Xcel Energy Inc. since 2000. From March 1, 2000 until the completion of the Merger, he served as Chairman, President and Chief Executive Officer of NCE and as a director and officer of several of NCE s subsidiaries. From August 1997 until March 1, 2000, Mr. Brunetti was Vice Chairman, President and Chief Operating Officer of NCE. Before the merger of PSCo and SPS to form NCE, Mr. Brunetti was President and CEO of PSCo. He joined PSCo in July 1994 as President and Chief Operating Officer. In January 1996, he added the title of CEO. Mr. Brunetti is the former President and CEO of Management Systems International, a Florida management consulting firm that he founded in 1991. Prior to that, he was Executive Vice President of Florida Power & Light Company. Mr. Brunetti has been active in various professional and civic groups. He currently serves on the executive committee and board of the Edison Electric Institute, the Medic Alert Foundation, Mountain States Employers Council, the board of advisors of the University of Colorado at Denver, the labor relations committee of the Chamber of Commerce of the United States of America, the Capital City Partnership and the Minnesota Orchestra. He is past chairman of the 2000 Mile High United Way campaign, past chairman of the board of the Colorado Association of Commerce and Industry and served on the Colorado Renewable

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Energy Task Force, an appointment made by Governor Roy Romer. He is the author of Achieving Total Quality in Integrated Business Strategy & Customer Needs. Mr. Brunetti holds a bachelor of science degree in business administration from the University of Florida. He is a graduate of the Harvard Business School s Program for Management Development.

Richard C. Kelly has been our Vice President and Chief Financial Officer since August 2002. Mr. Kelly has also been the acting President and Chief Operating Officer, NRG Energy since June 2002. Previously, Mr. Kelly was our President Enterprises since August 2000. Mr. Kelly also served as Executive Vice President and Chief Financial Officer for NCE from 1997 to August 2000 and Senior Vice President of PSCo from 1990 to 1997.

Paul J. Bonavia has been our President Energy Markets since August 2000. Previously, Mr. Bonavia served as Senior Vice President and General Counsel of NCE from 1997.

Cathy J. Hart has been our Vice President and Corporate Secretary since August 2000. Previously, Ms. Hart served as Secretary of NCE from 1998 and as Manager of Corporate Communications of PSCo from 1993 to 1996. For family reasons, Ms. Hart resigned as Manager of Corporate Communications at PSCo in June 1996 to move to Australia. From June 1996 to June 1998, Ms. Hart was not employed. She was re-employed by NCE as Corporate Secretary in June 1998.

Gary R. Johnson has been our Vice President and General Counsel since August 2000. Previously, Mr. Johnson served as Vice President and General Counsel of NSP from 1991.

Cynthia L. Lesher has been our Chief Administrative Officer since August 2000. She has also been our Chief Human Resources Officer since July 2001. Previously, Ms. Lesher served as President of NSP-Gas from July 1997 and previously Vice President-Human Resources of NSP.

Raymond E. Gogel has been our Vice President and Chief Information Officer since April 2002. Previously, Mr. Gogel was Vice President and Senior Client Services Principal for IBM Global Services since June 2001 and Senior Project Executive for IBM s Global Services since January 1998.

Benjamin G.S. Fowke, III has been our Vice President and Treasurer since November 2002. Previously, Mr. Fowke served as Vice President and Chief Financial Officer of our commodity trading and marketing business unit from 2000. He was Vice President of Retail Services and Energy Markets at NCE from January 1999 to July 2000 and Vice President-Finance/Accounting at e prime from May 1997 to December 1998.

David E. Ripka has been our Vice President and Controller since August 2000. Previously, Mr. Ripka served as Vice President and Controller of NRG from June 1999 to August 2000, Controller of NRG from March 1997 to June 1999 and Assistant Controller for NSP from June 1992 to March 1997.

James T. Petillo has been our President Energy Delivery since March 2001. Previously, Mr. Petillo served as our President Retail Services from August 2000 to March 2001, Executive Vice President of New Century Services from 1998 to August 2000 and President and Director of New Century International from 1997 to 1998.

Patricia K. Vincent has been our President Retail Services since March 2001. Previously, Ms. Vincent served as our Vice President of Marketing and Sales from August 2000 to March 2001, Vice President of Marketing & Sales of NCE from January 1999 to August 2000 and Manager, Director and Vice President of Marketing and Sales at Arizona Public Service Company from 1992 to January 1999.

David M. Wilks has been our President Energy Supply since August 2000. Previously, Mr. Wilks served as Executive Vice President and Director of PSCo and New Century Services from 1997 to August 2000 and President, Chief Operating Officer and Director of SPS from 1995 to August 2000.

C. Coney Burgess has been a Director of Xcel Energy Inc. since 2000. He is Chairman of the board of directors of Herring Bancorp, a national bank holding company based in Vernon, Texas. He is also Chairman of the board of Herring Bancshares, Inc., a holding company in Oklahoma. He has served as Chairman of Herring Bancorp and Herring Bancshares since 1992. Mr. Burgess is Chairman/ President of Burgess-Herring Ranch Company, a position he has held since 1974, and Chain-C, Inc., an agricultural firm with operations in

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the Texas Panhandle. He is President of Monarch Trust Company in Amarillo, Texas, and a director of the Herring National Bank. He served on the board of directors of NCE from 1997 until the completion of the Merger. Upon the completion of the Merger, the surviving corporation was renamed Xcel Energy Inc. Mr. Burgess also served on the board of directors of SPS from 1994 to 1997. Mr. Burgess is past President of Texas and Southwestern Cattle Raisers Association in Forth Worth, Texas, and is a director of the American Quarter Horse Association, Cattlemans Beef Board, National Cattlemans Beef Association and Panhandle Livestock Association. He is on the board of overseers and the board of endowment of the Ranching Heritage Association at Texas Tech University in Lubbock, Texas. Mr. Burgess is past Chairman of the Board of Cal Farley s Boys Ranch and Affiliates; a board member of the Boys Ranch Foundation; past President of the Amarillo Symphony; past President of the Amarillo Downtown Rotary; a trustee of Marine Military Academy; and an advisory Board member for Texas Tech University, College of Agricultural Sciences, Lubbock, Texas. Mr. Burgess received his B.S. and B.A. from Mississippi State University and attended law school at the University of Mississippi.

David A. Christensen has been a Director of Xcel Energy Inc. since 1976. He served as President and Chief Executive Officer of Raven Industries, Inc., a diversified manufacturer of plastics, electronics and special-fabric products in Sioux Falls, South Dakota, from 1971 until his retirement in August 2000 and continues as a director. He has been associated with Raven Industries since 1962, and also worked at John Morrell & Co. and served in the U.S. Army Corps of Engineers. He received his bachelors degree in industrial engineering from South Dakota State University, which later honored him with its distinguished engineer, distinguished service, and distinguished alumni awards. In 2000, Mr. Christensen received the Sioux Falls Development Foundation s Spirit of Sioux Falls award. Inducted into the South Dakota Hall of Fame in 1998, Mr. Christensen was presented with the Executive of the Year Award by Sales and Marketing Executives, Inc. of Sioux Falls, South Dakota in 1993, and was USD s South Dakotan of the Year in 1985. Mr. Christensen also serves as a director of Wells Fargo & Co., San Francisco, California and Medcomp Software, Inc., Colorado Springs, Colorado. A strong advocate for his community and state, he has served in many volunteer activities. He is a past director of the South Dakota Symphony and Sioux Falls Downtown Development Corp., as well as a past chairman of the Sioux Empire United Way.

Roger R. Hemminghaus has been a Director of Xcel Energy Inc. since 2000. He retired as Chairman of the Board of Ultramar Diamond Shamrock Corp. in January 2000 and as Chief Executive Officer in January 1999. Mr. Hemminghaus had become Chairman and CEO of Ultramar Diamond Shamrock Corporation following the merger of Diamond Shamrock, Inc. and Ultramar Corporation in 1996. Prior to the merger, Mr. Hemminghaus was Chairman, CEO and President of Diamond Shamrock, Inc. He started his career in the energy industry in 1962 as an engineer for Exxon, USA, after serving four years as a naval officer involved in nuclear power development. Mr. Hemminghaus served as a Director of NCE from 1997 until the completion of our Merger and on the SPS board of directors from 1994 until 1997. He is on the boards of directors of Luby s, Inc., CTS Corporation, Tandy Brands Accessories Incorporated, and billserv.com, Inc. Mr. Hemminghaus is Vice Chairman of the Southwest Research Institute. He is former Chairman of the Federal Reserve Bank of Dallas and former Chairman of the National Petrochemicals and Refiners Association. He is Chairman of the Board of Regents of Texas Lutheran University; he serves on the National Executive Board of the Boy Scouts of America and serves on various other non-profit association boards. Mr. Hemminghaus is a 1958 graduate of Auburn University, receiving a B.S. degree in chemical engineering and has done graduate work in business and nuclear engineering.

A. Barry Hirschfeld has been a Director of Xcel Energy Inc. since 2000. He is President of A.B. Hirschfeld Press, Inc., a commercial printing company. He has held this position since 1984. He is the third generation to head this family-owned business, which was founded in 1907. He received his M.B.A. from the University of Denver and a B.S. in business administration from California State Polytechnic University. Mr. Hirschfeld served on the NCE board from 1997 until the completion of our Merger and on the board of directors of the PSCo from 1988 to 1997. He serves on the boards of directors of the Boettcher Foundation; Mountain States Employers Council; the Denver Area Council of Boy Scouts of America, where he serves on the Board Affairs Committee; the Rocky Mountain Multiple Sclerosis Center; Colorado s Ocean Journey; the Cherry Creek Arts Festival; Up With People; and the National Jewish Center. He also serves on the

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advisory board of the Harvard University Divinity School Center for Values in Public Life. Mr. Hirschfeld is Executive Vice President of the Mile Hi Stadium Club; a member of the One Hundred Club of Denver; Colorado Concern, where he serves on the executive committee; the Colorado Forum; Denver Mayor Wellington Webb s Advisory Committee; and National Committee Member of the Kemper Museum, Kansas City, Missouri. He is past board Chairman and lifetime board member of the Denver Metro Convention and Visitors Bureau and past Chairman of the Denver Art Museum.

Douglas W. Leatherdale has been a Director of Xcel Energy Inc. since 1991. He is the retired Chairman and Chief Executive Officer of The St. Paul Companies, Inc., a worldwide property and liability insurance organization. Mr. Leatherdale joined The St. Paul Companies in 1972 and has held numerous executive positions with the Company, including President, Executive Vice President and Senior Vice President of Finance. He held the position of Chairman and Chief Executive Officer from 1990 until his retirement in 2001. Before joining The St. Paul Companies, Mr. Leatherdale was employed by the Lutheran Church of America in Minneapolis where he served as Associate Executive Secretary on the Board of Pensions. Prior to his four years at the Lutheran Church of America, he served as Investment Analyst Officer at Great West Life Assurance Company in Winnipeg. A native of Canada, Mr. Leatherdale attended United College in Winnipeg (now the University of Winnipeg) and later completed additional studies at Harvard Business School and The University of California-Berkeley. In 2000, he was awarded a Doctorate of Laws degree (honoris causa) from The University of Winnipeg. Mr. Leatherdale also serves as a director of The St. Paul Companies, The John Nuveen Company and United HealthCare Group. He is the Chairman of the Board of Directors of the International Insurance Society and The Minnesota Orchestral Association. He is the past Chairman of the University of Minnesota Foundation and the American Insurance Association.

Albert F. Moreno has been a Director of Xcel Energy Inc. since 2000. He is Senior Vice President and General Counsel of Levi Strauss & Co. (LS&CO.), a brand name apparel manufacturer. Mr. Moreno is directly responsible for LS&CO. s legal and brand protection affairs and oversees the company s global security department. He has held this position since 1996. Mr. Moreno joined LS&CO. in 1978 as Assistant General Counsel. In addition to his work with LS&CO., Mr. Moreno is a member of the Rosenberg Foundation and the Levi Strauss Foundation. He serves on the board of trustees for the Tomas Rivera Policy Institute, the Mexican Museum, the National Association of Latino Elected and Appointed Officials Education Fund, and the American Corporate Counsel Association. He served on the NCE board of directors from 1999 until the completion of our merger. Mr. Moreno received a bachelor s degree in economics from San Diego State University in 1966 and a degree in Latin American Economic Studies from the Universidad de Madrid in 1967. In 1970, he received his law degree from the University of California at Berkeley School of Law.

Dr. Margaret R. Preska has been a Director of Xcel Energy Inc. since 1980. She is the President Emerita, Minnesota State University, Mankato and Distinguished Service Professor, Minnesota State Universities. Dr. Preska served as founding campus CEO at Zayed University, Abu Dhabi, United Arab Emirates from 1998 to 2000. She was President of Minnesota State University, Mankato, from 1979 until 1992. She had served as its Vice President for Academic Affairs and Equal Opportunity Officer from 1975 until 1979. She previously was academic dean, instructor, assistant and associate professor of history and government at LaVerne College in LaVerne, California. Dr. Preska earned a bachelor of science degree at SUNY Brockport, where she graduated summa cum laude. She earned a masters at The Pennsylvania State University, a Ph.D. at Claremont Graduate University, and further studied at Manchester College of Oxford University. Dr. Preska is a member of Women Directors and Officers in Public Utilities and is a member of the board of directors of Milkweed Editions, a literary and educational publisher. She served as national President at Camp Fire Boys and Girls, Inc. from 1985 until 1987. She is a charter member of the board of directors of Executive Sports, Inc., a division of Golden Bear International. She is affiliated with several organizations, including the Retired Presidents Association of the American Association of State Colleges and Universities, the St. Paul/Minneapolis Committee on Foreign Relations, Rotary, Minnesota Women s Economic Roundtable, the American Historical Association and Horizon 100.

A. Patricia Sampson has been a Director of Xcel Energy Inc. since 1985. She currently operates The Sampson Group, Inc., a management development and strategic planning consulting business. Prior to that she served as a consultant with Dr. Sanders and Associates, a management and diversity consulting company. Prior to her current endeavors, Ms. Sampson served as Chief Executive Officer of the Greater Minneapolis Area Chapter of the American Red Cross from July 1993 until January 1, 1995. She also previously served successively as Executive Director from October 1986 until July 1993, Assistant Executive Director-Services (April 1985), and Assistant Manager (July 1984) of the Greater Minneapolis Area Chapter. Prior to the above, she served as the Director of Service to Military Families and Veterans and Director of Disaster Services for the St. Paul Area Chapter of the American Red Cross. Ms. Sampson received a masters degree from the University of Pennsylvania and a bachelors degree from Youngstown State University. Ms. Sampson is a member of the Utility Women s Conference. She is active in Christian education. She previously served on the David W. Preus Leadership Award Sponsoring Council as well as on the boards of the Greater Minneapolis Area United Way, Minneapolis Urban League, the Minnesota Orchestral Association, and the Minnesota Women s Economic Roundtable.

Allan L. Schuman has been a Director of Xcel Energy Inc. since 1976. He is Chairman of the Board, Chief Executive Officer, President and a director of Ecolab Inc. in St. Paul, Minnesota. Ecolab develops and manufactures cleaning, sanitizing, and maintenance products for the hospitality, institutional, and industrial markets. Mr. Schuman joined Ecolab in 1957, and became Vice President, Institutional Marketing and National Accounts in 1972. In 1985 he was named Executive Vice President and in 1988, President, Ecolab Services Group. He was promoted to President and Chief Operating Officer of Ecolab in August 1992 and named President and Chief Executive Officer in March 1995. Mr. Schuman serves as a director of the Soap and Detergent Association, National Association of Manufacturers, American Marketing Association Services Council, Hazelden Foundation, the Ordway Music Theatre and the Guthrie Theatre, and chairs the Capital City Partnership. He is also a Trustee of the Culinary Institute of America and of the National education foundation of the National Restaurant Association, and a member of the board of overseers of Carlson School of Management at the University of Minnesota.

Rodney E. Slifer has been a Director of Xcel Energy Inc. since 2000. He is a Partner in Slifer, Smith & Frampton, a diversified real estate company in Vail, Colorado. He has held this position since 1989. Mr. Slifer served on the NCE Board from 1997 until the completion of our merger and on the PSCo board since 1988. In addition, he currently is a director of Alpine Banks of Colorado, a position he has held since 1983. He is Vice President and a board member of the Vail Valley Foundation and a director of Colorado Open Lands. Mr. Slifer also is a member of the Board of Governors of the University of Colorado Real Estate Center and a member of the University of Colorado Foundation Board of Directors.

W. Thomas Stephens has been a Director of Xcel Energy Inc. since 2000. He retired in 1999 as President and CEO of MacMillan Bloedel Ltd., a forest products and building materials company with headquarters in Vancouver, British Columbia. He served as Chairman, President and CEO of Johns Manville, an international manufacturing and natural resources company located in Denver, Colorado, from 1986 until August 1996. Mr. Stephens served on the NCE board of directors from 1997 until the completion of our Merger and on the PSCo board since 1989. He is on the boards of directors of TransCanada Pipeline, Norske Canada Ltd., Qwest Communications International Inc., Mail-Well Inc., and The Putnam Funds. He received his B.S. and M.S. degrees in industrial engineering from the University of Arkansas.

Board Structure and Compensation

Our Board currently consists of twelve directors. Our Board was comprised of fourteen directors during 2001 until August 18, 2001 when James J. Howard, former Chairman of the Board, resigned. Giannantonio Ferrari, former Director of the Company, also resigned from the Board on November 8, 2001. No persons were appointed to replace Messrs. Howard and Ferrari to the Board.

The Board had the following four Committees during 2002: Audit, Finance, Compensation and Nominating, and Operations and Nuclear. The membership during 2002 and the function of each Committee are described below. During 2002, the Board met 21 times and various Committees of the Board met as indicated below. Each director attended at least 75% of the meetings of the Board and Committees on which such director served during 2002.

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Audit Committee

Members: Roger R. Hemminghaus (Chair), Albert F. Moreno, Margaret R. Preska, Allan L. Schuman, and Rodney E. Slifer.

Number of meetings in 2002: 7.

Function:

Oversees our financial reporting process, compliance with legal and regulatory requirements, and the independence and performance of our independent and internal auditors;

Reviews the audited financial statements with management;

Recommends the appointment of independent auditors;

Reviews with the independent auditors the scope and the planning of the annual audit; and

Reviews finding and recommendations of the independent auditors and management s response to the recommendations of the independent auditors.

The Audit Committee operates under a written Charter adopted by our Board of Directors.

Finance Committee

Members: Douglas W. Leatherdale (Chair), C. Coney Burgess, A. Barry Hirschfeld, Margaret R. Preska, Allan L. Schuman, and W. Thomas Stephens.

Number of meetings in 2002: 4.

Function:

Oversees corporate capital structure and budgets;

Oversees financial plans and dividend policies;

Recommends dividends;

Oversees insurance coverage and banking relationships;

Oversees investor relations;

Oversees risk management; and

Oversees dedicated funds, including ERISA plans and nuclear decommissioning fund.

Compensation and Nominating Committee

Members: W. Thomas Stephens (Chair), C. Coney Burgess, David A. Christensen, A. Barry Hirschfeld, Douglas W. Leatherdale, and A. Patricia Sampson.

Number of meetings in 2002: 4.

Function:

- Determines Board organization, selects director nominees and sets director compensation;
- Reviews senior management incentive structure and compensation; and
- Reviews corporate structure and policies with respect to human resource policies, corporate ethics, and long range planning and strategy.

Any shareholder may make recommendations to the Compensation and Nominating Committee for Membership on the Board by sending a written statement of the qualifications of the recommended individual to the Secretary of the Company at 800 Nicollet Mall, Suite 3000, Minneapolis, Minnesota 55402-2023.

Operations and Nuclear Committee

Members: David A Christensen (Chair), Roger R. Hemminghaus, Albert G. Moreno, A. Patricia Sampson and Rodney E. Slifer.

Number of meetings in 2002: 3.

Function:

Oversees all generation requirements (nuclear, hydro, coal, alternative);

Oversees bulk power supply planning;

Oversees major power supply facility construction and budgets;

Monitors nuclear plant safety, reliability and operation; and

Oversees environmental policy.

Directors Compensation

The following table provides information on our compensation and reimbursement practices during 2002 for nonemployee directors. The director who is employed by us, Mr. Wayne Brunetti, does not receive any compensation for his Board activities.

Directors Compensation for 2002

Annual Director Retainer	$ 33,600
Board Meeting Attendance Fees	$ 1,200
Committee Meeting Attendance Fees	$ 1,200
Additional Retainer for Committee Chair	$ 3,000
Stock Equivalent Units	$ 52,800

We have a Stock Equivalent Plan for Non-Employee Directors to more closely align directors interests with those of our shareholders. Under this Stock Equivalent Plan, directors may receive an annual award of stock equivalent units with each unit having a value equal to one share of our common stock. Stock equivalent units do not entitle a director to vote and are only payable as a distribution of whole shares of our common stock upon a director s termination of service. The stock equivalent units fluctuate in value as the value of our common stock fluctuates. Additional stock equivalent units are accumulated upon the payment of and at the same value as dividends declared on our common stock. On April 19, 2002, our non-employee directors received an award of 2,039.40 stock equivalent units representing approximately $52,800 in cash value. Additional stock equivalent units were accumulated during 2002 as dividends were paid on our common stock. The number of stock equivalents for each non-employee director is listed in the share ownership chart which is set forth below.

Directors also may participate in a deferred compensation plan which provides for deferral of director retainer and meeting fees until after retirement from the Board. A director may defer director retainer and meeting fees into the Stock Equivalent Plan. A director who elects to defter compensation under this plan receives a premium of 20% of the compensation that is deferred.

Common Stock Ownership of Directors and Executive Officers

The following table sets forth information concerning beneficial ownership of our common stock as of January 31, 2003, for: (a) each director; (b) named executive officers set forth in the Summary Compensation Table; and (c) the directors and executive officers as a group. Unless otherwise indicated, each person has sole investment and voting power (or shares such powers with his or her spouse) with respect to the

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shares set forth in the following table. None of the individuals listed in the Beneficial Ownership Table below own more than .22% of our common stock. None of these individuals owns any shares of our preferred stock.

Beneficial Ownership Table

Name and Principal Position of Beneficial Owner	Common Stock	Stock Equivalents	Options Exercisable Within 60 Days	Restricted Stock	Total
Wayne H. Brunetti Chairman of the Board, President and Chief Executive Officer	89,696.92	9,002.71	692,850.00	39,675.98	831,225.61
C. Coney Burgess Director	8,575.62	12,174.38			20,750.00
David A. Christensen Director	1,000.00	33,661.03			34,661.03
Roger R. Hemminghaus Director	6,565.34	23,825.56			30,390.90
A. Barry Hirschfeld Director	13,235.62	12,930.31			26,165.93
Douglas W. Leatherdale Director	1,100.00	32,755.25			33,855.25
Albert F. Moreno Director	4,325.00	18,775.88			23,100.88
Margaret R. Preska Director	1,300.00	26,497.34			27,797.34
A. Patricia Sampson Director	1,265.77	22,593.22			23,858.99
Allan L. Schuman Director	200.00	18,439.08			18,639.08
Rodney E. Slifer Director	17,945.85	22,712.46			40,658.31
W. Thomas Stephens Director	11,037.95	19,275.42			30,313.37
Paul J. Bonavia President, Energy Markets	5,251.92	1,440.07	186,000.00		192,691.99
Gary R. Johnson Vice President and General Counsel	19,582.30		116,465.00		136,047.30
Richard C. Kelly(1) Vice President and Chief Financial Officer	28,109.54	3,310.71	224,750.00	4,797.32	260,967.57
Edward J. McIntyre Former Chief Financial Officer*	54,979.70		160,101.00		215,080.70
Directors and Executive Officers as a group (25 persons)	369,417.51	264,878.59	1,934,400.85	66,039.79	2,634,814.34

* Resigned as Chief Financial Officer effective August 20, 2002.

(1) Mr. Kelly s wife owns 407.84 of these shares. Mr. Kelly disclaims beneficial ownership of these shares.

Executive Compensation

The following tables set forth cash and non-cash compensation for each of the last three fiscal years ended December 31, 2002, for our Chief Executive Officer, each of the five next most highly compensated executive officers serving as officers at December 31, 2002, including our former Chief Financial Officer who

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resigned in August 2002 (collectively, the Named Executive Officers). As set forth in the footnotes, the data presented in this table and the tables that follow include amounts paid to the Named Executive Officers in 2002 by us or any of our subsidiaries, as well as by NCE and NSP or any of their subsidiaries for the period prior to the Merger.

Summary Compensation Table

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Name and Principal Position	Year	Salary($)	Bonus($)(1)	Other Annual Compensation ($)(2)	Restricted Stock Awards ($)(3)	Number of Securities Underlying Options and SAR s(#)(4)	LTIP Payouts ($)(5)	All Other Compensation ($)(6)
Wayne H. Brunetti	2002	1,065,000		9,836				53,052
Chairman, President and	2001	895,000	953,873	9,267			902,271	81,360
Chief Executive Officer	2000	756,667	852,244	167,265				314,436
Richard C. Kelly	2002	510,000		3,814				25,337
Vice President*	2001	425,417	338,588	1,208			269,633	39,077
	2000	375,917	279,446	55,855		228,000		130,124
Gary R. Johnson	2002	390,000		1,329				1,936
Vice President and	2001	340,000	236,656	3,934			175,206	27,640
General Counsel	2000	313,750	240,378	3,613		185,188		25,409
Paul J. Bonavia	2002	385,000		3,956				1,278
President,	2001	350,000	262,920	15,416			180,338	16,503
Energy Markets	2000	325,500	218,074	2,182		153,000		14,258
James T. Petillo	2002	345,000		1,617				1,177
President,	2001	316,250	200,463	12,978			149,408	15,562
Energy Delivery	2000	249,167	163,582	7,596		126,000		12,877
David M. Wilks	2002	345,000		2,041				13,565
President,	2001	310,000	216,202	3,994			159,727	26,448
Energy Supply	2000	289,583	190,693	9,032		135,000		24,143

* Elected as Chief Financial Officer effective August 21, 2002.

(1) The amounts in this column for 2001 and 2002 represent awards earned under the Xcel Energy Executive Annual Incentive Award program. For Mr. Brunetti, Mr. Kelly, Mr. Petillo and Mr. Wilks, the amounts for 2001 include the value of 25,068, 4,449, 10,536 and 5,682 shares, respectively, of restricted common stock they received in lieu of a portion of the cash payments to which they were otherwise entitled under the Xcel Energy Executive Annual Incentive Award program. For Mr. Bonavia, the amount for 2001 includes the pre-tax value of 3,023 shares of common stock he received in lieu of a portion of the cash payment to which he was otherwise entitled under the Xcel Energy Executive Annual Incentive Award program.

(2) The amounts shown for 2001 and 2002 include reimbursements for taxes on certain personal benefits, including flexible perquisites received by the named executives. The 2000 amount for Messrs. Brunetti and Kelly also include taxes on relocation benefits of $162,745 and $55,855, respectively.

(3) At December 31, 2002, Messrs. Brunetti, Kelly, Petillo and Wilks held shares of restricted stock. As of December 31, 2002, Mr. Brunetti held 39,083, Mr. Kelly held 4,720, Mr. Petillo held 11,177, and Mr. Wilks held 7,442 shares of restricted stock with an aggregate value of $429,913.84, $51,916.99, $122,948.39 and 81,862.04, respectively. Restricted stock vests in three equal annual installments.

(4) The amounts shown for 2000 include stock option awards made to the named executives under the NSP LTIP for Mr. Johnson (38,188). The balance of the options for Mr. Johnson in 2000, and all of the options for Messrs. Brunetti, Kelly, Bonavia, Petillo and Wilks for 2000

were granted under the Xcel Energy Omnibus Incentive Plan. These grants were three-year front-loaded (i.e., they represented three years worth of options) and it is not expected that additional options will be granted until 2003.

(5) The amounts shown for 2001 include cash payments made under the Xcel Energy Long-term Incentive Program. NSP had no LTIP payouts in 2000. No performance cash awards under the NCE Value Creation Plan for Messrs. Brunetti, Kelly, Bonavia, Petillo and Wilks were paid during 2001 or 2000.

(6) The amounts represented in the All Other Compensation column for the year 2002 for the Named Executive Officers include the following:

Name	Imputed Income as a result of the Life Insurance paid by the Company($)	Earnings Accrued under Deferred Compensation Plan($)	Bonus related to Relocation Payments($)	(1) Total ($)
Wayne H. Brunetti	5,127	n/a	47,925	53,052
Richard C. Kelly	2,387	n/a	22,950	25,337
Gary R. Johnson	1,936	n/a	n/a	1,936
Paul J. Bonavia	1,278	n/a	n/a	1,278
James T. Petillo	1,177	n/a	n/a	1,177
David M. Wilks	1,490	n/a	12,075	13,565

(1) The total of All Other Compensation does not include Company Matching 401(k) Contributions, or Contributions to the Non-Qualified Savings Plans which have not yet been determined.

Aggregated Option/SAR Exercises in Last Fiscal Year and FY-End Option/SAR Values

The following table indicates for each of the named executives the number and value of exercisable and unexercisable options and SARs as of December 31, 2002.

Name	Shares Acquired on Exercise (#)	Value Realized ($)	Number of Securities Underlying Unexercised Options/ SARs at FY-End (#)		Value of Unexercised In-the-Money Options/ SARs at FY-End ($)(1)	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Wayne H. Brunetti			692,850	756,000		
Richard C. Kelly			224,750	228,000		
Gary R. Johnson			116,465	147,000		
Paul J. Bonavia			186,000	153,000		
James T. Petillo			112,530	126,000		
David M. Wilks			173,600	135,000		

(1) Option values were calculated based on a $11.00 closing price of Xcel Energy common stock, as reported on the New York Stock Exchange at December 31, 2002.

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Long-Term Performance Plan Awards in Last Fiscal Year(1)

The following table shows information on awards granted during 2002 under our Omnibus Incentive Plan for each person in the Summary Compensation Table.

Name	Number of Shares, Units or Other Rights(2)	Performance or Other Period Until Maturation or Payout	Estimated Future Payouts Under Non-Stock Price-Based Plans		
			Threshold ($)(3)	Target ($)	Maximum ($)
Wayne H. Brunetti	119,566	1/1/02-12/31/04	832,031	3,328,125	6,656,250
Richard C. Kelly	30,690	1/1/02-12/31/04	213,563	854,250	1,708,500
Gary R. Johnson	15,763	1/1/02-12/31/04	109,688	438,750	877,500
Paul J. Bonavia	15,560	1/1/02-12/31/04	108,281	433,125	866,250
James T. Petillo	13,944	1/1/02-12/31/04	97,031	388,125	776,250
David M. Wilks	13,944	1/1/02-12/31/04	97,031	388,125	776,250

(1) The amounts in this table for the year 2002 are for the performance period 1/1/02-12/31/04 and represent awards made under the performance unit component described under Long-term Incentives .

(2) Each unit represents the value of one share of our common stock.

(3) If the threshold for the performance unit component, of the 35th percentile is achieved, the payout could range between 25% and 200%. Performance below the threshold amount results in a payment of zero. The amounts are based on a stock price of $27.8350, which was the average high/low price on January 2, 2002.

Pension Plan Table

The following table shows estimated combined pension benefits payable to a covered participant from the qualified and non qualified defined benefit plans maintained by us and our subsidiaries and the Xcel Energy Supplemental Executive Retirement Plan (the SERP). The Named Executive Officers are all participants in the SERP and the qualified and non qualified defined benefit plans sponsored by us.

Remuneration	Years of Service		
	10 years	15 years	20 or more years
200,000	55,000	82,500	110,000
225,000	61,875	92,813	123,750
250,000	68,750	103,125	137,500
275,000	75,625	113,438	151,250
300,000	82,500	123,750	165,000
350,000	96,250	144,375	192,500
400,000	110,000	165,000	220,000
450,000	123,750	185,625	247,500
500,000	137,500	206,250	275,000
600,000	165,000	247,500	330,000
700,000	192,500	288,750	385,000
800,000	220,000	330,000	440,000
900,000	247,500	371,250	495,000
1,000,000	275,000	412,500	550,000
1,100,000	302,500	453,750	605,000
1,200,000	330,000	495,000	660,000
1,300,000	357,500	536,250	715,000
1,400,000	385,000	577,500	770,000

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Remuneration	Years of Service		
	10 years	15 years	20 or more years
1,500,000	412,500	618,750	825,000
1,600,000	440,000	660,000	880,000
1,700,000	467,500	701,250	935,000
1,800,000	495,000	742,500	990,000
1,900,000	522,500	783,750	1,045,000
2,000,000	550,000	825,000	1,100,000
2,100,000	577,500	866,250	1,155,000
2,200,000	605,000	907,500	1,210,000

The benefits listed in the Pension Plan Table are not subject to any deduction or offset. The compensation used to calculate the SERP benefits is base salary as of December 31 plus annual incentive. The Salary and Bonus columns of the Summary Compensation Table for 2002 reflect the covered compensation used to calculate SERP benefits.

The SERP benefit accrues ratably over 20 years and, when fully accrued, is equal to (a) 55% of the highest three years covered compensation of the five years preceding retirement or termination minus (b) any other qualified non-qualified benefits. The SERP benefit is payable as an annuity for 20 years, or as a single lump-sum amount equal to the actuarial equivalent present value of the 20-year annuity. Benefits are payable at age 62, or as early as age 55 reduced 5% for each year that the benefit commencement date precedes age 62. The approximate credited years of service under the SERP as of December 31, 2002, were as follows:

Mr. Brunetti	15 years
Mr. Kelly	35 years
Mr. Johnson	24 years
Mr. Bonavia	5 years
Mr. Petillo	6 years
Mr. Wilks	25 years

Notwithstanding any special provisions related to pension benefits described under Employment Agreements and Severance Arrangements, we have granted additional credited years of service to Mr. Brunetti for purposes of SERP accrual. The additional credited years of service (approximately seven) are included in the above table. Additionally, we have agreed to grant full accrual of SERP benefits to Mr. Brunetti at age 62 and to Mr. Bonavia at age 57 and 8 months, if they continue to be employed by us until such age.

Employment Agreements and Severance Arrangements

Wayne H. Brunetti Employment Agreement

At the time of the merger agreement, NCE and NSP also entered into a new employment agreement with Mr. Brunetti, which replaced his existing employment agreement with NCE when the Merger was completed. The initial term of the new agreement is four years, with automatic one-year extensions beginning at the end of the second year and continuing each year thereafter unless notice is given by either party that the agreement will not be extended. Under the terms of the agreement, Mr. Brunetti served as Chief Executive Officer and President and a member of our board of directors for one year following the Merger, and commencing August 18, 2001 (one year after the Merger) began serving as Chief Executive Officer and Chairman of our Board of Directors. Mr. Brunetti is required to perform the majority of his duties at our headquarters in Minneapolis, Minnesota, and was required to relocate the residence at which he spends the majority of his time to the Twin Cities area. His agreement also provides that if Mr. Brunetti becomes entitled to receive severance benefits, he will be forbidden from competing with us and our affiliates for two years following the termination of his employment, and from disclosing confidential information of us and our affiliates.

Under his employment agreement, Mr. Brunetti will receive the following compensation and benefits:

a base salary not less than his base salary immediately before the Merger;

the opportunity to earn annual and long-term incentive compensation amounts not less than he was able to earn immediately before the Merger;

life insurance coverage and participation in a supplemental executive retirement plan; and

the same fringe benefits as he received under his NCE employment agreement, or, if greater, as those of our next higher executive officer;

If Mr. Brunetti s employment were to be terminated by us without cause or if he were to terminate his employment for good reason, he would be entitled to receive the compensation and benefits described above as if he had remained employed for the employment period remaining under his employment agreement and then retired, at which time he would be eligible for all retiree benefits provided to our retired senior executives. In determining the level of his compensation following termination of employment, the amount of incentive compensation he would receive would be based upon the target level of incentive compensation he would have received in the year in which his termination occurred, and he would receive cash equal to the value of stock options, restricted stock and stock-based awards he would have received instead of receiving the awards. In addition, the restrictions on his restricted stock would lapse and his stock options would have become vested. Finally, we would be obligated to make Mr. Brunetti whole for any excise tax on severance payment that he incurs.

Mr. Brunetti also had a change-of-control employment agreement with NCE. The Merger did not cause a change of control under this agreement, so it did not become effective as a result of the Merger. However, in case his agreement becomes effective because of a later change of control, Mr. Brunetti has waived his right to receive any severance benefits under the change-of-control employment agreement to the extent they would duplicate severance benefits under his employment agreement.

Paul J. Bonavia Employment Agreement

In connection with and effective upon completion of the Merger, we and Paul J. Bonavia entered into an amendment to an employment agreement between Mr. Bonavia and NCE. Except as discussed below, the original agreement expired December 14, 2000. In connection with the Merger, Mr. Bonavia s position changed from Senior Vice President, General Counsel and President of NCE s International Business Unit to President of our Energy Markets Business Unit. In the amendment, Mr. Bonavia agreed not to assert before January 6, 2003 that his duties and responsibilities have been diminished, and thus he has waived the right to claim certain benefits under the Xcel Senior Executive Severance Policy relating to this change in his status prior to that date. If certain conditions are met on January 6, 2003 or within seven business days thereafter, which conditions include the termination of Mr. Bonavia s employment, Mr. Bonavia will be entitled to severance benefits comparable to those provided to the other senior executives under the Xcel Senior Executive Severance Policy described below. Mr. Bonavia and we have recently entered into another amendment to this agreement. As part of this amendment, Mr. Bonavia agreed to continue his employment through August 31, 2003. Mr. Bonavia also agreed not to assert that his duties and responsibilities have been diminished. In return, we agreed that if we terminate Mr. Bonavia s employment for any reason other than cause, or if Mr. Bonavia terminates his employment for any reason after August 31, 2003, then he will be entitled to severance benefits comparable to those provided to the other senior executives under the Xcel Senior Executive Severance Policy described below.

Severance Policy

NSP and NCE each adopted a 1999 senior executive severance policy in March 1999. These policies were combined into a single Xcel Energy Senior Executive Severance Policy which will continue until

August 18, 2003 and may be extended beyond August 2003. All of our executive officers other than Mr. Brunetti participate in the policy.

Under the policy, a participant whose employment is terminated at any time before August 18, 2003, the third anniversary of the Merger, will receive severance benefits unless:

- the employer terminated the participant for cause;
- the termination was because of the participant s death, disability or retirement;
- the division or subsidiary in which the participant worked was sold and the buyer agreed to continue the participant s employment with specified protections for the participant; or
- the participant terminated voluntarily without good reason.

To receive the severance benefits, the participant must also sign an agreement releasing all claims against the employer and its affiliates, and agreeing not to compete with the employer and its affiliates and not to solicit their employees and customers.

The severance benefits for executive officers under the policy include the following:

- a cash payment equal to 2.5 times the participant s annual base salary, annual bonus and annualized long-term incentive compensation, prorated incentive compensation for the year of termination and perquisite allowance;
- a cash payment equal to the additional amounts that would have been credited to the executive under pension and retirement savings plans, if the participant had remained employed for another 2.5 years;
- continued welfare benefits for 2.5 years;
- financial planning benefit for two years, and outplacement services costing not more than $30,000; and
- an additional cash payment to make the participant whole for any excise tax on excess severance payments that he or she may incur, with certain limitations specified in the policies.

Some of the executive officers of NCE who participate in the severance policy also had change-of-control employment agreements with NCE. The Merger was not considered a change of control under these agreements, so they did not become effective as a result of the Merger. However, if they become effective because of a later change of control, the severance benefits under the Xcel Senior Executive Severance Policy will be reduced by any severance benefits that the participant receives under such an employment agreement.

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DESCRIPTION OF THE NOTES

We issued the notes under an indenture between us and Wells Fargo Bank Minnesota, National Association, as trustee, dated November 21, 2002. The terms of the notes include those provided in the indenture and those provided in the registration rights agreement, which we entered into with the initial purchasers of the notes. For purposes of this Description of the Notes, any references to Xcel Energy, we, our or us refer Xcel Energy Inc. and not its subsidiaries.

The following description of provisions of the notes is not complete and is subject to, and qualified in its entirety by reference to, the notes, the indenture and the registration rights agreement, each of which has been filed with the SEC as an exhibit to the registration statement of which this prospectus is a part.

General

The notes are our general unsecured and unsubordinated obligations and are convertible into our common stock, at the option of the holders, as described under Conversion Rights below. The notes are limited to $230,000,000 aggregate principal amount (including $30,000,000 aggregate principal amount issued pursuant to an overallotment option exercised in full by the initial purchasers) and will mature on November 21, 2007, unless sooner repurchased by us at the option of the holder upon the occurrence of a Change of Control (as defined below).

The notes bear interest from November 21, 2002 at the rate of 7 1/2% per year. Interest is payable semi-annually on May 21 and November 21 of each year to holders of record at the close of business on the preceding May 6 and November 6, respectively, beginning May 21, 2003. We may pay interest on notes represented by certificated notes by check mailed to such holders. However, a holder of notes with an aggregate principal amount in excess of $5,000,000 will be paid by wire transfer in immediately available funds at the election of such holder. Interest will be computed on the basis of a 360-day year comprised of twelve 30-day months. Interest will cease to accrue on a note upon its maturity, conversion or purchase by us upon a Change of Control.

Principal will be payable, and the notes may be presented for conversion, registration of transfer and exchange, without service charge, at our office or agency maintained for such purposes, which shall initially be the office or agency of the trustee in Minneapolis, Minnesota. See Form, Denomination and Registration below.

The indenture does not contain any financial covenants or any restrictions on the payment of dividends, the repurchase of our securities or the incurrence of indebtedness. The indenture also does not contain any covenants or other provisions that afford protection to holders of notes in the event of a highly leveraged transaction or a Change of Control of us except to the extent described under Change of Control Permits Purchase of Notes at the Option of the Holder below.

Dividend Protection

We will make additional payments of interest, referred to in this prospectus as protection payments, on the notes in an amount equal to any portion of our per share dividends on our common stock that exceeds $0.1875 per quarter that would have been payable to the holders of the notes if such holders had converted their notes on the record date for such dividend (subject to adjustment for stock splits, stock dividends, stock combinations and other similar transactions). Such payment is referred to herein as a protection payment. The record date and payment date for such protection payment shall be the same as the corresponding record date and payment date of our common stock to which the protection payment relates. Holders of the notes will not be entitled to any protection payment if the dividend triggering the protection payment causes an adjustment to the conversion rate. See Conversion Rights.

Conversion Rights

The holders of notes may, at any time prior to the close of business on the final maturity date of the notes, convert any outstanding notes (or portions thereof) into, at the option of the holders, our common stock,

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initially at a conversion price of $12.33 per share, which is equal to a conversion rate of approximately 81.1359 shares per $1,000 principal amount of notes. The conversion rate is subject to adjustment upon the occurrence of certain events as described below. Holders may convert notes only in denominations of $1,000 and whole multiples of $1,000. Except as described below, no adjustment will be made on conversion of any notes for interest accrued thereon or dividends paid on any common stock. Notwithstanding the above, if notes are converted after a record date but prior to the next succeeding interest payment date, holders of such notes at the close of business on the record date will receive the semi-annual interest payable on such notes on the corresponding interest payment date notwithstanding the conversion. In such event, such notes, upon surrender for conversion, must be accompanied by funds equal to the amount of semi-annual interest payable on the principal amount of notes so converted. We are not required to issue fractional shares of common stock upon conversion of notes and instead will pay a cash adjustment based upon the market price of the common stock on the last trading day before the date of the conversion.

A holder may exercise the right of conversion by delivering the note to be converted to the specified office of a conversion agent, with a completed notice of conversion, together with any funds that may be required as described in the preceding paragraph. The conversion date will be the date on which the notes, the notice of conversion and any required funds have been so delivered. A holder delivering a note for conversion will not be required to pay any taxes or duties relating to the issuance or delivery of the common stock for such conversion, but will be required to pay any tax or duty which may be payable relating to any transfer involved in the issuance or delivery of the common stock in a name other than the holder of the note. Certificates representing shares of common stock will be issued or delivered only after all applicable taxes and duties, if any, payable by the holder have been paid. If any note is converted prior to the expiration of the holding period applicable for sales thereof under Rule 144(k) under the Securities Act (or any successive provision), the common stock issuable upon conversion will not be issued or delivered in a name other than that of the holder of the note unless the applicable restrictions on transfer have been satisfied.

We will adjust the conversion rate for certain events, including:

- the issuance of our common stock as a dividend or distribution on our common stock;

- certain subdivisions and combinations of our common stock;

- the issuance to all holders of our common stock of certain rights or warrants to purchase our common stock (or securities convertible into our common stock) at less than (or having a conversion price per share less than) the then current market price of our common stock;

- the dividend or other distribution to all holders of our common stock or shares of our capital stock (other than common stock) of evidences of indebtedness or assets (including securities, but excluding (A) those rights and warrants referred to in the immediately preceding bullet point above, (B) dividends and distributions in connection with a reclassification, change, consolidation, merger, combination, sale or conveyance resulting in a change in the conversion consideration pursuant to the second succeeding paragraph or (C) dividends or distributions paid exclusively in cash);

- dividends or other distributions (other than our regular quarterly dividends) consisting exclusively of cash to all holders of our common stock to the extent that such distributions, combined together with (A) all other such all cash distributions made within the preceding 12 months for which no adjustment has been made plus (B) any cash and the fair market value of other consideration paid in any tender offers by us or any of our subsidiaries for our common stock concluded within the preceding 12 months for which no adjustment has been made, exceeds 5% of our market capitalization (which is the product of the then current market price of our common stock times the number of shares of our common stock then outstanding) on the record date for such distribution; and

- the purchase of our common stock pursuant to a tender offer made by us or any of our affiliates to the extent that the same involves an aggregate consideration that, together with (A) any cash and the fair market value of any other consideration paid in any other tender offer by us or any of our affiliates for our common stock expiring within the 12 months preceding such tender offer for which no adjustment has been made plus (B) the aggregate amount of any all-cash distributions referred to in

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the immediately preceding bullet above to all holders of our common stock within 12 months preceding the expiration of tender offer for which no adjustments have been made, exceeds 5% of our market capitalization on the expiration of such tender offer.

If we pay a dividend or make a distribution on shares of our common stock consisting of capital stock of, or similar equity interests in, a subsidiary or other business unit of ours, the conversion rate will be adjusted based on the market value of the securities so distributed relative to the market value of our common stock, in each case based on the average sale prices of those securities for the ten trading days commencing on and including the fifth trading day after the date on which ex-dividend trading commences for such dividend or distribution on the New York Stock Exchange or such other national or regional exchange or market on which the securities are then listed or quoted.

No adjustment in the conversion rate will be required unless such adjustment would require a change of at least 1% in the conversion rate then in effect at such time. Any adjustment that would otherwise be required to be made shall be carried forward and taken into account in any subsequent adjustment. Except as stated above, the conversion rate will not be adjusted for the issuance of our common stock or any securities convertible into or exchangeable for our common stock or carrying the right to purchase any of the foregoing.

In the case of:

- any reclassification or change of our common stock (other than changes resulting from a subdivision or combination) or

- a consolidation, merger or combination involving us or a sale or conveyance to another corporation of all or substantially all of our property and assets,

in each case, as a result of which holders of our common stock are entitled to receive stock, other securities, other property or assets (including cash), or any combination thereof, with respect to or in exchange for our common stock, the holders of the notes then outstanding will be entitled thereafter to convert those notes into the kind and amount of shares of stock, other securities or other property or assets (including cash), or any combination thereof, which they would have owned or been entitled to receive upon such reclassification, change, consolidation, merger, combination, sale or conveyance had such notes been converted into our common stock immediately prior to such reclassification, change, consolidation, merger, combination, sale or conveyance.

We may not become a party to any such transaction unless its terms are consistent with the foregoing.

If a taxable distribution to holders of our common stock or other transaction occurs which results in any adjustment of the conversion price, the holders of notes may, in certain circumstances, be deemed to have received a distribution subject to U.S. income tax as a dividend. See Important United States Federal Income Tax Consequences.

We may from time to time, to the extent permitted by law, reduce the conversion price of the notes by any amount for any period of at least 20 days. In that case we will give at least 15 days notice of such decrease. We may make such reductions in the conversion price, in addition to those set forth above, as the board of directors deems advisable to avoid or diminish any income tax to holders of our common stock resulting from any dividend or distribution of stock (or rights to acquire stock) or from any event treated as such for income tax purposes.

Ranking

The notes are our unsecured and unsubordinated obligations. The notes rank on a parity in right of payment with all of our existing and future unsecured and unsubordinated indebtedness. As of December 31, 2002, we had approximately $600 million of long-term indebtedness outstanding in addition to the notes. There are currently no outstanding debt obligations junior to the notes. However, the notes are subordinated to any of our secured indebtedness, as to the assets securing such indebtedness. As of December 31, 2002, we had no secured indebtedness and our unsecured and unsubordinated long-term indebtedness was $830 million.

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In addition, the notes are effectively subordinated to all existing and future liabilities of our subsidiaries. We are a holding company and conduct business through our various subsidiaries. As a result, our cash flow and consequent ability to meet our debt obligations primarily depend on the earnings of our subsidiaries, and on dividends and other payments from our subsidiaries. Under certain circumstances, contractual and legal restrictions, as well as the financial condition and operating requirements of our subsidiaries, could limit our ability to obtain cash from our subsidiaries for the purpose of meeting debt service obligations, including the payment of principal and interest on the notes. Any rights to receive assets of any subsidiary upon its liquidation or reorganization and the consequent right of the holders of the notes to participate in those assets will be subject to the claims of that subsidiary s creditors, including trade creditors, except to the extent that we are recognized as a creditor of that subsidiary, in which case its claims would still be subordinate to any security interests in the assets of that subsidiary. As of December 31, 2002, our subsidiaries had approximately $20.7 billion of indebtedness and other liabilities outstanding.

Change of Control Permits Purchase of Notes at the Option of the Holder

If a Change of Control occurs, each holder of notes will have the right to require us to repurchase for cash all of that holder s notes or any portion thereof that is equal to $1,000 or a whole multiple of $1,000, on the date that is 45 days after the date we give notice of a Change of Control at a repurchase price equal to 100% of the principal amount of the notes to be repurchased, together with interest accrued and unpaid to, but excluding, the repurchase date.

Within 30 days after the occurrence of a Change of Control, we are required to give notice to all holders of notes, as provided in the indenture, of the occurrence of the Change of Control and of their resulting repurchase right. We must also deliver a copy of our notice to the trustee. To exercise this right, the holder must deliver a written notice to the paying agent prior to the close of business on the business day prior to the Change of Control purchase date. Any such notice may be withdrawn by the holder by a written notice of withdrawal delivered to the paying agent prior to the close of business on the business day prior to the Change of Control purchase date.

A Change of Control will be deemed to have occurred at such time after the original issuance of the notes when the following has occurred:

any person or group (as such terms are used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934, as amended (the Exchange Act)) acquires the beneficial ownership (as defined in Rules 13d-3 and 13d-5 under the Exchange Act, except that a person shall be deemed to have beneficial ownership of all securities that such person has the right to acquire, whether such right is exercisable immediately or only after the passage of time), directly or indirectly, through a purchase, merger or other acquisition transaction, of 50% or more of the total voting power of our total outstanding voting stock, other than an acquisition by us, any of our subsidiaries or any of our employee benefit plans;

we consolidate with, or merge with or into, another person or convey, transfer, lease or otherwise dispose of all or substantially all of our assets to any person, or any person consolidates with or merges with or into us, other than:

any transaction (A) that does not result in any reclassification, conversion, exchange or cancellation of outstanding shares of our capital stock and (B) pursuant to which holders of our capital stock immediately prior to the transaction have the entitlement to exercise, directly or indirectly, 50% or more of the total voting power of all shares of our capital stock entitled to vote generally in the election of directors of the continuing or surviving person immediately after the transaction; and

any merger solely for the purpose of changing our jurisdiction of incorporation and resulting in a reclassification, conversion or exchange of outstanding shares of common stock solely into shares of common stock of the surviving entity;

during any consecutive two-year period, individuals who at the beginning of that two-year period constituted our board of directors (together with any new directors whose election to such board of directors, or whose nomination for election by stockholders, was approved by a vote of a majority of the directors then still in office who were either directors at the beginning of such period or whose election or nomination for election was previously so approved) cease for any reason to constitute a majority of our board of directors then in office; or

our stockholders pass a special resolution approving a plan of liquidation or dissolution and no additional approvals of stockholders are required under applicable law to cause a liquidation or dissolution.

The definition of Change of Control includes a phrase relating to the lease, transfer, conveyance or other disposition of all or substantially all of our assets. There is no precise established definition of the phrase substantially all under applicable law. Accordingly, the ability of a holder of notes to require us to repurchase such notes as a result of a lease, transfer, conveyance or other disposition of less than all of our assets may be uncertain.

We will comply with the provisions of any tender offer rules under the Exchange Act that may then be applicable, and will file any schedule required under the Exchange Act in connection with any offer by us to purchase notes at the option of the holders of notes upon a Change of Control. In some circumstances, the Change of Control purchase feature of the notes may make more difficult or discourage a takeover of us and thus the removal of incumbent management. The Change of Control purchase feature, however, is not the result of management s knowledge of any specific effort to accumulate shares of common stock or to obtain control of us by means of a merger, tender offer, solicitation or otherwise, or part of a plan by management to adopt a series of anti-takeover provisions. Instead, the Change of Control purchase feature is the result of negotiations between us and the initial purchasers.

We may to the extent permitted by applicable law, at any time purchase the notes in the open market or by tender at any price or by private agreement. Any note so purchased by us may, to the extent permitted by applicable law, be reissued or resold or may be surrendered to the trustee for cancellation. Any notes surrendered to the trustee may not be reissued or resold and will be canceled promptly.

The foregoing provisions would not necessarily protect holders of the notes if highly leveraged or other transactions involving us occur that may adversely affect holders. Our ability to repurchase notes upon the occurrence of a Change of Control is subject to important limitations. The occurrence of a Change of Control could cause an event of default under, or be prohibited or limited by, the terms of indebtedness that we may incur in the future. Further, we cannot assure you that we would have the financial resources, or would be able to arrange financing, to pay the repurchase price for all the notes that might be delivered by holders of notes seeking to exercise the repurchase right. Any failure by us to repurchase the notes when required following a Change of Control would result in an event of default under the indenture. Any such default may, in turn, cause a default under indebtedness that we may incur in the future.

Events of Default

Each of the following will constitute an event of default under the indenture:

(1) our failure to pay when due the principal of the notes at maturity or upon exercise of a repurchase right or otherwise;

(2) our failure to pay an installment of interest (including liquidated damages, if any) on any of the notes for 30 days after the date when due;

(3) failure by us to deliver shares of common stock, together with cash instead of fractional shares, when those shares of common stock, or cash instead of fractional shares, are required to be delivered following conversion of a note, and that default continues for 10 days;

(4) failure by us to give the notice regarding a Change of Control within 30 days of the occurrence of the Change of Control;

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(5) our failure to perform or observe any other term, covenant or agreement contained in the notes or the indenture for a period of 60 days after written notice of such failure, requiring us to remedy the same, shall have been given to us by the trustee or to us and the trustee by the holders of at least 25% in aggregate principal amount of the notes then outstanding;

(6) in the event of either (a) our failure or the failure of any of our significant subsidiaries (not including NRG) to make any payment by the end of the applicable grace period, if any, after the final scheduled payment date for such payment with respect to any indebtedness for borrowed money in an aggregate principal amount in excess of $50 million, or (b) the acceleration of indebtedness for borrowed money of the company or any of our significant subsidiaries (not including NRG) in an aggregate principal amount in excess of $50 million because of a default with respect to such indebtedness, without such indebtedness referred to in either (a) or (b) above having been discharged, cured, waived, rescinded or annulled, for a period of 30 days after written notice to us by the trustee or to us and the trustee by holders of at least 25% in aggregate principal amount of the notes then outstanding;

(7) the failure to pay when due the principal of, or the acceleration of, any of the notes (including the Prior Notes) issued pursuant to the Purchase Agreement described under Prospectus Summary Our Business Recent Development ; and

(8) certain events of the bankruptcy, insolvency or reorganization of us or any of our significant subsidiaries (not including NRG).

The term significant subsidiary means a subsidiary, including our subsidiaries, that meets any of the following conditions:

- our and our other subsidiaries (not including NRG) investments in and advances to the subsidiary exceed 15% of the total assets of us and our subsidiaries (not including NRG) consolidated as of the end of the most recently completed fiscal year;

- our and our other subsidiaries (not including NRG) proportionate share of the total assets (after intercompany eliminations) of the subsidiary exceeds 15% of the total assets of us and our subsidiaries (not including NRG) consolidated as of the end of the most recently completed fiscal year; or, our and our other subsidiaries (not including NRG) equity in the income from continuing operations before income taxes, extraordinary items and cumulative effect of a change in accounting principle of the subsidiary exceeds 15% of such income of us and our subsidiaries (not including NRG) consolidated for the most recently completed fiscal year.

The indenture provides that the trustee shall, within 90 days after the occurrence of a default, give to the registered holders of the notes notice of all uncured defaults known to it, but the trustee shall be protected in withholding such notice if it, in good faith, determines that the withholding of such notice is in the best interest of such registered holders, except in the case of a default in the payment of the principal of or interest on, any of the notes when due or in the payment of any repurchase obligation.

If an event of default specified in clause (8) above occurs and is continuing, then automatically the principal of all the notes and the interest thereon shall become immediately due and payable. If an event of default shall occur and be continuing, other than with respect to clause (8) above (the default not having been cured or waived as provided under Modifications and Waiver below), the trustee or the holders of at least 25% in aggregate principal amount of the notes then outstanding may declare the notes due and payable at their principal amount together with accrued interest. If an event of default occurs and is continuing, the trustee may, at its discretion, proceed to protect and enforce the rights of the holders of notes by appropriate judicial proceedings. Such declaration may be rescinded or annulled with the written consent of the holders of a majority in aggregate principal amount of the notes then outstanding upon the conditions provided in the indenture. However, if an event of default is cured prior to such declaration by the trustee or holders of the notes as discussed above, the trustee and the holders of the notes will not be able to make such declaration as a result of that cured event of default.

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We will pay interest on overdue principal at the rate borne by the notes, and we shall pay interest on overdue installments of interest (including liquidated damages, if any) at the same rate to the extent lawful.

The indenture contains a provision entitling the trustee, subject to the duty of the trustee during default to act with the required standard of care, to be indemnified by the holders of notes before proceeding to exercise any right or power under the indenture at the request of such holders. The indenture provides that the holders of a majority in aggregate principal amount of the notes then outstanding through their written consent may direct the time, method and place of conducting any proceeding for any remedy available to the trustee or exercising any trust or power conferred upon the trustee.

We are required to furnish annually to the trustee a statement as to the fulfillment of our obligations under the indenture.

Consolidation, Merger or Assumption

We may, without the consent of the holders of notes, consolidate with, merge into or transfer all or substantially all of our assets to any other entity organized under the laws of the United States or any of its political subdivisions provided that:

- the surviving corporation assumes all our obligations under the indenture and the notes;
- at the time of and after giving effect to such transaction, no event of default, and no event which, after notice or lapse of time, would become an event of default, shall have happened and be continuing; and
- certain other conditions are met.

Modifications and Waiver

The indenture (including the terms and conditions of the notes) may be modified or amended by us and the trustee, without the consent of the holder of any note, for the purposes of, among other things:

- adding to our covenants for the benefit of the holders of notes;
- surrendering any right or power conferred upon us;
- providing for the assumption of our obligations to the holders of notes in the case of a merger, consolidation, conveyance, transfer or lease;
- reducing the conversion price, provided that the reduction will not adversely affect the interests of holders of notes in any material respect;
- complying with the requirements of the SEC in order to effect or maintain the qualification of the indenture under the Trust Indenture Act of 1939, as amended;
- making any changes or modification to the indenture necessary in connection with the registration of the notes under the Securities Act as contemplated by the registration rights agreement, provided that this action does not adversely affect the interests of the holders of the notes in any material respect;
- curing any ambiguity or correcting or supplementing any defective provision contained in the indenture; provided that such modification or amendment does not adversely affect the interests of the holders of the notes in any material respect; or
- adding, modifying or eliminating any other provisions which we and the trustee may deem necessary or desirable and which will not adversely affect the interests of the holders of notes in any material respect.

Modifications and amendments to the indenture or to the terms and conditions of the notes may also be made, and past default by us may be waived with the written consent of the holders of at least a majority in aggregate principal amount of the notes at the time outstanding. However, no such modification, amendment or waiver may, without the written consent or the affirmative vote of the holder of each note so affected:

- change the maturity of the principal of or any installment of interest on that note (including any payment of liquidated damages);
- reduce the principal amount of, or any premium or interest on (including any payment of liquidated damages), any note;
- change the currency of payment of such note or interest thereon;
- impair the right to institute suit for the enforcement of any payment on or with respect to any note;
- except as otherwise permitted or contemplated by provisions concerning corporate reorganizations, adversely affect the repurchase option of holders upon a Change of Control or the conversion rights of holders of the notes; or
- reduce the percentage in aggregate principal amount of notes outstanding necessary to modify or amend the indenture or to waive any past default.

Form, Denomination and Registration

The notes were issued in fully registered form, without coupons, in denominations of $1,000 principal amount and whole multiples of $1,000.

Global Notes; Book-Entry Form. Except as provided below, the notes are evidenced by one or more global notes deposited with the trustee as custodian for The Depository Trust Company, New York, New York (DTC), and registered in the name of Cede & Co. as DTC s nominee. Record ownership of the global notes may be transferred, in whole or in part, only to another nominee of DTC or to a successor of DTC or its nominee, except as set forth below. A holder of the notes may hold its interests in a global note directly through DTC if such holder is a participant in DTC, or indirectly through organizations which are direct DTC participants. Transfers between direct DTC participants will be effected in the ordinary way in accordance with DTC s rules and will be settled in same-day funds. Holders may also beneficially own interests in the global notes held by DTC through certain banks, brokers, dealers, trust companies and other parties that clear through or maintain a custodial relationship with a direct DTC participant, either directly or indirectly. So long as Cede & Co., as nominee of DTC, is the registered owner of the global notes, Cede & Co. for all purposes will be considered the sole holder of the global notes. Except as provided below, owners of beneficial interests in the global notes will not be entitled to have certificates registered in their names, will not receive or be entitled to receive physical delivery of certificates in definitive form, and will not be considered holders thereof. The laws of some states require that certain persons take physical delivery of securities in definitive form. Consequently, the ability to transfer a beneficial interest in the global notes to such persons may be limited. We will wire, through the facilities of the trustee, principal, premium, if any, and interest payments on the global notes to Cede & Co., the nominee for DTC, as the registered owner of the global notes. We, the trustee and any paying agent will have no responsibility or liability for paying amounts due on the global notes to owners of beneficial interests in the global notes. It is DTC s current practice, upon receipt of any payment of principal of and premium, if any, and interest on the global notes, to credit participants accounts on the payment date in amounts proportionate to their respective beneficial interests in the notes represented by the global notes, as shown on the records of DTC. Payments by DTC participants to owners of beneficial interests in notes represented by the global notes held through DTC participants will be the responsibility of DTC participants, as is now the case with securities held for the accounts of customers registered in street name.

If you would like to convert your notes into common stock pursuant to the terms of the notes, you should contact your broker or other direct or indirect DTC participant to obtain information on procedures, including proper forms and cut-off times, for submitting those requests. Because DTC can only act on behalf of DTC participants, who in turn act on behalf of indirect DTC participants and other banks, your ability to pledge your interest in the notes represented by global notes to persons or entities that do not participate in the DTC system, or otherwise take actions in respect of such interest, may be affected by the lack of a physical certificate. Neither we nor the trustee (nor any registrar, paying agent or conversion agent under the indenture) will have any responsibility for the performance by DTC or direct or indirect DTC participants of their obligations under the rules and procedures governing their operations. DTC has advised us that it will take any action permitted to be taken by a holder of notes, including, without limitation, the presentation of notes for conversion as described below, only at the direction of one or more direct DTC participants to whose account DTC interests in the global notes are credited and only for the principal amount of the notes for which directions have been given.

DTC has advised us as follows: DTC is a limited purpose trust company organized under the laws of the State of New York, a member of the Federal Reserve System, a clearing corporation within the meaning of the Uniform Commercial Code and a clearing agency registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934, as amended. DTC was created to hold securities for DTC participants and to facilitate the clearance and settlement of securities transactions between DTC participants through electronic book-entry changes to the accounts of its participants, thereby eliminating the need for physical movement of certificates. Participants include securities brokers and dealers, banks, trust companies and clearing corporations and may include certain other organizations such as the initial purchasers of the notes. Certain DTC participants or their representatives, together with other entities, own DTC. Indirect access to the DTC system is available to others such as banks, brokers, dealers and trust companies that clear through, or maintain a custodial relationship with, a participant, either directly or indirectly. Although DTC has agreed to the foregoing procedures in order to facilitate transfers of interests in the global notes among DTC participants, it is under no obligation to perform or continue to perform such procedures, and such procedures may be discontinued at any time. If DTC is at any time unwilling or unable to continue as depositary and a successor depositary is not appointed by us within 90 days, we will cause notes to be issued in certificated form in exchange for the global notes. None of us, the trustee or any of their respective agents will have any responsibility for the performance by DTC or direct or indirect DTC participants of their obligations under the rules and procedures governing their operations, including maintaining, supervising or reviewing the records relating to, or payments made on account of, beneficial ownership interests in global notes. According to DTC, the foregoing information with respect to DTC has been provided to its participants and other members of the financial community for informational purposes only and is not intended to serve as a representation, warranty or contract modification of any kind.

Certificated notes may be issued in exchange for beneficial interests in notes represented by the global notes only in the limited circumstances set forth in the indenture.

Registration Rights Agreement

Pursuant to the Registration Rights Agreement (the Registration Rights Agreement), dated November 21, 2002, entered into between us and the Initial Purchasers, we were required to file with the SEC not later than the date that is 90 days after November 21, 2002 (the date of original issuance of the notes) this registration statement on Form S-1 covering resales by holders of the notes and the common stock issuable upon conversion of the notes. Under the terms of the Registration Rights Agreement, we agreed to use our best efforts to (i) cause the registration statement to become effective as promptly as is practicable, but in no event later than 180 days after November 21, 2002; and (ii) keep the registration statement effective until the date that the holders of the notes and the common stock issuable upon conversion of the notes are able to sell all such securities immediately pursuant to Rule 144(k) under the Securities Act or any successor rule thereto or otherwise.

We agreed to provide to each registered holder copies of the prospectus, notify each registered holder when the registration statement has become effective and take certain other actions as are required to permit unrestricted resales of the notes and the common stock issuable upon conversion of the notes. If a registration statement covering the notes and the common stock issuable upon conversion of the notes is not effective, they may not be sold or otherwise transferred except pursuant to an exemption from registration under the Securities Act and any other applicable securities laws or in a transaction not subject to those laws. Pursuant to the Registration Rights Agreement, we may suspend the selling security holders use of the prospectus for a reasonable period not to exceed 30 days in any 90-day period, and not to exceed an aggregate of 90 days in any 12-month period, if we, in our reasonable judgment, believe we may possess material non-public information the disclosure of which would have a material adverse effect on us and our subsidiaries taken as a whole. Each holder, by its acceptance of a note, agrees to hold in confidence any communication by us with respect to any such suspension.

If, (i) on the 90th day following November 21, 2002, the registration statement would not have been filed with the SEC; or (ii) on the 180th day following November 21, 2002 this registration statement has not been declared effective; or (iii) the registration statement shall cease to be effective or fail to be usable without being succeeded within five business days by a post-effective amendment or a report filed with the SEC pursuant to the Exchange Act that cures the failure of the registration statement to be effective or usable; or (iv) on the 30th day of any period that the prospectus has been suspended as described in the preceding paragraph, such suspension has not been terminated (each, a registration default), additional interest as liquidated damages will accrue on the notes, from and including the day following the registration default to but excluding the day on which the registration default has been cured. Liquidated damages will be paid semi-annually in arrears, with the first semi-annual payment due on the first interest payment date, as applicable, following the date on which such liquidated damages begin to accrue, and will accrue at a rate per year equal to: (a) an additional 0.25% of the principal amount to and including the 90th day following such registration default; and (b) an additional 0.25% of the principal amount from and after the 91st day following such registration default.

In no event will liquidated damages accrue at a rate per year exceeding 0.5%, even if multiple events of registration default occur. If a holder has converted some or all of its notes into common stock, the holder will be entitled to receive equivalent amounts based on the principal amount of the notes converted.

Governing Law

The indenture and the notes are governed by, and construed in accordance with, the law of the State of New York.

Concerning the Trustee

Wells Fargo Bank Minnesota, National Association, as trustee under the indenture, has been appointed by us as paying agent, conversion agent, registrar and custodian with regard to the notes. Wells Fargo is also the transfer agent and registrar for our common stock. Wells Fargo or its affiliates may from time to time in the future provide banking and other services to us in the ordinary course of their business.

DESCRIPTION OF OTHER INDEBTEDNESS

In addition to the notes, we have currently other unsecured indebtedness in the amount of approximately $1 billion outstanding that rank pari passu with the notes. Furthermore, as of December 31, 2002, our subsidiaries had approximately $20.7 billion of indebtedness and other liabilities, all of which is effectively senior to the notes and some of which is secured by the assets of the respective subsidiaries.

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DESCRIPTION OF CAPITAL STOCK

The following summary description sets forth some of the general terms and provisions of our capital stock. Because this is a summary description, it does not contain all of the information that may be important to you. For a more detailed description of the common stock, you should refer to the provisions of our Restated Articles of Incorporation and Bylaws.

General

Our capital stock consists of two classes: common stock, par value $2.50 per share (1,000,000,000 shares currently authorized of which 398,714,039 shares were outstanding as of December 31, 2002; and preferred stock, par value $100 per share (7,000,000 shares authorized, of which the following series were outstanding as of December 31, 2002: $3.60 Series 275,000 shares; $4.08 Series 150,000 shares; $4.10 Series 175,000 shares; $4.11 Series 200,000 shares; $4.16 Series 98,000 shares; and $4.56 Series 150,000 shares). Our board of directors is authorized to provide for the issue from time to time of preferred stock in series and, as to each series, to fix the designation, dividend rates and times of payment, redemption price, and liquidation price or preference as to assets in voluntary liquidation. Cumulative dividends, redemption provisions and sinking fund requirements, to the extent that some or all of these features are or may be present when preferred stock is issued, could have an adverse effect on the availability of earnings for distribution to the holders of the common stock or for other corporate purposes.

Dividend Rights

Before we can pay any dividends on our common stock, the holders of our preferred stock are entitled to receive their dividends at the respective rates provided for in the terms of the shares of their series. Under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. Due to 2002 losses incurred by NRG, retained earnings of Xcel Energy were a deficit of $101 million at December 31, 2002 and, accordingly, dividends cannot be declared until earnings in 2003 are sufficient to eliminate this deficit or Xcel Energy is granted relief under the PUHCA. Xcel Energy has requested authorization from the SEC to pay dividends out of paid-in capital up to $260 million until September 30, 2003. It is not known when or if the SEC will act on this request. See Management s Discussion and Analysis of Financial Conditions and Results of Operation Common Stock Dividends for a discussion of factors affecting our payment of dividends.

Limitations on Payment of Dividends on and Acquisitions of Common Stock

So long as any shares of our preferred stock are outstanding, dividends (other than dividends payable in common stock), distributions or acquisitions of our common stock:

- may not exceed 50% of net income for a prior twelve-month period, after deducting dividends on any preferred stock during the period, if the sum of the capital represented by the common stock, premiums on capital stock (restricted to premiums on common stock only by SEC orders), and surplus accounts is less than 20% of capitalization;

- may not exceed 75% of net income for such twelve-month period, as adjusted if this capitalization ratio is 20% or more, but less than 25%; and

- if this capitalization ratio exceeds 25%, dividends, distributions or acquisitions may not reduce the ratio to less than 25% except to the extent permitted by the provisions described in the above two bullet points.

The above restrictions are contained in our Articles of Incorporation. For purposes of these provisions, the capitalization ratio (on a holding company basis only, i.e., not on a consolidated basis) is equal to the (i) common stock, plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, our capitalization ratio at December 31, 2002 was 85 percent. Although, we have preferred stock outstanding, the restrictions do not place any effective limit on our ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be

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reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of our common stock.

Because we are a holding company and conduct all of our operations through our subsidiaries, our cash flow and ability to pay dividends will be dependent on the earnings and cash flows of our subsidiaries and the distribution or other payment of those earnings to us in the form of dividends, or in the form of repayments of loans or advances to us. Some of our subsidiaries may have restrictions on their ability to pay dividends including covenants under their borrowing arrangements and mortgage indentures, and possibly also restrictions imposed by their regulators.

Voting Rights

The holders of shares of preferred stock of the $3.60 Series are entitled to three votes for each share held, and the holders of our common stock and of all of our other series of preferred stock are entitled to one vote for each share held on all matters submitted to a vote of our stockholders. If, however, dividends payable on any series of our preferred stock are in default in an amount equal to the amount payable during the immediately preceding twelve-month period, the holders of shares of preferred stock, voting as a class and without regard to series, are entitled to elect the smallest number of directors necessary to constitute a majority of our board of directors and the holders of shares of common stock, voting as a class, are entitled to elect our remaining directors.

The affirmative vote or consent of the holders of various specified percentages of preferred stock is required to effect selected changes in our capital structure and other transactions that might affect their rights. Except to the extent required by law, holders of common stock do not vote as a class in case of any modification of their rights.

Change of Control

Our Bylaws, our shareholder rights plan (discussed below) and the Minnesota Business Corporation Act, as amended (the Minnesota BCA), contain provisions that could discourage or make more difficult a change of control of our company. These provisions are designed to protect our shareholders against coercive, unfair or inadequate tender offers and other abusive takeover tactics and to encourage any person contemplating a business combination with us to negotiate with our board of directors for the fair and equitable treatment of all of our shareholders.

Election of Directors. In electing directors, shareholders may cumulate their votes in the manner provided in the Minnesota BCA. Our board of directors is divided into three classes as nearly equal in number as possible with staggered terms of office so that only approximately one-third of the directors are elected at each annual meeting of shareholders. The existence of a classified board of directors along with cumulative voting rights may make it more difficult for a group owning a significant amount of our voting securities to effect a change in the majority of the board of directors than would be the case if cumulative voting did not exist.

Bylaw Provisions. Under our Bylaws, our shareholders must provide us advance notice of the introduction by them of business at annual or special meetings of our shareholders. For a shareholder to properly bring a proposal before an annual or special meeting, the shareholder must comply with the shareholder proposal requirements under the federal proxy rules or deliver a written notice to the Corporate Secretary not less than 45 days nor more than 90 days prior to the date on which we first mailed our proxy materials for the prior year s annual meeting. If, however, during the prior year we did not hold an annual meeting, or if the date of the meeting has changed more than 30 days from the date of the prior year s meeting, the notice must be delivered to us within a reasonable time before we mail our proxy materials for the current year. If we have provided less than 30 days notice or prior public disclosure of the date by which the shareholder s notice must be given, the shareholders notice must be delivered to us not later than ten days following the earlier of the day on which we provided notice of the date by which such shareholder s notice is required. The required notice from a shareholder must contain (i) a description of the proposed business and the reasons for conducting such business, (ii) the name and address of each shareholder supporting the proposal as it appears on our books, (iii) the class and number of shares beneficially owned by each shareholder supporting the proposal, and (iv) a description of any financial or other interest of each shareholder in the proposal.

Minnesota BCA. Section 302A.671 of the Minnesota BCA applies to potential acquirers of 20% or more of our voting shares. Section 302A.671 provides in substance that shares acquired by such acquirer will not have any voting rights unless:

- the acquisition is approved by (i) a majority of the voting power of all of our shares entitled to vote and (ii) a majority of the voting power of all of our shares entitled to vote excluding all shares owned by the acquirer or by any of our officers; or

- the acquisition (i) is pursuant to an all-cash tender offer for all of our voting shares, (ii) results in the acquirer becoming the owner of at least a majority of our outstanding voting shares, and (iii) has been approved by a committee of disinterested directors.

Section 302A.673 of the Minnesota BCA generally prohibits public Minnesota corporations, including us, from engaging in any business combination with a person or entity owning 10% or more of our voting shares for a period of four years after the date of the transaction in which such person or entity became a 10% shareholder unless the business combination or the acquisition resulting in 10% ownership was approved by a committee of disinterested directors prior to the date such person or entity became a 10% shareholder. Section 302A.675 of the Minnesota BCA provides in substance that a person or entity making a takeover offer (an offeror) for us is prohibited from acquiring any additional shares of our company within two years following the last purchase of shares pursuant to the offer with respect to that class unless (i) the acquisition is approved by a committee of disinterested directors before the purchase of any shares by the offeror pursuant to the offer or (ii) our shareholders are afforded, at the time of the acquisition, a reasonable opportunity to dispose of their shares to the offeror upon substantially equivalent terms as those provided in the earlier takeover offer.

Liquidation Rights

In the event of liquidation, after all outstanding debt has been repaid and after the holders of all series of preferred stock have received $100 per share in the case of involuntary liquidation, and the then applicable redemption prices in the case of voluntary liquidation, plus in either case an amount equal to all accumulated and unpaid dividends, the holders of the common stock are entitled to the remaining assets.

Preemptive and Subscription Rights

No holder of our capital stock has the preemptive right to purchase or subscribe for any additional shares of our capital stock.

Our common stock is listed on the New York Stock Exchange, the Chicago Stock Exchange and the Pacific Stock Exchange. Wells Fargo Bank Minnesota is the Transfer Agent and Registrar for the common stock.

Stockholder Rights Plan

Our board of directors declared a dividend of one right (a Right) for each outstanding share of common stock of our company held of record at the close of business on June 28, 2001. Shares of common stock issued after June 28, 2001 and prior to the Separation Time (as defined below) or issued at any time after June 28, 2001 pursuant to any options and convertible securities outstanding at the Separation Time will also have Rights attached to them.

Trading and Distribution of the Rights. The Rights were issued under a Stockholder Protection Rights Agreement (the Rights Agreement), between us and Wells Fargo Bank Minnesota, National Association, as Rights Agent (the Rights Agent). Each Right entitles its registered holder to purchase from or exchange with us, after the Separation Time, one share of common stock, for a price of $95.00 (the Exercise

Price), subject to adjustment. Until the Separation Time, the Rights will not trade separately, but instead will be represented by, and transferred with, the common stock certificates (or in the case of uncertificated common stock, by the registration of the associated share of common stock on our stock transfer books). Common stock certificates issued after June 28, 2001 and prior to the Separation Time will represent one Right for each share of common stock and will contain a legend incorporating by reference the terms of the Rights Agreement (as it may be amended from time to time). Common stock certificates outstanding on June 28, 2001 also will represent one Right for each share of common stock even though they do not have this legend. Uncertificated common stock issued after June 28, 2001, but prior to the Separation Time which has been registered on our stock transfer books will represent one Right for each share of common stock registered. Promptly following the Separation Time, separate certificates representing the Rights will be mailed to holders of record of common stock at the Separation Time.

The Separation Time will be the close of business on the earlier to occur of (1) the tenth business day (or any later date our board of directors determines prior to the Separation Time that would otherwise have occurred) after the date on which any person commences a tender or exchange offer which, if completed, would result in the person becoming an Acquiring Person (as defined below), and (2) the first date or any later date as our board of directors may determine (the Flip-in Date) of public announcement by us expressly stating that any person has become an Acquiring Person (the date of the public announcement being the Stock Acquisition Date). If a tender or exchange offer referred to in clause (1) is cancelled, terminated or otherwise withdrawn prior to the Separation Time without the purchase of any shares of stock, the offer will be deemed never to have been made.

Acquiring Persons. An Acquiring Person is any person, or group of affiliated or associated persons, having Beneficial Ownership (as defined in the Rights Agreement) of 15% or more of the outstanding shares of common stock. However, the following will not be deemed Acquiring Persons:

- our company, any of our wholly-owned subsidiaries or any employee stock ownership or other employee benefit plan of ours or of a wholly-owned subsidiary of ours;

- any person who is the Beneficial Owner of 15% or more of the outstanding common stock as of the date of the Rights Agreement or who becomes the Beneficial Owner of 15% or more of the outstanding common stock solely as a result of an acquisition of common stock by us, until the time the person acquires additional common stock, other than through a dividend or stock split;

- any person who becomes the Beneficial Owner of 15% or more of the outstanding common stock without any plan or intent to seek or affect control of our company if the person promptly divests sufficient securities so that the person no longer is the Beneficial Owner of 15% or more of the common stock; or

- any person who Beneficially Owns shares of common stock consisting solely of:

  - shares acquired pursuant to the grant or exercise of an option granted by us in connection with an agreement to merge with, or acquire, us entered into prior to a Flip-in Date;

  - shares owned by the person and its affiliates and associates at the time of the grant; and

  - shares, amounting to less than 1% of the outstanding common stock, acquired by affiliates and associates of the person after the time of the grant.

Exercisability and Expiration. The Rights will not be exercisable until the business day following the Separation Time. The Rights will expire (the Expiration Time) on the earliest to occur of:

- the Exchange Time (as defined below);

- the close of business on June 28, 2011, unless extended by action of the board of directors; the date on which the Rights are redeemed as described below; and

- upon the merger of our company into another corporation pursuant to an agreement entered into prior to a Stock Acquisition Date.

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Adjustments. The Exercise Price and the number of Rights outstanding are subject to adjustment from time to time to prevent dilution in the event of a common stock dividend on, or a subdivision or a combination into a smaller number of shares of, common stock, or the issuance or distribution of any securities or assets in respect of, in lieu of or in exchange for common stock.

Flip-in and Flip-over. If a Flip-in Date (as defined above) occurs prior to the Expiration Time, we will take any necessary action to ensure and provide, to the extent permitted by applicable law, that each Right (other than Rights Beneficially Owned by the Acquiring Person or any affiliate or associate of an Acquiring Person, which Rights will become void) will constitute the right to purchase from us, upon exercise in accordance with the terms of the Rights Agreement, that number of shares of our common stock having an aggregate Market Price (as defined in the Rights Agreement), on the Stock Acquisition Date that gave rise to the Flip-in Date, equal to twice the Exercise Price for an amount in cash equal to the then-current Exercise Price. For example, at an Exercise Price of $95 per Right, each Right not owned by an Acquiring Person (or by related parties) flips-in following a Flip-in Date so that it entitles its holder to purchase $190 worth of our common stock for $95. Assuming that the common stock had a per share market value of $25 at the time, the holder of each valid Right would, therefore, be entitled to purchase 7.6 shares of common stock for $95.

Prior to the Expiration Time, if an Acquiring Person controls our board of directors and we then enter into, consummate or permit to occur a transaction or series of transactions in which, directly or indirectly:

we will consolidate or merge or participate in a binding share exchange with any other person and (A) any term or arrangement concerning the treatment of shares of capital stock in such merger, consolidation or share exchange relating to the Acquiring Person is not identical to the terms and arrangements relating to other holders of common stock or (B) the person with whom such transaction or series of transactions occurs is the Acquiring Person or an affiliate or associate of the Acquiring Person; or

we will sell or otherwise transfer (or one or more of its subsidiaries will sell or otherwise transfer) assets (A) aggregating more than 50% of our assets (measured by either book value or fair market value) or (B) generating more than 50% of our operating income or cash flow, to any other person (other than us or one or more of our wholly-owned subsidiaries) or to two or more persons which are affiliated or otherwise acting in concert, (a Flip-over Transaction or Event), we will take any necessary action to ensure, and will not enter into, consummate or permit to occur such Flip-over Transaction or Event until we have entered into a supplemental agreement with the person engaging in such Flip-over Transaction or Event (the Flip-over Entity), for the benefit of the holders of the Rights, this supplemental agreement will provide that upon consummation or occurrence of the Flip-over Transaction or Event:

each Right flips-over so that it constitutes the right to purchase from the Flip-over Entity, upon exercise in accordance with the terms of the Rights Agreement, that number of shares of common stock of the Flip-over Entity having an aggregate Market Price on the date of consummation or occurrence of the Flip-over Transaction or Event equal to twice the Exercise Price for an amount in cash equal to the then current Exercise Price; and

the Flip-over Entity will thereafter be liable for, and will assume, all of our obligations and duties pursuant to the Rights Agreement.

Redemption. Our board of directors may, at its option, at any time prior to the close of business on the Flip-in Date, redeem all (but not less than all) the then-outstanding Rights at a price of $0.01 per Right (the Redemption Price), as provided in the Rights Agreement. Immediately upon the action of the board of directors electing to redeem the Rights, without any further action and without any notice, the right to exercise the Rights will terminate and each Right will thereafter represent only the right to receive the Redemption Price in cash for each Right so held.

Exchange Option. In addition, the board of directors may, at its option, at any time after a Flip-in Date and prior to the time that an Acquiring Person becomes the Beneficial Owner of more than 50% of the outstanding shares of common stock, elect to exchange all (but not less than all) the then-outstanding Rights (other than Rights Beneficially Owned by the Acquiring Person or any affiliate or associate thereof, which Rights will become void) for shares of common stock at an exchange ratio of one share of common stock per Right, appropriately adjusted to reflect any stock split, stock dividend or similar transaction occurring after the date of the Separation Time (the Exchange Ratio). Immediately upon such action by the board of directors, the right to exercise the Rights will terminate and each Right will thereafter represent only the right to receive a number of shares of common stock equal to the Exchange Ratio.

Amendments. The terms of the Rights may be amended by the board of directors (1) prior to the Flip-in Date in any manner and (2) on or after the Flip-in Date to cure any ambiguity, to correct or supplement any provision of the Rights Agreement which may be defective or inconsistent with any other provisions, or in any manner not adversely affecting the interests of the holders of the Rights generally.

Other Provisions. The holders of Rights will, solely by reason of their ownership of Rights, have no rights as stockholders of our company, including, without limitation, the right to vote or to receive dividends. The Rights will not prevent a takeover of our company. However, the Rights may cause substantial dilution to a person or group that acquires 15 percent or more of the common stock unless the Rights are first redeemed by the board of directors. Nevertheless, the Rights should not interfere with a transaction that is in our best interests and our stockholders because the Rights can be redeemed on or prior to the Flip-in Date, before the consummation of such transaction.

MATERIAL FEDERAL INCOME TAX CONSEQUENCES

The following is a summary of the material United States federal income tax consequences of the purchase, ownership and disposition of the notes and of the common stock into which the notes may be converted. This summary is based on the Internal Revenue Code of 1986, as amended (the Code), Treasury regulations, administrative pronouncements and judicial decisions, all as in effect on the date of this prospectus and all subject to change or differing interpretations, possibly with retroactive effect. This summary discusses only the tax consequences applicable to investors that will hold the notes and the common stock into which the notes may be converted as capital assets within the meaning of Section 1221 of the Code. This summary does not purport to address all of the tax consequences that may be relevant to a holder in light of the holder s particular circumstances or to holders subject to special rules, such as financial institutions, insurance companies, tax-exempt organizations, dealers in securities or foreign currencies, persons that will hold the notes as part of a hedge, straddle, conversion or other integrated transaction, or persons whose functional currency is not the U.S. dollar. Nor does it address the tax consequences to persons other than U.S. holders, as defined below.

We have not sought any ruling from the Internal Revenue Service (the IRS) with respect to the statements made and the conclusions reached in the following discussion, and we cannot assure you that the IRS will agree with those statements and conclusions. In addition, the IRS will not be precluded from successfully adopting a contrary position. This discussion does not consider the effect of any applicable foreign, state, local or other tax laws.

Investors considering the purchase, ownership, conversion or other disposition of notes are urged to consult their own tax advisors with respect to the application of the United States federal income tax laws to their particular situations, as well as any tax consequences arising under the laws of any state, local or foreign taxing jurisdiction or under any applicable tax treaty.

As used in this prospectus, the term U.S. holder means a beneficial owner of a note or of common stock into which a note is converted that is for United States federal income tax purposes:

an individual citizen or resident alien of the United States;

a corporation or partnership created or organized in or under the laws of the United States, any state thereof or the District of Columbia;

- an estate the income of which is includible in gross income for United States federal income tax purposes regardless of its source; or

- a trust if (1) a court within the United States is able to exercise primary supervision over the administration of the trust and one or more United States persons have the authority to control all substantial decisions of the trust or (2) the trust has a valid election in effect under applicable Treasury regulations to be treated as a United States person.

If a partnership holds a note or common stock into which a note is converted, the partnership itself will not be subject to United States federal income tax on a net income basis, but the tax treatment of a partner will generally depend upon the status of the partner and the activities of the partnership.

Payment of Interest

Interest on a note generally will be includible in the income of a U.S. holder as ordinary income at the time the interest is received or accrued, according to the holder s method of tax accounting. We are obligated to pay protection payments to holders of the notes in circumstances described under Description of Notes Dividend Protection. According to Treasury regulations which we believe are applicable to the notes, the possibility of such protection payments on the notes will not affect the amount of interest income recognized by a holder, or the timing of this recognition. Accordingly, under these regulations, if any such protection payments are paid, we will treat the payments as payments of interest includible in income as described in the first sentence above. If the IRS were to assert successfully a contrary position, the amount of interest income recognized by a holder for United States federal income tax purposes could be materially greater than the actual amount of such additional payments, which interest income would be required to be recognized over the term of the notes.

Market Discount and Bond Premium

In general, if a U.S. holder acquires a note for an amount that is less than its stated redemption price at maturity, then the difference will be treated as market discount for United States federal income tax purposes, unless the difference is less than a specified de minimis amount. Under the Code s market discount rules, a U.S. holder will be required to treat any gain on the sale, exchange or other disposition of a note as ordinary income to the extent of the accrued market discount that the U.S. holder has not previously included in income (pursuant to an election by the U.S. holder to include such market discount in income as it accrues).

In general, if a U.S. holder purchases a note for an amount in excess of the stated principal amount of the note, the excess will constitute amortizable bond premium for United States federal income tax purposes. A U.S. holder generally may elect to amortize the premium over the term of the note on a constant yield method as an offset to interest when includible in income under the U.S. holder s regular method of tax accounting. If a U.S. holder does not elect to amortize bond premium, that premium will decrease the gain or increase the loss the holder would otherwise recognize on disposition of the note. An election to amortize premium will also apply to all taxable debt obligations held or subsequently acquired by the electing U.S. holder on or after the first day of the first taxable year to which the election applies. The election may not be revoked without the consent of the IRS. U.S. holders are urged to consult their own tax adviser before making this election.

Sale, Exchange or Other Disposition of the Notes

Except as described below under Conversion of Notes, a U.S. holder will generally recognize capital gain or loss upon the sale, exchange or other disposition of a note equal to the difference between (i) the amount of cash proceeds and the fair market value of property received on the sale, exchange or other disposition (except to the extent such amount is attributable to accrued interest on the note not previously included in income, which is taxable as ordinary interest income, or is attributable to accrued interest that was previously included in income, which does not generate further income) and (ii) the holder s adjusted tax basis in the note. A U.S. holder s adjusted tax basis in a note generally will equal the cost of the note to the holder. The capital gain or loss will be long-term if the U.S. holder s holding period is more than one year at the time of sale, exchange or other disposition and will be short-term if the holding period is one year or less. The deductibility of capital losses is subject to limitations.

Constructive Dividends on the Notes

The conversion price of the notes is subject to adjustment under certain circumstances. Certain of the adjustments to the conversion price provided for in the notes (for example, adjustments that are made as a result of certain taxable distributions to our stockholders) may result in a deemed distribution to U.S. holders of the notes, which would be taxable as a dividend, return of capital or capital gain in accordance with the rules discussed below under Dividends on Common Stock. U.S. holders of notes could therefore have taxable income as a result of an event in which they receive no cash or property.

Conversion of Notes

A U.S. holder generally will not recognize any income, gain or loss upon conversion of a note into our common stock, except with respect to cash received instead of a fractional share of common stock. The holder s tax basis in our common stock received upon conversion of a note will be the same as the holder s adjusted tax basis of the note at the time of conversion, reduced by any basis allocable to a fractional share interest, and the holding period for the common stock received upon conversion generally will include the holding period of the note converted.

Cash received instead of a fractional share of our common stock upon conversion will generally be treated as a payment in exchange for the fractional share of common stock. Accordingly, the receipt of cash instead of a fractional share of our common stock generally will result in capital gain or loss, measured by the difference between the cash received for the fractional share and the holder s adjusted tax basis in the fractional share.

Dividends on Common Stock

Generally, distributions received by a U.S. holder in respect of our common stock will be treated first as a dividend, subject to tax as ordinary income, to the extent of our current or accumulated earnings and profits, then as a tax-free return of capital to the extent of the U.S. holder s tax basis in the common stock, and thereafter as gain from the sale or exchange of the common stock. The portion of any distribution treated as a non-taxable return of capital will reduce the holder s tax basis in the common stock.

Any distribution on our common stock qualifying as a dividend will be eligible for the dividends received deduction if the U.S. holder is an otherwise qualifying corporate holder that meets the holding period and other requirements for the dividends received deduction.

Sale, Exchange or other Disposition of Common Stock

Upon the sale, exchange or other disposition of our common stock, a U.S. holder generally will recognize capital gain or loss equal to the difference between (i) the amount of cash and the fair market value of any property received upon the sale, exchange or other disposition, and (ii) the holder s adjusted tax basis in the common stock. This capital gain or loss will be long-term if the holder s holding period is more than one year and will be short-term if the holding period is one year or less. A U.S. holder s tax basis and holding period for common stock received upon conversion of a note are determined as discussed above under Conversion of Notes. The deductibility of capital losses is subject to limitations.

Information Reporting and Backup Withholding Tax

In general, information reporting requirements will apply to payments of interest on a note, payments of dividends on common stock, and payments of the proceeds of the sale or other disposition of a note or

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common stock made with respect to certain non-corporate U.S. holders, unless an exception applies. Further, U.S. holders will be subject to backup withholding if:

- the payee fails to furnish a taxpayer identification number, or TIN, to the payer or establish an exemption from backup withholding;
- the IRS notifies the payer that the TIN furnished by the payee is incorrect;
- the payee has received notification of under-reporting with respect to interest or dividends described in Section 3406(c) of the Code;
- there has been a failure of the payee to certify under penalties of perjury that the payee is not subject to backup withholding under the Code; or
- there has been a failure of the payee to certify under penalties of perjury that the payee is a U.S. person.

Some U.S. holders, including corporations, will be exempt from backup withholding. Any amounts withheld under the backup withholding rules from a payment to a holder will be allowed as a credit against the holder s United States federal income tax and may entitle the holder to a refund, provided that the required information is furnished to the IRS.

SELLING SECURITY HOLDERS

The notes were originally issued by us and sold to Merrill Lynch, Pierce, Fenner & Smith Incorporated and Lazard Frères & Co. LLC, to whom we refer to elsewhere in this prospectus as the initial purchasers, in transactions exempt from the registration requirements of the federal securities laws. The initial purchasers resold the notes to persons reasonably believed by them to be qualified institutional buyers (as defined by Rule 144A under the Securities Act). The selling security holders (which term includes their transferees, pledges, donees or successors) may from time to time offer and sell pursuant to this prospectus any and all of the notes and the shares of common stock issuable upon conversion of the notes. Set forth below are the names of each selling security holder, the principal amount of the notes that may be offered by such selling security holder pursuant to this prospectus and the number of shares of common stock into which such notes are convertible, each to the extent known to us as of the date of this prospectus. Unless set forth below, none of the selling security holders has had a material relationship with us or any of our predecessors or affiliates within the past three years.

Any or all of the notes or common stock listed below may be offered for sale pursuant to this prospectus by the selling security holders from time to time. Accordingly, no estimate can be given as to the amounts of notes or common stock that will be held by the selling security holders upon consummation of any such sales. In addition, the selling security holders identified below may have sold, transferred, or otherwise disposed of all or a portion of their notes since the date on which the information regarding their notes was provided in transactions exempt from the registration requirements of the Securities Act.

Name	Aggregate Principal Amount of Notes at Maturity that may be Sold	Percentage of Notes Outstanding	Common Stock Owned Prior to Conversion	Common Stock Registered Hereby(1)
Highbridge International LLC	$ 10,100,000	4.391%		819,140
Credit Suisse First Boston-London	$ 9,000,000	3.913%		729,927
AIG DKR Sound Shore Opportunity Holding Fund Ltd.	$ 1,500,000	0.652%		121,654
Oppenheimer Convertible Securities Fund	$ 1,000,000	0.435%		81,103
Royal Bank of Canada	$ 4,000,000	1.739%	217,556	324,412
UBS O Connor LLC F/B/O O Connor Global Convertible Arbitrage Master Limited	$ 5,000,000	2.174%		405,515

Name	Aggregate Principal Amount of Notes at Maturity that may be Sold	Percentage of Notes Outstanding	Common Stock Owned Prior to Conversion	Common Stock Registered Hereby(1)
TQA Master Fund, Ltd.	$ 4,250,000	1.848%		344,687
TQA Master Plus Fund, Ltd.	$ 3,430,000	1.491%		278,183
TQA Sphinx Fund	$ 610,000	0.265%		49,472
Zurich Institutional Benchmarks Fund Ltd. c/o TQA Investors, LLC	$ 310,000	0.135%		25,141
HFR Master Trust c/o TQA Investors, LLC	$ 380,000	0.165%		30,819
Lexington Vantage Fund Ltd c/o TQA Investors LLC	$ 260,000	0.113%		21,086
Xavex Convertible Arbitrage #5	$ 400,000	0.174%		32,441
Xavex Convertible Arbitrage #7 Fund c/o TQA Investors LLC	$ 300,000	0.130%		24,330
WPG Convertible Arbitrage Overseas Master Fund LP	$ 1,000,000	0.435%		81,103
DNB Investment	$ 500,000	0.217%		40,551
Northern Income Equity Fund	$ 200,000	0.087%		16,220
Thrivent Financial for Lutherans, As Successor to Lutheran Brotherhood	$ 200,000	0.087%		16,220
Bank Austria Cayman Islands, LTD.	$ 2,000,000	0.870%		162,206
RCG Latitude Master Fund, LTD.	$ 1,600,000	0.695%		129,764
RCG Multi Strategy A/C LP	$ 3,000,000	1.304%		243,309
RCG Halifax Master Fund, LTD.	$ 500,000	0.217%		40,551
RCG Baldwin, LP	$ 650,000	0.283%		52,716
Ramius, LP	$ 150,000	0.065%		12,165
Guggenheim Portfolio Co. XU, LLC	$ 750,000	0.326%		60,827
Ramius Capital Group	$ 500,000	0.217%		40,551
Ramius Partners II, LP	$ 250,000	0.108%		20,275
Forest Fulcrum Fund L.L.P.	$ 100,000	0.174%		8,110
Forest Multi-Strategy Master Fund SPC, on behalf of Series F, Multi-Strategy Segregated Portfolio	$ 150,000	0.065%		12,165
Zurich Master Hedge Fund c/o Forest Investment Mngt. L.L.C	$ 125,000	0.054%		10,137
Forest Global Convertible Fund	$ 840,000	0.365%		68,126
Series A-5				
Lyxor Master Fund c/o Forest Investment Mngt. L.L.C	$ 175,000	0.076%		14,193
Relay II Holdings c/o Forest Investment Mngt. L.L.C	$ 50,000	0.021%		4,055
RBC Alternative Assets L.P. c/o Forest Investment Mngt. L.L.C	$ 25,000	0.010%		2,027
Sphinx Convertible Arbitrage c/o Forest Investment Mngt. L.L.C	$ 10,000	0.004%		811
SilverPoint Capital Fund, LP	$ 43,750	0.019%		3,548

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Name	Aggregate Principal Amount of Notes at Maturity that may be Sold	Percentage of Notes Outstanding	Common Stock Owned Prior to Conversion	Common Stock Registered Hereby(1)
SilverPoint Capital Offshore Fund, Ltd.	$ 81,250	0.035%		6,589
Laurel Ridge Capital LP	$ 500,000	0.217%		40,551
BNP Paribas Equity Strategies, SNC	$ 2,637,000	1.146%	29,840	213,868
CooperNeff Convertible Strategies (Cayman) Master Fund, LP	$ 1,521,000	0.661%		123,357
Sturgeon Limited	$ 342,000	0.149%		27,737
Victus Capital, LP	$ 8,000,000	3.478%		648,824
LLT Limited	$ 25,000	0.010%		2,027
LDG Limited	$ 550,000	0.239%		44,606
Credit Suisse First Boston Europe Limited	$ 450,000	0.196%		36,496
Continental Assurance Company	$ 173,000	0.075%		14,030
Continental Casualty Company	$ 1,400,000	0.608%		113,544
Citadel Jackson Investment Fund Ltd.	$ 5,935,000	2.580%		481,346
Citadel Equity Fund, Ltd.	$ 46,000,000	20.000%		3,730,738
Citadel Credit Trading Ltd.	$ 5,750,000	2.500%		466,342
Sunrise Partners Limited Partnership	$ 2,950,000	1.283%	3,500	239,253
HBK Master Fund L.P.	$ 3,250,000	1.413%		263,584
Argent LowLev Convertible Arbitrage Fund Ltd.	$ 500,000	0.217%		40,551
McMahan Securities Co. L.P.	$ 1,000,000	0.435%		81,103
State of Florida Division of Treasury	$ 1,450,000	0.630%		117,599
Wachovia Bank National Association	$ 20,000,000	8.696%		1,622,060
VICTUS CAPITAL, LP	$ 4,000,000	1.739%		324,412
DBAG-London	$ 7,500,000	3.269%		608,272
Zurich Institutional Benchmarks Foster Fund Ltd.	$ 175,000	0.076%		14,193
Zazove Convertible Securities Fund Inc.	$ 315,000	0.137%		25,547
Zazove Convertible Arbitrage Fund L.P.	$ 200,000	0.087%		16,220
Field Holdings Inc.	$ 66,000	0.026%		4,866
Allstate Life Insurance Company	$ 750,000	0.326%		60,827
Sage Capital	$ 100,000	0.174%		8,110
AG Offshore Convertibles Ltd	$ 8,450,000	3.674%		685,320
Angelo, Gordon & Co., L.P.	$ 30,000	0.013%		2,433
AG Domestic Convertibles, L.P.	$ 4,550,000	1.978%		369,018
Common Fund Long/Short Equity Co.	$ 40,000	0.017%		3,244
AG&J Power Plus Ltd.	$ 130,000	0.056%		10,543
AG&J Power Fund, L.P.	$ 350,000	0.152%		28,386
AG&J Power 2 Ltd.	$ 260,000	0.113%		21,086
AG&J Power Opportunity Fund, L.P.	$ 190,000	0.082%		15,409

Name	Aggregate Principal Amount of Notes at Maturity that may be Sold	Percentage of Notes Outstanding	Common Stock Owned Prior to Conversion	Common Stock Registered Hereby(1)
All other holders of notes or future transferees, pledges, donees or successors of any such holders(2)(3)	$ 47,217,000	20.529%		3,829,440
Total	$ 230,000,000	100.00%		18,653,690(4)

(1) Assumes conversion of all of the holder s notes at a conversion price of $12.33 per share, which is equal to a conversion rate of approximately 81.1359 shares of common stock per $1,000 principal amount of notes. However, this conversion price (and conversion rate) will be subject to adjustment as described under Description of the Notes Conversion Rights. As a result, the amount of common stock issuable upon conversion of the notes may increase or decrease in the future.

(2) Information about other selling security holders will be set forth in prospectus supplements, if required.

(3) Assumes that any other holders of notes, or any future transferees, pledges, donees or successors of or from any such other holders of notes, do not beneficially own any common stock other than the common stock issuable upon conversion of the notes at the initial conversion rate.

(4) Because we will not issue fractional shares of our common stock upon conversion of the notes, the common stock registered hereunder for all of the security holders may not total the amount shown above.

The preceding table has been prepared based upon information furnished to us by the selling security holders named in the table. From time to time, additional information concerning ownership of the notes and common stock may be known by certain holders thereof not named in the preceding table, with whom we believe we have no affiliation. Information about the selling security holders may change over time. Any changed information will be set forth in prospectus supplements.

PLAN OF DISTRIBUTION

The notes and the common stock issuable upon conversion of the notes are being registered to permit public secondary trading of these securities by the holders thereof from time to time after the date of this prospectus. We have agreed, among other things, to bear all expenses (other than underwriting discounts and selling commissions) in connection with the registration and sale of the notes and the common stock covered by this prospectus.

We will not receive any of the proceeds from the offering of notes or the common stock by the selling security holders. We have been advised by the selling security holders that the selling security holders may sell all or a portion of the notes and common stock beneficially owned by them and offered hereby from time to time on any exchange on which the securities are listed on terms to be determined at the times of such sales. The selling security holders may also make private sales directly or through a broker or brokers. Alternatively, any of the selling security holders may from time to time offer the notes or the common stock beneficially owned by them through underwriters, dealers or agents, who may receive compensation in the form of underwriting discounts, commissions or concessions from the selling security holders and the purchasers of the notes and the common stock for whom they may act as agent. The aggregate proceeds to the selling security holders from the sale of the notes or common stock offering will be the purchase price of such notes or common stock less discounts and commissions, if any.

The notes and common stock may be sold from time to time in one or more transactions at fixed offering prices, which may be changed, or at varying prices determined at the time of sale or at negotiated prices. These prices will be determined by the holders of such securities or by agreement between these holders and underwriters or dealers that may receive fees or commissions in connection therewith.

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These transactions may include block transactions or crosses. Crosses are transactions in which the same broker acts as an agent on both sides of the trade.

In connection with sales of the notes and the underlying common stock or otherwise, the selling security holders may enter into hedging transactions with broker-dealers. These broker-dealers may in turn engage in short sales of the notes and the underlying common stock in the course of hedging their positions. The selling security holders may also sell the notes and underlying common stock short and deliver notes and the underlying common stock to close out short positions, or loan or pledge notes and the underlying common stock to broker-dealers that in turn may sell the notes and the underlying common stock.

To our knowledge, there are currently no plans, arrangements or understandings between any selling security holders and any underwriter, broker-dealer or agent regarding the sale of the notes and the underlying common stock by the selling security holders. Selling security holders may choose not sell any or all of the notes and the underlying common stock offered by them pursuant to this prospectus. In addition, we cannot assure you that any such selling security holder will not transfer, devise or gift the notes and the underlying common stock by other means not described in this prospectus. In addition, any securities covered by this prospectus which qualify for sale pursuant to Rule 144 or Rule 144A of the Securities Act may be sold under Rule 144 or Rule 144A rather than pursuant to this prospectus.

Our outstanding common stock is listed for trading on the New York Stock Exchange under the symbol XEL.

The selling security holders and any broker and any broker-dealers, agents or underwriters that participate with the selling security holders in the distribution of the notes or the common stock may be deemed to be underwriters within the meaning of the Securities Act, in which event any commission received by such broker-dealers, agents or underwriters and any profit on the resale of the notes or the common stock purchased by them may be deemed to be underwriting commissions or discounts under the Securities Act.

In addition, in connection with any resales of the notes, any broker-dealer who acquired the notes for its own account as a result of market-making activities or other trading activities must deliver a prospectus meeting the requirements of the Securities Act. Broker-dealers may fulfill their prospectus delivery requirements with respect to the notes with this prospectus.

The notes were issued and sold on November 21, 2002 in transactions exempt from the registration requirements of the federal securities laws to the initial purchasers. We have agreed to indemnify the initial purchasers and each selling security holder, including each person, if any, who controls any of them within the meaning of either Section 15 of the Securities Act or Section 20 of the Exchange Act, and each selling security holder had agreed severally and not jointly, to indemnify us, the initial purchasers and each other selling shareholder, including each person, if any, who controls us or any of them within the meaning of either Section 15 of the Securities Act or Section 20 of the Exchange Act against certain liabilities arising under the Securities Act.

The selling security holders and any other persons participating in the distribution will be subject to certain provisions under the federal securities laws, including Regulation M, which may limit the timing of purchases and sales of the notes and the underlying common stock by the selling security holders and any other such person. In addition, Regulation M may restrict the ability of any person engaged in the distribution of the notes and the underlying common stock to engage in market-making activities with respect to the particular notes and the underlying common stock being distributed for a period of up to five business days prior to the commencement of such distribution. This may affect the marketability of the notes and the underlying common stock and the ability of any person or entity to engage in market-making activities with respect to the notes and the underlying common stock.

We will use our reasonable best efforts to keep the registration statement of which this prospectus is a part effective until the earlier of (1) the sale pursuant to the registration statement of all the securities registered thereunder and (2) the expiration of the holding period applicable to such securities held by persons that are not our affiliates under Rule 144(k) under the Securities Act or any successor provision,

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subject to certain permitted exceptions in which case we may prohibit offers and sales of notes and common stock pursuant to the registration statement to which this prospectus relates

LEGAL MATTERS

The validity of the notes and the shares of common stock issuable upon conversion of the notes will be passed upon for us, with respect to matters pertaining to the laws of the State of New York and federal law, by Jones Day, New York, New York, and, with respect to matters pertaining to the laws of the State of Minnesota, by Gary R. Johnson, Minneapolis, Minnesota. Gary R. Johnson is our Vice President and General Counsel and is the beneficial owner, as of January 31, 2003 of 136,761 shares of our common stock.

EXPERTS

The consolidated financial statements of Xcel Energy Inc. (the Company) and its consolidated subsidiaries, except NRG Energy, Inc. and subsidiaries, as of December 31, 2002 and 2001, and for each of the three years in the period ended December 31, 2002, included in this prospectus have been audited by Deloitte & Touche LLP as stated in their report appearing herein (which report expresses an unqualified opinion and is based in part on the report of other auditors and includes emphasis of a matter paragraphs relating to the adoption of Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities,* on January 1, 2001, the adoption of SFAS No. 142, *Goodwill and Other Intangible Assets,* and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* on January 1, 2002 and implications to Xcel Energy Inc. related to credit and liquidity constraints, various defaults under credit arrangements, and a likely Chapter 11 bankruptcy protection filing at NRG Energy, Inc.). The financial statements of NRG Energy, Inc. and subsidiaries (consolidated with those of the Company) not presented separately herein have been audited by PricewaterhouseCoopers LLP, as stated in their report included herein. Such financial statements of the Company and its consolidated subsidiaries are included herein in reliance upon the respective reports of such firms given upon their authority as experts in accounting and auditing. All of the foregoing firms are independent auditors.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the Securities and Exchange Commission, 450 Fifth Street, N.W., Washington, D.C. 20549, a Registration Statement on Form S-1 under the Securities Act relating to the offering. As permitted by the rules and regulations of the SEC, this prospectus does not contain all the information contained in the registration statement. For further information about us and the offering, you can read the registration statement and the exhibits and financial schedules filed with the registration statement. The statements contained in this prospectus about the contents of any contract or other document are not necessarily complete. You can read a copy of each contract or other document filed as an exhibit to the registration statement.

We are currently subject to the information reporting requirements of the Securities Exchange Act and we file annual, quarterly and special reports and other information with the SEC. Our SEC filings are available to the public over the Internet at the SEC s web site at http://www.sec.gov. Our SEC filings are also available at our web site at http://www.xcelenergy.com. You may also read and copy any document we file at the SEC s public reference room at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

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INDEPENDENT AUDITORS REPORT

To Xcel Energy Inc.:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Xcel Energy Inc. (a Minnesota corporation) and subsidiaries (the Company) as of December 31, 2002 and 2001, and the related consolidated statements of operations, common stockholders equity and other comprehensive income and cash flows for the three years ended December 31, 2002. Our audit also included the financial statement schedule listed in the Index at F-1. These consolidated financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We did not audit the consolidated balance sheet of NRG Energy, Inc. (a wholly owned subsidiary of Xcel Energy Inc.) for the years ended December 31, 2002 and 2001, or the consolidated statements of operations, stockholder s (deficit)/equity and cash flows for the three years ended December 31, 2002 included in the consolidated financial statements of the Company, which statements reflect total assets and revenues of 40% and 24% for 2002, respectively, and total assets and revenues of 45% and 21% for 2001, respectively, and revenues of 20% for 2000, of the related consolidated totals. Those statements were audited by other auditors whose report has been furnished to us (which as to 2002 expresses an unqualified opinion and includes an explanatory paragraph describing conditions that raise substantial doubt about NRG Energy, Inc. s ability to continue as a going concern and emphasis of a matter paragraphs related to the adoption of Statement of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible* Assets and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* on January 1, 2002 and the adoption of SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* on January 1, 2001), and our opinion, insofar as it relates to the amounts included for NRG Energy, Inc. for the periods described above, is based solely on the report of the other auditors.

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

In our opinion, based on our audits and the report of other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2002 and 2001 and the results of their operations and their cash flows for each of the three years ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Note 17 to the consolidated financial statements, effective January 1, 2001 Xcel Energy Inc. and subsidiaries adopted SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities.*

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2002, Xcel Energy Inc. and subsidiaries adopted SFAS No. 142, *Goodwill and Other Intangible Assets,* and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.*

Note 4 to the consolidated financial statements discusses the implications to the Company related to credit and liquidity constraints, various defaults under credit arrangements and a likely Chapter 11 bankruptcy protection filing at NRG Energy, Inc.

/s/ DELOITTE & TOUCHE LLP

Deloitte & Touche LLP

Minneapolis, Minnesota

March 28, 2003

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REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholder of NRG Energy, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, cash flows and stockholder s (deficit)/equity present fairly, in all material respects, the financial position of NRG Energy, Inc. and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management and evaluating the overall financial statement presentation. We believe our audits provide a reasonable basis for our opinion.

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the consolidated financial statements, the Company is experiencing credit and liquidity constraints and has various credit arrangements that are in default. As a direct consequence, during 2002 the Company entered into discussions with its creditors to develop a comprehensive restructuring plan. In connection with its restructuring efforts, it is likely the Company and certain of its subsidiaries will file for Chapter 11 bankruptcy protection. These conditions raise substantial doubt about the Company s ability to continue as a going concern. Management s plans in regard to these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 19 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets, for the year ended December 31, 2002. As discussed in Note 26 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, on January 1, 2001. As discussed in Notes 3 and 5 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, on January 1, 2002.

/s/ PRICEWATERHOUSECOOPERS LLP

PricewaterhouseCoopers LLP

Minneapolis, Minnesota

March 28, 2003

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended Dec. 31,		
	2002	2001	2000
		(Thousands of dollars, except per share data)	
Operating revenues:			
Electric utility	$ 5,435,377	$ 6,394,737	$ 5,674,485
Natural gas utility	1,397,800	2,052,651	1,468,880
Electric and natural gas trading margin	8,485	89,249	41,357
Nonregulated and other	2,611,149	2,579,715	1,856,030
Equity earnings from investments in affiliates	71,561	217,070	182,714
Total operating revenues	9,524,372	11,333,422	9,223,466
Operating expenses:			
Electric fuel and purchased power utility	2,199,099	3,171,660	2,580,723
Cost of natural gas sold and transported utility	851,987	1,517,557	948,145
Cost of sales nonregulated and other	1,361,466	1,318,586	876,698
Other operating and maintenance expenses utility	1,501,602	1,506,039	1,446,122
Other operating and maintenance expenses nonregulated	787,968	676,408	533,379
Depreciation and amortization	1,037,429	906,303	766,746
Taxes (other than income taxes)	318,641	316,492	351,412
Writedowns and disposal losses from investments (see Notes 2 and 3)	207,290		
Special charges (see Note 2)	2,691,223	62,230	241,042
Total operating expenses	10,956,705	9,475,275	7,744,267
Operating income (loss)	(1,432,333)	1,858,147	1,479,199
Interest income	45,863	43,548	27,480
Other non-operating income	28,167	17,961	5,094
Other non-operating expense	(30,043)	(15,623)	(15,994)
Interest charges and financing costs:			
Interest charges net of amounts capitalized (includes other financing costs of $59,724, $21,058 and $20,772, respectively)	879,736	727,976	614,173
Distributions on redeemable preferred securities of subsidiary trusts	38,344	38,800	38,800
Total interest charges and financing costs	918,080	766,776	652,973
Income (loss) from continuing operations before income taxes and minority interest	(2,306,426)	1,137,257	842,806
Income taxes	(627,985)	331,371	299,030
Minority interest	(17,071)	68,199	29,994
Income (loss) from continuing operations	(1,661,370)	737,687	513,782
Income (loss) from discontinued operations net of tax (see Note 3)	(556,621)	46,992	32,006
Income (loss) before extraordinary items	(2,217,991)	784,679	545,788

Extraordinary items net of income taxes of $0, $4,807 and ($8,549), respectively		10,287	(18,960)
Net income (loss)	(2,217,991)	794,966	526,828
Dividend requirements on preferred stock	4,241	4,241	4,241
Earnings available for common shareholders	$ (2,222,232)	$ 790,725	$ 522,587
Weighted average common shares outstanding (in thousands):			
Basic	382,051	342,952	337,832
Diluted	382,051	343,742	338,111
Earnings (loss) per share basic:			
Income (loss) from continuing operations	$ (4.36)	$ 2.14	$ 1.51
Discontinued operations (see Note 3)	(1.46)	0.14	0.09
Extraordinary items (see Note 15)		0.03	(0.06)
Earnings (loss) per share	$ (5.82)	$ 2.31	$ 1.54
Earnings (loss) per share diluted:			
Income (loss) from continuing operations	$ (4.36)	$ 2.13	$ 1.51
Discontinued operations (see Note 3)	(1.46)	0.14	0.09
Extraordinary items (see Note 15)		0.03	(0.06)
Earnings (loss) per share	$ (5.82)	$ 2.30	$ 1.54

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended Dec. 31,		
	2002	2001	2000
		(Thousands of dollars)	
Operating activities:			
Net (loss) income	$ (2,217,991)	$ 794,966	$ 526,828
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	1,028,494	945,555	828,780
Nuclear fuel amortization	48,675	41,928	44,591
Deferred income taxes	(781,531)	11,190	62,716
Amortization of investment tax credits	(13,272)	(12,867)	(15,295)
Allowance for equity funds used during construction	(7,810)	(6,829)	3,848
Undistributed equity in earnings of unconsolidated affiliates	(16,478)	(124,277)	(87,019)
Gain on sale of property	(6,785)		
Write-downs and losses from investments	207,290		
Gain on sale of discontinued operations	(2,814)		
Non-cash special charges asset write-downs	3,160,374		41,991
Conservation incentive accrual adjustments	(9,152)	(49,271)	19,248
Unrealized gain on derivative financial instruments	(8,407)	(9,804)	
Extraordinary items net of tax (see Note 15)		(10,287)	18,960
Change in accounts receivable	126,073	218,353	(443,347)
Change in inventories	8,620	(178,530)	21,933
Change in other current assets	67,596	340,478	(484,288)
Change in accounts payable	80,338	(325,946)	713,069
Change in other current liabilities	156,471	142,617	183,679
Change in other noncurrent assets	(203,997)	(329,442)	(130,764)
Change in other noncurrent liabilities	99,417	136,178	102,795
Net cash provided by operating activities	1,715,111	1,584,012	1,407,725
Investing activities:			
Nonregulated capital expenditures and asset acquisitions	(1,502,601)	(4,259,791)	(2,196,168)
Utility capital/construction expenditures	(906,341)	(1,105,989)	(984,935)
Proceeds from sale of discontinued operations	160,791		
Allowance for equity funds used during construction	7,810	6,829	(3,848)
Investments in external decommissioning fund	(57,830)	(54,996)	(48,967)
Equity investments, loans, deposits and sales of nonregulated projects	(118,844)	154,845	(93,366)
Restricted cash	(220,800)		
Collection of loans made to nonregulated projects	22,498	6,374	17,039
Other investments net	(102,457)	84,769	(36,749)
Net cash used in investing activities	(2,717,774)	(5,167,959)	(3,346,994)
Financing activities:			
Short-term borrowings net	(663,365)	708,335	42,386
Proceeds from issuance of long-term debt	2,521,375	3,777,075	3,565,227
Repayment of long-term debt, including reacquisition premiums	(362,760)	(860,623)	(1,667,335)
Proceeds from issuance of common stock	581,212	133,091	116,678
Proceeds from NRG stock offering		474,348	453,705
Dividends paid	(496,375)	(518,894)	(494,992)
Net cash provided by financing activities	1,580,087	3,713,332	2,015,669

Effect of exchange rate changes on cash	6,448	(4,566)	360
Net increase in cash and cash equivalents discontinued operations	56,096	(21,570)	(57,638)
Net increase in cash and cash equivalents continuing operations	639,968	103,249	19,122
Cash and cash equivalents at beginning of year	261,305	158,056	138,934
Cash and cash equivalents at end of year	$ 901,273	$ 261,305	$ 158,056
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ 640,628	$ 708,560	$ 610,584
Cash paid for income taxes (net of refunds received)	$ 24,935	$ 327,018	$ 216,087

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	Dec. 31, 2002	Dec. 31, 2001
	(Thousands of dollars)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 901,273	$ 261,305
Restricted cash	305,581	142,676
Accounts receivable net of allowance for bad debts: $92,745 and $37,487, respectively	961,060	1,048,073
Accrued unbilled revenues	390,984	495,994
Materials and supplies inventories at average cost	321,863	308,593
Fuel inventory at average cost	207,200	250,043
Natural gas inventories replacement cost in excess of LIFO: $20,502 and $11,331, respectively	147,306	126,563
Recoverable purchased natural gas and electric energy costs	63,975	52,583
Derivative instruments valuation at market	62,206	20,794
Prepayments and other	267,185	307,169
Current assets held for sale	108,535	316,621
Total current assets	3,737,168	3,330,414
Property, plant and equipment, at cost:		
Electric utility plant	16,516,790	16,099,655
Nonregulated property and other	8,411,088	6,924,894
Natural gas utility plant	2,603,545	2,493,028
Construction work in progress: utility amounts of $856,008 and $669,895, respectively	1,513,807	3,663,371
Total property, plant and equipment	29,045,230	29,180,948
Less accumulated depreciation	(10,303,575)	(9,495,835)
Nuclear fuel net of accumulated amortization: $1,058,531 and $1,009,855, respectively	74,139	96,315
Net property, plant and equipment	18,815,794	19,781,428
Other assets:		
Investments in unconsolidated affiliates	1,001,380	1,196,702
Notes receivable, including amounts from affiliates of $206,308 and $202,411, respectively	987,714	779,186
Nuclear decommissioning fund and other investments	732,166	695,070
Regulatory assets	576,403	502,442
Derivative instruments valuation at market	93,225	96,095
Prepaid pension asset	466,229	378,825
Goodwill, net	35,538	36,916
Intangible assets, net	68,210	66,700
Other	364,243	360,158
Noncurrent assets held for sale	379,772	1,530,178
Total other assets	4,704,880	5,642,272

Total assets	$ 27,257,842	$ 28,754,114

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	Dec. 31, 2002	Dec. 31, 2001
	(Thousands of dollars)	
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 7,756,261	$ 392,938
Short-term debt	1,541,963	2,224,812
Accounts payable	1,399,195	1,263,690
Taxes accrued	267,214	246,098
Dividends payable	75,814	130,845
Derivative instruments valuation at market	38,767	83,122
Other	749,521	698,142
Current liabilities held for sale	520,101	429,433
Total current liabilities	12,348,836	5,469,080
Deferred credits and other liabilities:		
Deferred income taxes	1,283,667	2,134,977
Deferred investment tax credits	169,696	184,148
Regulatory liabilities	518,427	483,942
Derivative instruments valuation at market	102,779	42,444
Benefit obligations and other	722,264	692,090
Minimum pension liability	106,897	
Noncurrent liabilities held for sale	155,962	783,297
Total deferred credits and other liabilities	3,059,692	4,320,898
Minority interest in subsidiaries	34,762	614,750
Commitments and contingencies (see Note 18) Capitalization (see Statements of Capitalization):		
Long-term debt	6,550,248	11,555,589
Mandatorily redeemable preferred securities of subsidiary trusts (see Note 9)	494,000	494,000
Preferred stockholders equity	105,320	105,320
Common stockholders equity	4,664,984	6,194,477
Total liabilities and equity	$ 27,257,842	$ 28,754,114

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY AND

OTHER COMPREHENSIVE INCOME

	Common Stock Issued			Retained		Accumulated Other Comprehensive	Total
	Shares	Par Value	Capital in Excess Of Par Value	Earnings (Deficit)	Shares Held By ESOP	Income (Loss)	Stockholders Equity
				(Thousands of Dollars)			
Balance at Dec. 31, 1999	335,277	$ 838,193	$ 2,288,254	$ 2,253,800	$ (11,606)	$ (78,421)	$ 5,290,220
Net income				526,828			526,828
Currency translation adjustments						(78,508)	(78,508)
Comprehensive income for 2000							448,320
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(4,241)			(4,241)
Common stock				(492,183)			(492,183)
Issuances of common stock net proceeds	5,557	13,892	102,785				116,677
Tax benefit from stock options exercised			53				53
Other				16			16
Gain recognized from NRG stock offering			215,933				215,933
Loan to ESOP to purchase shares					(20,000)		(20,000)
Repayment of ESOP loan (a)					6,989		6,989
Balance at Dec. 31, 2000	340,834	852,085	2,607,025	2,284,220	(24,617)	(156,929)	5,561,784
Net income				794,966			794,966
Currency translation adjustments						(56,693)	(56,693)
Cumulative effect of accounting change net							
Unrealized transition loss upon adoption of SFAS No. 133 (see Note 17)						(28,780)	(28,780)
After-tax net unrealized losses related to derivatives accounted for as hedges (see Note 17)						43,574	43,574
After-tax net realized losses on derivative transactions reclassified into earnings (see Note 17)						19,449	19,449
Unrealized loss marketable securities						(75)	(75)
Comprehensive income for 2001							772,441
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(4,241)			(4,241)
Common stock				(516,515)			(516,515)
Issuances of common stock net proceeds	4,967	12,418	120,673				133,091
Other				(27)			(27)
Gain recognized from NRG stock offering			241,891				241,891

Repayment of ESOP loan (a)					6,053		6,053
Balance at Dec. 31, 2001	345,801	864,503	2,969,589	2,558,403	(18,564)	(179,454)	6,194,477
Net loss				(2,217,991)			(2,217,991)
Currency translation adjustments						30,008	30,008
Minimum pension liability						(107,782)	(107,782)
After-tax net unrealized losses related to derivatives accounted for as hedges (see Note 17)						(68,266)	(68,266)
After-tax net realized losses on derivative transactions reclassified into earnings (see Note 17)						28,791	28,791
Unrealized loss marketable securities						(457)	(457)
Comprehensive income (loss) for 2002							(2,335,697)
Dividends declared:							
Cumulative preferred stock of Xcel Energy				(4,241)			(4,241)
Common stock				(437,113)			(437,113)
Issuances of common stock net proceeds	27,148	67,870	513,342				581,212
Acquisition of NRG minority common shares	25,765	64,412	555,220			28,150	647,782
Repayment of ESOP loan (a)					18,564		18,564
Balance at Dec. 31, 2002	398,714	$ 996,785	$ 4,038,151	$ (100,942)	$	$ (269,010)	$ 4,664,984

(a) Did not affect cash flows.

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION

	Dec. 31, 2002	Dec. 31, 2001
	(Thousands of Dollars)	
Long-Term Debt		
NSP-Minnesota Debt		
First Mortgage Bonds, Series due:		
Dec. 1, 2003 2006, 3.75 4.1%	$ 9,145(a)	$ 11,225(a)
March 1, 2003, 5.875%	100,000	100,000
April 1, 2003, 6.375%	80,000	80,000
Dec. 1, 2005, 6.125%	70,000	70,000
Aug. 28, 2012, 8%	450,000	
March 1, 2011, variable rate, 6.265% at Dec. 31, 2002, and 1.8% at Dec. 31, 2001	13,700(b)	13,700(b)
March 1, 2019, 8.50% at Dec. 31, 2002, and a variable rate of 2.04% at Dec. 31, 2001	27,900(b)	27,900(b)
Sept. 1, 2019, 8.5% at Dec. 31, 2002, and a variable rate of 1.76% and 2.04% at Dec 31, 2001	100,000(b)	100,000(b)
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
April 1, 2030, 8.50% at Dec. 31, 2002, and 1.85% at Dec. 31, 2001	69,000(b)	69,000(b)
Dec. 1, 2003 2008, 4.25% 5%	14,090(a)	16,090(a)
Guaranty Agreements, Series due Feb. 1, 2003 May 1, 2003, 5.375% 7.4%	28,450(b)	29,200(b)
Senior Notes due Aug. 1, 2009, 6.875%	250,000	250,000
Retail Notes due July 1, 2042, 8%	185,000	
Employee Stock Ownership Plan Bank Loans, variable rate		18,564
Other	427	390
Unamortized discount net	(8,931)	(5,015)
Total	1,788,781	1,181,054
Less redeemable bonds classified as current (see Note 6)	13,700	141,600
Less current maturities	212,762	11,134
Total NSP-Minnesota long-term debt	$ 1,562,319	$ 1,028,320
PSCo Debt		
First Mortgage Bonds, Series due:		
April 15, 2003, 6%	$ 250,000	$ 250,000
March 1, 2004, 8.125%	100,000	100,000
Nov. 1, 2005, 6.375%	134,500	134,500
June 1, 2006, 7.125%	125,000	125,000
April 1, 2008, 5.625%	18,000(b)	18,000(b)
June 1, 2012, 5.5%	50,000(b)	50,000(b)
Oct. 1, 2012, 7.875%	600,000	
April 1, 2014, 5.875%	61,500(b)	61,500(b)
Jan. 1, 2019, 5.1%	48,750(b)	48,750(b)
March 1, 2022, 8.75%	146,340	147,840
Jan. 1, 2024, 7.25%	110,000	110,000

Unsecured Senior A Notes, due July 15, 2009, 6.875%	200,000	200,000
Secured Medium-Term Notes, due Nov. 25, 2003 March 5, 2007, 6.45% 7.11%	175,000	190,000
Unamortized discount	(4,612)	(5,282)
Capital lease obligations, 11.2% due in installments through May 31, 2025	49,747	51,921
Total	2,064,225	1,482,229
Less current maturities	282,097	17,174
Total PSCo long-term debt	$ 1,782,128	$ 1,465,055

(a) Resource recovery financing

(b) Pollution control financing

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31, 2002	Dec. 31, 2001
	(Thousands of Dollars)	
SPS Debt		
Unsecured Senior A Notes, due March 1, 2009, 6.2%	$ 100,000	$ 100,000
Unsecured Senior B Notes, due Nov. 1, 2006, 5.125%	500,000	500,000
Pollution control obligations, securing pollution control revenue bonds due:		
July 1, 2011, 5.2%	44,500	44,500
July 1, 2016, 1.6% at Dec. 31, 2002, and 1.7% at Dec. 31, 2001	25,000	25,000
Sept. 1, 2016, 5.75% series	57,300	57,300
Unamortized discount	(1,138)	(1,425)
Total SPS long-term debt	$ 725,662	$ 725,375
NSP-Wisconsin Debt		
First Mortgage Bonds Series due:		
Oct. 1, 2003, 5.75%	$ 40,000	$ 40,000
March 1, 2023, 7.25%	110,000	110,000
Dec. 1, 2026, 7.375%	65,000	65,000
City of La Crosse Resource Recovery Bond, Series due Nov. 1, 2021, 6%	18,600(a)	18,600(a)
Fort McCoy System Acquisition, due Oct. 31, 2030, 7%	930	963
Senior Notes due Oct. 1, 2008, 7.64%	80,000	80,000
Unamortized discount	(1,388)	(1,475)
Total	313,142	313,088
Less current maturities	40,034	34
Total NSP-Wisconsin long-term debt	$ 273,108	$ 313,054

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31, 2002	Dec. 31, 2001
	(Thousands of Dollars)	
NRG Debt		
Remarketable or Redeemable Securities due March 15, 2005, 7.97%	$ 257,552	$ 232,960
NRG Energy, Inc. Senior Notes, Series due Feb. 1, 2006, 7.625%	125,000	125,000
June 15, 2007, 7.5%	250,000	250,000
June 1, 2009, 7.5%	300,000	300,000
Nov. 1, 2013, 8%	240,000	240,000
Sept. 15, 2010, 8.25%	350,000	350,000
July 15, 2006, 6.75%	340,000	340,000
April 1, 2011, 7.75%	350,000	350,000
April 1, 2031, 8.625%	500,000	500,000
May 16, 2006, 6.5%	285,728	284,440
NRG Finance Co. I LLC, due May 9, 2006, various rates	1,081,000	697,500
NRG debt secured solely by project assets:		
NRG Northeast Generating Senior Bonds, Series due:		
Dec. 15, 2004, 8.065%	126,500	180,000
June 15, 2015, 8.842%	130,000	130,000
Dec. 15, 2024, 9.292%	300,000	300,000
South Central Generating Senior Bonds, Series due:		
May 15, 2016, 8.962%	450,750	463,500
Sept. 15, 2024, 9.479%	300,000	300,000
MidAtlantic various, due Oct 1, 2005, 4.625%	409,201	420,892
Flinders Power Finance Pty, due September 2012, various rates 6.14 6.49% at Dec 31, 2002, and 8.56% at Dec. 31, 2001	99,175	74,886
Brazos Valley, due June 30, 2008, 6.75%	194,362	159,750
Camas Power Boiler, due June 30, 2007, and Aug. 1, 2007, 3.65% and 3.38%	17,861	20,909
Sterling Luxembourg #3 Loan, due June 30, 2019, variable rate 7.86% at Dec. 31, 2001	360,122	329,842
Crockett Corp. LLP debt, due Dec. 31, 2014, 8.13%		234,497
Csepel Aramtermelo, due Oct. 2, 2017, 3.79% and 4.846%		169,712
Hsin Yu Energy Development, due November 2006 April 2012, 4 6.475%	85,607	89,964
LSP Batesville, due Jan. 15, 2014, 7.164% and July 15, 2025, 8.16%	314,300	321,875
LSP Kendall Energy, due Sept. 1, 2005, 2.65%	495,754	499,500
McClain, due Dec. 31, 2005, 6.75%	157,288	159,885
NEO, due 2005 2008, 9.35%	7,658	23,956
NRG Energy Center, Inc. Senior Secured Notes, Series due June 15, 2013, 7.31%	133,099	62,408
NRG Peaking Finance LLC, due 2019, 6.67%	319,362	
NRG Pike Energy LLC, due 2010, 4.92%	155,477	
PERC, due 2017 2018, 5.2%	28,695	33,220
Audrain Capital Lease Obligation, due Dec. 31, 2023, 10%	239,930	239,930
	333,926	311,867

Saale Energie GmbH Schkopau Capital Lease, due May 2021, various rates		
Various debt, due 2003 2007, 0.0 20.8%	92,573	147,493
Other	676	
Total	8,831,596	8,343,986
Less current maturities continuing operations	7,193,237	210,885
Less discontinued operations	445,729	851,196
Total NRG long-term debt	$ 1,192,630	$ 7,281,905

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31, 2002	Dec. 31, 2001
	(Thousands of Dollars)	
Other Subsidiaries Long-Term Debt		
First Mortgage Bonds Cheyenne:		
Series due April 1, 2003 Jan. 1, 2024, 7.5 7.875%	$ 12,000	$ 12,000
Industrial Development Revenue Bonds, due Sept. 1, 2021 March 1, 2027, variable rate, 1.7% and 1.8% at Dec. 31, 2002 and 2001	17,000	17,000
Viking Gas Transmission Co. Senior Notes-Series due:		
Oct. 31, 2008 Sept. 30, 2014, 6.65% 8.04%	40,421	45,181
Various Eloigne Co. Affordable Housing Project Notes, due 2003 2027, 0.3% 9.91%	41,353	47,856
Other	97,895	35,608
Total	208,669	157,645
Less current maturities	14,431	12,110
Total other subsidiaries long-term debt	$ 194,238	$ 145,535
Xcel Energy Inc. Debt		
Unsecured senior notes, due Dec. 1, 2010, 7%	$ 600,000	$ 600,000
Convertible notes, due Nov. 21, 2007, 7.5%	230,000	
Unamortized discount	(9,837)	(3,655)
Total Xcel Energy Inc. debt	$ 820,163	$ 596,345
Total long-term debt	$ 6,550,248	$ 11,555,589
Mandatorily Redeemable Preferred Securities of Subsidiary Trusts		
holding as their sole asset the junior subordinated deferrable debentures of:		
NSP-Minnesota, due 2037, 7.875%	$ 200,000	$ 200,000
PSCo, due 2038, 7.6%	194,000	194,000
SPS, due 2036, 7.85%	100,000	100,000
Total mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000	$ 494,000
Cumulative Preferred Stock authorized 7,000,000 shares of $100 par value; outstanding shares: 2002, 1,049,800; 2001, 1,049,800		
$3.60 series, 275,000 shares	$ 27,500	$ 27,500
$4.08 series, 150,000 shares	15,000	15,000
$4.10 series, 175,000 shares	17,500	17,500
$4.11 series, 200,000 shares	20,000	20,000
$4.16 series, 99,800 shares	9,980	9,980
$4.56 series, 150,000 shares	15,000	15,000

Total	104,980	104,980
Capital in excess of par value on preferred stock	340	340
Total preferred stockholders equity	$ 105,320	$ 105,320
Common Stockholders Equity		
Common stock authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2002, 398,714,039; 2001, 345,801,028	$ 996,785	$ 864,503
Capital in excess of par value on common stock	4,038,151	2,969,589
Retained earnings (deficit)	(100,942)	2,558,403
Leveraged common stock held by ESOP shares at cost: 2002, 0; 2001, 783,162		(18,564)
Accumulated other comprehensive income (loss)	(269,010)	(179,454)
Total common stockholders equity	$ 4,664,984	$ 6,194,477

(a) Resource recovery financing

(b) Pollution control financing

See Notes to Consolidated Financial Statements

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Merger and Basis of Presentation On Aug. 18, 2000, Northern States Power Co. (NSP) and New Century Energies, Inc. (NCE) merged and formed Xcel Energy Inc. Each share of NCE common stock was exchanged for 1.55 shares of Xcel Energy common stock. NSP shares became Xcel Energy shares on a one-for-one basis. Cash was paid in lieu of any fractional shares of Xcel Energy common stock. The merger was structured as a tax-free, stock-for-stock exchange for shareholders of both companies, except for fractional shares, and accounted for as a pooling-of-interests. At the time of the merger, Xcel Energy registered as a holding company under the PUHCA. References herein to Xcel Energy relates to Xcel Energy, Inc. and its consolidated subsidiaries.

Pursuant to the merger agreement, NCE was merged with and into NSP. NSP, as the surviving legal corporation, changed its name to Xcel Energy. Also, as part of the merger, NSP transferred its existing utility operations that were being conducted directly by NSP at the parent company level to a newly formed wholly owned subsidiary of Xcel Energy, which was renamed NSP-Minnesota.

Consistent with pooling accounting requirements, results and disclosures for all periods prior to the merger have been restated for consistent reporting with post-merger organization and operations. All earnings-per-share amounts previously reported for NSP and NCE have been restated for presentation on an Xcel Energy share basis.

Business and System of Accounts Xcel Energy s domestic utility subsidiaries are engaged principally in the generation, purchase, transmission, distribution and sale of electricity and in the purchase, transportation, distribution and sale of natural gas. Xcel Energy and its subsidiaries are subject to the regulatory provisions of the PUHCA. The utility subsidiaries are subject to regulation by the FERC and state utility commissions. All of the utility companies accounting records conform to the FERC uniform system of accounts or to systems required by various state regulatory commissions, which are the same in all material aspects.

Principles of Consolidation Xcel Energy directly owns six utility subsidiaries that serve electric and natural gas customers in 12 states. These six utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo, SPS, BMG and Cheyenne. Their service territories include portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. During the period covered by this report, Xcel Energy s regulated businesses also included Viking, which was sold in January 2003, and WGI.

Xcel Energy also owns or has an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc., an independent power producer. Xcel Energy owned 100 percent of NRG until the second quarter of 2000, when NRG completed its initial public offering, and 82 percent until a secondary offering was completed in March 2001. At Dec. 31, 2001, Xcel Energy indirectly owned approximately 74 percent of NRG. During the second quarter of 2002, Xcel Energy acquired the 26 percent of NRG shares that it did not own through a tender offer and merger. See Note 4 to the Consolidated Financial Statements for further discussion of the acquisition of minority NRG common shares.

In addition to NRG, Xcel Energy s nonregulated subsidiaries include Utility Engineering Corp. (engineering, construction and design), Seren Innovations, Inc. (broadband telecommunications services), e prime inc. (natural gas marketing and trading), Planergy International, Inc. (enterprise energy management solutions), Eloigne Co. (investments in rental housing projects that qualify for low-income housing tax credits) and Xcel Energy International Inc. (an international independent power producer).

Xcel Energy owns the following additional direct subsidiaries, some of which are intermediate holding companies with additional subsidiaries: Xcel Energy Wholesale Energy Group Inc., Xcel Energy Markets Holdings Inc., Xcel Energy Ventures Inc., Xcel Energy Retail Holdings Inc., Xcel Energy Communications Group Inc., Xcel Energy WYCO Inc. and Xcel Energy O & M Services Inc. Xcel Energy and its subsidiaries collectively are referred to as Xcel Energy.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Xcel Energy uses the equity method of accounting for its investments in partnerships, joint ventures and certain projects. Under this method, we record our proportionate share of pre-tax income as equity earnings from investments in affiliates. We record our portion of earnings from international investments after subtracting foreign income taxes, if applicable. In the consolidation process, we eliminate all significant intercompany transactions and balances.

Revenue Recognition Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers is based of the reading of their meter, 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 the last meter reading are estimated and the corresponding unbilled revenue is estimated.

Xcel Energy s utility subsidiaries have various rate adjustment mechanisms in place that currently provide for the recovery of certain purchased natural gas and electric energy costs. These cost adjustment tariffs may increase or decrease the level of costs recovered through base rates and are revised periodically, as prescribed by the appropriate regulatory agencies, for any difference between the total amount collected under the clauses and the recoverable costs incurred. In addition Xcel Energy presents its revenue net of any excise or other fiduciary-type taxes or fees.

PSCo s electric rates in Colorado are adjusted under the ICA mechanism, which takes into account changes in energy costs and certain trading revenues and expenses that are shared with the customer. For fuel and purchased energy expense incurred beginning Jan. 1, 2003, the recovery mechanism shall be determined by the CPUC in the PSCo 2002 general rate case. In the interim, 2003 fuel and purchased energy expense is recovered through an Interim Adjustment Clause.

NSP-Minnesota s rates include a cost-of-fuel and cost-of-gas recovery mechanism allowing dollar-for-dollar recovery of the respective costs, which are trued-up on an two-month and annual basis, respectively.

NSP-Wisconsin s rates include a cost-of-energy adjustment clause for purchased natural gas, but not for purchased electricity or electric fuel. In Wisconsin, we can request recovery of those electric costs prospectively through the rate review process, which normally occurs every two years, and an interim fuel-cost hearing process.

In Colorado, PSCo operates under an electric performance-based regulatory plan, which results in an annual earnings test. NSP-Minnesota and PSCo s rates include monthly adjustments for the recovery of conservation and energy management program costs, which are reviewed annually.

SPS rates in Texas have fixed fuel factor and periodic fuel filing, reconciling and reporting requirements, which provide cost recovery. In New Mexico, SPS also has a monthly fuel and purchased power cost recovery factor.

Trading Operations In June 2002, the EITF of the FASB reached a partial consensus on Issue No. 02-03 Recognition and Reporting of Gains and Losses on Energy Trading Contracts under EITF Issue No. 98-10 Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF No. 02-03). The EITF concluded that all gains and losses related to energy trading activities within the scope of EITF No. 98-10, whether or not settled physically, must be shown net in the statement of operations, effective for periods ending after July 15, 2002. Xcel Energy has reclassified revenue from trading activities for all comparable prior periods reported. Such energy trading activities recorded as a component of Electric and Gas Trading Costs, which have been reclassified to offset Electric and Gas Trading Revenues to present Electric and Gas Trading Margin on a net basis, were $3.3 billion, $3.1 billion and $2.0 billion for the years ended Dec. 31, 2002, 2001 and 2000, respectively. This reclassification had no impact on operating income or reported net income.

On Oct. 25, 2002, the EITF rescinded EITF No. 98-10. With the rescission of EITF No. 98-10, energy trading contracts that do not also meet the definition of a derivative under SFAS No. 133 must be accounted

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

for as executory contracts. Contracts previously recorded at fair value under EITF No. 98-10 that are not also derivatives under SFAS No. 133 must be restated to historical cost through a cumulative effect adjustment. Xcel Energy does not expect the effect of adopting this decision will be material.

Xcel Energy s commodity trading operations are conducted by NSP-Minnesota (electric), PSCo (electric) and e prime (natural gas). Pursuant to a joint operating agreement (JOA), approved by the FERC as part of the merger, some of the electric trading activity conducted at NSP-Minnesota and PSCo is apportioned to the other operating utilities of Xcel Energy. Trading revenue and costs do not include the revenue and production costs associated with energy produced from Xcel Energy s generation assets or energy and capacity purchased to serve native load. Trading results are recorded using the mark-to-market accounting. In addition, trading results include the impacts of the ICA rate-sharing mechanism. Trading revenue and costs associated with NRG s operations are included in nonregulated margins. For more information, see Notes 16 and 17 to the Consolidated Financial Statements.

Property, Plant, Equipment and Depreciation Property, plant and equipment is stated at original cost. The cost of plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of plant retired, plus net removal cost, is charged to accumulated depreciation and amortization. Significant additions or improvements extending asset lives are capitalized, while repairs and maintenance are charged to expense as incurred. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses.

Xcel Energy determines the depreciation of its plant by using the straight-line method, which spreads the original cost equally over the plant s useful life. Depreciation expense, expressed as a percentage of average depreciable property, was approximately 3.4, 3.1 and 3.3 percent for the years ended Dec. 31, 2002, 2001 and 2000, respectively.

Property, plant and equipment includes approximately $18 million and $25 million, respectively, for costs associated with the engineering design of the future Pawnee 2 generating station and certain water rights obtained for another future generating station in Colorado. PSCo is earning a return on these investments based on its weighted average cost of debt in accordance with a CPUC rate order.

Allowance for Funds Used During Construction (AFDC) and Capitalized Interest AFDC, a noncash item, represents the cost of capital used to finance utility construction activity. AFDC is computed by applying a composite pretax rate to qualified construction work in progress. The amount of AFDC capitalized as a utility construction cost is credited to other nonoperating income (for equity capital) and interest charges (for debt capital). AFDC amounts capitalized are included in Xcel Energy s rate base for establishing utility service rates. In addition to construction-related amounts, AFDC also is recorded to reflect returns on capital used to finance conservation programs in Minnesota. Interest capitalized for all Xcel Energy entities (as AFDC for utility companies) was approximately $83 million in 2002, $56 million in 2001 and $23 million in 2000.

Decommissioning Xcel Energy accounts for the future cost of decommissioning-or permanently retiring-its nuclear generating plants through annual depreciation accruals using an annuity approach designed to provide for full rate recovery of the future decommissioning costs. Our decommissioning calculation covers all expenses, including decontamination and removal of radioactive material, and extends over the estimated lives of the plants. The calculation assumes that NSP-Minnesota and NSP-Wisconsin will recover those costs through rates. For more information on nuclear decommissioning, see Note 19 to the Consolidated Financial Statements.

PSCo also previously operated a nuclear generating plant, which has been decommissioned and re-powered using natural gas. PSCo s costs associated with decommissioning were deferred and are being amortized consistent with regulatory recovery.

Nuclear Fuel Expense Nuclear fuel expense, which is recorded as our nuclear generating plants use fuel, includes the cost of fuel used in the current period, as well as future disposal costs of spent nuclear fuel.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In addition, nuclear fuel expense includes fees assessed by the U.S. Department of Energy (DOE) for NSP-Minnesota s portion of the cost of decommissioning the DOE s fuel enrichment facility.

Environmental Costs We record environmental costs when it is probable Xcel Energy is liable for the costs and we can reasonably estimate the liability. We may defer costs as a regulatory asset based on our expectation that we will recover these costs from customers in future rates. Otherwise, we expense the costs. If an environmental expense is related to facilities we currently use, such as pollution-control equipment, we capitalize and depreciate the costs over the life of the plant, assuming the costs are recoverable in future rates or future cash flow.

We record estimated remediation costs, excluding inflationary increases and possible reductions for insurance coverage and rate recovery. The estimates are based on our experience, our assessment of the current situation and the technology currently available for use in the remediation. We regularly adjust the recorded costs as we revise estimates and as remediation proceeds. If we are one of several designated responsible parties, we estimate and record only our share of the cost. We treat any future costs of restoring sites where operation may extend indefinitely as a capitalized cost of plant retirement. The depreciation expense levels we can recover in rates include a provision for these estimated removal costs.

Income Taxes Xcel Energy and its domestic subsidiaries, other than NRG and its domestic subsidiaries, file consolidated federal income tax returns. NRG and its domestic subsidiaries were included in Xcel Energy s consolidated federal income tax returns prior to NRG s March 2001 public equity offering, but filed consolidated federal income tax returns, with NRG as the common parent, separate and apart from Xcel Energy for the periods of March 13, 2001, through Dec. 31, 2001, and Jan. 1, 2002, through June 3, 2002. Since becoming wholly owned indirect subsidiaries of Xcel Energy on June 3, 2002, NRG and its domestic subsidiaries have not been reconsolidated with Xcel Energy for federal income tax purposes, and each of NRG and its domestic subsidiaries will file separate federal income tax returns as a result of their inclusion in the Xcel Energy consolidated federal income tax return within the last five years. Xcel Energy and its domestic subsidiaries file combined and separate state income tax returns. NRG and one or more of its domestic subsidiaries will be included in some, but not all, of these combined returns in 2002. Federal income taxes paid by Xcel Energy, as parent of the Xcel Energy consolidated group, are allocated to the Xcel Energy subsidiaries based on separate company computations of tax. A similar allocation is made for state income taxes paid by Xcel Energy in connection with combined state filings. In accordance with PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive tax liability of each company. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases of assets and liabilities. Xcel Energy uses the tax rates that are scheduled to be in effect when the temporary differences are expected to turn around, or reverse.

Due to the effects of past regulatory practices, when deferred taxes were not required to be recorded, we account for the reversal of some temporary differences as current income tax expense. We defer investment tax credits and spread their benefits over the estimated lives of the related property. Utility rate regulation also has created certain regulatory assets and liabilities related to income taxes, which we summarize in Note 20 to the Consolidated Financial Statements. We discuss our income tax policy for international operations in Note 11 to the Consolidated Financial Statements.

Foreign Currency Translation Xcel Energy s foreign operations generally use the local currency as their functional currency in translating international operating results and balances to U.S. currency. Foreign currency denominated assets and liabilities are translated at the exchange rates in effect at the end of a reporting period. Income, expense and cash flows are translated at weighted-average exchange rates for the period. We accumulate the resulting currency translation adjustments and report them as a component of Other Comprehensive Income in common stockholders equity. When we convert cash distributions made in one currency to another currency, we include those gains and losses in the results of operations as a

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

component of Other Nonoperating Income. Currency exchange transactions resulted in a pretax gain (loss) of $30 million in 2002, $(57) million in 2001 and $(79) million in 2000.

Derivative Financial Instruments Xcel Energy and its subsidiaries utilize a variety of derivatives, including interest rate swaps and locks, foreign currency hedges and energy contracts, to reduce exposure to corresponding risks. The energy contracts are both financial- and commodity-based in the energy trading and energy nontrading operations. These contracts consist mainly of commodity futures and options, index or fixed price swaps and basis swaps.

On Jan. 1, 2001, Xcel Energy adopted SFAS No. 133. For more information on the impact of SFAS No. 133, see Note 17 to the Consolidated Financial Statements.

For further discussion of Xcel Energy s risk management and derivative activities, see Notes 16 and 17 to the Consolidated Financial Statements.

Use of Estimates In recording transactions and balances resulting from business operations, Xcel Energy uses estimates based on the best information available. We use estimates for such items as plant depreciable lives, tax provisions, uncollectible amounts, environmental costs, unbilled revenues and actuarially determined benefit costs. We revise the recorded estimates when we get better information or when we can determine actual amounts. Those revisions can affect operating results. Each year we also review the depreciable lives of certain plant assets and revise them if appropriate.

Cash Items Xcel Energy considers investments in certain debt instruments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. Those debt instruments are primarily commercial paper and money market funds.

Restricted cash consists primarily of cash collateral for letters of credit issued in relation to project development activities. In addition, it includes funds held in trust accounts to satisfy the requirements of certain debt agreements and funds held within NRG s projects that are restricted in their use. Restricted cash is classified as a current asset as all restricted cash is designated for interest and principal payments due within one year.

Cash and cash equivalents includes $385 million held by NRG, which is not legally restricted. However, this cash is not available for Xcel Energy s general corporate purposes.

Inventory All inventory is recorded at average cost, with the exception of natural gas in underground storage at PSCo, which is recorded using last-in-first-out pricing.

Regulatory Accounting Our regulated utility subsidiaries account for certain income and expense items using SFAS No. 71 Accounting for the Effects of Certain Types of Regulation. Under SFAS No. 71:

- we defer certain costs, which would otherwise be charged to expense, as regulatory assets based on our expected ability to recover them in future rates; and
- we defer certain credits, which would otherwise be reflected as income, as regulatory liabilities based on our expectation they will be returned to customers in future rates.

We base our estimates of recovering deferred costs and returning deferred credits on specific ratemaking decisions or precedent for each item. We amortize regulatory assets and liabilities consistent with the period of expected regulatory treatment. See more discussion of regulatory assets and liabilities at Note 20 to the Consolidated Financial Statements.

Stock-Based Employee Compensation We have several stock-based compensation plans. We account for those plans using the intrinsic value method. We do not record compensation expense for stock options because there is no difference between the market price and the purchase price at grant date. We do, however, record compensation expense for restricted stock awarded to certain employees, which is held until

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the restriction lapses or the stock is forfeited. For more information on stock compensation impacts, see Note 12 to the Consolidated Financial Statements.

Intangible Assets During 2002, Xcel Energy adopted SFAS No. 142- Goodwill and Other Intangible Assets, which requires new accounting for intangible assets and goodwill. Intangible assets with finite lives will be amortized over their economic useful lives and periodically reviewed for impairment. Goodwill is no longer being amortized, but will be tested for impairment annually and on an interim basis if an event occurs or a circumstance changes between annual tests that may reduce the fair value of a reporting unit below its carrying value.

Xcel Energy had goodwill of approximately $35 million at Dec. 31, 2002, which will not be amortized, consisting of $27.8 million of project-related goodwill at NRG and $7.7 million of project-related goodwill at Utility Engineering. As part of Xcel Energy s acquisition of NRG s minority shares (see Note 4), $62 million of excess purchase price was allocated to fixed assets related to projects where the fair value of the fixed assets was higher than the carrying value as of June 2002, to prepaid pension assets, and to other assets. Net goodwill decreased between 2002 and 2001 due to asset sales at NRG. During 2002, Xcel Energy performed impairment tests of its intangible assets. Tests have concluded that no write-down of these intangible assets is necessary.

Intangible assets with finite lives continue to be amortized, and the aggregate amortization expense recognized in the years ended Dec. 31, 2002, 2001 and 2000, were $4.3 million, $6.3 million and $3.9 million, respectively. The annual aggregate amortization expense for each of the five succeeding years is expected to approximate $3.4 million. Intangible assets consisted of the following:

	Dec. 31, 2002		Dec. 31, 2001	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(Millions of dollars)			
Not amortized:				
Goodwill	$ 42.5	$ 7.0	$ 44.1	$ 7.2
Amortized:				
Service contracts	$ 73.2	$ 17.9	$ 76.2	$ 15.6
Trademarks	$ 5.0	$ 0.5	$ 5.0	$ 0.4
Prior service costs	$ 6.9	$	$	$
Other (primarily franchises)	$ 2.0	$ 0.5	$ 1.9	$ 0.4

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The following table summarizes the pro forma impact of implementing SFAS No. 142 at Jan. 1, 2000, on the net income for the periods presented. The pro forma income adjustment to remove goodwill amortization is not material to earnings per share previously reported.

	Year Ended	
	Dec. 31, 2001	Dec. 31, 2000
	(Millions of dollars)	
Reported income from continuing operations	$ 737.7	$ 513.8
Add back: goodwill amortization (after tax)	1.2	1.8
Adjusted income from continuing operations	$ 738.9	$ 515.6
Reported income before extraordinary items	$ 784.7	$ 545.8
Add back: goodwill amortization (after tax)	3.2	2.5
Adjusted income before extraordinary items	$ 787.9	$ 548.3
Reported net income	$ 795.0	$ 526.8
Add back: goodwill amortization (after tax)	3.2	2.5
Adjusted net income	$ 798.2	$ 529.3
Earnings per share	$ 2.31	$ 1.55

Asset Valuation On Jan. 1, 2002, Xcel Energy adopted SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets, which supercedes previous guidance for measurement of asset impairments. Xcel Energy did not recognize any asset impairments as a result of the adoption. The method used in determining fair value was based on a number of valuation techniques, including present value of future cash flows. SFAS No. 144 is being applied to NRG s sale of assets as they are reclassified to held for sale and discontinued operations (see Note 3). In addition, SFAS No. 144 is being applied to test for and measure impairment of NRG s long-lived assets held for use (primarily energy projects in operation and under construction), as discussed further in Note 2 to the Consolidated Financial Statements.

Deferred Financing Costs Other assets also included deferred financing costs, net of amortization, of approximately $198 million at Dec. 31, 2002. We are amortizing these financing costs over the remaining maturity periods of the related debt.

Diluted Earnings Per Share Diluted earnings per share is based on the weighted average number of common and common equivalent shares outstanding each period. However, no common equivalent shares are included in the computation when a loss from continuing operations exists due to their antidilutive effect (that is, they would make the loss per share smaller). Therefore, common equivalent shares of approximately 5.4 million were excluded from the diluted earnings-per-share computations for the year ended Dec. 31, 2002, as shown in Note 12.

FASB Interpretation No. 46 (FIN No. 46) In January 2003, the FASB issued FIN No. 46 requiring an enterprise s consolidated financial statements to include subsidiaries in which the enterprise has a controlling financial interest. Historically, that requirement has been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise s consolidated financial statements do not include the consolidations of variable interest entities with which it has similar relationships but no majority voting interest. Under FIN No. 46, the voting interest approach is not effective in identifying controlling financial interest. As a result, Xcel Energy expects that it will have to consolidate its affordable housing investments made through Eloigne, which currently are accounted for under the equity method.

As of Dec. 31, 2002, the assets of these entities were approximately $155 million and long-term liabilities were approximately $87 million. Currently, investments of $62 million are reflected as a component of investments in unconsolidated affiliates in the Dec. 31, 2002, Consolidated Balance Sheet. FIN No. 46

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

requires that for entities to be consolidated, the entities assets be initially recorded at their carrying amounts at the date the new requirement first apply. If determining carrying amounts as required is impractical, then the assets are to be measured at fair value as of the first date the new requirements apply. Any difference between the net consolidated amounts added to the Xcel Energy s balance sheet and the amount of any previously recognized interest in the newly consolidated entity should be recognized in earnings as the cumulative effect adjustment of an accounting change. Had Xcel Energy adopted FIN No. 46 requirements early in 2002, there would have been no material impact to net income. Xcel Energy plans to adopt FIN No. 46 when required in the third quarter of 2003.

Reclassifications We reclassified certain items in the 2000 and 2001 statements of operations and the 2001 balance sheet to conform to the 2002 presentation. These reclassifications had no effect on net income or earnings per share. The reclassifications were primarily to conform the presentation of all consolidated Xcel Energy subsidiaries to a standard corporate presentation.

2. Special Charges and Asset Impairments

Special charges included in Operating Expenses for the years ended Dec. 31, 2002, 2001 and 2000 include the following:

	2002	2001	2000
	(Millions of dollars)		
NRG Special Charges:			
Asset impairments continuing operations	$ 2,545	$	$
Financial restructuring and NEO costs	111		
Total NRG special charges	2,656		
Regulated Utility Special Charges:			
Regulatory recovery adjustment (SPS)	5		
Restaffing (utility and service companies)	9	39	
Postemployment benefits (PSCo)		23	
Merger costs severance and related costs			77
Merger costs transaction-related			52
Other merger costs transition and integration			70
Total regulated charges utility special	14	62	199
Other nonregulated Special Charges:			
Asset impairments	16		42
Holding company NRG restructuring charges	5		
Total nonregulated special charges	21		42
Total Special Charges	$ 2,691	$ 62	$ 241

NRG Asset Impairments As discussed further in Note 4, NRG in 2002 experienced credit-rating downgrades, defaults under numerous credit agreements, increased collateral requirements and reduced liquidity. These events resulted in impairment reviews of a number of NRG assets. NRG completed an analysis of the recoverability of the asset carrying values of its projects, factoring in the probability weighting of different courses of action available to NRG, given its financial position and liquidity constraints. This approach was applied consistently to asset groups with similar uncertainties and cash flow streams. As a result, NRG determined that many of its construction projects and its operational projects became impaired during 2002 and should be written down to fair market value. In applying those provisions, NRG

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

management considered cash flow analyses, bids and offers related to those projects. The resulting impairments were recognized as Special Charges in 2002, as follows:

	Status	Pretax Charge	Fair Value Basis
		(Millions of dollars)	
Projects In Construction or Development			
Nelson	Terminated	$ 468	Similar asset prices
Pike	Terminated chapter 7 involuntary bankruptcy petition filed October 2002	402	Similar asset prices
Bourbonnais	Terminated	265	Similar asset prices
Meriden	Terminated	144	Similar asset prices
Brazos Valley	Foreclosure completed in January 2003	103	Projected cash flows
Kendall, Batesville and other expansion projects	Terminated	120	Projected cash flows
Langage (UK)	Terminated	42	Estimated market price
Turbines and other costs	Equipment being marketed	702	Similar asset prices
Total		$ 2,246	
Operating Projects			
Audrain	Operating at a loss	$ 66	Projected cash flows
Somerset	Operating at a loss	49	Projected cash flows
Bayou Cove	Operating at a loss	127	Projected cash flows
Other	Operating at a loss	57	Projected cash flows
Total		$ 299	
Total NRG Impairment Charges		$ 2,545	

All of these impairment charges relate to assets considered held for use under SFAS No. 144. For fair values determined by similar asset prices, the fair value represents NRG s current estimate of recoverability, if the project assets were to be sold. For fair values determined by estimated market price, the fair value represents a market bid or appraisal received by NRG that NRG believes is best reflective of fair value. For fair values determined by projected cash flows, the fair value represents a discounted cash flow amount over the remaining life of each project that reflects project-specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operation given assumed market conditions.

Additional asset impairments may be recorded by NRG in periods subsequent to Dec. 31, 2002, given the changing business conditions and the resolution of the pending financial restructuring plan. Management is unable to determine the possible magnitude of any additional asset impairments, but it could be material.

NRG Financial Restructuring and NEO Costs In 2002, NRG expensed a pretax charge of $26 million for expected severance and related benefits related to its financial restructuring and business realignment. Through Dec. 31, 2002, severance costs have been recognized for all employees who had been terminated as of that date. See Note 4 for further discussion of NRG financial restructuring activities and developments. These costs also include a charge related to NRG s NEO landfill gas generation operations, for the estimated impact of a dispute settlement with NRG s partner on the NEO project, Fortistar.

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2002 Regulatory Recovery Adjustment SPS In late 2001, SPS filed an application requesting recovery of costs incurred to comply with transition to retail competition legislation in Texas and New Mexico. During 2002, SPS entered into a settlement agreement with intervenors regarding the recovery of restructuring costs in Texas, which was approved by the state regulatory commission in May 2002. Based on the settlement agreement, SPS wrote off pretax restructuring costs of approximately $5 million.

2002 Other Nonregulated Asset Impairments In 2002, a subsidiary of Xcel Energy decided it would no longer fund one of its power projects in Argentina. This decision resulted in the shutdown of the Argentina plant facility, pending financing of a necessary maintenance outage. Updated cash flow projections for the plant were insufficient to provide recovery of Xcel International s investment. Nonregulated asset impairments include a write-down of approximately $13 million, for this Argentina facility.

2002 Holding Company NRG Restructuring Charges In 2002, the Xcel Energy holding company incurred approximately $5 million for charges related to NRG s financial restructuring.

2002 and 2001 Utility Restaffing During 2001, Xcel Energy expensed pretax special charges of $39 million for expected staff consolidation costs for an estimated 500 employees in several utility operating and corporate support areas of Xcel Energy. In 2002, the identification of affected employees was completed and additional pretax special charges of $9 million were expensed for the final costs of staff consolidations. Approximately $6 million of these restaffing costs were allocated to Xcel Energy s Utility Subsidiaries. All 564 of accrued staff terminations have occurred. See the summary of costs below.

2001 Postemployment Benefits PSCo adopted accrual accounting for postemployment benefits under SFAS No. 112 Employers Accounting for Postemployment Benefits in 1994. The costs of these benefits had been recorded on a pay-as-you-go basis and, accordingly, PSCo recorded a regulatory asset in anticipation of obtaining future rate recovery of these transition costs. PSCo recovered its FERC jurisdictional portion of these costs. PSCo requested approval to recover its Colorado retail natural gas jurisdictional portion in a 1996 retail rate case and its retail electric jurisdictional portion in the electric earnings test filing for 1997. In the 1996 rate case, the CPUC allowed recovery of postemployment benefit costs on an accrual basis, but denied PSCo s request to amortize the transition costs regulatory asset. Following various appeals, which proved unsuccessful, PSCo wrote off $23 million pretax of regulatory assets related to deferred postemployment benefit costs as of June 30, 2001.

2000 Merger Costs At the time of the NCE and NSP-Minnesota merger in 2000, Xcel Energy expensed pretax special charges totaling $241 million.

The pretax charges included $199 million associated with the costs of merging regulated operations. Of these pretax charges, $52 million related to one-time, transaction-related costs incurred in connection with the merger of NSP and NCE, and $147 million pertained to incremental costs of transition and integration activities associated with merging NSP and NCE to begin operations as Xcel Energy. The transition costs include approximately $77 million for severance and related expenses associated with staff reductions. All 721 of accrued staff terminations have occurred. The staff reductions were nonbargaining positions mainly in corporate and operations support areas. Other transition and integration costs include amounts incurred for facility consolidation, systems integration, regulatory transition, merger communications and operations integration assistance. An allocation of the regulated portion of merger costs was made to utility operating companies using a basis consistent with prior regulatory filings, in proportion to expected merger savings by company and consistent with service company cost allocation methodologies utilized under the PUHCA requirements.

The pretax charges also included $42 million of asset impairments and other costs resulting from the post-merger strategic alignment of Xcel Energy s nonregulated businesses.

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Accrued Special Charges The following table summarizes activity related to accrued special charges in 2002 and 2001 (Millions of dollars):

	Utility Severance*	NRG Severance**	Merger Transition Costs*
Balance, Dec. 31, 1999	$	$	$
2000 accruals recorded merger costs	77		70
Adjustments/revisions to prior accruals			
Cash payments made in 2000	(29)		(63)
Balance, Dec. 31, 2000	48		7
2001 accruals recorded restaffing	39		
Adjustments/revisions to prior accruals			
Cash payments made in 2001	(50)		(7)
Balance, Dec. 31, 2001	37		

	Utility Severance*	NRG Severance**	Merger Transition Costs*
2002 accruals recorded various		23	
Adjustments/revisions to prior accruals	9		
Cash payments made in 2002	(33)	(5)	
Balance, Dec. 31, 2002	$ 13	$ 18	$

* Reported on the balance sheet in Other Current Liabilities.

** $15.5 million reported on the balance sheet in Other Current Liabilities and $2.5 million reported in Benefit Obligations and Other.

3. Discontinued Operations and Losses on Equity Investments

Pursuant to the requirements of SFAS No. 144, NRG has classified and is accounting for certain of its assets as held-for-sale at Dec. 31, 2002. SFAS No. 144 requires that assets held for sale be valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions, NRG s management considered cash flow analyses, bids and offers related to those assets and businesses. As a result, NRG recorded estimated after-tax losses on assets held for sale of $5.8 million for the year ended Dec. 31, 2002. This amount is included in Income (loss) from discontinued operations in the accompanying Statement of Operations. In accordance with the provisions of SFAS No. 144, assets held for sale will not their depreciated commencing with their classification as such.

Discontinued Operations

During 2002, NRG agreed to sell certain assets and has entered into purchase and sale agreements or has committed to a plan to sell. As of Dec. 31, 2002, five international projects (Bulo Bulo, Csepel, Entrade, Killingholme and Hsin Yu) and one domestic project (Crockett Cogeneration) had been classified as held-for-sale. The assets and liabilities of these six projects have been reclassified to the held-for-sale category on the balance sheet and meet the requirements of SFAS No. 144 for discontinued operations reporting. As of Dec. 31, 2002, only Hsin Yu and Killingholme s assets and liabilities remain in the held-for-sale categories of the balance sheet as the other entities have been sold. Accordingly, operating results and estimated losses on disposal of these six projects have been reclassified to discontinued operations for current and prior periods.

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Projects included in discontinued operations are as follows (Dollars in Millions):

Project	Location	Pre-tax Disposal Gain (Loss)	Status
Crockett Cogeneration	United States	$ (11.5)	Sale final 2002
Bulo Bulo	Bolivia	$ (10.6)	Sale final 2002
Csepel	Hungary	$ 21.2	Sale final 2002
Entrade	Czech Republic	$ 2.8	Sale final 2002
Killingholme*	United Kingdom	$	Sale final 2003
Hsin Yu	Taiwan	$	Held for sale
Other	Various	$ 0.9	Sales final 2002
Total		$ 2.8	

* The foreclosure of Killingholme in January 2003 for a gain of $182.3 million.

Description	Year Ended Dec. 31, 2002	Year Ended Dec. 31, 2001	Year Ended Dec. 31, 2000
		(In thousands)	
Operating revenue	$ 729,408	$ 597,181	$ 347,848
Operating and other expenses	1,300,131	544,837	310,007
Pre-tax (loss)/income from operations of discontinued components	(570,723)	52,344	37,841
Income tax (benefit)/expense	(8,296)	5,352	5,835
(Loss)/income from operations of discontinued components	(562,427)	46,992	32,006
Estimated pre-tax gain on disposal of discontinued components	2,814		
Income tax (benefit)/expense	(2,992)		
Gain on disposal of discontinued components	5,806		
Net (loss)/income on discontinued operations	$ (556,621)	$ 46,992	$ 32,006

Special charges from discontinued operations included in Operating & Other Expenses above include the following:

	2002	2001	2000
		(In Thousands)	
Asset Impairments			
Killingholme (UK)	$ 477,868	$	$
Hsin Yu (Taiwan)	121,864		
	599,732		
Severance and other charges:	7,389		

Total Special Charges	$ 607,121	$	$

These impairment charges relate to assets considered held for sale under SFAS No. 144, as of Dec. 31, 2002. In January 2003, Killingholme was transferred to the project lenders. Hsin Yu has historically operated at a loss and its funding has been discontinued as of Dec. 31, 2002. The fair values represent discounted cash flows over the remaining life of each project and reflects project-specific assumptions for long-term power pool

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prices, escalated future project operating costs, and expected plant operation given assumed market conditions.

The major classes of assets and liabilities held for sale are as follows as of December 31:

	2002	2001
	(Thousands of dollars)	
Cash	$ 23,911	$ 99,171
Receivables, net	28,220	129,220
Derivative instruments valuation at market	29,795	38,996
Other current assets	26,609	49,234
Current assets held for sale	108,535	316,621
Property, Plant and equipment, net	274,544	1,383,690
Derivative instruments valuation at market	87,803	83,588
Other noncurrent assets	17,425	62,900
Noncurrent assets held for sale	379,772	1,530,178
Current portion of long-term debt	445,656	289,269
Accounts payable trade	55,707	97,654
Other current liabilities	18,738	42,510
Current liabilities held for sale	520,101	429,433
Long-term debt	73	561,927
Deferred income tax	129,640	154,573
Derivative instruments valuation at market	12,302	15,131
Other noncurrent liabilities	13,947	51,666
Noncurrent liabilities held for sale	$ 155,962	$ 783,297

Included in other noncurrent assets held for sale is approximately $27 million, net of $3.6 million of amortization, of goodwill and $11 million, net of $1.9 million of amortization, of intangible assets as of Dec. 31, 2002. There are no amounts of goodwill or intangibles assets included in noncurrent assets held for sale.

Losses Related to NRG Equity Investments

As of Dec. 31, 2002, several projects of NRG incurred losses related to disposal transactions or asset impairments. In the accompanying financial statements, the operating results of these projects are classified in equity earnings from investments in affiliates, and write-downs of the carrying amount of the investments and losses on disposal have been classified and reported as a component of write-downs and disposal losses from

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

investments. During 2002, NRG recorded write-downs and losses on disposal of $196.2 million of equity investments as follows:

Project	Location	Impairment Loss	Disposal Gain (Loss)	Status
Collinsville	Australia	$	$ (3.6)	Sale final 2002
EDL	Australia	$	$ (14.2)	Sale final 2002
ECKG	Czech Republic	$	$ (2.1)	Sale final 2003
SRW Cogeneration	United States	$	$ (48.4)	Sale final 2002
Mt. Poso	United States	$	$ (1.0)	Sale final 2002
Kingston	Canada	$	$ 9.9	Sale final 2002
Kondapalli	India	$ (12.7)	$	Sale pending
Loy Yang	Australia	$ (111.4)		Operating
NEO MESI	United States	$	$ 2.0	Sale final 2002
Other		$ (14.7)	$	
Total		$ (138.8)	$ (57.4)	

During fourth quarter of 2002, NRG and the other owners of the Loy Yang project engaged in a joint marketing of the project for possible sale. Based on a new market valuation and negotiations with a potential purchaser, NRG recorded a write down of $58 million in the fourth quarter of 2002, in addition to the $54 million previously recorded in 2002. At Dec. 31, 2002, the carrying value of the investment in Loy Yang is approximately $72.9 million. Accumulated other comprehensive loss at Dec. 31, 2002 includes a reduction for foreign currency translation losses of approximately $77 million related to Loy Yang. The foreign currency translation losses will continue to be included as a component of accumulated other comprehensive loss until NRG commits to a plan to dispose of its investment.

Other Equity Investment Losses

Yorkshire Power Group Sale In August 2002, Xcel Energy announced it had sold its 5.25-percent interest in Yorkshire Power Group Limited for $33 million to CE Electric UK. Xcel Energy and American Electric Power Co. each held a 50-percent interest in Yorkshire, a UK retail electricity and gas supplier and electricity distributor, before selling 94.75 percent of Yorkshire to Innogy Holdings plc in April 2001. The sale of the 5.25-percent interest resulted in an after-tax loss of $8.3 million, or 2 cents per share, in the third quarter of 2002. The loss is included in write-downs and disposal losses from investments on the Consolidated Statements of Operations.

4. NRG Acquisition and Restructuring Plan

During 2002, Xcel Energy acquired all of the 26 percent of NRG shares not then owned by Xcel Energy through a tender offer and merger involving a tax-free exchange of 0.50 shares of Xcel Energy common stock for each outstanding share of NRG common stock. The transaction was completed on June 3, 2002.

The exchange of NRG common shares for Xcel Energy common shares was accounted for as a purchase. The 25,764,852 shares of Xcel Energy stock issued were valued at $25.14 per share, based on the average market price of Xcel Energy shares for three days before and after April 4, 2002, when the revised terms of the exchange were announced and recommended by the independent members of the NRG Board. Including other costs of acquisition, this resulted in a total purchase price to acquire NRG s shares of approximately $656 million.

The process to allocate the purchase price to underlying interests in NRG assets, and to determine fair values for the interests in assets acquired resulted in approximately $62 million of amounts being allocated to fixed assets related to projects where the fair values were in excess of carrying values, to prepaid pension

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

assets and to other assets. The preliminary purchase price allocation is subject to change as the final purchase price allocation and asset valuation process is completed.

In December 2001, Moody s Investor Service (Moody s) placed NRG s long-term senior unsecured debt rating on review for possible downgrade. In February 2002, in response to this threat to NRG s investment grade rating, Xcel Energy announced a financial improvement plan for NRG, which included an initial step of acquiring 100 percent of NRG through a tender offer and merger involving a tax-free exchange of 0.50 shares of Xcel Energy common stock for each outstanding share of NRG common stock. The transaction was completed on June 3, 2002. In addition, the initial plan included: financial support to NRG from Xcel Energy; marketing certain NRG generating assets for possible sale; canceling and deferring capital spending for NRG projects; and combining certain of NRG s functions with Xcel Energy s systems and organization. During 2002, Xcel Energy provided NRG with $500 million of cash infusions. Throughout this period, Xcel Energy was in discussions with credit agencies and believed that its actions would be sufficient to avoid a downgrade of NRG s credit rating.

However, even with NRG s efforts to avoid a downgrade, on July 26, 2002, Standard & Poor s (S&P) downgraded NRG s senior unsecured bonds below investment grade, and, three days later, Moody s also downgraded NRG s senior unsecured debt rating below investment grade. Over the next few months, NRG senior unsecured debt, as well as the secured NRG Northeast Generating LLC bonds, the secured NRG South Central Generating LLC bonds and secured LSP Energy (Batesville) bonds were downgraded multiple times. After NRG failed to make the payment obligations due under certain unsecured bond obligations on Sept. 16, 2002, both Moody s and S&P lowered their ratings on NRG s unsecured bonds once again. Currently, unsecured bond obligations carry a rating of between CCC and D at S&P and between Ca and C at Moody s depending on the specific debt issue.

Many of the corporate guarantees and commitments of NRG and its subsidiaries require that they be supported or replaced with letters of credit or cash collateral within 5 to 30 days of a ratings downgrade below investment grade by Moody s or S&P. As a result of the multiple downgrades, NRG estimated that it would be required to post collateral of approximately $1.1 billion.

Starting in August 2002, NRG engaged in the preparation of a comprehensive business plan and forecast. The business plan detailed the strategic merits and financial value of NRG s projects and operations. It also anticipated that NRG would function independently from Xcel Energy and thus all plans and efforts to combine certain functions of the companies were terminated. NRG utilized independent electric revenue forecasts from an outside energy markets consulting firm to develop forecasted cash flow information included in the business plan. NRG management concluded that the forecasted free cash flow available to NRG after servicing project-level obligations would be insufficient to service recourse debt obligations. Based on this information and in consultation with Xcel Energy and its financial advisor, NRG prepared and submitted a restructuring plan in November 2002 to various lenders, bondholders and other creditor groups (collectively, NRG s Creditors) of NRG and its subsidiaries. The restructuring plan expected to serve as a basis for negotiations with NRG s Creditors in a financially restructured NRG.

The restructuring plan also included a proposal by Xcel Energy that in return for a release of any and all claims against Xcel Energy, upon consummation of the restructuring, Xcel Energy would pay $300 million to NRG and surrender its equity ownership of NRG.

In mid-December 2002, the NRG bank steering committee submitted a counterproposal and in January 2003, the bondholder credit committee issued its counterproposal to the NRG restructuring plan. The counterproposal would request substantial additional payments by Xcel Energy. A new NRG restructuring proposal was presented to the creditors at the end of January 2003. A preliminary settlement has been reached with NRG s creditors. Since many of these conditions are not within Xcel Energy s control, Xcel Energy cannot state with certainty that the settlement will be effectuated. Nevertheless, the Xcel Energy management is optimistic at this time that the settlement will be implemented.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

On March 26, 2003, Xcel Energy s board of directors approved a tentative settlement with holders of most of NRG s long-term notes and the steering committee representing NRG s bank lenders regarding alleged claims of such creditors against Xcel Energy, including claims related to the support and capital subscription agreement between Xcel Energy and NRG dated May 29, 2002 (Support Agreement). The settlement is subject to a variety of conditions as set forth below, including definitive documentation. The principal terms of the settlement as of the date of this report were as follows:

Xcel Energy would pay up to $752 million to NRG to settle all claims of NRG, and the claims of NRG against Xcel Energy, including all claims under the Support Agreement.

$350 million would be paid at or shortly following the consummation of a restructuring of NRG s debt through a bankruptcy proceeding. It is expected that this payment would be made prior to year-end 2003. $50 million would be paid on Jan. 1, 2004, and all or any part of such payment could be made, at Xcel Energy s election, in Xcel Energy common stock. Up to $352 million would be paid on April 30, 2004, except to the extent that Xcel Energy had not received at such time tax refunds equal to $352 million associated with the loss on its investment in NRG. To the extent Xcel Energy had not received such refunds, the April 30 payment would be due on May 30, 2004.

$390 million of the Xcel Energy payments are contingent on receiving releases from NRG creditors. To the extent Xcel Energy does not receive a release from an NRG creditor. Xcel Energy s obligation to make $390 million of the payments would be reduced based on the amount of the creditor s claim against NRG. As noted below, however, the entire settlement is contingent upon Xcel Energy receiving releases from at least 85 percent of the claims in various NRG creditor groups. As a result, it is not expected that Xcel Energy s payment obligations would be reduced by more than approximately $60 million. Any reduction would come from the Xcel Energy payment due on April 30, 2004.

Upon the consummation of NRG s debt restructuring through a bankruptcy proceeding, Xcel Energy s exposure on any guarantees or other credit support obligations incurred by Xcel Energy for the benefit of NRG or any subsidiary would be terminated and any cash collateral posted by Xcel Energy would be returned to it. The current amount of such cash collateral is approximately $11.5 million.

As part of the settlement with Xcel Energy, any intercompany claims of Xcel Energy against NRG or any subsidiary arising from the provision of intercompany goods or services or the honoring of any guarantee will be paid in full in cash in the ordinary course except that the agreed amount of such intercompany claims arising or accrued as of Jan. 31, 2003 will be reduced from approximately $55 million as asserted by Xcel Energy to $13 million. The $13 million agreed amount is to be paid upon the consummation of NRG s debt restructuring with $3 million in cash and an unsecured promissory note of NRG on market terms in the principal amount of $10 million.

NRG and its direct and indirect subsidiaries would not be reconsolidated with Xcel Energy or any of its other affiliates for tax purposes at any time after their June 2002 re-affiliation or treated as a party to or otherwise entitled to the benefits of any tax sharing agreement with Xcel Energy. Likewise, NRG would not be entitled to any tax benefits associated with the tax loss Xcel Energy expects to incur in connection with the write down of its investment in NRG.

Xcel Energy s obligations under the tentative settlement, including its obligations to make the payments set forth above, are contingent upon, among other things, the following:

(1) Definitive documentation, in form and substance satisfactory to the parties;

(2) Between 50 percent and 100 percent of the claims represented by various NRG facilities or creditor groups (the NRG Credit Facilities) having executed an agreement, in form and substance satisfactory to Xcel Energy, to support the settlement;

(3) Various stages of the implementation of the settlement occurring by dates currently being negotiated, with the consummation of the settlement to occur by Sept. 30, 2003;

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(4) The receipt of releases in favor of Xcel Energy by at least 85 percent of the claims represented by the NRG Credit Facilities;

(5) The receipt by Xcel Energy of all necessary regulatory approvals; and

(6) No downgrade prior to consummation of the settlement of any Xcel Energy credit rating from the level of such rating as of March 25, 2003.

Based on the foreseeable effects of a settlement agreement with the major NRG noteholders and bank lenders and the tax effect of an expected write-off of Xcel Energy s investment in NRG, Xcel Energy would recognize the expected tax benefits of the write-off as of Dec. 31, 2002. The tax benefit has been estimated at approximately $706 million. This benefit is based on the tax basis of Xcel Energy s investment in NRG.

Xcel Energy expects to claim a worthless stock deduction in 2003 on its investment. This would result in Xcel Energy having a net operating loss for the year. Under current law, this 2003 net operating loss could be carried back two years for federal purposes. Xcel Energy expects to file for a tax refund of approximately $355 million in first quarter 2004. This refund is based on a two-year carryback. However, under the Bush administration s new dividend tax proposal, the carryback could be one year, which would reduce the refund to $125 million.

As to the remaining $351 million of expected tax benefits, Xcel Energy expects to eliminate or reduce estimated quarterly income tax payments, beginning in 2003. The amount of cash freed up by the reduction in estimated tax payments would depend on Xcel Energy s taxable income.

Negotiations are ongoing. These can be no assurance the NRG creditors ultimately will accept any consensual restructuring plan, or whether, in the interim, NRG lenders and bondholders will forbear from exercising any or all of the remedies available to them, including acceleration of NRG s indebtedness, commencement of an involuntary proceeding in bankruptcy and, in the case of a certain lender, realization on the collateral for their indebtedness.

Throughout the restructuring process, NRG seeks to operate the business in a manner that NRG management believes will offer to creditors similar protection as would be offered by a bankruptcy court. NRG attempts to preserve the enterprise value of the business and to treat creditors within each creditor class without preference, unless otherwise agreed to by advisors to all potentially affected creditors. By operating NRG within this framework, NRG desires to mitigate the risk that creditors will pursue involuntary bankruptcy proceedings against NRG or its material subsidiaries.

Whether or not NRG reaches a consensual arrangement with NRG s Creditors, there is a substantial likelihood that NRG will be the subject of a bankruptcy proceeding. If an agreement were reached with NRG s Creditors on a restructuring plan, it is expected that NRG would commence a Chapter 11 bankruptcy case and immediately seek approval of a prenegotiated plan of reorganization. Absent an agreement with NRG s Creditors and the continued forbearance by such creditors, NRG will be subject to substantial doubt as to its ability to continue as a going concern and will likely be the subject of a voluntary or involuntary bankruptcy proceeding, which, due to the lack of a prenegotiated plan of reorganization, would be expected to take an extended period of time to be resolved and may involve claims against Xcel Energy under the equitable doctrine of substantive consolidation.

Potential NRG Bankruptcy A preliminary settlement agreement with NRG s creditors on a comprehensive financial restructuring plan that, among other things, addresses Xcel Energy s continuing role and degree of ownership in NRG and obligations to NRG in a restructured NRG has been reached. Following an agreement on the restructuring with NRG s creditors and as described previously, it is expected that NRG would commence a Chapter 11 bankruptcy proceeding and immediately seek approval of a prenegotiated plan of reorganization. Absent an agreement with NRG s creditors and the continued forbearance by such creditors, NRG will be subject to substantial doubt as to its ability to continue as a going concern and will

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

likely be the subject of a voluntary or involuntary bankruptcy proceeding, which, due to the lack of a prenegotiated plan of reorganization, would be expected to take an extended period of time to be resolved.

While it is an exception rather than the rule, especially where one of the companies involved is not in bankruptcy, the equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities, consolidate and pool the entities assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. Xcel Energy believes that any effort to substantively consolidate Xcel Energy with NRG would be without merit. However, it is possible that NRG or its creditors would attempt to advance such claims or other claims under piercing the corporate veil, alter ego or related theories should an NRG bankruptcy proceeding commence, particularly in the absence of a prenegotiated plan of reorganization, and Xcel Energy cannot be certain how a bankruptcy court would resolves these issue. One of the creditors of an NRG project, as previously discussed, has already filed involuntary bankruptcy proceedings against that project and has included claims against both NRG and Xcel Energy. If a bankruptcy court were to allow substantive consolidation of Xcel Energy and NRG, it would have a material adverse effect on Xcel Energy.

The accompanying Consolidated Financial Statements do not reflect any conditions or matters that would arise if NRG were in bankruptcy.

If NRG were to file for bankruptcy, and the necessary actions were taken by Xcel Energy to fully relinquish its effective control over NRG, Xcel Energy anticipates that NRG would no longer be included in Xcel Energy s consolidated financial statements, prospectively from the date such actions were taken. Such de-consolidation of NRG would encompass a change in Xcel Energy s accounting for NRG to the equity method, under which Xcel Energy would continue to record its interest in NRG s income or losses until Xcel Energy s investment in NRG (under the equity method) reached the level of obligations that Xcel Energy had either guaranteed on behalf of NRG or was otherwise committed to in the form of financial assistance to NRG. Prior to completion of a bankruptcy proceeding, a prenegotiated plan of reorganization or other settlement reached with NRG s creditors would be the determining factors in assessing whether a commitment to provide financial assistance to NRG existed at the time of de-consolidation.

At Dec. 31, 2002, Xcel Energy s pro forma investment in NRG, calculated under the equity method if applied at that date, was a negative $625 million. If the amount of guarantees or other financial assistance committed to NRG by Xcel Energy exceeded that level after de-consolidation of NRG, then NRG s losses would continue to be included in Xcel Energy s results until the amount of negative investment in NRG reaches the amount of guarantees and financial assistance committed to by Xcel Energy. As of Dec. 31, 2002, the estimated guarantee exposure that Xcel Energy had related to NRG liabilities was $96 million, as discussed in Note 16, and potential financial assistance was committed in the form of a support and capital subscription agreement pursuant to which Xcel Energy agreed, under certain circumstances, to provide an additional $300 million contribution to NRG if the financial restructuring plan discussed earlier is approved by NRG s creditors. Additional commitments for financial assistance to NRG could be created in 2003 as Xcel Energy, NRG and NRG s creditors continue to negotiate terms of a possible prenegotiated plan of reorganization to resolve NRG s financial difficulties.

In addition to the effects of NRG s losses, Xcel Energy s operating results and retained earnings in 2003 could also be affected by the tax effects of any guarantees or financial commitments to NRG, if such income tax benefits were considered likely of realization in the foreseeable future. The income tax benefits recorded in 2002 related to Xcel Energy s investment in NRG, as discussed in Note 11 to the Consolidated Financial Statements, includes only the tax benefits related to cash and stock investments already made in NRG at Dec. 31, 2002. Additional tax benefits could be recorded in 2003 at the time that such benefits are considered likely of realization, when the payment of guarantees and other financial assistance to NRG become probable.

Xcel Energy believes that the ultimate resolutions of NRG s financial difficulties and going-concern uncertainty will not affect Xcel Energy s ability to continue as a going concern. Xcel Energy is not dependent

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

on cash flows from NRG, nor is Xcel Energy contingently liable to creditors of NRG in an amount material to Xcel Energy s liquidity. Xcel Energy believes that its cash flows from regulated utility operations and anticipated financing capabilities will be sufficient to fund its non-NRG-related operating, investing and financing requirements. Beyond these sources of liquidity, Xcel Energy believes it will have adequate access to additional debt and equity financing that is not conditioned upon the outcome of NRG s financial restructuring plan.

5. Short-Term Borrowings

Notes Payable and Commercial Paper Information regarding notes payable and commercial paper for the years ended Dec. 31, 2002 and 2001, is:

	2002	2001
	(Millions of dollars, except interest rates)	
Notes payable to banks	$ 1,542	$ 835
Commercial paper		1,390
Total short-term debt	$ 1,542	$ 2,225
Weighted average interest rate at year-end	4.33%	3.41%

Credit Facilities As of Dec. 31, 2002, Xcel Energy had the following credit facilities available:

	Maturity	Term	Credit Line
Xcel Energy	November 2005	5 years	$400 million
NSP-Minnesota	August 2003	364 days	$300 million
PSCo	June 2003	364 days	$530 million
SPS	February 2003	364 days	$250 million
Other subsidiaries	Various	Various	$55 million

The lines of credit provide short-term financing in the form of bank loans and letters of credit, and, depending on credit ratings, provide support for commercial paper borrowings. At Dec. 31, 2002, there were $399 million of loans outstanding under the Xcel Energy line of credit and $88 million for PSCo. The borrowing rates under these lines of credit is based on the applicable London Interbank Offered Rate (LIBOR) plus an applicable spread, a euro dollar rate margin and the amount of money borrowed. At Dec. 31, 2002, the weighted average interest rate would have been 2.70 percent and 2.42 percent, respectively. See discussion of NRG short-term debt at Note 7.

On Jan. 22, 2003, Xcel Energy entered into an agreement with Perry Capital and King Street Capital to provide Xcel Energy with a 9-month, $100-million term loan facility. The facility carries a 9 percent per annum coupon rate and fees for early termination, prepayment and extensions within the 9-month period. Xcel Energy has no current need to draw on the facility, but sought the additional liquidity to provide financing flexibility. Xcel Energy, absent SEC approval under PUHCA, can only draw on this facility when its common equity exceeds 30 percent of total capitalization.

The SPS $250-million facility expired in February 2003 and was replaced with a $100-million unsecured, 364-day credit agreement. The NSP-Minnesota and PSCo credit facilities are secured by first mortgages and first collateral trust bonds, respectively.

6. Long-Term Debt

Except for SPS and other minor exclusions, all property of our utility subsidiaries is subject to the liens of their first mortgage indentures, which are contracts between the companies and their bondholders. In

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

addition, certain SPS payments under its pollution-control obligations are pledged to secure obligations of the Red River Authority of Texas.

The utility subsidiaries first mortgage bond indentures provide for the ability to have sinking-fund requirements. These annual sinking-fund requirements are 1 percent of the highest principal amount of the series of first mortgage bond at any time outstanding. Sinking-fund requirements at NSP-Wisconsin, PSCo and Cheyenne are $2.8 million and are for one series of first mortgage bonds for each. Such sinking-fund requirements may be satisfied with property additions or cash. NSP-Minnesota and SPS have no sinking fund-requirements.

NSP-Minnesota s 2011 series bonds are redeemable upon seven-days notice at the option of the bondholder. Because of the terms that allow the holders to redeem these bonds on short notice, we include them in the current portion of long-term debt reported under current liabilities on the balance sheets.

See discussion of NRG long-term debt at Note 7.

Maturities and sinking fund requirements of long-term debt are:

2003	$	7,759 million
2004	$	239 million
2005	$	313 million
2006	$	722 million
2007	$	420 million

7. NRG Debt and Capital Leases

As of Dec. 31, 2002, NRG has failed to make scheduled payments on interest and/or principal on approximately $4 billion of its recourse debt and is in default under the related debt instruments. These missed payments also have resulted in cross-defaults of numerous other nonrecourse and limited recourse debt instruments of NRG. In addition to the missed debt payments, a significant amount of NRG s debt and other obligations contain terms that require that they be supported with letters of credit or cash collateral following a ratings downgrade. As a result of the downgrades that NRG has experienced in 2002, NRG estimates that it is in default of its obligations to post collateral ranging from $1.1 billion to $1.3 billion, principally to fund equity guarantees associated with its construction revolver financing facility, to fund debt service reserves and other guarantees related to NRG projects and to fund trading operations. Absent an agreement on a comprehensive restructuring plan, NRG will remain in default under its debt and other obligations, because it does not have sufficient funds to meet such requirements and obligations. As a result, the lenders will be able, if they choose, to seek to enforce their remedies at any time, which would likely lead to a bankruptcy filing by NRG. There can be no assurance that NRG s creditors ultimately will accept any consensual restructuring plan, or that, in the interim, NRG s lenders and bondholders will continue to forbear from exercising any or all of the remedies available to them, including acceleration of NRG s indebtedness, commencement of an involuntary proceeding in bankruptcy and, in the case of certain lenders, realization on the collateral for their indebtedness. See Note 4 for discussion of 2003 developments regarding NRG s financial restructuring.

Pending the resolution of NRG s credit contingencies and the timing of possible asset sales, a portion of NRG s long-term debt obligations has been classified as current liabilities for those long-term obligations that lenders have the ability to accelerate such debt within 12 months of the balance sheet date.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-term and Short-term Debt Defaults

NRG and its subsidiaries have failed to timely make the following interest and/or principal payments on its indebtedness:

Debt	Amount Issued	Rate	Maturity	Interest Due	Principal Due	Date Due
			($ in millions)			
Recourse Debt (unsecured)						
NRG Energy ROARS	$ 250.0	8.700%	3/15/2005	$ 10.9	$ 0.0	9/16/2002
	$ 250.0	8.700%	3/15/2005	$ 10.9	$ 0.0	3/17/2003
NRG Energy senior notes	$ 350.0	8.250%	9/15/2010	$ 14.4	$ 0.0	9/16/2002
	$ 350.0	8.250%	9/15/2010	$ 14.4	$ 0.0	3/17/2003
NRG Energy senior notes	$ 350.0	7.750%	4/1/2011	$ 13.6	$ 0.0	10/1/2002
NRG Energy senior notes	$ 500.0	8.625%	4/1/2031	$ 21.6	$ 0.0	10/1/2002
NRG Energy senior notes	$ 240.0	8.000%	11/1/2003	$ 9.6	$ 0.0	11/1/2002
NRG Energy senior notes	$ 300.0	7.500%	6/1/2009	$ 11.3	$ 0.0	12/1/2002
NRG Energy senior notes	$ 250.0	7.500%	6/15/2007	$ 9.4	$ 0.0	12/15/2002
NRG Energy senior notes	$ 340.0	6.750%	7/15/2006	$ 11.5	$ 0.0	1/15/2003
NRG Energy senior debentures (NRZ Equity Units)	$ 287.5	6.500%	5/16/2006	$ 4.7	$ 0.0	11/16/2002
	$ 287.5	6.500%	5/16/2006	$ 4.7	$ 0.0	2/17/2003
NRG Energy senior notes	$ 125.0	7.625%	2/1/2006	$ 4.8	$ 0.0	2/1/2003
NRG Energy 364-day corporate revolving facility	$ 1,000.0	various	3/7/2003	$ 7.6	$ 0.0	9/30/2002
NRG Energy 364-day corporate revolving facility	$ 1,000.0	various	3/7/2003	$ 18.6	$ 0.0	12/31/2002
Non-Recourse Debt (secured)						
NRG Northeast Generating LLC	$ 320.0	8.065%	12/15/2004	$ 5.1	$ 53.5	12/15/2002
NRG Northeast Generating LLC	$ 130.0	8.842%	6/15/2015	$ 5.7	$ 0.0	12/15/2002
NRG Northeast Generating LLC	$ 300.0	9.292%	12/15/2024	$ 13.9	$ 0.0	12/15/2002
NRG South Central Generating LLC	$ 500.0	8.962%	3/15/2016	$ 20.2	$ 12.8	9/16/2002
	$ 500.0	8.962%	3/15/2016	$ 0.0	$ 12.8	3/17/2003
NRG South Central Generating LLC	$ 300.0	9.479%	9/15/2024	$ 14.2	$ 0.0	9/16/2002

These missed payments may have also resulted in cross-defaults of numerous other non-recourse and limited recourse debt instruments of NRG.

Short-term Debt

NRG had an unsecured, revolving line of credit of $1 billion, which terminated on March 7, 2003. At Dec. 31, 2002, NRG had a $1 billion outstanding balance under this credit facility. NRG has failed to make interest payments when due. In addition, NRG violated both the minimum net worth covenant and the minimum interest coverage ratio requirements of the facility. On Feb. 27, 2003, NRG received a notice of default on the corporate revolver financing facility, rendering the debt immediately due and payable. The recourse revolving credit facility matured on March 7, 2003, and the $1 billion drawn remains outstanding. Accordingly, the facility is in default.

NRG s $125-million syndicated letter of credit facility contains terms, conditions and covenants that are substantially the same as those in NRG s $1-billion, 364-day revolving line of credit. As of Dec. 31, 2002, NRG violated both the minimum net worth covenant and the minimum interest coverage ratio requirements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of the facility. Accordingly, the facility is in default. NRG had $110 million and $170 million in outstanding letters of credit as of Dec. 31, 2002 and 2001, respectively.

Long-term Debt Corporate Debt

Equity Units and Debentures In 2001, NRG completed the sale of 11.5 million equity units for an initial price of $25 per unit. Each equity unit initially consists of a corporate unit comprising a $25 principal amount of NRG s senior debentures and an obligation to acquire shares of NRG common stock no later than May 18, 2004, at a price ranging from between $27.00 and $32.94. Approximately $4.1 million of the gross proceeds have been recorded as additional paid in capital to reflect the value of the obligation to purchase NRG s common stock. As a result of the merger by Xcel Energy of NRG, holders of the equity units are no longer obligated to purchase shares of NRG common stock under the purchase contracts. Instead, holders of the equity units are now obligated to purchase a number of shares of Xcel Energy common stock upon settlement of the purchase contracts equal to the adjusted settlement rate or the adjusted early settlement rate as applicable. As a result of the short-form merger, the adjusted settlement rate is 0.4630, resulting in a settlement price of approximately $55 per Xcel Energy common share, and the adjusted early settlement rate is 0.3795, resulting in a settlement price of approximately $65 per Xcel Energy common share, subject to the terms and conditions of the purchase contracts set forth in a purchase contract agreement. In October 2002, NRG announced it would not make the November 2002 quarterly interest payment on the 6.50-percent senior unsecured debentures due in 2006, which trade with the associated equity units. The 30-day grace period to make payment ended Dec. 16, 2002, and NRG did not make payment. As a result, this issue is in default. In addition, NRG did not make the Feb. 17, 2003 quarterly interest payment. In the event of an NRG bankruptcy, the obligation to purchase shares of Xcel Energy stock terminates.

Senior Unsecured Notes The NRG $125-million, $250-million, $300-million, $350-million, and $240-million senior notes are unsecured and are used to support equity requirements for projects acquired and in development. The interest is paid semi-annually. The 30-day grace period to make payment related to these issues has passed. NRG did not make the required payments, and is in default on these notes.

Remarketable or Redeemable Securities The $240-million NRG senior notes due Nov. 1, 2013, are Remarketable or Redeemable Securities (ROARS). Nov. 1, 2003 is the first remarketing date for these notes. Interest is payable semi-annually on May 1, and November 1, of each year through 2003, and then at intervals and interest rates as discussed in the indenture. On the remarketing date, the notes must either be mandatorily tendered to and purchased by Credit Suisse Financial Products or mandatorily redeemed by NRG at prices discussed in the indenture. The notes are unsecured debt that rank senior to all of NRG s existing and future subordinated indebtedness. On Oct. 16, 2002, NRG entered into a termination agreement with the agent that terminated the remarketing agreement. A termination payment of $31.4 million due on Oct. 17, 2002 has not been paid.

In March 2000, an NRG sponsored non-consolidated pass-through trust issued $250 million of 8.70 percent certificates due March 15, 2005. Each certificate represents a fractional undivided beneficial interest in the assets of the trust. Interest is payable on the certificates semi-annually on March 15 and September 15 of each year through 2005. The sole assets of the trust consist of £160 million, approximately $250 million on the date of issuance, principal amount 7.97 percent Reset Senior Notes due March 15, 2020 issued by NRG. The Reset Senior Notes were used principally to finance NRG s acquisition of the Killingholme facility. Interest is payable semi-annually on the Reset Senior Notes on March 15 and September 15 through March 15, 2005, and then at intervals and interest rates established in a remarketing process. If the Reset Senior Notes are not remarketed on March 15, 2005, they must be mandatorily redeemed by NRG on such date. On Sept. 16, 2002, NRG Pass-through Trust I failed to make a $10.9 million interest payment due on the $250 million bonds, as a consequence of NRG failing to pay interest due on £160 million of 7.97 percent debt. The 30-day grace period to make payment related to this issue has passed and NRG did not make the required payments. NRG is in default on these bonds.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Audrain Capital Lease In connection with NRG s acquisition of the Audrain facilities, NRG recognized a capital lease on its balance sheet within long-term debt in the amount of $239.9 million, as of Dec. 31, 2002 and 2001. The capital lease obligation is recorded at the net present value of the minimum lease obligation payable. The lease terminates in May 2023. During the term of the lease only interest payments are due, no principal is due until the end of the lease. In addition, NRG has recorded in notes receivable, an amount of approximately $239.9 million, which represents its investment in the bonds that the county of Audrain issued to finance the project. During December 2002, NRG Energy received a notice of a waiver of a $24.0-million interest payment due on the capital lease obligation.

Long-term Debt Subsidiary

NEO Corp. The various NEO notes are term loans. The loans are secured principally by long-term assets of NEO Landfill Gas collection system. NEO Landfill Gas is required to maintain compliance with certain covenants primarily related to incurring debt, disposing of the NEO Landfill Gas assets, and affiliate transactions. On Oct. 30, 2002, NRG failed to make $3.1 million in payments under certain non-operating interest acquisition agreements. As a result, NEO Corp., a direct wholly owned subsidiary of NRG, and NEO Landfill Gas, Inc., an indirect wholly owned subsidiary of NRG, failed to make approximately $1.4 million in loan payments. Also, the subsidiaries of NEO Corp. and NEO Landfill Gas, Inc. failed to make approximately $2 million in payments pursuant to various agreements. NRG received an extension until November 2002 with respect to NEO Landfill Gas, Inc. to make payments under such agreements, and such payments were made during the extension period. The payments relating to NEO Corp. were not made, and the loan was due and payable on Dec. 20, 2002. A letter of credit was drawn to pay the NEO Corp. loan in full on Dec. 23, 2002. As of Dec. 31, 2002, NEO Landfill Gas, Inc. was in default under the loan agreement dated July 6, 1998 due to the failure to meet the insurance requirements under the loan document. On Jan. 30, 2003, NRG failed to make $2.7 million in payments under certain acquisition agreements. As a result, NEO Landfill Gas, Inc. failed to make its payment due on Jan. 30, 2003, under the loan agreement and the subsidiaries of NEO Landfill Gas failed to make their payments pursuant to various agreements.

Northeast Generating LLC In February 2000, NRG Northeast Generating LLC, an indirect, wholly owned subsidiary of NRG, issued $750 million of project level senior secured bonds to refinance short-term project borrowings and for certain other purposes. The bonds are jointly and severally guaranteed by each of NRG Northeast s existing and future subsidiaries. The bonds are secured by a security interest in NRG Northeast s membership or other ownership interests in the guarantors and its rights under all inter-company notes between NRG Northeast and the guarantors. In December 2002, NRG Northeast Generating failed to make $24.7-million interest and $53.5-million principal payments. NRG Northeast Generating had a 15-day grace period to make payment. On Dec. 27, 2002, NRG made the $24.7 million interest payment due on the NRG Northeast Generating bonds but failed to make the $53.5 million principal payment. As a result, the payment default associated with its failure to make principal payments when they come due is currently in effect. NRG also failed to make a debt service reserve account cash deposit within 30 days of a credit rating downgrade in July 2002. In addition, NRG Northeast Generation is also in default of its debt covenants because of the lapse of the 60-day grace period regarding the necessary dismissal of an involuntary bankruptcy proceeding. For these reasons, NRG Northeast Generating is in default on these notes.

NRG South Central Generating LLC In March 2000, NRG South Central Generating LLC, an indirect wholly owned subsidiary of NRG, issued $800 million of senior secured bonds in a two-part offering to finance its acquisition of the Cajun generating facilities. The bonds are secured by a security interest in NRG Central U.S. LLC s and South Central Generating Holding LLC s membership interests in NRG South Central and NRG South Central s membership interests in Louisiana Generating and all of the assets related to the Cajun facilities, including its rights under a guarantor loan agreement and all inter-company notes between it and Louisiana Generating, and a revenue account and a debt service reserve account. On Sept. 15, 2002, NRG South Central Generating missed a $47-million principal and interest payment. The 15-day grace period to make payment related to this issue has passed ,and NRG South Central Generating did not make

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the required payments. In January 2003, the South Central Generating bondholders unilaterally withdrew $35.6 million from the restricted revenue account, relating to the Sept. 15, 2002, interest payment and fees. On March 17, 2003, South Central bondholders were paid $34.4 million due in relation to the semi-annual interest payment, and the $12.8 million principal payment was deferred. NRG South Central remains in default on these notes.

Flinders Power Finance In September 2000, Flinders Power Finance Pty (Flinders Power), an Australian wholly owned subsidiary, entered into a twelve year AUD $150 million promissory note (US $81.4 million at September 2000). As of Dec. 31, 2002, there remains $80.5 million outstanding under this facility. In March 2002, Flinders Power entered into a 10-year AUD $165 million (US $85.4 million at March 2002) floating rate promissory note for the purpose of refurbishing the Flinders Playford generating station. As of Dec. 31, 2002, Flinders Power had drawn $18.7 million (AUD $33 million) of this facility. Upon NRG s credit rating downgrade in 2002, there existed a potential default under these agreements related to the funding of reserve funds. Flinders continues to work with its lenders subsequent to the downgrade.

NRG Peaker Finance Company LLC In June 2002, NRG Peaker Finance Co. LLC (NRG Peaker), an indirect wholly owned subsidiary of NRG, completed the issuance of $325 million of Series A Floating Rate Senior Secured Bonds, due 2019. The bonds are secured by a pledge of membership interests in NRG Peaker and a security interest in all of its assets, which initially consisted of notes evidencing loans to the affiliate project owners. The project owners jointly and severally guaranteed the entire principal amount of the bonds and interest on such principal amount. The project owner guaranties are secured by a pledge of the membership interest in three of five project owners and a security interest in substantially all of the project owners assets related to the peaker projects, including equipment, real property rights, contracts and permits. NRG has entered into a contingent guaranty agreement in favor of the collateral agent for the benefit of the secured parties, under which it agreed to make payments to cover scheduled principal and interest payments on the bonds and regularly scheduled payments under the interest rate swap agreement, to the extent that the net revenues from the peaker projects are insufficient to make such payments, in specified circumstances. As a result of cross-default provisions, this facility is in default. On Dec. 10, 2002, $16.0 million in interest, principal, and swap payments were made from restricted cash accounts. As a result, $319.4 million in principal remains outstanding as of Dec. 31, 2002.

LSP-Pike Energy LLC LSP-Pike Energy LLC received a loan to construct its power generation facility in Pike County, Mississippi that was financed by the issuance of Industrial Revenue Bonds (Series 2002). NRG Finance Co. I LLC, an affiliate of LSP-Pike Energy LLC, purchased the Series 2002 bonds. These bonds are subject to a subordination agreement between NRG Finance Co. I LLC, as purchaser, LSP-Pike Energy LLC, and Credit Suisse First Boston, as administrative agent to a senior claim. In the case of insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings, and even in the event of any proceedings for voluntary liquidation, dissolutions, or other winding up of the company, the holders of the senior claims shall be entitled to receive payment in full or cash equivalents of all principal, interest, charges and fees on all senior claims before the purchaser is entitled to receive any payment on account of the principal of or interest on these bonds. As of Oct. 17, 2002, the United States Bankruptcy Court for the Southern District of Mississippi granted an order of relief to the debtor under the U.S. bankruptcy laws, thus forcing LSP-Pike Energy LLC into default and cessation of all benefits granted under the terms of the loan agreement and issuance of the bonds.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Long-term Debt Credit Facilities

NRG has several credit facilities used for long-term financing:

Facility	Available Line of Credit	Recourse to NRG	End Date	Outstanding Dec. 31, 2002	Rate at Dec. 31, 2002
			(Currency in thousands)		
Revolving lines of credit:					
NRG Finance Co. I LLC	$ 2,000,000	Yes	May 2006	$ 1,081,000	4.92%
Term loan facilities:					
MidAtlantic	$ 580,000	No	November 2005	$ 409,200	3.30%
LSP Kendall Energy	$ 554,200	No	September 2005	$ 495,800	3.19%
Brazos Valley	$ 180,000	No	June 2008	$ 194,400	4.41%
McClain	$ 296,000	No	November 2006	$ 157,300	4.57%

NRG Financing Co. I LLC The NRG Finance Co. I LLC facility has been used to finance the acquisition, development and construction of power generating plants located in the United States, and to finance the acquisition of turbines for such facilities. The facility is nonrecourse to NRG other than its obligation to contribute equity at certain times in respect of projects and turbines financed under the facility. NRG estimates the obligations to contribute equity to be approximately $819 million as of Dec. 31, 2002. At Dec. 31, 2002, interest and fees due in September 2002 were not paid, and NRG has suspended required equity contributions to the projects. Supporting construction and other contracts associated with NRG s Pike and Nelson projects were violated by NRG, in September and October 2002, respectively. In November 2002, lenders to NRG accelerated the approximately $1.08 billion of debt under the construction revolver facility, rendering the debt immediately due and payable. Thus, this facility is currently in default.

LSP Kendall Energy As part of NRG s acquisition of the LS Power assets in January 2001, NRG, through its wholly owned subsidiary LSP Kendall Energy LLC, has acquired a $554.2-million credit facility. On Jan. 10, 2003, NRG received a notice of default from LSP Kendall s lenders indicating that certain events of default have taken place. By issuing this notice of default, the lenders have preserved all of their rights and remedies under the Credit Agreement and other Credit Documents. NRG is negotiating a waiver to this default notice with the creditors to LSP Kendall.

Brazos Valley In June 2001, NRG, through its wholly owned subsidiaries Brazos Valley Energy LP and Brazos Valley Technology LP, entered into a $180-million nonrecourse construction credit facility to fund the construction of the 600-megawatt Brazos Valley gas-fired combined-cycle merchant generation facility, located in Texas. On Jan. 31, 2003, NRG consented to the foreclosure of its Brazos Valley project by its lenders. As consequence of foreclosure, NRG no longer has any interest in the Brazos Valley project. However, NRG may be obligated to infuse additional capital to fund a debt service reserve account that had never been funded, and may be obligated to make an equity infusion to satisfy a contingent equity agreement. As of Dec. 31, 2002, NRG recorded $24 million for the potential obligations.

McClain In August 2001, NRG entered into a 364-day term loan of up to $296 million. The credit facility was structured as a senior unsecured loan and was partially nonrecourse to NRG. The proceeds were used to finance the McClain generating facility acquisition. In November 2001, the credit facility was repaid from the proceeds of a $181.0 million term loan and $8.0 million working capital facility entered into by NRG McClain LLC, with Westdeutsche Landesbank Girozentrale, non-recourse to NRG. On Sept. 17, 2002, NRG McClain LLC received notice from the agent bank that the project loan was in default as a result of the downgrade of NRG and of defaults on material obligations.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Preferred Stock

At Dec. 31, 2002, Xcel Energy had six series of preferred stock outstanding, which were callable at its option at prices ranging from $102.00 to $103.75 per share plus accrued dividends. Xcel Energy can only pay dividends on its preferred stock from retained earnings absent approval of the SEC under PUHCA. See Note 12 for a description of such restrictions.

The holders of the $3.60 series preferred stock are entitled to three votes for each share held. The holders of the other preferred stocks are entitled to one vote per share. While dividends payable on the preferred stock of any series outstanding is in arrears in an amount equal to four quarterly dividends, the holders of preferred stocks, voting as a class, are entitled to elect the smallest number of directors necessary to constitute a majority of the board of directors, and the holders of common stock, voting as a class, are entitled to elect the remaining directors.

The charters of some of Xcel Energy s subsidiaries also authorize the issuance of preferred shares. However, at this time, there are no such shares outstanding. This chart shows data for first- and second-tier subsidiaries:

	Preferred Shares Authorized	Par Value	Preferred Shares Outstanding
Cheyenne Light, Fuel & Power Co.	1,000,000	$ 100.00	None
Southwestern Public Service Co.	10,000,000	$ 1.00	None
Public Service Co. of Colorado	10,000,000	$ 0.01	None

9. Mandatorily Redeemable Preferred Securities of Subsidiary Trusts

SPS Capital I, a wholly owned, special-purpose subsidiary trust of SPS, has $100 million of 7.85-percent trust preferred securities issued and outstanding that mature in 2036. Distributions paid by the subsidiary trust on the preferred securities are financed through interest payments on debentures issued by SPS and held by the subsidiary trust, which are eliminated in consolidation. The securities are redeemable at the option of SPS after October 2001, at 100 percent of the principal amount plus accrued interest. Distributions and redemption payments are guaranteed by SPS.

NSP Financing I, a wholly owned, special-purpose subsidiary trust of NSP-Minnesota, has $200 million of 7.875-percent trust preferred securities issued and outstanding that mature in 2037. Distributions paid by the subsidiary trust on the preferred securities are financed through interest payments on debentures issued by NSP-Minnesota and held by the subsidiary trust, which are eliminated in consolidation. The preferred securities are redeemable at NSP Financing I s option at $25 per share, beginning in 2002. Distributions and redemption payments are guaranteed by NSP-Minnesota.

PSCo Capital Trust I, a wholly owned, special-purpose subsidiary trust of PSCo, has $194 million of 7.60-percent trust preferred securities issued and outstanding that mature in 2038. Distributions paid by the subsidiary trust on the preferred securities are financed through interest payments on debentures issued by PSCo and held by the subsidiary trust, which are eliminated in consolidation. The securities are redeemable at the option of PSCo after May 2003 at 100 percent of the principal amount outstanding plus accrued interest. Distributions and redemption payments are guaranteed by PSCo.

The mandatorily redeemable preferred securities of subsidiary trusts are consolidated in Xcel Energy s Consolidated Balance Sheets. Distributions paid to preferred security holders are reflected as a financing cost in the Consolidated Statements of Operations, along with interest charges.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Joint Plant Ownership

The investments by Xcel Energy s subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2002, are:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
		(Thousands of dollars)		
NSP-Minnesota-Sherco Unit 3	$ 612,643	$ 291,754	$ 943	59.0
PSCo:				
Hayden Unit 1	$ 84,486	$ 38,429	$ 446	75.5
Hayden Unit 2	79,882	42,291	6	37.4
Hayden Common Facilities	27,339	3,300	250	53.1
Craig Units 1 & 2	59,636	31,963	258	9.7
Craig Common Facilities Units 1, 2 & 3	18,473	9,029	3,409	6.5 9.7
Transmission Facilities, including Substations	89,254	29,365	1,208	42.0 73.0
Total PSCo.	$ 359,070	$ 154,377	$ 5,577	
NRG:				
McClain	$ 277,566	$ 12,329	$	77.0
Big Cajun II Unit 3	188,758	12,275	244	58.0
Conemaugh	62,045	4,134	766	3.7
Keystone	52,905	3,543	5,039	3.7
Total NRG	$ 581,274	$ 32,281	$ 6,049	

NSP-Minnesota is part owner of Sherco 3, an 860-megawatt coal-fueled electric generating unit. NSP-Minnesota is the operating agent under the joint ownership agreement. NSP-Minnesota s share of operating expenses for Sherco 3 is included in the applicable utility components of operating expenses. PSCo s assets include approximately 320 megawatts of jointly owned generating capacity. PSCo s share of operating expenses and construction expenditures are included in the applicable utility components of operating expenses. NRG s share of operating expenses and construction expenditures are included in the applicable nonregulated components of operating expenses. Each of the respective owners is responsible for the issuance of its own securities to finance its portion of the construction costs.

11. Income Taxes

As discussed in Note 1 to the Consolidated Financial Statements, the tax filing status of NRG for 2002 will change from filing as a separate consolidated group, apart from the Xcel Energy consolidated group, to the NRG members filing on a stand-alone basis. On a stand-alone basis, the NRG member companies do not have the ability to recognize all tax benefits that may ultimately accrue from its losses incurred in 2002. NRG may have the ability to receive tax benefits for such losses in future periods as income is earned.

In consideration of the foreseeable effects of the NRG restructuring plan on Xcel Energy s investment in NRG, Xcel Energy has recognized the expected tax benefits from this investment as of Dec. 31, 2002. The tax benefit was estimated to be $706 million and was recorded at one of Xcel Energy s nonregulated intermediate holding companies. This benefit is based on the difference between the book and tax bases of Xcel Energy s investment in NRG.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The actual amount of tax benefit derived by Xcel Energy for its investment in NRG is dependent upon various factors, including certain factors that may be affected by the terms of any financial restructuring agreement reached with NRG s creditors. Similarly, the amount and timing of tax benefits to be recorded by NRG, related to 2002 losses, is dependent on estimated future results of NRG.

Total income tax expense from operations differs from the amount computed by applying the statutory federal income tax rate to income before income tax expense. The reasons for the difference are:

	2002	2001	2000
Federal statutory rate	35.0%	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	5.6	3.6	6.0
Life insurance policies	1.1	(2.0)	(2.5)
Tax credits recognized	1.5	(6.9)	(10.7)
Equity income from unconsolidated affiliates	0.8	(1.7)	(2.3)
Income from foreign consolidated affiliates	1.8	(6.0)	1.8
Regulatory differences utility plant items	(0.5)	1.9	2.4
Valuation Allowance	(46.8)	5.8	
Xcel Energy tax benefit on NRG	30.7		
Nondeductible merger costs			3.1
Other net	(1.9)	(0.5)	2.9
Total effective income tax rate	27.3	29.2	35.7
Extraordinary item		(0.4)	1.0
Effective income tax rate from continuing operations	27.3%	28.8%	36.7%

Income taxes comprise the following expense (benefit) items:

	2002	2001	2000
		(Thousands of dollars)	
Current federal tax expense	$ 114,273	$ 373,710	$ 205,472
Current state tax expense	21,724	26,927	63,428
Current foreign tax expense	18,973	10,988	1,693
Current tax credits	(18,067)	(66,179)	(71,270)
Deferred federal tax expense	(631,468)	(24,323)	103,033
Deferred state tax expense	(114,486)	18,702	12,547
Deferred foreign tax expense	(2,248)	4,529	(578)
Deferred investment tax credits	(16,686)	(12,983)	(15,295)
Income tax expense (benefit) excluding extraordinary items	(627,985)	331,371	299,030
Tax expense (benefit) on extraordinary items		4,807	(8,549)
Total income tax expense from continuing operations	$ (627,985)	$ 336,178	$ 290,481

As of Dec. 31, 2001, Xcel Energy management intended to reinvest the earnings of NRG s foreign operations to the extent the earnings were subject to current U.S. income taxes. Accordingly, U.S. income taxes and foreign withholding taxes were not provided on a cumulative amount of unremitted earnings of foreign subsidiaries of approximately $345 million at Dec. 31, 2001. As of Dec. 31, 2002, Xcel Energy management has revised its strategy and no longer intends to indefinitely reinvest the full amount of earnings

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

of NRG s foreign operations. However, no U.S. income tax benefit has been provided on the cumulative amount of unremitted losses of $339.7 million at Dec. 31, 2002 due to the uncertainty of realization.

Xcel Energy management intends to indefinitely reinvest the earnings of the Argentina operations of Xcel Energy International and, therefore, has not provided deferred taxes for the effects of currency devaluations.

The components of Xcel Energy s net deferred tax liability (current and noncurrent portions) at Dec. 31 were:

	2002	2001
	(Thousands of dollars)	
Deferred tax liabilities:		
Differences between book and tax basis of property	$ 2,060,450	$ 2,083,965
Regulatory assets	159,942	155,587
Partnership income/loss	33,739	53,955
Unrealized gains and losses on mark-to-market transactions		9,348
Tax benefit transfer leases	10,993	14,765
Employee benefits and other accrued liabilities	8,883	16,559
Other	78,250	66,538
Total deferred tax liabilities	$ 2,352,257	$ 2,400,717
Deferred tax assets:		
Xcel Energy benefit on NRG	$ 706,000	$
Book write-down (impairment of assets)	707,183	
Net operating loss carry forward	473,220	3,867
Differences between book and tax basis of contracts	19,806	82,972
Deferred investment tax credits	66,801	72,345
Regulatory liabilities	48,558	66,507
Unrealized gains and losses on mark-to-market transactions	30,707	
Foreign tax loss carryforwards	16,088	90,251
Other	73,838	83,484
Total deferred tax assets	$ 2,142,201	$ 399,426
Less Valuation allowance	1,077,047	66,622
Net deferred tax liability	$ 1,287,103	$ 2,067,913

12. Common Stock and Incentive Stock Plans

Common Stock and Equivalents In February 2002, Xcel Energy issued 23 million shares of common stock at $22.50 per share. In June 2002, Xcel Energy issued 25.7 million shares of common stock to complete its exchange offer for the publicly held stock of NRG. As a result of these issuances, Xcel Energy had approximately 399 million shares outstanding on Dec. 31, 2002.

In November 2002, Xcel Energy issued $230 million of 7.5-percent convertible senior notes. The senior notes are convertible into shares of Xcel Energy common stock at a conversion price of $12.33 per share. The conversion of $230 million in notes at a share price of $12.33 would be the equivalent of approximately 18.7 million shares. However, due to losses experienced in 2002, the impact of the convertible senior notes was antidilutive and, therefore, was not included in the common stock and equivalent calculation in 2002.

Other common stock equivalents included stock options, as discussed further, and NRG equity units. See discussion of NRG equity units, which are convertible to Xcel Energy common stock, at Note 7. Due to the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

losses experienced in 2002, these equivalents were also antidilutive and were not incorporated in the common stock and equivalents calculation in 2002.

The dilutive impacts of common stock equivalents affected earnings per share as follows for the years ending Dec. 31:

	2002	2001	2000
	(In thousands, except per share amounts)		
Basic EPS Calculation:			
Earnings (loss) available for common	$ (2,222,232)	$ 790,725	$ 522,587
Weighted average common stock outstanding	382,051	342,952	337,832
Basic earnings per share	$ (5.82)	$ 2.31	$ 1.54
Diluted Calculation:			
Earnings (loss) available for common	$ (2,222,232)	$ 790,725	$ 522,587
Adjustments for Dilutive Securities			
Earnings (loss) for Dilutive Securities	$ (2,222,232)	$ 790,725	$ 522,587
Weighted average common stock outstanding	382,051	342,952	337,832
Adjustments for Common Stock Equivalents		790	279
Weighted average Common Stock and Equivalents	382,051	343,742	338,111
Diluted earnings per share	$ (5.82)	$ 2.30	$ 1.54

Incentive Stock Plans Xcel Energy and some of its subsidiaries have incentive compensation plans under which stock options and other performance incentives are awarded to key employees. The weighted average number of common and potentially dilutive shares outstanding used to calculate our earnings per share include the dilutive effect of stock options and other stock awards based on the treasury stock method. The options normally have a term of 10 years and generally become exercisable from three to five years after grant date or upon specified circumstances. The tables below include awards made by us and some of our predecessor companies, adjusted for the merger stock exchange ratio, and are presented on an Xcel Energy share basis.

Activity in stock options and performance awards were as follows for the years ended Dec. 31:

	2002		2001		2000	
	Awards	Average Price	Awards	Average Price	Awards	Average Price
	(Awards in thousands)					
Outstanding beginning of year	15,214	$ 25.65	14,259	$ 25.35	8,490	$ 25.12
Granted			2,581	25.98	6,980	25.31
Options adopted from NRG	3,328	29.97				
Exercised	(112)	20.27	(1,472)	23.00	(453)	20.33
Forfeited	(1,349)	28.43	(142)	27.08	(704)	25.70
Expired	(100)	28.87	(12)	24.07	(54)	22.62
Outstanding at end of year	16,981	26.29	15,214	25.65	14,259	25.35
Exercisable at end of year	8,993	24.78	7,154	24.78	8,221	24.46

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Range of Exercise Prices		
	11.50 to $25.50	$25.51 to $ 27.00	$27.01 to 63.60
Options outstanding:			
Number outstanding	4,449,827	7,878,856	4,652,424
Weighted average remaining contractual life (years)	4.7	7.3	7.4
Weighted average exercise price	$ 19.87	$ 26.29	$ 32.44
Options exercisable:			
Number exercisable	4,091,097	3,158,956	1,742,579
Weighted average exercise price	$ 20.17	$ 26.46	$ 32.57

Certain employees also may be awarded restricted stock under our incentive plans. We hold restricted stock until restrictions lapse, generally from two to three years from the date of grant. We reinvest dividends on the shares we hold while restrictions are in place. Restrictions also apply to the additional shares acquired through dividend reinvestment. Restricted shares have a value equal to the market trading price of Xcel Energy s stock at the grant date. We granted 50,083 restricted shares in 2002 when the grant-date market price was $22.83, 21,774 restricted shares in 2001 when the grant-date market price was $26.06 and 58,690 restricted shares in 2000 when the grant-date market price was $19.25. Compensation expense related to these awards was immaterial.

The NCE/ NSP merger was a change in control under the NSP incentive plan, so all stock option and restricted stock awards under that plan became fully vested and exercisable as of the merger date. The NCE/NSP merger was not a change in control under the NCE incentive plans, so there was no accelerated vesting of stock options issued under them. When NCE and NSP merged, each outstanding NCE stock option was converted to 1.55 Xcel Energy options.

We apply Accounting Principles Board Opinion No. 25 in accounting for our stock-based compensation and, accordingly, no compensation cost is recognized for the issuance of stock options as the exercise price of the options equals the fair-market value of our common stock at the date of grant. If we had used the SFAS No. 123 method of accounting, earnings would have been the same for 2002 and reduced by approximately 1 cent per share for 2001 and 2 cents per share for 2000.

The weighted-average fair value of options granted, and the assumptions used to estimate such fair value on the date of grant using the Black-Scholes Option Pricing Model were as follows:

	2002*	2001	2000
Weighted-average fair-value per option share at grant date		$ 2.13	$ 2.57
Expected option life		3 5 years	3 5 years
Stock volatility		18%	15%
Risk-free interest rate		3.8 4.8%	5.3 6.5%
Dividend yield		4.9 5.8%	5.4 7.5%

* There were no options granted in 2002.

Common Stock Dividends Per Share Historically, we have paid quarterly dividends to our shareholders. For each quarter in 2001 and for the first two quarters of 2002, we paid dividends to our shareholders of $0.375 per share. In the third and fourth quarters of 2002, we paid dividends of $0.1875 per share. In making the decision to reduce the dividend, the board of directors considered several factors, including the goal of funding customer growth in our core business through internal cash flow and reducing our reliance on debt and equity financings. The board of directors also compared our dividend to its utility earnings and to the dividend payout of comparable utilities. Dividends on our common stock are paid as declared by our board of directors.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Dividend and Other Capital-Related Restrictions Under PUHCA, unless there is an order from the SEC, a holding company or any subsidiary may only declare and pay dividends out of retained earnings. Due to 2002 losses incurred by NRG, retained earnings of Xcel Energy were a deficit of $101 million at Dec. 31, 2002 and, accordingly, dividends cannot be declared until earnings in 2003 are sufficient to eliminate this deficit or Xcel Energy is granted relief under the PUHCA. Xcel Energy has requested authorization from the SEC to pay dividends out of paid-in capital up to $260 million until Sept. 30, 2003. Xcel Energy did not declare a dividend on its Common Stock during the first quarter of 2003. It is not known when or if the SEC will act on this request.

The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Under the provisions, dividend payments may be restricted if Xcel Energy s capitalization ratio (on a holding company basis only, *i.e.*, not on a consolidated basis) is less than 25 percent. For these purposes, the capitalization ratio is equal to (i) common stock plus surplus divided by (ii) the sum of common stock plus surplus plus long-term debt. Based on this definition, our capitalization ratio at Dec. 31, 2002, was 85 percent. Therefore, the restrictions do not place any effective limit on our ability to pay dividends because the restrictions are only triggered when the capitalization ratio is less than 25 percent or will be reduced to less than 25 percent through dividends (other than dividends payable in common stock), distributions or acquisitions of our common stock.

In addition, NSP-Minnesota s first mortgage indenture places certain restrictions on the amount of cash dividends it can pay to Xcel Energy, the holder of its common stock. Even with these restrictions, NSP-Minnesota could have paid more than $825 million in additional cash dividends on common stock at Dec. 31, 2002.

Under PUHCA, Xcel Energy is also restricted from financing activities when its common equity to total capitalization ratio is less than 30 percent. As a result of significant asset impairments at NRG, Xcel Energy s common equity ratio fell below 30 percent during 2002. However, the SEC approved Xcel Energy s request to allow certain financing transactions through March 31, 2003, so long as its common equity ratio, as reported in its most recent quarterly or annual report with the SEC and as adjusted for pending subsequent items that affect capitalization, was at least 24 percent of its total capitalization. At Dec. 31, 2002, and as adjusted for subsequent items that affect capitalization, Xcel Energy s common equity ratio was 23 percent of its total capitalization. As a result, Xcel Energy could not finance at Dec. 31, 2002 absent SEC approval.

Stockholder Protection Rights Agreement In June 2001, Xcel Energy adopted a Stockholder Protection Rights Agreement. Each share of Xcel Energy s common stock includes one shareholder protection right. Under the agreement s principal provision, if any person or group acquires 15 percent or more of Xcel Energy s outstanding common stock, all other shareholders of Xcel Energy would be entitled to buy, for the exercise price of $95 per right, common stock of Xcel Energy having a market value equal to twice the exercise price, thereby substantially diluting the acquiring person s or group s investment. The rights may cause substantial dilution to a person or group that acquires 15 percent or more of Xcel Energy s common stock. The rights should not interfere with a transaction that is in the best interests of Xcel Energy and its shareholders because the rights can be redeemed prior to a triggering event for $0.01 per right.

13. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its benefit employees. Approximately 51 percent of benefit employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2002, NSP-Minnesota had 2,246 and NSP-Wisconsin had 419 union employees covered under a collective-bargaining agreement, which expires at the end of 2004. PSCo had 2,193 union employees covered under a collective-bargaining agreement, which expires in May 2003. SPS had 757 union employees covered under a collective-bargaining agreement, which expires in October 2005.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Pension Benefits Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all employees. Benefits are based on a combination of years of service, the employee s average pay and Social Security benefits.

Xcel Energy s policy is to fully fund into an external trust the actuarially determined pension costs recognized for ratemaking and financial reporting purposes, subject to the limitations of applicable employee benefit and tax laws. Plan assets principally consist of the common stock of public companies, corporate bonds and U.S. government securities. The target range for our pension asset allocation is 75 to 80 percent with equity investments, 5 to 10 percent with fixed income investments, no cash investments and 10 to 15 percent with nontraditional investments (such as real estate and timber ventures). At Dec. 31, 2002, the actual pension portfolio mix was 68 percent equity, 16 percent fixed income, 4 percent cash investments and 12 percent nontraditional investments.

A comparison of the actuarially computed pension benefit obligation and plan assets, on a combined basis, is presented in the following table:

	2002	2001
	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at Jan. 1	$ 2,409,186	$ 2,254,138
Service cost	65,649	57,521
Interest cost	172,377	172,159
Acquisitions	7,848	
Plan amendments	3,903	2,284
Actuarial loss	65,763	108,754
Settlements	(994)	
Special termination benefits	4,445	
Benefit payments	(222,601)	(185,670)
Obligation at Dec. 31	$ 2,505,576	$ 2,409,186
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	$ 3,267,586	$ 3,689,157
Actual return on plan assets	(404,940)	(235,901)
Employer contributions acquisitions	912	
Settlements	(994)	
Benefit payments	(222,601)	(185,670)
Fair value of plan assets at Dec. 31	$ 2,639,963	$ 3,267,586
Funded Status of Plans at Dec. 31		
Net Asset	$ 134,387	$ 858,400
Unrecognized transition asset	(2,003)	(9,317)
Unrecognized prior service cost	224,651	242,313
Unrecognized (gain) loss	182,927	(712,571)
Net pension amounts recognized on Consolidated Balance Sheets	$ 539,962	$ 378,825
Prepaid pension asset recorded	$ 466,229	$ 378,825
Intangible asset recorded prior service costs	6,943	
Minimum pension liability recorded	(106,897)	
Accumulated other comprehensive income recorded pretax	173,687	

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2002	2001
	(Thousands of dollars)	
Significant Assumptions		
Discount rate for year-end valuation	6.75%	7.25%
Expected average long-term increase in compensation level	4.00%	4.50%
Expected average long-term rate of return on assets	9.50%	9.50%

The discount rate and compensation increase assumptions above affect the succeeding year s pension costs. The rate of return assumption affects the current year s pension cost. The return assumption used for 2003 pension cost calculations will be 9.25 percent. Pension costs include an expected return impact for the current year that may differ from actual investment performance in the plan. The cost calculation uses a market-related valuation of pension assets, which reduces year-to-year volatility by recognizing the differences between assumed and actual investment returns over a five-year period.

NRG also offers another noncontributory, defined benefit pension plan sponsored by one of its affiliates. For the year ended Dec. 31, 2002, the total assets of this plan were $20 million, and its benefit obligation was $30 million. The pension liability recorded by NRG for this plan was $12 million, and its annual pension cost was $2 million.

During 2002, one of Xcel Energy s pension plans (other than the NRG plan just described) became underfunded, with projected benefit obligations of $590 million exceeding plan assets of $452 million on Dec. 31, 2002. All other Xcel Energy plans, excluding the NRG plan just described, in the aggregate had plan assets of $2,188 million and projected benefit obligations of $1,916 million on Dec. 31, 2002. A minimum pension liability of $107 million was recorded related to the underfunded plan as of that date. A corresponding reduction in Accumulated Other Comprehensive Income (a component of Stockholders Equity) was also recorded by Xcel Energy, as previously recorded prepaid pension assets were reduced to record the minimum liability. Net of the related deferred income tax effects of the adjustments, total Stockholders Equity was reduced by $108 million at Dec. 31, 2002, due to the minimum pension liability for the underfunded plan.

The components of net periodic pension cost (credit) are:

	2002	2001	2000
		(Thousands of dollars)	
Service cost	$ 65,649	$ 57,521	$ 59,066
Interest cost	172,377	172,159	172,063
Expected return on plan assets	(339,932)	(325,635)	(292,580)
Curtailment		1,121	
Amortization of transition asset	(7,314)	(7,314)	(7,314)
Amortization of prior service cost	22,663	20,835	19,197
Amortization of net gain	(69,264)	(72,413)	(60,676)
Net periodic pension cost (credit) under SFAS No. 87	$ (155,821)	$ (153,726)	$ (110,244)
Credits not recognized due to effects of regulation	71,928	76,509	49,697
Net benefit cost (credit) recognized for financial reporting	$ (83,893)	$ (77,217)	$ (60,547)

Xcel Energy also maintains noncontributory, defined benefit supplemental retirement income plans for certain qualifying executive personnel. Benefits for these unfunded plans are paid out of Xcel Energy s operating cash flows.

Defined Contribution Plans Xcel Energy maintains 401(k) and other defined contribution plans that cover substantially all employees. Total contributions to these plans were approximately $23 million in 2002, $29 million in 2001 and $24 million in 2000.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Until May 6, 2002, Xcel Energy had a leveraged employee stock ownership plan (ESOP) that covered substantially all employees of NSP-Minnesota and NSP-Wisconsin. Xcel Energy made contributions to this noncontributory, defined contribution plan to the extent it realized tax savings from dividends paid on certain ESOP shares. ESOP contributions had no material effect on Xcel Energy earnings because the contributions were essentially offset by the tax savings provided by the dividends paid on ESOP shares. Xcel Energy allocated leveraged ESOP shares to participants when it repaid ESOP loans with dividends on stock held by the ESOP.

In May 2002, the ESOP was terminated and its assets were combined into the Xcel Energy Retirement Savings 401(k) Plan. Starting with the 2003 plan year, the ESOP component of the 401(k) Plan will no longer be leveraged.

Xcel Energy s leveraged ESOP held no shares of Xcel Energy common stock at the end of 2002, 10.7 million shares of Xcel Energy common stock at May 6, 2002, 10.5 million shares of Xcel Energy common stock at the end of 2001, and 12 million shares of Xcel Energy common stock at the end of 2000. Xcel Energy excluded the following average number of uncommitted leveraged ESOP shares from earnings per share calculations: 0.7 million in 2002, 0.9 million in 2001 and 0.7 million in 2000. On Nov. 19, 2002, Xcel Energy paid off all of the ESOP loans. All uncommitted ESOP shares were released and will be used by Xcel Energy for the 2002 employer matching contribution to its 401(k) plan.

Postretirement Health Care Benefits Xcel Energy has contributory health and welfare benefit plans that provide health care and death benefits to most Xcel Energy retirees. The former NSP discontinued contributing toward health care benefits for nonbargaining employees retiring after 1998 and for bargaining employees of NSP-Minnesota and NSP-Wisconsin who retired after 1999. However, employees of the former NCE who retired in 2002 continue to receive employer-subsidized health care benefits. Employees of the former NSP who retired after 1998 are eligible to participate in the Xcel Energy health care program with no employer subsidy.

In conjunction with the 1993 adoption of SFAS No. 106 Employers Accounting for Postretirement Benefits Other Than Pension, Xcel Energy elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulatory agencies for nearly all of Xcel Energy s retail and wholesale utility customers have allowed rate recovery of accrued benefit costs under SFAS No. 106. PSCo transitioned to full accrual accounting for SFAS No. 106 costs between 1993 and 1997, consistent with the accounting requirements for rate-regulated enterprises. The Colorado jurisdictional SFAS No. 106 costs deferred during the transition period are being amortized to expense on a straight-line basis over the 15-year period from 1998 to 2012. NSP-Minnesota also transitioned to full accrual accounting for SFAS No. 106 costs, with regulatory differences fully amortized prior to 1997.

Certain state agencies that regulate Xcel Energy s utility subsidiaries have also issued guidelines related to the funding of SFAS No. 106 costs. SPS is required to fund SFAS No. 106 costs for Texas and New Mexico jurisdictional amounts collected in rates, and PSCo is required to fund SFAS No. 106 costs in irrevocable external trusts that are dedicated to the payment of these postretirement benefits. Minnesota and Wisconsin retail regulators required external funding of accrued SFAS No. 106 costs to the extent such funding is tax advantaged. Plan assets held in external funding trusts principally consist of investments in equity mutual funds, fixed-income securities and cash equivalents.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A comparison of the actuarially computed benefit obligation and plan assets for Xcel Energy postretirement health care plans that benefit employees of its utility subsidiaries is presented in the following table.

	2002	2001
	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at Jan. 1	$ 687,455	$ 576,727
Service cost	7,173	6,160
Interest cost	50,135	46,579
Acquisitions	773	3,212
Plan amendments		(278)
Plan participants contributions	5,755	3,517
Actuarial loss	61,276	100,386
Special termination benefits	(173)	
Benefit payments	(44,419)	(48,848)
Obligation at Dec. 31	$ 767,975	$ 687,455
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	$ 242,803	$ 223,266
Actual return on plan assets	(13,632)	(3,701)
Plan participants contributions	5,755	3,517
Employer contributions	60,476	68,569
Benefit payments	(44,419)	(48,848)
Fair value of plan assets at Dec. 31	$ 250,983	$ 242,803
Funded Status at Dec. 31		
Net obligation	$ 516,992	$ 444,652
Unrecognized transition asset (obligation)	(169,328)	(186,099)
Unrecognized prior service cost	10,904	12,812
Unrecognized gain (loss)	(206,601)	(134,225)
Accrued benefit liability recorded	$ 151,967	$ 137,140
Significant Assumptions		
Discount rate for year-end valuation	6.75%	7.25%
Expected average long-term rate of return on assets (pretax)	8.0-9.0%	9.0%

The assumed health care cost trend rate for 2002 for most Xcel Energy plans is approximately 8 percent, decreasing gradually to 5.5 percent in 2007 and remaining level thereafter. The assumed health care cost trend rate for 2002 for plans of four of NRG s affiliates is approximately 12 percent, decreasing gradually to 5.5 percent in 2009 and remaining level thereafter. A 1-percent change in the assumed health care cost trend rate would have the following effects:

	(Thousands of dollars)
1-percent increase in APBO components at Dec. 31, 2002	$ 79,028
1-percent decrease in APBO components at Dec. 31, 2002	(65,755)
1-percent increase in service and interest components of the net periodic cost	6,285
	(5,181)

1-percent decrease in service and interest components of the net periodic cost

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of net periodic postretirement benefit cost are:

	2002	2001	2000
		(Thousands of dollars)	
Service cost	$ 7,173	$ 6,160	$ 5,679
Interest cost	50,135	46,579	43,477
Expected return on plan assets	(21,030)	(18,920)	(17,902)
Amortization of transition obligation	16,771	16,771	16,773
Amortization of prior service cost (credit)	(1,130)	(1,235)	(1,211)
Amortization of net loss (gain)	5,380	1,457	915
Net periodic postretirement benefit cost (credit) under SFAS No. 106	57,299	50,812	47,731
Additional cost recognized due to effects of regulation	4,043	3,738	6,641
Net cost recognized for financial reporting	$ 61,342	$ 54,550	$ 54,372

14. Equity Investments

Xcel Energy s nonregulated subsidiaries have investments in various international and domestic energy projects, and domestic affordable housing and real estate projects. We use the equity method of accounting for such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents Xcel Energy from exercising a controlling influence over the operating and financial policies of the projects. Under this method, Xcel Energy records its portion of the earnings or losses of unconsolidated affiliates as equity earnings.

A summary of Xcel Energy s significant equity method investments is listed in the following table:

Name	Entity Form	Xcel Energy Owner Functions	Geographic Area	Dec. 31, 2002 Economic Interest
Loy Yang Power A	Partnership	None	Australia	25.37%
Gladstone Power Station	Joint Venture	Operator	Australia	37.50%
MIBRAG GmbH	Partnership	None	Europe	50.00%
West Coast Power	Partnership	Operator	USA	50.00%
Lanco Kondapalli Power(1)	Partnership	Operator	India	30.00%
Rocky Road Power	Partnership	Operator	USA	50.00%
Schkopau	Tenants in Common	None	Europe	41.67%
ECK Generating(1)	Partnership	Operator	Czech Republic	44.50%
Commonwealth Atlantic			USA	50.00%
Mustang	Joint Venture	None	USA	50.00%
Quixx Linden L.P.	General/ Limited Partnership	Operator	USA	50.00%
Borger Energy L.P.	General/ Limited Partnership	Operator	USA	45.00%
Various Affordable Housing Limited Partnerships	Limited Partnerships	Various	USA	20.00% 99.99%

(1) Pending disposition at Dec. 31, 2002.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table summarizes financial information for these projects, including interests owned by Xcel Energy and other parties for the years ended Dec. 31:

Results of Operations

	2002	2001	2000
	(Millions of Dollars)		
Operating revenues	$ 2,516	$ 3,583	$ 4,664
Operating income (loss)	137	442	464
Net income (loss)	111	422	447
Xcel Energy s equity earnings of unconsolidated affiliates	72	217	183

Financial Position

	2002	2001
	(Millions of Dollars)	
Current assets	$ 1,102	$ 1,478
Other assets	7,155	7,396
Total assets	$ 8,257	$ 8,874
Current liabilities	$ 1,108	$ 1,229
Other liabilities	4,087	4,841
Equity	3,062	2,804
Total liabilities and equity	$ 8,257	$ 8,874
Xcel Energy s share of undistributed retained earnings	$ 466	$ 449
Xcel Energy equity in underlying net assets	1,285	1,099
Difference other than temporary writedowns, capitalized project costs and other	(284)	98
Xcel Energy s investment in unconsolidated affiliates (per balance sheet)	$ 1,001	$ 1,197

West Coast Power In 2001, Xcel Energy had a significant investment in West Coast Power, LLC (through NRG), as defined by applicable SEC regulations, and accounts for its investments using the equity method. The following is summarized pretax financial information for West Coast Power:

Results of Operations

	2001
	(Millions of Dollars)
Operating revenues	$ 1,562
Operating income (loss)	345

Net income (loss)	326

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Position

	2001
	(Millions of Dollars)
Current assets	$ 401
Other assets	659
Total assets	$ 1,060
Current liabilities	$ 138
Other liabilities	269
Equity	653
Total liabilities and equity	$ 1,060

Yorkshire Power During February 2001, Xcel Energy reached an agreement to sell the majority of its investment in Yorkshire Power to Innogy Holdings plc. As a result of this sales agreement, Xcel Energy did not record any equity earnings from Yorkshire Power after January 2001. In April 2001, Xcel Energy closed the sale of Yorkshire Power. Xcel Energy had retained an interest of approximately 5.25-percent in Yorkshire Power to comply with pooling-of-interests accounting requirements associated with the merger of NSP and NCE in 2000. Xcel Energy received approximately $366 million for the sale, which approximated the book value of Xcel Energy s investment. On Aug. 28, 2002, Xcel Energy sold its remaining 5.25-percent interest in Yorkshire Power at slightly less than book value.

15. Extraordinary Items

SPS In the second quarter of 2000, SPS discontinued regulatory accounting under SFAS No. 71 for the generation portion of its business due to the issuance of a written order by the Public Utility Commission of Texas (PUCT) in May 2000, addressing the implementation of electric utility restructuring. SPS transmission and distribution business continued to meet the requirements of SFAS No. 71, as that business was expected to remain regulated. During the second quarter of 2000, SPS wrote off its generation-related regulatory assets and other deferred costs totaling approximately $19.3 million. This resulted in an after-tax extraordinary charge of approximately $13.7 million. During the third quarter of 2000, SPS recorded an extraordinary charge of $8.2 million before tax, or $5.3 million after tax, related to the tender offer and defeasance of first mortgage bonds. The first mortgage bonds were defeased to facilitate the legal separation of generation, transmission and distribution assets, which was expected to eventually occur in 2001 under restructuring requirements in effect in 2000.

In March 2001, the state of New Mexico enacted legislation that amended its Electric Utility Restructuring Act of 1999 and delayed customer choice until 2007. SPS has requested recovery of its costs incurred to prepare for customer choice in New Mexico. A decision on this and other matters is pending before the New Mexico Public Regulation Commission. SPS expects to receive future regulatory recovery of these costs.

In June 2001, the governor of Texas signed legislation postponing the deregulation and restructuring of SPS until at least 2007. This legislation amended the 1999 legislation, Senate Bill No. 7 (SB-7), which provided for retail electric competition beginning in Texas in January 2002. Under the amended legislation, prior PUCT orders issued in connection with the restructuring of SPS are considered null and void. In addition, under the new legislation, SPS is entitled to recover all reasonable and necessary expenditures made or incurred before Sept. 1, 2001, to comply with SB-7.

As a result of these recent legislative developments, SPS reapplied the provisions of SFAS No. 71 for its generation business during the second quarter of 2001. More than 95 percent of SPS retail electric revenues are from operations in Texas and New Mexico. Because of the delays to electric restructuring passed by

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Texas and New Mexico, SPS previous plans to implement restructuring, including the divestiture of generation assets, have been abandoned. Accordingly, SPS will now continue to be subject to rate regulation under traditional cost-of-service regulation, consistent with its past accounting and ratemaking practices for the foreseeable future, at least until 2007.

During the fourth quarter of 2001, SPS completed a $500-million, medium-term debt financing with the proceeds used to reduce short-term borrowings that had resulted from the 2000 defeasance. In its regulatory filings and communications, SPS proposed to amortize its defeasance costs over the five-year life of the refinancing, consistent with historical ratemaking, and has requested incremental rate recovery of $25 million of other restructuring costs in Texas and New Mexico. These nonfinancing restructuring costs have been deferred and are being amortized consistent with rate recovery. Based on these 2001 events, management s expectation of rate recovery of prudently incurred costs and the corresponding reduced uncertainty surrounding the financial impacts of the delay in restructuring, SPS restored certain regulatory assets totaling $17.6 million as of Dec. 31, 2001, and reported related after-tax extraordinary income of $11.8 million, or 3 cents per share. Regulatory assets previously written off in 2000 were restored only for items currently being recovered in rates and items where future rate recovery is considered probable.

PSCo During 2001, PSCo s subsidiary, 1480 Welton, Inc. redeemed its long term debt and in doing so incurred redemption premiums and other costs of $2.5 million or $1.5 million or $1.5 million after tax. These items are reported as an extraordinary item on Xcel Energy s Consolidated Statement of Operations.

16. Financial Instruments
Fair Values

The estimated Dec. 31 fair values of Xcel Energy s recorded financial instruments are:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of dollars)			
Mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000	$ 463,348	$ 494,000	$ 486,270
Long-term investments	653,208	651,443	619,976	620,703
Notes receivable, including current portion	996,167	996,167	782,079	782,079
Long-term debt, including current portion	14,306,509	12,172,059	11,948,527	11,955,741

The carrying amount of cash, cash equivalents and short-term investments approximates fair value because of the short maturity of those instruments. The fair values of Xcel Energy s long-term investments, mainly debt securities in an external nuclear decommissioning fund, are estimated based on quoted market prices for those or similar investments. The fair value of notes receivable is based on expected future cash flows discounted at market interest rates. The balance in notes receivable consists primarily of fixed rate, from 4.75 to 19.5 percent, and variable rate notes that mature between 2003 and 2024. Notes receivable include a $366-million direct financing lease related to a long-term sales agreement for NRG Energy s Schkopau project, and other notes related to projects at NRG Energy that are generally secured by equity interests in partnerships and joint ventures. The fair value of Xcel Energy s long-term debt and the mandatorily redeemable preferred securities are estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality.

The fair value estimates presented are based on information available to management as of Dec. 31, 2002 and 2001. These fair value estimates have not been comprehensively revalued for purposes of these

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Consolidated Financial Statements since that date, and current estimates of fair values may differ significantly from the amounts presented herein.

Guarantees

Xcel Energy provides various guarantees and bond indemnities supporting certain of its subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. Unless otherwise indicated below, the guarantees require no liability to be recorded, contain no recourse provisions and require no collateral. On Dec. 31, 2002, Xcel Energy had the following amount of guarantee and exposure under these guarantees:

Nature of Guarantee	Guarantor	Guarantee Amount ($ Millions)	Current Exposure ($ Millions)	Term or Expiration Date	Triggering Event Requiring Performance	Assets Held as Collateral ($ Millions)
Guarantee performance and payment of surety bonds for itself and its subsidiaries	Xcel Energy(d)	$ 342.7	$ 5.6	2003, 2004, 2005, 2007 and 2012	(b)	$10.0
Guarantee performance and payment of surety bonds for those subsidiaries	Various subsidiaries(e)	$ 493.8	$ 116.0	2003, 2004 and 2005	(b)	N/A
Guarantees made to facilitate e prime s natural gas acquisition, marketing and trading operations	Xcel Energy	$ 264.0	$ 88.0	Continuous	(a)	N/A
Guarantees for NRG liabilities associated with power marketing obligations, fuel purchasing transactions and hedging activities	Xcel Energy	$ 219.5	$ 96.3	Latest expiration is Dec. 31, 2003	(a)	N/A
Guarantee of payments of notes issued by Guardian Pipeline, LLC, of which Viking is one of three partners	Xcel Energy	$ 60	$ 60	Terminated Jan 17, 2003	(a)	N/A
Two guarantees benefiting Cheyenne to guarantee the payment obligations under gas and power purchase agreements	Xcel Energy	$ 26.5	$ 1.7	2011 and 2013	(a)	N/A
Construction contract performance guarantee of Utility Engineering subsidiaries	Xcel Energy	$ 25.0	$ 25.0	July 1, 2003	(c)	N/A

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Nature of Guarantee	Guarantor	Guarantee Amount ($ Millions)	Current Exposure ($ Millions)	Term or Expiration Date	Triggering Event Requiring Performance	Assets Held as Collateral ($ Millions)
Guarantee for obligations of a customer in connection with an electric sale agreement	SPS(f)	$ 17.7	$ 11.0	September 2003	(a)	Electric transmission system
Guarantees related to energy conservation projects in which Planergy has guaranteed certain energy savings to the customer	Xcel Energy	$ 26.7	$ 26.7	Expired Jan. 1, 2003	N/A	N/A
Guarantee for payments related to energy or financial transactions for XERS Inc., a nonregulated subsidiary of Xcel Energy	Xcel Energy	$ 11.1	$ 4.1	Continuous	(a)	N/A
Guarantee of collection of receivables sold to a third party	NSP-Minnesota	$ 6.2	$ 6.2	Latest expiration in 2007	(a)	Security interest in underlying receivable agreements
Combination of guarantees benefiting various Xcel Energy subsidiaries	Xcel Energy	$ 16.4	$ 5.4	Continuous	(a)	N/A

(a) Nonperformance and/or nonpayment

(b) Failure of Xcel Energy or one of its subsidiaries to perform under the agreement that is the subject of the relevant bond. In addition, per the indemnity agreement between Xcel Energy and the various surety companies, the surety companies have the discretion to demand that collateral be posted.

(c) Failure to meet emission compliance at relevant facility.

(d) $5.6-million exposure is related to $265 million of performance bonds associated with a single construction project in which Utility Engineering is participating. On Dec. 31, 2002 this project was 93 percent complete, and is expected to be fully complete in April 2003. An estimate of exposure for the remaining bonds cannot be determined as these are largely bonds posted for the benefit of various municipalities relating to the normal course of business activities.

(e) $116-million exposure is related to $491 million of performance bonds associated with three construction projects in which Utility Engineering is participating. An estimate of exposure for the remaining bonds cannot be determined as these are largely bonds posted for the benefit of various municipalities relating to the normal course of business activities. Xcel Energy is not obligated under these agreements.

(f) SPS would hold title to the collateral and would not be required to transfer the ownership of the additional transmission related facilities to the customer. SPS would also have access to the customer sinking fund account, which is approximately $6.7 million.

Xcel Energy may be required to provide credit enhancements in the form of cash collateral, letters of credit or other security to satisfy part or potentially all of these exposures, in the event that Standard & Poor s

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

or Moody s downgrade Xcel Energy s credit rating below investment grade. In the event of a downgrade, Xcel Energy would expect to meet its collateral obligations with a combination of cash on hand and, upon receipt of an SEC order permitting such actions, utilization of credit facilities and the issuance of securities in the capital markets.

NRG is directly liable for the obligations of certain of its project affiliates and other subsidiaries pursuant to guarantees relating to certain of their indebtedness, equity and operating obligations. In addition, in connection with the purchase and sale of fuel emission credits and power generation products to and from third parties with respect to the operation of some of NRG s generation facilities in the United States, NRG may be required to guarantee a portion of the obligations of certain of its subsidiaries. As of Dec. 31, 2002, NRG s obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries totaled approximately $374.0 million.

In addition, Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. The total amount of bonds with this indemnity outstanding as of Dec. 31, 2002, was approximately $342.7 million, of which $6.4 million relates to NRG. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total indemnification.

Fair Value of Derivative Instruments

The following discussion briefly describes the derivatives of Xcel Energy and its subsidiaries and discloses the respective fair values at Dec. 31, 2002 and 2001. For more detailed information regarding derivative financial instruments and the related risks, see Note 17 to the Consolidated Financial Statements.

Interest Rate Swaps On Dec. 31, 2002, NRG Energy had interest rate swaps outstanding with a notional amount of approximately $1.7 billion. The fair value of those swaps on Dec. 31, 2002, was a liability of approximately $41 million. Other subsidiaries of Xcel Energy also had interest rate swaps outstanding with a notional amount of approximately $100 million, and a fair value that was a liability of approximately $12 million, at Dec. 31, 2002.

As of Dec. 31, 2001, Xcel Energy had several interest rate swaps converting project financing from variable-rate debt to fixed-rate debt with a notional amount of approximately $2.5 billion. The fair value of the swaps as of Dec. 31, 2001, was a liability of approximately $92 million.

Electric Trading Operations Xcel Energy participates in the trading of electricity as a commodity. This trading includes forward contracts, futures and options. Xcel Energy makes purchases and sales at existing market points or combines purchases with available transmission to make sales at other market points. Options and hedges are used to either minimize the risks associated with market prices, or to profit from price volatility related to our purchase and sale commitments.

Beginning with the third quarter of 2002, Xcel Energy has presented the results of its electric trading activity using the net accounting method. The Consolidated Statements of Operations for 2001 and 2000 have been reclassified to be consistent. In earlier presentations, the gross accounting method was used. All financial derivative contracts and contracts that do not include physical delivery are recorded at the amount of the gain or loss received from the contract. The mark-to-market adjustments for these transactions are appropriately reported in the Consolidated Statements of Operations in Electric and Gas Trading Revenues.

Regulated Operations Xcel Energy s regulated energy marketing operation uses a combination of electricity and natural gas purchase for resale futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2002, the notional value of these contracts was approximately $(64.3) million. The fair value of these contracts as of Dec. 31, 2002, was an asset of approximately $33.3 million.

Nonregulated Operations Xcel Energy s nonregulated operations use a combination of energy futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31,

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2002, the notional value of these contracts was approximately $253.8 million. The fair value of these contracts as of Dec. 31, 2002, was an asset of approximately $69.3 million.

Foreign Currency Xcel Energy and its subsidiaries have two foreign currency swaps to hedge or protect foreign currency denominated cash flows. At Dec. 31, 2002 and 2001, the net notional amount of these contracts was approximately $3.0 million and $46.3 million, respectively. The fair value of these contracts as of Dec. 31, 2002 and 2001, was a liability of approximately $0.3 million and $2.4 million, respectively.

Letters of Credit

Xcel Energy and its subsidiaries use letters of credit, generally with terms of one or two years, to provide financial guarantees for certain operating obligations. In addition, NRG uses letters of credit for nonregulated equity commitments, collateral for credit agreements, fuel purchase and operating commitments, and bids on development projects. At Dec. 31, 2002, there were $154.6 million in letters of credit outstanding, including $110.0 million related to NRG commitments. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

17. Derivative Valuation and Financial Impacts

Use of Derivatives to Manage Risk

Business and Operational Risk Xcel Energy and its subsidiaries are exposed to commodity price risk in their generation, retail distribution and energy trading operations. In certain jurisdictions, purchased power expenses and natural gas costs are recovered on a dollar-for-dollar basis. However, in other jurisdictions, Xcel Energy and its subsidiaries are exposed to market price risk for the purchase and sale of electric energy and natural gas. In such jurisdictions, we recover purchased power expenses and natural gas costs based on fixed price limits or under established sharing mechanisms.

Commodity price risk is managed by entering into purchase and sales commitments for electric power and natural gas, long-term contracts for coal supplies and fuel oil, and derivative financial instruments. Xcel Energy s risk management policy allows us to manage the market price risk within each rate-regulated operation to the extent such exposure exists. Management is limited under the policy to enter into only transactions that manage market price risk where the rate regulation jurisdiction does not already provide for dollar-for-dollar recovery. One exception to this policy exists in which we use various physical contracts and derivative instruments to reduce the cost of natural gas and electricity we provide to our retail customers even though the regulatory jurisdiction provides dollar-for-dollar recovery of actual costs. In these instances, the use of derivative instruments and physical contracts is done consistently with the local jurisdictional cost recovery mechanism.

Xcel Energy and its subsidiaries are exposed to market price risk for the sale of electric energy and the purchase of fuel resources, including coal, natural gas and fuel oil used to generate the electric energy within its nonregulated operations. Xcel Energy manages this market price risk by entering into firm power sales agreements for approximately 55 to 75 percent of its electric capacity and energy from each generation facility, using contracts with terms ranging from one to 25 years. In addition, we manage the market price risk covering the fuel resource requirements to provide the electric energy by entering into purchase commitments and derivative instruments for coal, natural gas and fuel oil as needed to meet fixed-priced electric energy requirements. Xcel Energy s risk management policy allows us to manage the market price risks and provides guidelines for the level of price risk exposure that is acceptable within our operations.

Xcel Energy is exposed to market price risk for the sale of electric energy and the purchase of fuel resources used to generate the electric energy from our equity method investments that own electric operations. Xcel Energy manages this market price risk through our involvement with the management committee or board of directors of each of these ventures. Our risk management policy does not cover the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

activities conducted by the ventures. However, other policies are adopted by the ventures as necessary and mandated by the equity owners.

Interest Rate Risk Xcel Energy and its subsidiaries are exposed to fluctuations in interest rates where we enter into variable rate debt obligations to fund certain power projects being developed or purchased. Exposure to interest rate fluctuations may be mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to the volatility of cash flows for interest and result in primarily fixed-rate debt obligations when taking into account the combination of the variable rate debt and the interest rate derivative instrument. Xcel Energy s risk management policy allows us to reduce interest rate exposure from variable rate debt obligations.

Currency Exchange Risk Xcel Energy and its subsidiaries have certain investments in foreign countries exposing us to foreign currency exchange risk. The foreign currency exchange risk includes the risk relative to the recovery of our net investment in a project, as well as the risk relative to the earnings and cash flows generated from such operations. Xcel Energy manages its exposure to changes in foreign currency by entering into derivative instruments as determined by management. Our risk management policy provides for this risk management activity.

Trading Risk Xcel Energy and its subsidiaries conduct various trading operations and power marketing activities, including the purchase and sale of electric capacity and energy and natural gas. The trading operations are conducted both in the United States and Europe with primary focus on specific market regions where trading knowledge and experience have been obtained. Xcel Energy s risk management policy allows management to conduct the trading activity within approved guidelines and limitations as approved by our risk management committee made up of management personnel not involved in the trading operations.

Derivatives as Hedges

2001 Accounting Change On Jan. 1, 2001, Xcel Energy and its subsidiaries adopted SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities. This statement requires that all derivative instruments as defined by SFAS No. 133 be recorded on the balance sheet at fair value unless exempted. Changes in a derivative instrument s fair value must be recognized currently in earnings unless the derivative has been designated in a qualifying hedging relationship. The application of hedge accounting allows a derivative instrument s gains and losses to offset related results of the hedged item in the statement of operations, to the extent effective. SFAS No. 133 requires that the hedging relationship be highly effective and that a company formally designate a hedging relationship to apply hedge accounting.

A fair value hedge requires that the effective portion of the change in the fair value of a derivative instrument be offset against the change in the fair value of the underlying asset, liability or firm commitment being hedged. That is, fair value hedge accounting allows the offsetting gain or loss on the hedged item to be reported in an earlier period to offset the gain or loss on the derivative instrument. A cash flow hedge requires that the effective portion of the change in the fair value of a derivative instrument be recognized in Other Comprehensive Income, and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. The ineffective portion of a derivative instrument s change in fair value is recognized currently in earnings.

Xcel Energy and its subsidiaries formally document hedge relationships, including, among other things, the identification of the hedging instrument and the hedged transaction, as well as the risk management objectives and strategies for undertaking the hedged transaction. Derivatives are recorded in the balance sheet at fair value. Xcel Energy and its subsidiaries also formally assess, both at inception and at least quarterly thereafter, whether the derivative instruments being used are highly effective in offsetting changes in either the fair value or cash flows of the hedged items.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Impacts of Derivatives

The impact of the components of SFAS No. 133 on Xcel Energy s Other Comprehensive Income, included in Stockholders Equity, are detailed in the following table:

	(Millions of Dollars)
Net unrealized transition loss at adoption, Jan. 1, 2001	$ (28.8)
After-tax net unrealized gains related to derivatives accounted for as hedges	43.6
After-tax net realized losses on derivative transactions reclassified into earnings	19.4
Accumulated other comprehensive income related to SFAS No. 133 at Dec. 31, 2001	$ 34.2
After-tax net unrealized losses related to derivatives accounted for as hedges	(68.3)
After-tax net realized losses on derivative transactions reclassified into earnings	28.8
Acquisition of NRG minority interest	27.4
Accumulated other comprehensive income related to SFAS No. 133 at Dec. 31, 2002	$ 22.1

Xcel Energy records the fair value of its derivative instruments in its Consolidated Balance Sheet as a separate line item noted as Derivative Instruments Valuation for assets and liabilities, as well as current and noncurrent.

Cash Flow Hedges Xcel Energy and its subsidiaries enter into derivative instruments to manage exposure to changes in commodity prices. These derivative instruments take the form of fixed-price, floating-price or index sales, or purchases and options, such as puts, calls and swaps. These derivative instruments are designated as cash flow hedges for accounting purposes, and the changes in the fair value of these instruments are recorded as a component of Other Comprehensive Income. At Dec. 31, 2002, Xcel Energy had various commodity-related contracts extending through 2018. Amounts deferred in Other Comprehensive Income are recorded as the hedged purchase or sales transaction is completed. This could include the physical sale of electric energy or the use of natural gas to generate electric energy. Xcel Energy expects to reclassify into earnings during 2003 net gains from Other Comprehensive Income of approximately $12.9 million.

Xcel Energy and its subsidiaries enter into interest rate swap instruments that effectively fix the interest payments on certain floating rate debt obligations. These derivative instruments are designated as cash flow hedges for accounting purposes, and the change in the fair value of these instruments is recorded as a component of Other Comprehensive Income. Xcel Energy expects to reclassify into earnings during 2003 net losses from Other Comprehensive Income of approximately $13.4 million.

Hedge effectiveness is recorded based on the nature of the item being hedged. Hedging transactions for the sales of electric energy are recorded as a component of revenue, hedging transactions for fuel used in energy generation are recorded as a component of fuel costs, and hedging transactions for interest rate swaps is recorded as a component of interest expense.

Hedges of Foreign Currency Exposure of a Net Investment in Foreign Operations To preserve the U.S. dollar value of projected foreign currency cash flows, Xcel Energy, through NRG, may hedge, or protect those cash flows if appropriate foreign hedging instruments are available.

Derivatives Not Qualifying for Hedge Accounting Xcel Energy and its subsidiaries have trading operations that enter into derivative instruments. These derivative instruments are accounted for on a mark-to-market basis in the Consolidated Statements of Operations. All derivative instruments are recorded at the amount of the gain or loss from the transaction within Operating Revenues on the Consolidated Statements of Operations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Normal Purchases or Normal Sales Xcel Energy and its subsidiaries enter into fixed-price contracts for the purchase and sale of various commodities for use in its business operations. SFAS No. 133 requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that literally meet the definition of a derivative may be exempted from SFAS No. 133 as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial instrument or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that meet the requirements of normal are documented as normal and exempted from the accounting and reporting requirements of SFAS No. 133.

Xcel Energy evaluates all of its contracts within the regulated and nonregulated operations when such contracts are entered to determine if they are derivatives and if so, if they qualify and meet the normal designation requirements under SFAS No. 133. None of the contracts entered into within the trading operation are considered normal.

Normal purchases and normal sales contracts are accounted for as executory contracts as required under other generally accepted accounting principles.

18. Commitments and Contingencies

Commitments

Legislative Resource Commitments In 1994, NSP-Minnesota received Minnesota legislative approval for additional on-site temporary spent fuel storage facilities at its Prairie Island nuclear power plant, provided NSP-Minnesota satisfies certain requirements. Seventeen dry cask containers were approved. As of Dec. 31, 2002, NSP-Minnesota had loaded 17 of the containers. The Minnesota Legislature established several energy resource and other commitments for NSP-Minnesota to obtain the Prairie Island temporary nuclear fuel storage facility approval. These commitments can be met by building, purchasing or, in the case of biomass, converting generation resources.

Other commitments established by the Legislature included a discount for low-income electric customers, required conservation improvement expenditures and various study and reporting requirements to a legislative electric energy task force. NSP-Minnesota has implemented programs to meet the legislative commitments. NSP-Minnesota s capital commitments include the known effects of the Prairie Island legislation. The impact of the legislation on future power purchase commitments and other operating expenses is not yet determinable.

See additional discussion of the current operating contingency related to the spent fuel storage facilities under Operating Contingency.

Capital Commitments As discussed in Liquidity and Capital Resources under Management s Discussion and Analysis, the estimated cost, as of Dec. 31, 2002, of the capital expenditure programs of Xcel Energy and its subsidiaries and other capital requirements is approximately $1.5 billion in 2003, $1.2 billion in 2004 and $1.3 billion in 2005.

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting Xcel Energy s long-term energy needs. In addition, Xcel Energy s ongoing evaluation of merger, acquisition and divestiture opportunities to support corporate strategies, address restructuring requirements and comply with future requirements to install emission-control equipment may impact actual capital requirements.

Support and Capital Subscription Agreement In May 2002, Xcel Energy and NRG entered into a support and capital subscription agreement pursuant to which Xcel Energy agreed under certain circum-

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

stances to provide up to $300 million to NRG. Xcel Energy has not to date provided funds to NRG under this agreement. However, Xcel Energy is willing to make a contribution of $300 million if the restructuring plan discussed earlier is approved by the creditors. See additional discussion of NRG restructuring at Note 4.

Leases Our subsidiaries lease a variety of equipment and facilities used in the normal course of business. Some of these leases qualify as capital leases and are accounted for accordingly. The capital leases expire between 2002 and 2025. The net book value of property under capital leases was approximately $624 million and $605 million at Dec. 31, 2002 and 2001, respectively. Assets acquired under capital leases are recorded as property at the lower of fair-market value or the present value of future lease payments and are amortized over their actual contract term in accordance with practices allowed by regulators. The related obligation is classified as long-term debt. Executory costs are excluded from the minimum lease payments.

The remainder of the leases, primarily real estate leases and leases of coal-hauling railcars, trucks, cars and power-operated equipment are accounted for as operating leases. Rental expense under operating lease obligations was approximately $86 million, $58 million and $56 million for 2002, 2001 and 2000, respectively.

Future commitments under operating and capital leases are:

	Operating Leases	Capital Leases
	(Millions of dollars)	
2003	$ 66	$ 83
2004	64	80
2005	61	78
2006	58	75
2007	51	73
Thereafter	86	1,030
Total minimum obligation		$ 1,419
Interest		(795)
Present value of minimum obligation		$ 624

Technology Agreement We have a contract that extends through 2011 with International Business Machines Corp. (IBM) for information technology services. The contract is cancelable at our option, although there are financial penalties for early termination. In 2002, we paid IBM $131.9 million under the contract and $26 million for other project business. The contract also commits us to pay a minimum amount each year from 2002 through 2011.

Fuel Contracts Xcel Energy has contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. These contracts expire in various years between 2003 and 2025. In total, Xcel Energy is committed to the minimum purchase of approximately $2.3 billion of coal, $122.2 million of nuclear fuel and $1.6 billion of natural gas including $1.2 billion of natural gas storage and transportation, or to make payments in lieu thereof, under these contracts. In addition, Xcel Energy is required to pay additional amounts depending on actual quantities shipped under these agreements. Xcel Energy s risk of loss, in the form of increased costs, from market price changes in fuel is mitigated through the cost-of-energy adjustment provision of the ratemaking process, which provides for recovery of most fuel costs.

Purchased Power Agreements The utility and nonregulated subsidiaries of Xcel Energy have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. NSP-Minnesota, PSCo, SPS and certain nonregulated subsidiaries have various pay-for-performance contracts with expiration dates through the year 2050. In general, these contracts provide for capacity payments, subject to meeting certain contract obligations, and energy payments based on

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actual power taken under the contracts. Most of the capacity and energy costs are recovered through base rates and other cost-recovery mechanisms.

NSP-Minnesota has a 500-megawatt participation power purchase commitment with Manitoba Hydro, which expires in 2005. The cost of this agreement is based on 80 percent of the costs of owning and operating NSP-Minnesota s Sherco 3 generating plant, adjusted to 1993 dollars. This agreement was extended through a new agreement during 2002 to include the period starting May 2005 through April 2015. The cost of the agreement for this extended period is based on a base price, which was established from May 2001 through April 2002 and will be escalated by the change in the United States Gross National Product to reflect the current year. In addition, NSP-Minnesota and Manitoba Hydro have seasonal diversity exchange agreements, and there are no capacity payments for the diversity exchanges. These commitments represent about 17 percent of Manitoba Hydro s system capacity and account for approximately 9 percent of NSP-Minnesota s 2002 electric system capability. The risk of loss from nonperformance by Manitoba Hydro is not considered significant, and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

At Dec. 31, 2002, the estimated future payments for capacity that the utility and nonregulated subsidiaries of Xcel Energy are obligated to purchase, subject to availability, are as follows:

	Total (Thousands of dollars)
2003	$ 528,978
2004	548,173
2005	549,261
2006	540,245
2007 and thereafter	5,067,551
Total	$ 7,234,208

Environmental Contingencies

We are subject to regulations covering air and water quality, land use, the storage of natural gas and the storage and disposal of hazardous or toxic wastes. We continuously assess our compliance. Regulations, interpretations and enforcement policies can change, which may impact the cost of building and operating our facilities. This includes NRG, which is subject to regional, federal and international environmental regulation.

Site Remediation We must pay all or a portion of the cost to remediate sites where past activities of our subsidiaries and some other parties have caused environmental contamination. At Dec. 31, 2002, there were three categories of sites:

third-party sites, such as landfills, to which we are alleged to be a potentially responsible party (PRP) that sent hazardous materials and wastes;

the site of a former federal uranium enrichment facility; and

sites of former manufactured gas plants (MGPs) operated by our subsidiaries or predecessors.

We record a liability when we have enough information to develop an estimate of the cost of environmental remediation and revise the estimate as information is received. The estimated remediation cost may vary materially.

To estimate the cost to remediate these sites, we may have to make assumptions when facts are not fully known. For instance, we might make assumptions about the nature and extent of site contamination, the extent of required cleanup efforts, costs of alternative cleanup methods and pollution-control technologies, the

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

period over which remediation will be performed and paid for, changes in environmental remediation and pollution-control requirements, the potential effect of technological improvements, the number and financial strength of other PRPs and the identification of new environmental cleanup sites.

We revise our estimates as facts become known but, at Dec. 31, 2002, our liability for the cost of remediating sites, including NRG, for which an estimate was possible was $49 million, of which $11 million was considered to be a current liability. Some of the cost of remediation may be recovered from:

- insurance coverage;
- other parties that have contributed to the contamination; and
- customers.

Neither the total remediation cost nor the final method of cost allocation among all PRPs of the unremediated sites has been determined. We have recorded estimates of our share of future costs for these sites. We are not aware of any other parties inability to pay, nor do we know if responsibility for any of the sites is in dispute.

Approximately $15 million of the long-term liability and $4 million of the current liability relate to a U.S. Department of Energy assessment to NSP-Minnesota and PSCo for decommissioning a federal uranium enrichment facility. These environmental liabilities do not include accruals recorded and collected from customers in rates for future nuclear fuel disposal costs or decommissioning costs related to NSP-Minnesota s nuclear generating plants. See Note 19 to the Consolidated Financial Statements for further discussion of nuclear obligations.

Ashland MGP Site NSP-Wisconsin was named as one of three PRPs for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland site includes property owned by NSP-Wisconsin and two other properties: an adjacent city lakeshore park area and a small area of Lake Superior s Chequemegon Bay adjoining the park.

The Wisconsin Department of Natural Resources (WDNR) and NSP-Wisconsin have each developed several estimates of the ultimate cost to remediate the Ashland site. The estimates vary significantly, between $4 million and $93 million, because different methods of remediation and different results are assumed in each. The Environmental Protection Agency (EPA) and WDNR have not yet selected the method of remediation to use at the site. Until the EPA and the WDNR select a remediation strategy for all operable units at the site and determine the level of responsibility of each PRP, we are not able to accurately determine our share of the ultimate cost of remediating the Ashland site.

In the interim, NSP-Wisconsin has recorded a liability of $19 million for its estimate of its share of the cost of remediating the portion of the Ashland site that it owns, using information available to date and reasonably effective remedial methods. NSP-Wisconsin has deferred, as a regulatory asset, the remediation costs accrued for the Ashland site because we expect that the Public Service Commission of Wisconsin (PSCW) will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site, and has authorized recovery of similar remediation costs for other Wisconsin utilities.

As an interim action, Xcel Energy proposed, and the EPA and WDNR have approved, a coal tar removal/groundwater treatment system for one operable unit at the site for which NSP-Wisconsin has accepted responsibility. The groundwater treatment system began operating in the fall of 2000. In 2002, NSP-Wisconsin installed additional monitoring wells in the deep aquifer to better characterize the extent and degree of contaminants in that aquifer while the coal tar removal system is operational. In 2002, a second interim response action was also implemented. As approved by the WDNR, this interim response action involved the removal and capping of a seep area in a city park. Surface soils in the area of the seep were

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

contaminated with tar residues. The interim action also included the diversion and ongoing treatment of groundwater that contributed to the formation of the seep.

On Sept. 5, 2002, the Ashland site was placed on the National Priorities List (NPL). The NPL is intended primarily to guide the EPA in determining which sites require further investigation. Resolution of Ashland remediation issues is not expected until 2004 or 2005.

NSP-Wisconsin continues to work with the WDNR to access state and federal funds to apply to the ultimate remediation cost of the entire site.

Other MGP Sites NSP-Minnesota has investigated and remediated MGP sites in Minnesota and North Dakota. The MPUC allowed NSP-Minnesota to defer, rather than immediately expense, certain remediation costs of four active remediation sites in 1994. This deferral accounting treatment may be used to accumulate costs that regulators might allow us to recover from our customers. The costs are deferred as a regulatory asset until recovery is approved, and then the regulatory asset is expensed over the same period as the regulators have allowed us to collect the related revenue from our customers. In September 1998, the MPUC allowed the recovery of a portion of these MGP site remediation costs in natural gas rates. Accordingly, NSP-Minnesota has been amortizing the related deferred remediation costs to expense. In 2001, the North Dakota Public Service Commission allowed the recovery of part of the cost of remediating another former MGP site in Grand Forks, N.D. The $2.9-million recovered cost of remediating that site was accumulated in a regulatory asset that is now being expensed evenly over eight years. NSP-Minnesota may request recovery of costs to remediate other sites following the completion of preliminary investigations.

NRG Site Remediation As part of acquiring existing generating assets, NRG has acquired certain environmental liabilities associated with regulatory compliance and site contamination. Often, potential compliance implementation plans are changed, delayed or abandoned due to one or more of the following conditions: (a) extended negotiations with regulatory agencies, (b) a delay in promulgating rules critical to dictating the design of expensive control systems, (c) changes in governmental/regulatory personnel, (d) changes in governmental priorities or (e) selection of a less expensive compliance option than originally envisioned.

In response to liabilities associated with these activities, NRG has established accruals where reasonable estimates of probable liabilities are possible. As of Dec. 31, 2002 and 2001, NRG has established such accruals in the amount of approximately $3.8 million and $5.0 million, respectively, primarily related to its Northeast region facilities. NRG has not used discounting in determining its accrued liabilities for environmental remediation and no claims for possible recovery from third party issuers or other parties related to environmental costs have been recognized in NRG s consolidated financial statements. NRG adjusts the accruals when new remediation responsibilities are discovered and probable costs become estimable, or when current remediation estimates are adjusted to reflect new information. During the years ended Dec. 31, 2002, 2001 and 2000, NRG recorded expenses of approximately $10.9 million, $15.3 million and $3.4 million related to environmental matters, respectively.

Asbestos Removal Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Since we intend to operate most of these facilities indefinitely, we cannot estimate the amount or timing of payments for its final removal. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Leyden Gas Storage Facility In February 2001, the CPUC granted PSCo s application to abandon the Leyden natural gas storage facility (Leyden) after 40 years of operation. In July 2001, the CPUC decided that the recovery of all Leyden costs would be addressed in a future rate proceeding when all costs were known. Since late 2001, PSCo has operated the facility to withdraw the recoverable gas in inventory. Beginning in 2003, PSCo will start to flood the facility with water, as part of an overall plan to convert Leyden

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into a municipal water storage facility owned and operated by the city of Arvada, Colo. As of Dec. 31, 2002, PSCo has deferred approximately $4.5 million of costs associated with engineering buffer studies, damage claims paid to landowners and other closure costs. PSCo expects to incur an additional $6 million to $8 million of costs through 2005 to complete the decommissioning and closure of the facility. PSCo believes that these costs will be recovered through future rates. Any costs that are not recoverable from customers will be expensed.

PSCo Notice of Violation On Nov. 3, 1999, the United States Department of Justice filed suit against a number of electric utilities for alleged violations of the Clean Air Act s New Source Review (NSR) requirements related to alleged modifications of electric generating stations located in the South and Midwest. Subsequently, the U.S. Environmental Protection Agency (EPA) also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities, including Xcel Energy, seeking to determine whether these utilities engaged in activities that may have been in violation of the NSR requirements. In 2001, Xcel Energy responded to EPA s initial information requests related to PSCo plants in Colorado.

On July 1, 2002, Xcel Energy received a Notice of Violation (NOV) from the EPA alleging violations of the NSR requirements of the Clean Air Act at the Comanche and Pawnee Stations in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid- to late-1990s should have required a permit under the NSR process. Xcel Energy believes it acted in full compliance with the Clean Air Act and NSR process. It believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. Xcel Energy also believes that the projects would be expressly authorized under the EPA s NSR policy announced by the EPA administrator on June 22, 2002, and proposed in the Federal Register on Dec. 31, 2002. Xcel Energy disagrees with the assertions contained in the NOV and intends to vigorously defend its position. As required by the Clean Air Act, the EPA met with Xcel Energy in September 2002 to discuss the NOV.

If the EPA is successful in any subsequent litigation regarding the issues set forth in the NOV or any matter arising as a result of its information requests, it could require Xcel Energy to install additional emission-control equipment at the facilities and pay civil penalties. Civil penalties are limited to not more than $25,000 to $27,500 per day for each violation, commencing from the date the violation began. The ultimate financial impact to Xcel Energy is not determinable at this time.

NSP-Minnesota NSR Information Request As stated previously, on Nov. 3, 1999, the United States Department of Justice filed suit against a number of electric utilities for alleged violations of the Clean Air Act s NSR requirements related to alleged modifications of electric generating stations located in the South and Midwest. Subsequently, the EPA also issued requests for information pursuant to the Clean Air Act to numerous other electric utilities, including Xcel Energy, seeking to determine whether these utilities engaged in activities that may have been in violation of the NSR requirements. In 2001, Xcel Energy responded to the EPA s initial information requests related to NSP-Minnesota plants in Minnesota. On May 22, 2002, the EPA issued a follow-up information request to Xcel Energy seeking additional information regarding NSR compliance at its plants in Minnesota. Xcel Energy completed its response to the follow-up information request during the fall of 2002.

NSP-Minnesota Notice of Violation On Dec. 10, 2001, the Minnesota Pollution Control Agency issued a notice of violation to NSP-Minnesota alleging air quality violations related to the replacement of a coal conveyor and violations of an opacity limitation at the A.S. King generating plant. NSP-Minnesota has responded to the notice of violation and is working to resolve the allegations.

Nuclear Insurance NSP-Minnesota s public liability for claims resulting from any nuclear incident is limited to $9.4 billion under the 1988 Price-Anderson amendment to the Atomic Energy Act of 1954. NSP-Minnesota has secured $200 million of coverage for its public liability exposure with a pool of insurance companies. The remaining $9.2 billion of exposure is funded by the Secondary Financial Protection Program,

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available from assessments by the federal government in case of a nuclear accident. NSP-Minnesota is subject to assessments of up to $88 million for each of its three licensed reactors to be applied for public liability arising from a nuclear incident at any licensed nuclear facility in the United States. The maximum funding requirement is $10 million per reactor during any one year.

NSP-Minnesota purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Ltd. (NEIL). The coverage limits are $1.5 billion for each of NSP-Minnesota s two nuclear plant sites. NEIL also provides business interruption insurance coverage, including the cost of replacement power obtained during certain prolonged accidental outages of nuclear generating units. Premiums are expensed over the policy term. All companies insured with NEIL are subject to retroactive premium adjustments if losses exceed accumulated reserve funds. Capital has been accumulated in the reserve funds of NEIL to the extent that NSP-Minnesota would have no exposure for retroactive premium assessments in case of a single incident under the business interruption and the property damage insurance coverage. However, in each calendar year, NSP-Minnesota could be subject to maximum assessments of approximately $7.5 million for business interruption insurance and $21.6 million for property damage insurance if losses exceed accumulated reserve funds.

Louisiana Generating Pointe Coupee On Dec. 2, 2002, a petition was filed to appeal the EPA s approval of the Louisiana Department of Environmental Quality s (LDEQ) revisions to the state implementation plan (SIP) regarding emissions regulations. Pointe Coupee and NRG s subsidiary, Louisiana Generating, object to the permitting requirements regarding nitrogen oxides (NOx) sources requiring the LDEQ to obtain offsets of major increases in emissions of NOx associated with major modifications of existing facilities or construction of new facilities areas, including Pointe Coupee Parish. The plaintiffs challenge is based on LDEQ s failure to comply with requirements related to rulemaking and the EPA s regulations, which prohibit EPA from approving a SIP not prepared in accordance with state law. The court granted a 60-day stay of this proceeding on Feb. 25, 2003 to allow the parties to conduct settlement discussions. At this time, NRG is unable to predict the eventual outcome of this matter or any potential loss contingencies.

Louisiana Generating New Construction Air Permits During 2000, the LDEQ issued an air permit modification to Louisiana Generating to construct and operate two 240-megawatt, natural gas-fired turbines. The permit set emissions limits for certain air pollutants, including NOx. The limitation for NOx was based on the guarantees of the manufacturer, Siemens Westinghouse Power Corporation (Siemens). Louisiana Generating sought an interim emissions limit to allow Siemens time to install additional control equipment. To establish the interim limit, LDEQ issued an order and Notice of Potential Penalty in September 2002, which is, in part, subject to a hearing. LDEQ alleged that Louisiana Generating did not meet its NOx emissions limit on certain days, did not conduct all opacity monitoring and did not complete all record keeping and certification requirements. Louisiana Generating intends to vigorously defend certain claims and any future penalty assessment, while also seeking an amendment of its limit for NOx. An initial status conference has been held with the administrative law judge, and quarterly reports will be submitted to describe progress, including settlement and amendment of the limit. In addition, NRG may assert breach of warranty claims against the manufacturer. With respect to the administrative action described above, at this time NRG is unable to predict the eventual outcome of this matter or the potential loss contingencies, if any, to which NRG may be subject.

Legal Contingencies

In the normal course of business, Xcel Energy is a party to routine claims and litigation arising from prior and current operations. Xcel Energy is actively defending these matters and has recorded an estimate of the probable cost of settlement or other disposition.

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The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on Xcel Energy s financial position and results of operations.

St. Cloud Gas Explosion On Dec. 11, 1998, a natural gas explosion in St. Cloud, Minn., killed four people, including two NSP-Minnesota employees, injured approximately 14 people and damaged several buildings. The accident occurred as a crew from Cable Constructors Inc. (CCI) was installing fiber-optic cable for Seren. Seren, CCI and Sirti, an architecture/engineering firm retained by Seren, are named as defendants in 24 lawsuits relating to the explosion. NSP-Minnesota, Seren s parent company at the time, is a defendant in 21 of the lawsuits. In addition to compensatory damages, plaintiffs are seeking punitive damages against CCI and Seren. NSP-Minnesota and Seren deny any liability for this accident. On July 11, 2000, the National Transportation Safety Board issued a report, which determined that CCI s inadequate installation procedures and delay in reporting the natural gas hit were the proximate causes of the accident. NSP-Minnesota has a self-insured retention deductible of $2 million with general liability coverage limits of $185 million. Seren s primary insurance coverage is $1 million and its secondary insurance coverage is $185 million. The ultimate cost to Xcel Energy, NSP-Minnesota and Seren, if any, is presently unknown.

California Litigation NRG and other power generators and power traders have been named as defendants in a multi-district litigation proceeding. These cases were all filed in late 2000 and 2001 in various state courts throughout California. They allege unfair competition, market manipulation, and price fixing. All the cases were removed to the appropriate United States District Courts, and were thereafter made the subject of a petition to the multi-district litigation panel. The cases were ultimately assigned to Judge Whaley. In December 2002, Judge Whaley issued an opinion finding that federal jurisdiction was absent in the district court, and remanded the cases to state court. On Feb. 20, 2003, however, the Ninth Circuit stayed the remand order and accepted jurisdiction to hear an appeal of the remand order. NRG anticipates that filed-rate/federal preemption pleading challenges will once again be filed once the remand appeal is decided. A notice of bankruptcy filing regarding NRG has also been filed in this action, providing notice of the involuntary petition.

Although the complaints contain a number of allegations, the basic claim is that, by underbidding forward contracts and exporting electricity to surrounding markets, the defendants, acting in collusion, were able to drive up wholesale prices on the Real Time and Replacement Reserve markets, through the Western Coordinating Council and otherwise. The complaints allege that the conduct violated California antitrust and unfair competition laws. NRG does not believe that it has engaged in any illegal activities, and intends to vigorously defend these lawsuits. These six civil actions brought against NRG and other power generators and power traders in California have been consolidated in the San Diego County Superior Court, and the plaintiffs in these six consolidated civil actions filed a master amended complaint reiterating the allegations contained in their complaints and alleging that the defendants anti-competitive conduct damaged the general public and class members in an amount in excess of $1.0 billion. Two of the defendants in these actions, Reliant and Duke, subsequently filed cross-complaints naming additional market participants, some of whom removed the actions to the United States District Court for the Southern District of California federal court. Now under advisement in that court is the plaintiffs motion to remand the cases to state court and motions by the cross-defendants to dismiss the cases against them.

In addition, Public Utility District No. 1 of Snohomish County, Washington, has filed a suit against NRG, Xcel Energy and several other market participants in United States District Court for the Central District of California contending that some of its trading strategies, as reported to the FERC in response to that agency s investigation of trading strategies discussed above, violated the California Business and Professions Code. Public Utility District No. 1 of Snohomish County contends that the effect of those strategies was to increase amounts that it paid for wholesale power in the spot market in the Pacific Northwest. Judge Whaley granted a motion to dismiss on the grounds of federal preemption and filed-rate doctrine, which the plaintiffs have appealed.

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Separate class action lawsuits alleging unfair competition similar to those filed in California, as discussed previously, have bee filed in Oregon and Washington. These lawsuits have named both Xcel Energy and NRG as respondents.

California Attorney General In addition to the litigation described above, the California Attorney General has undertaken an investigation into actions affecting electricity prices in California. In connection with this investigation, the Attorney General has issued subpoenas and requested other information from Dynegy and NRG. NRG responded to the interrogatories as requested. Management cannot make any evaluation of the likelihood of an unfavorable outcome or an estimate of the amount or range of potential loss in the above-referenced private actions at this time. NRG knows of no evidence implicating NRG Energy in plaintiffs allegations of collusion.

FirstEnergy Arbitration Claim In August 2002, FirstEnergy terminated the purchase agreements pursuant to which NRG had agreed to purchase four generating stations for approximately $1.5 billion. FirstEnergy s cited rationale for terminating the agreements was an alleged anticipatory breach by NRG. FirstEnergy notified NRG that it is reserving the right to pursue legal action against NRG and us for damages. On Feb. 21, 2003, FirstEnergy submitted filings with the United States Bankruptcy Court in Minnesota seeking permission to file a demand for arbitration against NRG. On Feb. 26, 2002, FirstEnergy commenced the arbitration proceedings against NRG, but have yet to quantify their damage claim. NRG cannot presently predict the outcome of this dispute.

General Electric Company and Siemens Westinghouse Turbine Purchase Disputes NRG and/or its affiliates have entered into several turbine purchase agreements with affiliates of General Electric Company (GE) and Siemens. GE and Siemens have notified NRG that it is in default under certain of those contracts, terminated such contracts, and demanded that NRG pay the termination fees set forth in such contracts. GE s claim amounts to $120 million and Siemens approximately $45 million in cumulative termination charges. NRG has recorded a liability for the amounts they believe they owe under the contracts and termination provisions. NRG cannot estimate the likelihood of unfavorable outcomes in these disputes.

Fortistar Litigation On Feb. 26, 2003, Fortistar Capital, Inc. and Fortistar Methane, LLC filed a $1-billion lawsuit in the Federal District Court for the Northern District of New York against Xcel Energy Inc. and five former NRG Energy, Inc. (NRG) or NEO Corp. employees. In the lawsuit, Fortistar claims that the defendants violated the Racketeer Influenced and Corrupt Organizations Act (RICO) and committed fraud by engaging in a pattern of negotiating and executing agreements they intended not to comply with and made false statements later to conceal their fraudulent promises. The allegations against Xcel Energy are, for the most part, limited to purported activities related to the contract for the Pike Energy power facility in Mississippi and statements related to an equity infusion into NRG by Xcel Energy. The plaintiffs allege damages of some $350 million and also assert entitlement to a trebling of these damages under the provisions of the RICO. The present and former NRG and NEO officers and employees have requested indemnity from NRG, which requests NRG is now examining. Xcel Energy cannot at this time estimate the likelihood of an unfavorable outcome to the defendants in this lawsuit.

Itiquira Energetica NRG s indirectly controlled Brazilian project company, Itiquira Energetica S.A., the owner of a 156-megawatt hydro project in Brazil, is currently in arbitration with a former contractor for the project, Inepar Industria e Construcoes (Inepar). The dispute was commenced by Itiquira in September, 2002 and pertains to certain matters arising under the agreement with the contractor. Itiquira principally asserts that Inepar breached the contract and caused damages to Itiquira by (i) failing to meet milestones for substantial completion; (ii) failing to provide adequate resources to meet such milestones; (iii) failing to pay subcontractors amounts due; and (iv) being insolvent. Itiquira s arbitration claim is for approximately $40 million. Inepar has asserted in the arbitration that Itiquira breached the contact and caused damages to Inepar by failing to recognize events of force majeure as grounds for excused delay and extensions of scope of services and material under the contract. Inepar s damage claim is for approximately $10 million. On Nov. 12, 2002, Inepar submitted its affirmative statement of claim, and Itiquira submitted its response and

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statement of counterclaims on Dec. 14, 2002. Inepar replied to Itiquira s response and counterclaims on Jan. 14, 2003. Itiquira was to submit its reply on March 14, 2003, and a hearing was held on March 21, 2003. NRG cannot estimate the likelihood of an unfavorable outcome in this dispute.

NRG Bankruptcy On Oct. 17, 2002, a petition commencing an involuntary bankruptcy proceeding pursuant to Chapter 7 of the Bankruptcy Code was filed against LSP-Pike Energy, LLC, a subsidiary of NRG, by Stone & Webster, Inc. and Shaw Constructors, Inc., the joining petitioners in the Minnesota involuntary case described above, in the United States Bankruptcy Court for the Southern District of Mississippi. In their petition, the joining petitioners sought recovery of allegedly unpaid contractual construction-related obligations in an aggregate amount of $74 million, which amount LSP-Pike Energy, LLC has disputed. LSP-Pike Energy, LLC filed an answer to the petition in the Mississippi involuntary case and served various interrogatory and deposition discovery requests on the joining petitioners. The Mississippi Bankruptcy Court has not entered any order for relief in the Mississippi involuntary case.

On Nov. 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG in the United States Bankruptcy Court for the District of Minnesota (Minnesota bankruptcy Court). Under provisions of federal law, NRG has the full authority to continue to operate its business as if the involuntary petition had not been filed unless and until a court hearing on the validity of the involuntary petition is resolved adversely to NRG. NRG responded to the involuntary petition, contesting the petitioners claims and filing a motion to dismiss the case. A hearing has been set for April 10, 2003 to consider the motion to dismiss. In their petition, the petitioners sought recover of severance and other benefits of approximately $28 million.

NRG and its counsel have been involved in negotiations with the petitioners and their counsel. As a result of these negotiations, NRG and the petitioners reached an agreement and compromise regarding their respective claims against each other (Settlement Agreement). In February 2003, the settlement agreement was executed, pursuant to which NRG agreed to pay the petitioners an aggregate settlement in the amount of $12 million.

On Feb. 28, 2003, Stone & Webster, Inc. and Shaw Constructors, Inc. filed a petition alleging that they hold unsecured, non-contingent claims against NRG in a joint amount of $100 million. The Minnesota Bankruptcy Court has discretion in reviewing and ruling on the motion to dismiss and the review and approval of the Settlement Agreement. There is a risk that the Minnesota Bankruptcy Court may, among other things, reject the Settlement Agreement or enter an order for relief under Chapter 11 of Title 11 of the Bankruptcy Code.

See Note 4 for additional discussion of possible NRG bankruptcy.

NRG Energy, Inc. Shareholder Litigation (Delaware); Rosenfeld v. NRG Energy, Inc. (Minnesota) In February 2002, individual stockholders of NRG filed nine separate, but similar, purported class action complaints in the Delaware Court of Chancery, subsequently consolidated and with a single amended complaint, against Xcel Energy, NRG and the nine members of NRG s board of directors. In March, 2002, a similar class action lawsuit was filed in the state trial court for Hennepin County Minnesota. Each of the actions challenged the proposed purchase by Xcel Energy, via exchange offer and follow-up merger, of the approximately 26 percent of the outstanding shares of NRG that it did not already own; contained various allegations of wrongdoing on the part of the defendants in connection with the proposed purchase, including violations of fiduciary duties of loyalty and candor; and sought injunctive and damage relief and an award of fees and expenses. In April 2002 counsel for the parties to the consolidated action in the Delaware Court of Chancery and the Minnesota action entered into a memorandum of understanding setting forth an agreement in principle to settle the actions based on the increase by Xcel Energy of the exchange ratio in the offer and merger to 0.5000 but subject to confirmatory discovery, definitive documentation, and court approval. The Minnesota action has subsequently been dismissed without prejudice. As to the Delaware actions, the settlement has not been documented, approved or consummated, and, in light of developments in the litigation that is described under the heading immediately below, it is uncertain whether the settlement will proceed.

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Xcel Energy, Inc. Securities Litigation On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of Xcel Energy s common stock between Jan. 31, 2001 and July 26, 2002, was filed in the United States District Court for the District of Minnesota. The complaint named Xcel Energy; Wayne H. Brunetti, chairman, president and chief executive officer; Edward J. McIntyre, former vice president and chief financial officer; and former chairman, James J. Howard as defendants. Among other things, the complaint alleged violations of Section 10(b) of the Securities Exchange Act and Rule 10(b-5) related to allegedly false and misleading disclosures concerning various issues including but not limited to round trip energy trades, the nature, extent and seriousness of liquidity and credit difficulties at NRG, and the existence of cross-default provisions (with NRG credit agreements) in certain of Xcel Energy s credit agreements. After the filing of the lawsuit, several additional lawsuits were filed with similar allegations, one of which added claims on behalf of a purported class of purchasers of two series of Senior Notes issued by NRG in January 2001. The cases have all been consolidated, and a consolidated amended complaint has been filed. The amended complaint charges false and misleading disclosures concerning round trip energy trades and the existence of provisions in Xcel Energy s credit agreements for cross-defaults in the event of a default by NRG in one or more of NRG s credit agreements; it adds as additional defendants Gary R. Johnson, General Counsel, Richard C. Kelly, president of Xcel Energy Enterprises, three former executive officers of NRG, David H. Peterson, Leonard A. Bluhm, and William T. Pieper, and a former independent director of NRG, Luella G. Goldberg; and it adds claims of false and misleading disclosures, also regarding round trip trades and the cross-default provisions, as well the extent to which the fortunes of NRG were tied to Xcel Energy, especially in the event of a buyback of NRG s publicly owned shares, under Section 11 of the Securities Act with respect to issuance of the Senior Notes. The amended complaint seeks compensatory and rescissionary damages, interest, and an award of fees and expenses. The defendants have not yet responded to the amended complaint. Discovery has not commenced.

Xcel Energy Inc. Shareholder Derivative Action; Essmacher v. Brunetti; McLain v. Brunetti On Aug. 15, 2002, a shareholder derivative action was filed in the United States District Court for the District of Minnesota, purportedly on behalf of Xcel Energy, against the directors and certain present and former officers citing essentially the same circumstances as the securities class actions described immediately preceding and asserting breach of fiduciary duty. This action has been consolidated for pre-trial purposes with the securities class actions. After the filing of this action, two additional derivative actions were filed in the state trial court for Hennepin County, Minnesota, against essentially the same defendants, focusing on allegedly wrongful energy trading activities and asserting breach of fiduciary duty for failure to establish adequate accounting controls, abuse of control, and gross mismanagement. Considered collectively, the complaints seek compensatory damages, a return of compensation received, and awards of fees and expenses. In each of the cases, the defendants filed motions to dismiss the complaint for failure to make a proper pre-suit demand, or in the federal court case, to make any pre-suit demand at all, upon Xcel Energy s board of directors. The motions have not yet been ruled upon. Discovery has not commenced.

Newcome v. Xcel Energy Inc.; Barday v. Xcel Energy Inc. On Sept. 23, 2002 and Oct. 9, 2002, two essentially identical actions were filed in the United States District Court for the District of Colorado, purportedly on behalf of classes of employee participants in Xcel Energy s, and its predecessors , 401(k) or ESOP plans from as early as Sept. 23, 1999 forward. The complaints in the actions, which name as defendants Xcel Energy, its directors, certain former directors, and certain of present and former officers. The complaints allege violations of the Employee Retirement Income Security Act in the form of breach of fiduciary duty in allowing or encouraging purchase, contribution and/or retention of Xcel Energy s common stock in the plans and making misleading statements and omissions in that regard. The complaints seek injunctive relief, restitution, disgorgement and other remedial relief, interest and an award of fees and expenses. The defendants have filed motions to dismiss the complaints upon which no rulings have yet been made. The plaintiffs have made certain voluntary disclosure of information, but otherwise discovery has not commenced. Upon motion of defendants, the cases have been transferred to the District of Minnesota for purposes of coordination with the securities class actions and shareholders derivative action pending there.

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Stone & Webster, Inc. v. Xcel Energy, Inc. On Oct. 17, 2002, Stone & Webster, Inc. and Shaw Constructors, Inc. filed an action in the United States District Court in Mississippi against Xcel Energy; Wayne H. Brunetti, chairman, president and chief executive officer; Richard C. Kelly, president of Xcel Energy Enterprises; NRG and certain NRG subsidiaries. Plaintiffs allege they had a contract with a single purpose NRG subsidiary for construction of a power generation facility, which was abandoned before completion but after substantial sums had been spent by plaintiffs. They allege breach of contract, breach of an NRG guarantee, breach of fiduciary duty, tortious interference with contract, detrimental reliance, misrepresentation, conspiracy, and aiding and abetting, and seek to impose alter ego liability on defendants other than the contracting NRG subsidiary through piercing the corporate veil. The complaint seeks compensatory damages of at least $130 million plus demobilization and cancellation costs and punitive damages at least treble the compensatory damages. On Dec. 23, 2002, defendants filed motions to dismiss the complaint, which have not yet been ruled upon. No trial date has been set in this matter, and Xcel Energy cannot presently predict the outcome of this dispute. Plaintiffs have commenced what they characterize as jurisdictional discovery, which defendants are resisting.

New York Independent System Operator (NYISO) Claims In November 2002, the NYISO notified NRG of claims related to New York City mitigation adjustments, general NYISO billing adjustments and other miscellaneous charges related to sales between November 2000 and October 2002. NRG contests both the validity and calculation of the claims and is currently negotiating with the NYISO over the ultimate disposition. Accordingly, NRG reduced its revenues by $21.7 million and recorded a corresponding reserve for the receivable.

Huntley and Dunkirk Litigation In January 2002, the New York Attorney General and the New York Department of Environmental Control (NYDEC) filed suit in federal district court in New York against NRG and Niagara Mohawk Power Corp. (NiMo), the prior owner of the Huntley and Dunkirk facilities in New York. The lawsuit relates to physical changes made at those facilities prior to NRG s assumption of ownership. The complaint alleges that these changes represent major modifications undertaken without the required permits having been obtained. Although NRG has a right to indemnification by the previous owner for fines, penalties, assessments and related losses resulting from the previous owner s failure to comply with environmental laws and regulations, NRG could be enjoined from operating the facilities if the facilities are found not to comply with applicable permit requirements. In addition, NRG could be required to bear the costs of installing emissions controls. In July, 2002, NRG filed a motion to dismiss. On March 27, 2003, the court dismissed the complaint against NRG without prejudice. If the case is litigated to a judgment and there is an unfavorable outcome, NRG has estimated that the total investment that would be required to install pollution control devices could be as high as $300 million over a ten to twelve-year period. NRG has asserted that NiMo is obligated to indemnify it for any related compliance costs associated with resolution of the NYDEC enforcement action.

In July 2001, Niagara Mohawk Power Corp. filed a declaratory judgment action in the Supreme Court for the State of New York, County of Onondaga, against NRG and its wholly owned subsidiaries Huntley Power LLC and Dunkirk Power LLC. Niagara Mohawk Power Corp. requests a declaration by the court that, pursuant to the terms of the asset sales agreement (ASA) under which NRG purchased the Huntley and Dunkirk generating facilities from Niagara Mohawk, defendants have assumed liability for any costs for the installation of emissions controls or other modifications to or related to the Huntley or Dunkirk plants imposed as a result of violations or alleged violations of environmental law. Niagara Mohawk Power Corporation also requests a declaration by the court that, pursuant to the ASA, defendants have assumed all liabilities, including liabilities for natural resource damages, arising from emissions or releases of pollutants from the Huntley and Dunkirk plants, without regard to whether such emissions or releases occurred before, on or after the closing date for the purchase of the Huntley and Dunkirk plants. NRG has counterclaimed against Niagara Mohawk Power Corp., and the parties have exchanged discovery requests.

On Oct. 2, 2000, plaintiff NiMo commenced an action against NRG to recover net damages through the date of judgment, as well as any additional amounts due and owing for electric service provided to the

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Dunkirk Plant after Sept. 18, 2000. NiMo claims that NRG has failed to pay retail tariff amounts for utility services commencing on or about June 11, 1999 and continuing to Sept. 18, 2000 and thereafter. On Aug. 9, 2002 the parties filed a stipulation consolidating this action with two other actions against the Huntley and Oswego subsidiaries of NRG. On Oct. 8, 2002, a Stipulation and Order was filed in the Erie County Clerk s Office staying this action pending submission of some or all of the disputes in the action to the FERC. NRG cannot make an evaluation of the likelihood of an unfavorable outcome. The cumulative potential loss could exceed $35 million.

Other Contingencies

Operating Contingency As discussed in Note 19, NSP-Minnesota is experiencing uncertainty regarding its ability to store used nuclear fuel from its Prairie Island and Monticello nuclear generating facilities. These facilities store used nuclear fuel in a storage pool or dry cask storage on the plant site, pending the availability of a DOE high-level radioactive substance storage or permanent disposal facility, or a private interim storage facility.

The Prairie Island plant is licensed by the federal Nuclear Regulatory Commission (NRC) to store up to 48 casks of spent fuel at the plant. In 1994, the Minnesota Legislature adopted a limit on dry cask storage of 17 casks for the entire state. The 17 casks, which stand outside the Prairie Island plant, are now full, and under the current configuration, the storage pool within the plant would be full by 2007. Prairie Island cannot operate beyond 2007 unless the existing spent fuel is moved or the storage capacity is increased. Because the 17-cask limit is a statewide limit, the Monticello plant cannot, under current state law, store spent fuel in dry casks. Monticello s on-site storage pool is expected to be full in 2010. Monticello cannot operate beyond 2010 unless the existing spent fuel is moved or the storage capacity is increased. Capitalized costs for Prairie Island and Monticello are being depreciated over these available storage periods, and no unamortized plant investment is expected to remain if the plants must shut down in 2007 and 2010, respectively.

Due to the investment decisions required to be made in conjunction with the continued efficient operation of the nuclear plants, as well as the time and cost involved to develop alternatives to the existing nuclear power generation, NSP-Minnesota believes a decision is necessary in 2003 by the Minnesota Legislature whether the state will allow the continued use of nuclear power in the future. Prairie Island will only be able to continue operating beyond 2007 with legislative authorization of additional storage space. If additional storage space for continued operations is not authorized, and interim storage is not available, legislation may be required to ensure expedited siting and permitting of new generation or transmission facilities in time to replace the power supply currently provided from NSP-Minnesota s nuclear plants.

NSP-Minnesota has developed replacement power options, including purchasing new coal or natural gas generation sources. The feasibility of supplementing new generation sources with additional wind turbines has been reviewed. These options have been presented to the 2003 Minnesota Legislature. Each option involves a balance of cost, environmental impacts and production efficiencies. Based on the review of these options, NSP-Minnesota believes the most reliable, lowest-cost, emissions-free method to provide the needed 1,700 megawatts of energy is to continue to operate the nuclear power plants at Prairie Island and Monticello, which is possible only with the additional approved storage capacity for spent fuel, either on-site or in a private facility. We cannot predict at this time what resource decisions the Minnesota Legislature or MPUC may make regarding the continued use of NSP-Minnesota s Prairie Island and Monticello nuclear plants. If decisions are not made that allow the plants use beyond the storage capacity period, additional costs may need to be incurred to provide replacement power, either from new generating plants or from purchased power. The amount of such additional costs, and the level of corresponding rate recovery provided, are not determinable at this time but may be material.

Tax Matters PSCo s wholly owned subsidiary PSR Investments, Inc. (PSRI) owns and manages permanent life insurance policies on PSCo employees, known as corporate-owned life insurance (COLI). At various times, we have made borrowings against the cash values of these COLI policies and deducted the

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interest expense on these borrowings. The IRS had issued a Notice of Proposed Adjustment proposing to disallow interest expense deductions taken in tax years 1993 through 1997 related to COLI policy loans. A request for technical advice from the IRS National Office with respect to the proposed adjustment had been pending. Late in 2001, Xcel Energy received a technical advice memorandum from the IRS National Office, which communicated a position adverse to PSRI. Consequently, we expect the IRS examination division to begin the process of disallowing the interest expense deductions for the tax years 1993 through 1997.

After consultation with tax counsel, it is Xcel Energy s position that the IRS determination is not supported by the tax law. Based upon this assessment, management continues to believe that the tax deduction of interest expense on the COLI policy loans is in full compliance with the tax law. Therefore, Xcel Energy intends to challenge the IRS determination, which could require several years to reach final resolution. Although the ultimate resolution of this matter is uncertain, management continues to believe the resolution of this matter will not have a material adverse impact on Xcel Energy s financial position, results of operations or cash flows. For this reason, PSRI has not recorded any provision for income tax or interest expense related to this matter and has continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years. However, defense of Xcel Energy s position may require significant cash outlays on a temporary basis, if refund litigation is pursued in United States District Court.

The total disallowance of interest expense deductions for the period of 1993 through 1997, as proposed by the IRS, is approximately $175 million. Additional interest expense deductions for the period 1998 through 2002 are estimated to total approximately $317 million. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2002, would reduce earnings by an estimated $214 million after tax.

Seren At Dec. 31, 2002, Xcel Energy s investment in Seren was approximately $255 million. Seren had capitalized $290 million for plant in service and had incurred another $21 million for construction work in progress for these systems. The construction of its broadband communications network in Minnesota and California has resulted in consistent losses. Management currently intends to hold and operate Seren, and believes that no asset impairment exists. Xcel Energy projects improvements in Seren s operating results, with positive cash flows in 2005 and an earnings contribution anticipated in 2008.

Xcel Energy International At Dec. 31, 2002, Xcel Energy s investment in Argentina, through Xcel Energy International, was approximately $112 million. In December 2002, a subsidiary of Xcel Energy decided it would no longer fund one of its power projects in Argentina. This decision resulted in the shutdown of the Argentina plant facility, pending financing of a necessary maintenance outage. Updated cash flow projections for the plant were insufficient to provide full recovery of Xcel International s investment. An impairment write-down of approximately $13 million was recorded in the fourth quarter of 2002.

19. Nuclear Obligations

Fuel Disposal NSP-Minnesota is responsible for temporarily storing used or spent nuclear fuel from its nuclear plants. The DOE is responsible for permanently storing spent fuel from NSP-Minnesota s nuclear plants as well as from other U.S. nuclear plants. NSP-Minnesota has funded its portion of the DOE s permanent disposal program since 1981. The fuel disposal fees are based on a charge of 0.1 cent per kilowatt-hour sold to customers from nuclear generation. Fuel expense includes DOE fuel disposal assessments of approximately $13 million in 2002, $11 million in 2001 and $12 million in 2000. In total, NSP-Minnesota had paid approximately $312 million to the DOE through Dec. 31, 2002. However, we cannot determine whether the amount and method of the DOE s assessments to all utilities will be sufficient to fully fund the DOE s permanent storage or disposal facility.

The Nuclear Waste Policy Act required the DOE to begin accepting spent nuclear fuel no later than Jan. 31, 1998. In 1996, the DOE notified commercial spent fuel owners of an anticipated delay in accepting spent nuclear fuel by the required date and conceded that a permanent storage or disposal facility will not be available until at least 2010. NSP-Minnesota and other utilities have commenced lawsuits against the DOE to recover damages caused by the DOE s failure to meet its statutory and contractual obligations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NSP-Minnesota has its own temporary, on-site storage facilities for spent fuel at its Monticello and Prairie Island nuclear plants. With the dry cask storage facilities approved in 1994, management believes it has adequate storage capacity to continue operation of its Prairie Island nuclear plant until at least 2007. The Monticello nuclear plant has storage capacity to continue operations until 2010. Storage availability to permit operation beyond these dates is not assured at this time. We are investigating all of the alternatives for spent fuel storage until a DOE facility is available, including pursuing the establishment of a private facility for interim storage of spent nuclear fuel as part of a consortium of electric utilities. If on-site temporary storage at Prairie Island reaches approved capacity, we could seek interim storage at this or another contracted private facility, if available.

Nuclear fuel expense includes payments to the DOE for the decommissioning and decontamination of the DOE s uranium enrichment facilities. In 1993, NSP-Minnesota recorded the DOE s initial assessment of $46 million, which is payable in annual installments from 1993 to 2008. NSP-Minnesota is amortizing each installment to expense on a monthly basis. The most recent installment paid in 2002 was $4 million; future installments are subject to inflation adjustments under DOE rules. NSP-Minnesota is obtaining rate recovery of these DOE assessments through the cost-of-energy adjustment clause as the assessments are amortized. Accordingly, we deferred the unamortized assessment of $21 million at Dec. 31, 2002, as a regulatory asset.

Plant Decommissioning Decommissioning of NSP-Minnesota s nuclear facilities is planned for the years 2010 through 2022, using the prompt dismantlement method. We are currently following industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in Accumulated Depreciation. Consequently, the total decommissioning cost obligation and corresponding assets currently are not recorded in Xcel Energy s Consolidated Financial Statements.

Monticello began operation in 1971 and is licensed to operate until 2010. Prairie Island units 1 and 2 began operation in 1973 and 1974, respectively, and are licensed to operate until 2013 and 2014, respectively. Once a decision is made by the Minnesota Legislature regarding interim spent fuel storage facilities, Xcel Energy will make a decision on whether to pursue license renewal for Monticello and Prairie Island plants. Applications for license renewal must be submitted to the Nuclear Regulatory Commission (NRC) at least five years prior to license expiration. Preliminary scoping efforts for license renewal of the Monticello plant have begun, including data collection and review. The Prairie Island license renewal process has not yet begun. Xcel Energy s decision whether to apply for license renewal approval could be contingent on incremental plant maintenance or capital expenditures, recovery of which would be expected from customers through the respective rate recovery mechanisms. Management cannot predict the specific impact of such future requirements, if any, on its results of operations.

In 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143 Accounting for Asset Retirement Obligations. This statement will require NSP-Minnesota to record its future nuclear plant decommissioning obligations as a liability at fair value with a corresponding increase to the carrying value of the related long-lived asset. The liability will be increased to its present value each period, and the capitalized cost will be depreciated over the useful life of the related long-lived asset. If at the end of the asset s useful life the recorded liability differs from the actual obligations paid, SFAS No. 143 requires a gain or loss be recognized at that time. However, rate-regulated entities may recognize a regulatory asset or liability instead, if the criteria for SFAS No. 71 are met. NSP-Minnesota adopted SFAS No. 143 as required on Jan. 1, 2003. For additional information, see Note 20 to the Financial Statements.

Consistent with cost recovery in utility customer rates, we record annual decommissioning accruals based on periodic site-specific cost studies and a presumed level of dedicated funding. Cost studies quantify decommissioning costs in current dollars. Funding presumes that current costs will escalate in the future at a rate of 4.35 percent per year. The total estimated decommissioning costs that will ultimately be paid, net of income earned by external trust funds, is currently being accrued using an annuity approach over the approved plant recovery period. This annuity approach uses an assumed rate of return on funding, which is currently 5.5 percent, net of tax, for external funding and approximately 8 percent, net of tax, for internal funding.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Unrealized gains on nuclear decommissioning investments are deferred as Regulatory Liabilities based on the assumed offsetting against decommissioning costs in current ratemaking treatment.

The MPUC last approved NSP-Minnesota s nuclear decommissioning study request in April 2000, using 1999 cost data. A new filing was submitted to the MPUC in October 2002 and requests continuation of the current accrual. Since the timeframe is getting short on the recovery of the Prairie Island costs, less than five years at the start of 2003, NSP-Minnesota has recommended that the next filing be submitted in October 2003. The Department of Commerce has recommended that the internal fund, which is currently being transferred to the external funds, be transferred over a shorter period of time. This proposal would increase the fund cash contribution by approximately $13 million in 2003, but may not have a statement of operations impact. Although we expect to operate Prairie Island through the end of each unit s licensed life, the approved capital recovery would allow for the plant to be fully depreciated, including the accrual and recovery of decommissioning costs, in 2007. This is about seven years earlier than each unit s licensed life. The approved recovery period for Prairie Island has been reduced because of the uncertainty regarding spent-fuel storage. We believe future decommissioning cost accruals will continue to be recovered in customer rates.

The total obligation for decommissioning currently is expected to be funded 100 percent by external funds, as approved by the MPUC. Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. The assets held in trusts as of Dec. 31, 2002, primarily consisted of investments in fixed income securities, such as tax-exempt municipal bonds and U.S. government securities that mature in one to 20 years, and common stock of public companies. We plan to reinvest matured securities until decommissioning begins.

At Dec. 31, 2002, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of $662 million. The following table summarizes the funded status of NSP-Minnesota s decommissioning obligation at Dec. 31, 2002:

	2002 (Thousands of dollars)
Estimated decommissioning cost obligation from most recently approved study (1999 dollars)	$ 958,266
Effect of escalating costs to 2002 dollars (at 4.35 percent per year)	130,573
Estimated decommissioning cost obligation in current dollars	1,088,839
Effect of escalating costs to payment date (at 4.35 percent per year)	805,435
Estimated future decommissioning costs (undiscounted)	1,894,274
Effect of discounting obligation (using risk-free interest rate)	(828,087)
Discounted decommissioning cost obligation	1,066,187
Assets held in external decommissioning trust	617,048
Discounted decommissioning obligation in excess of assets currently held in external trust	$ 449,139

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Decommissioning expenses recognized include the following components:

	2002	2001	2000
	(Thousands of dollars)		
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	$ 51,433	$ 51,433	$ 51,433
Internally funded (including interest costs)	(18,797)	(17,396)	(16,111)
Interest cost on externally funded decommissioning obligation	(32)	4,535	5,151
Earnings from external trust funds	32	(4,535)	(5,151)
Net decommissioning accruals recorded	$ 32,636	$ 34,037	$ 35,322

Decommissioning and interest accruals are included with Accumulated Depreciation on the Consolidated Balance Sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Nonoperating Income on the statement of operations.

Negative accruals for internally funded portions in 2000, 2001 and 2002 reflect the impacts of the 1999 decommissioning study, which has approved an assumption of 100-percent external funding of future costs. Previous studies assumed a portion was funded internally; beginning in 2000, accruals are reversing the previously accrued internal portion and increasing the external portion prospectively.

20. Regulatory Assets and Liabilities

Our regulated businesses prepare their Consolidated Financial Statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the Consolidated Financial Statements. Under SFAS No. 71, regulatory assets and liabilities can be created for amounts that regulators may allow us to collect, or may require us to pay back to customers in future electric and natural gas rates. Any portion of our business that is not regulated cannot use SFAS No. 71 accounting. The components of unamortized regulatory assets and liabilities shown on the balance sheet at Dec. 31 were:

	Note Reference	Remaining Amortization Period	2002	2001
			(Thousands of dollars)	
AFDC recorded in plant(a)		Plant Lives	$ 154,158	$ 149,591
Conservation programs(a)(e)		Up to Five Years	53,860	65,825
Losses on reacquired debt	1	Term of Related Debt	85,888	95,394
Environmental costs	18, 19	To be determined	30,974	20,169
Unrecovered electric production costs(d)	1	27 months	67,709	
Unrecovered natural gas costs(b)	1	One to Two Years	11,950	11,316
Deferred income tax adjustments	1	Mainly Plant Lives	18,611	17,799

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Note Reference	Remaining Amortization Period	2002	2001
			(Thousands of dollars)	
Nuclear decommissioning costs(c)		Up to Eight Years	53,567	68,484
Employees postretirement benefits other than pension	13	Ten Years	38,899	42,942
Employees postemployment benefits	2	One Year		119
Renewable resource costs		To be determined	26,000	17,500
State commission accounting adjustments(a)		Plant Lives	19,157	7,578
Other		Various	15,630	5,725
Total regulatory assets			$ 576,403	$ 502,442
Investment tax credit deferrals			$ 109,571	$ 117,257
Unrealized gains from decommissioning investments	19		112,145	149,041
Pension costs regulatory differences	13		287,615	215,687
Interest on income tax refunds			6,569	
Fuel costs, refunds and other			2,527	1,957
Total regulatory liabilities			$ 518,427	$ 483,942

(a) Earns a return on investment in the ratemaking process. These amounts are amortized consistent with recovery in rates.

(b) Excludes current portion with expected rate recovery within 12 months of $12 million and $22 million for 2002 and 2001, respectively.

(c) These costs do not relate to NSP-Minnesota s nuclear plants. They relate to DOE assessments, as discussed previously, and unamortized costs for PSCo s Fort St. Vrain nuclear plant decommissioning.

(d) Excludes current portion with expected rate recovery within 12 months of $54 million and $0 million for 2002 and 2001, respectively

(e) 2001 amount includes accrued conservation incentives, which were approved in 2001. This table excludes deferred energy charges expected to be recovered within the next 12 months of $28 million for 2002, and energy cost recovery expected to be returned to customers within the next 12 months of $26 million for 2001.

SFAS No. 143 In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 143 Accounting for Asset Retirement Obligations. This statement will require Xcel Energy to record its future nuclear plant decommissioning obligations as a liability at fair value with a corresponding increase to the carrying value of the related long-lived asset. The liability will be increased to its present value each period, and the capitalized cost will be depreciated over the useful life of the related long-lived asset. If at the end of the asset s life the recorded liability differs from the actual obligations paid, SFAS No. 143 requires that a gain or loss be recognized at that time. However, rate-regulated entities may recognize a regulatory asset or liability instead, if the criteria for SFAS No. 71 Accounting for the Effects of Certain Types of Regulation are met.

Xcel Energy currently follows industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in accumulated depreciation. At Dec. 31, 2002, Xcel Energy recorded and recovered in rates $662 million of decommissioning obligations and had

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

estimated discounted decommissioning cost obligations of $1.1 billion based on approvals from the various state commissions, which used a single scenario. However, with the adoption of SFAS No. 143, a probabilistic view of several decommissioning scenarios were used, resulting in an estimated discounted decommissioning cost obligation of $1.6 billion.

Xcel Energy expects to adopt SFAS No. 143 as required on Jan. 1, 2003. In current estimates for adoption, the initial value of the liability, including cumulative accretion expense through that date, would be approximately $869 million. This liability would be established by reclassifying accumulated depreciation of $573 million and by recording two long-term assets totaling $296 million. A gross capitalized asset of $130 million would be recorded and would be offset by accumulated depreciation of $89 million. In addition, a regulatory asset of approximately $166 million would be recorded for the cumulative effect adjustment related to unrecognized depreciation and accretion under the new standard. Management expects that the entire transition amount would be recoverable in rates over time and, therefore, would support this regulatory asset upon adoption of SFAS No. 143.

Xcel Energy has completed a detailed assessment of the specific applicability and implications of SFAS No. 143 for obligations other than nuclear decommissioning. Other assets that may have potential asset retirement obligations include ash ponds, any generating plant with a Part 30 license and electric and natural gas transmission and distribution assets on property under easement agreements. Easements are generally perpetual and require retirement action only upon abandonment or cessation of use of the property for the specified purpose. The liability is not estimable because Xcel Energy intends to utilize these properties indefinitely. The asset retirement obligations for the ash ponds and generating plants cannot be reasonably estimated due to an indeterminate life for the assets associated with the ponds and uncertain retirement dates for the generating plants. Since the time period for retirement is unknown, no liability would be recorded. When a retirement date is certain, a liability will be recorded.

The adoption of SFAS No. 143 in 2003 will also affect Xcel Energy s accrued plant removal costs for other generation, transmission and distribution facilities for its utility subsidiaries. Although SFAS No. 143 does not recognize the future accrual of removal costs as a Generally Accepted Accounting Principles liability, long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for such costs in historical depreciation rates. These removal costs have accumulated over a number of years based on varying rates as authorized by the appropriate regulatory entities. Given the long periods over which the amounts were accrued and the changing of rates through time, we have estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Accordingly, the estimated amounts of future removal costs, which are considered regulatory liabilities under SFAS No. 143 that are accrued in accumulated depreciation, are as follows at December 31, 2002:

	(Millions of Dollars)
NSP-Minnesota	$ 304
NSP-Wisconsin	70
PSCo	329
SPS	97

21. Segments and Related Information

Xcel Energy has the following reportable segments: Electric Utility, Natural Gas Utility and its nonregulated energy business, NRG. Previously, e prime was considered a reportable segment due to the significance of its gross trading revenues. However, with the change in reporting of trading operations to a net basis, as discussed in Note 1 to the Consolidated Financial Statements, e prime is no longer a reportable segment due to its net trading margins/revenue being below the quantitative thresholds. e prime is included in the All Other category for all periods presented.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Xcel Energy s Electric Utility generates, transmits and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas, New Mexico, Wyoming, Kansas and Oklahoma. It also makes sales for resale and provides wholesale transmission service to various entities in the United States. Electric Utility also includes electric trading.

Xcel Energy s Natural Gas Utility transmits, transports, stores and distributes natural gas and propane primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan, Arizona, Colorado and Wyoming.

NRG develops, acquires, owns and operates several nonregulated energy-related businesses, including independent power production, commercial and industrial heating and cooling, and energy-related refuse-derived fuel production, both domestically and outside the United States.

Revenues from operating segments not included previously are below the necessary quantitative thresholds and are therefore included in the All Other category. Those primarily include a company that trades and markets natural gas throughout the United States; a company involved in nonregulated power and natural gas marketing activities throughout the United States; a company that invests in and develops cogeneration and energy-related projects; a company that is engaged in engineering, design construction management and other miscellaneous services; a company engaged in energy consulting, energy efficiency management, conservation programs and mass market services; an affordable housing investment company; a broadband telecommunications company; and several other small companies and businesses.

To report net income for electric and natural gas utility segments, Xcel Energy must assign or allocate all costs and certain other income. In general, costs are:

directly assigned wherever applicable;

allocated based on cost causation allocators wherever applicable; and

allocated based on a general allocator for all other costs not assigned by the above two methods.

The accounting policies of the segments are the same as those described in Note 1 to the Consolidated Financial Statements. Xcel Energy evaluates performance by each legal entity based on profit or loss generated from the product or service provided.

Business Segments

	Electric Utility	Natural Gas Utility	NRG(b)	All Other(b)	Reconciling Eliminations	Consolidated Total
	(Thousands of dollars)					
2002						
Operating revenues from external customers(a)	$ 5,437,017	$ 1,397,799	$ 2,212,153	$ 405,839	$	$ 9,452,808
Intersegment revenues	987	4,949		165,732	(171,665)	3
Equity in earnings (losses) of unconsolidated affiliates(a)			68,996	2,565		71,561
Total revenues	$ 5,438,004	$ 1,402,748	$ 2,281,149	$ 574,136	$ (171,665)	$ 9,524,372
Depreciation and amortization	$ 647,491	$ 92,868	$ 256,199	$ 40,871	$	$ 1,037,429
Financing costs, mainly interest expense	286,180	52,583	493,956	131,383	(46,022)	918,080
Income tax expense (credit)	301,875	53,831	(165,382)	(818,309)		(627,985)
Segment net income (loss)	$ 478,711	$ 98,517	$ (3,464,282)	$ 715,140	$ (46,077)	$ (2,217,991)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Electric Utility	Natural Gas Utility	NRG(b)	All Other(b)	Reconciling Eliminations	Consolidated Total
	(Thousands of dollars)					
2001						
Operating revenues from external customers(a)	$ 6,463,401	$ 2,051,199	$ 2,201,427	$ 397,895	$	$ 11,113,922
Intersegment revenues	978	4,501	1,859	178,111	(183,019)	2,430
Equity in earnings (losses) of unconsolidated affiliates(a)			210,032	7,038		217,070
Total revenues	$ 6,464,379	$ 2,055,700	$ 2,413,318	$ 583,044	$ (183,019)	$ 11,333,422
Depreciation and amortization	$ 617,320	$ 92,989	$ 169,596	$ 26,398	$	$ 906,303
Financing costs, mainly interest expense	265,285	49,108	389,311	115,127	(52,055)	766,776
Income tax expense (credit)	351,181	41,077	28,052	(88,939)		331,371
Segment income (loss) before extraordinary items	$ 535,182	$ 81,562	$ 265,204	$ (56,879)	$ (40,390)	$ 784,679
Extraordinary items, net of tax	11,821			(1,534)		10,287
Segment net income (loss)	$ 547,003	$ 81,562	$ 265,204	$ (58,413)	$ (40,390)	$ 794,966
2000						
Operating revenues from external customers(a)	$ 5,704,683	$ 1,466,478	$ 1,670,774	$ 195,236	$	$ 9,037,171
Intersegment revenues	1,179	5,761	2,256	132,347	(137,962)	3,581
Equity in earnings (losses) of unconsolidated affiliates(a)			139,364	43,350		182,714
Total revenues	$ 5,705,862	$ 1,472,239	$ 1,812,394	$ 370,933	$ (137,962)	$ 9,223,466
Depreciation and amortization	$ 574,018	$ 85,353	$ 97,304	$ 10,071	$	$ 766,746
Financing costs, mainly interest expense	333,512	60,755	250,790	67,696	(59,780)	652,973
Income tax expense (credit)	261,942	36,962	86,903	(86,777)		299,030
Segment income (loss) before extraordinary items	$ 340,634	$ 57,911	$ 182,935	$ (20,083)	$ (15,609)	$ 545,788
Extraordinary items, net of tax	(18,960)					(18,960)
Segment net income (loss)	$ 321,674	$ 57,911	$ 182,935	$ (20,083)	$ (15,609)	$ 526,828

(a)

	2002		2001		2000	
	NRG	All Other	NRG	All Other	NRG	All Other
	(Millions of dollars)					
Operating revenues from external customers United States	$ 1,874	$ 369	$ 1,886	$ 362	$ 1,575	$ 195
Operating revenues from external customers international	338	37	315	36	96	
Equity in earnings of unconsolidated affiliates United States	20	3	151	6	121	8
Equity in earnings of unconsolidated affiliates international	49		59	1	18	35
Consolidated earnings (loss) international	(695)	18	100	6	39	29

NRG s international assets were $2,369 million and $3,199 million in 2002 and 2001, respectively. NRG s equity investments and projects outside the United States were $310 million and $417 million in 2002 and 2001, respectively.

All Other s international assets were $69 million and $138 million in 2002 and 2001, respectively. All Other s investments and projects outside the United States were $0 and $37 million in 2002 and 2001, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(b) NRG segment represents the consolidated results of NRG excluding the earnings attributable to minority shareholders of NRG prior to June 2002, when Xcel Energy acquired a 100 percent ownership in NRG. All Other includes minority interest income (expense) related to NRG of $13.6 million in 2002, $(65.6) million in 2001, and $(29.2) million in 2000. Also, in 2002 All Other includes income tax benefits related to Xcel Energy s investment in NRG of $706 million, as discussed in Note 11 to the Consolidated Financial Statements.

22. Summarized Quarterly Financial Data (Unaudited)

Subsequent to the issuance of Xcel Energy s financial statements for the quarter ended Sept. 30, 2002, NRG s management determined that the accounting for certain transactions required revision.

NRG determined that it had misapplied the provisions of SFAS No. 144 related to asset grouping in connection with the review for impairment of its long-lived assets during the quarter ended Sept. 30, 2002. SFAS No. 144 requires that for purposes of testing recoverability, assets be grouped at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets. NRG recalculated the asset impairment tests in accordance with SFAS No. 144 using the appropriate asset grouping for independent cash flows for each generation facility. As a result, NRG concluded that asset impairments should have been recorded for two projects known as Bayou Cove Peaking Power LLC and Somerset Power LLC. Since NRG concluded that the triggering events that led to the impairment charge were experienced in the third quarter of 2002, the asset impairments related to these projects should have been recorded as of Sept. 30, 2002. NRG calculated the asset impairment charges for Bayou Cove Peaking Power LLC and Somerset Power LLC to be $126.5 million and $49.3 million, respectively.

In connection with NRG s year-end audit, two additional items were found to be inappropriately recorded as of Sept. 30, 2002. These items included the inappropriate treatment of interest rate swap transactions as cash flow hedges and the decrease in the value of a bond remarketing option from the original price paid by NRG. The error correction for the interest rate swaps resulted in the recording of additional income of $61.6 million as of Sept. 30, 2002. The recognition of the decrease in the value of the remarketing option resulted in a charge to income of $15.9 million as of Sept. 30, 2002.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A summary of the significant effects of the restatement including the impact of fourth quarter discontinued operations decisions, on Xcel Energy s consolidated statements of operations for the three and nine months ended Sept. 30, 2002 is as follows:

	As Previously Reported		As Restated	
	Three Months Ended	Nine Months Ended	Three Months Ended	Nine Months Ended
	(Thousands of dollars, except per share amounts)			
Consolidated Statements of Operations:				
Revenue	$ 2,473,331	$ 7,070,824	$ 2,473,331	$ 7,070,824
Operating income	(1,948,725)	(1,334,201)	(2,140,418)	(1,525,894)
Income (loss) from continuing operations	(1,496,959)	(1,317,413)	(1,627,039)	(1,447,493)
Discontinued operations income (loss)	(577,001)	(565,741)	(577,001)	(565,741)
Net income (loss)	(2,073,960)	(1,883,154)	(2,204,040)	(2,013,234)
Earnings (loss) available for common shareholders	(2,075,020)	(1,886,334)	(2,205,100)	(2,016,414)
Earnings (loss) per share from continuing operations: basic and diluted	$ (3.77)	$ (3.51)	$ (4.10)	$ (3.85)
Earnings (loss) per share discontinued operations: basic and diluted	$ (1.45)	$ (1.50)	$ (1.45)	$ (1.50)
Earnings per share: basic and diluted	$ (5.22)	$ (5.01)	$ (5.55)	$ (5.35)

During the fourth quarter of 2002, NRG determined that it had inadvertently offset its investment in Jackson County, Mississippi, bonds in the amount of $155.5 million against long-term debt of the same amount owed to the County. This resulted in an understatement of NRG s assets and liabilities by $155.5 million as of Sept. 30, 2002. In addition, the restatement for Bayou Cove Peaking LLC and Somerset Power LLC impairments reduced the previously reported net property, plant and equipment balance by $175.8 million. The restatement for the interest rate swaps had no impact on total shareholder s equity and the restatement for the remarketing option reduced other assets by $15.9 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Summarized quarterly unaudited financial data is as follows:

	Quarter Ended			
	March 31, 2002(a)	June 30, 2002(a)	Sept. 30, 2002 As Restated(a)(d)	Dec. 31, 2002(a)
	(Thousands of dollars, except per share amounts)			
Revenue(c)	$ 2,370,584	$ 2,226,909	$ 2,473,331	$ 2,453,548
Operating income (loss)	298,977	315,548	(2,140,418)	93,562
Income (loss) from continuing operations	93,929	85,617	(1,627,039)	(213,877)
Discontinued operations income (loss)	9,575	1,685	(577,001)	9,120
Net income (loss)	103,504	87,302	(2,204,040)	(204,757)
Earnings (loss) available for common shareholders	102,444	86,242	(2,205,100)	(205,818)
Earnings (loss) per share from continuing operations: basic and diluted	$ 0.26	$ 0.22	$ (4.10)	$ (0.54)
Earnings (loss) per share discontinued operations: basic and diluted	$ 0.03	$	$ (1.45)	$ 0.02
Earnings (loss) per share total: basic and diluted	$ 0.29	$ 0.22	$ (5.55)	$ (0.52)

	Quarter Ended			
	March 31, 2001	June 30, 2001(b)	Sept. 30, 2001	Dec. 31, 2001(b)
	(Thousands of dollars, except per share amounts)			
Revenue(c)	$ 3,174,066	$ 2,743,822	$ 2,931,799	$ 2,483,735
Operating income	461,097	416,843	635,884	344,323
Income from continuing operations before extraordinary items	191,974	162,654	264,823	118,236
Discontinued operations income (loss)	17,336	5,203	8,080	16,373
Extraordinary items income				10,287
Net income	209,310	167,857	272,903	144,896
Earnings available for common shareholders	208,250	166,797	271,843	143,835
Earnings per share from continuing operations before extraordinary items: basic & diluted	$ 0.56	$ 0.47	$ 0.77	$ 0.34
Earnings per share discontinued operations: basic & diluted	$ 0.05	$ 0.02	$ 0.02	$ 0.05
Earnings per share extraordinary items: basic and diluted	$	$	$	$ 0.03
Earnings per share: basic and diluted	$ 0.61	$ 0.49	$ 0.79	$ 0.42

(a) 2002 results include special charges and unusual items in all quarters, as discussed in Note 2 to the Consolidated Financial Statements.

First-quarter results were decreased by $9 million, or 1 cent per share, for a special charge related to utility/service company employee restaffing costs, and by $5 million, or 1 cent per share, for regulatory recovery adjustments at SPS.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Second-quarter results were decreased by $36 million, or 9 cents per share, for NEO-related special charges taken by NRG.

Third-quarter results (as restated) were decreased by $2.5 billion, or $5.97 per share, for special charges related to NRG asset impairments and financial restructuring, and were increased by $676 million, or $1.77 per share, due to estimated tax benefits related to Xcel Energy s investment in NRG.

Fourth-quarter results were decreased by $100 million, or 24 cents per share, for special charges related to NRG asset impairments and financial restructuring costs, and increased by $30 million, or $0.08 per share, due to revisions to the estimated tax benefits related to Xcel Energy s investment in NRG.

(b) 2001 results include special charges and unusual items in the second and fourth quarters, as discussed in Note 2 to the Consolidated Financial Statements.

Second-quarter results were increased by $41 million, or 7 cents per share, for conservation incentive adjustments, and decreased by $23 million, or 4 cents per share, for a special charge related to post employment benefits.

Fourth-quarter results were decreased by $39 million, or 7 cents per share, for a special charge related to employee restaffing costs.

(c) Certain items in the 2001 and 2002 quarterly income statements have been reclassified to conform to the 2002 annual presentation. These reclassifications included the netting of trading revenues and expenses previously reported gross, and NRG s discontinued operations, as discussed in Notes 1 and 3 to the Consolidated Financial Statements, respectively.

(d) Third-quarter 2002 results for NRG have been restated from amounts previously reported. NRG s asset impairments and restructuring charges for the quarter have been restated, increasing NRG s operating expenses by $192 million and a correction for interest rate swaps resulted in additional income of $62 million, for a net effect of $130 million in additional loss for the quarter. As a result, Xcel Energy s Special Charges included in operating expenses for the quarter ended Sept. 30, 2002 increased by $192 million, or $0.50 per share.

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SCHEDULE II

XCEL ENERGY INC.

AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Years ended Dec. 31, 2000, 2001 and 2002

	Balance at Beginning of Period	Additions: Charged to Cost and Expenses	Additions: Charged to Other Accounts	Deductions from Reserves(1)	Balance at End of Period
			(In thousands)		
Xcel Energy					
Reserve deducted from related assets:					
Provision for uncollectible accounts:					
2002	$ 37,487	$ 80,272	$ 10,129	$ 35,142	$ 92,746
2001	$ 41,350	$ 25,412	$ 6,487	$ 35,762	$ 37,487
2000	$ 13,043	$ 51,052	$ 3,953	$ 26,698	$ 41,350
Income tax valuation allowance, deducting					
From deferred tax assets in balance sheet:					
2002	$ 66,622	$ 1,010,425	$	$	$ 1,077,047
2001	$ 40,649	$ 25,973	$	$	$ 66,622
2000	$ 15,006	$ 25,643	$	$	$ 40,649

(1) Uncollectible accounts written off or transferred to other parties.

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UNAUDITED CONSOLIDATED PRO-FORMA FINANCIAL INFORMATION

ACCOUNTING FOR NRG ON THE EQUITY METHOD

Background

NRG voluntarily filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code on May 14, 2003. As part of this action, the tentative settlement agreement reached in March 2003 among Xcel Energy, NRG and NRG s creditors (the Settlement) was filed with a bankruptcy court for its consideration as a resolution of NRG s financial difficulties. If the court approves the terms of the Settlement, upon emergence from bankruptcy Xcel Energy will divest its ownership interests in NRG. This divestiture will result in NRG ultimately being reported as a discontinued operation of Xcel Energy. However, pending the outcome of the bankruptcy proceeding, Xcel Energy will remain 100 percent owner of NRG but will not have sufficient control to continue consolidating NRG. During the period between NRG s filing for bankruptcy and its actual divestiture by Xcel Energy, Xcel Energy will report NRG as an equity investment under generally accepted accounting principles. Because such accounting requirements do not allow equity accounting until the period that includes the bankruptcy filing, Xcel Energy is providing pro-forma information for historical periods presenting NRG under the equity method of accounting.

Pro-forma Information

The following summary of unaudited pro-forma financial information for Xcel Energy gives effect to the change in the accounting for NRG from consolidated financial reporting to the equity method of accounting. Under the equity method, NRG is not consolidated in Xcel Energy s financial statements but instead is reported as a single investment-related item (NRG Losses In Excess of Investment) on the Balance Sheets, and a single item (Equity in Losses of NRG) on the Statements of Operations. Because Xcel Energy s cumulative equity in NRG s losses to date exceed the cumulative investments made in NRG, the investment-related balance sheet item is not an asset but is reported as a current liability.

The following pro-forma Balance Sheets and Statements of Operations are treated as if Xcel Energy had never consolidated NRG for financial reporting purposes. This unaudited pro-forma financial information should be read in conjunction with the historical financial statements and related notes of Xcel Energy, which are included in the 2002 Annual Report on Form 10-K. The unaudited pro-forma Balance Sheet information at Dec. 31, 2002 assumes that NRG had been deconsolidated (that is, the equity method had been applied) on that date. The unaudited pro-forma Statement of Operations information for the year ended Dec. 31, 2002 assumes that NRG had been deconsolidated on Jan. 1, 2002, the beginning of the earliest period presented.

These summarized pro-forma amounts do not include any of the future financial impacts that may occur from NRG s filing for bankruptcy, or from implementing the Settlement. Also, the unaudited pro-forma financial information does not necessarily indicate what Xcel Energy s financial position or operating results would have been if NRG had filed for bankruptcy (or had been divested) in the periods presented, and does not necessarily indicate future operating results of Xcel Energy (with or without NRG).

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XCEL ENERGY INC. AND SUBSIDIARIES

PRO-FORMA CONSOLIDATED STATEMENTS OF INCOME (W/O NRG)

		Pro-forma Adjustments for NRG		
	As Reported 12/31/2002(a)	Apply Equity Accounting(b)	Adjust Eliminations(c)	Pro-forma Adjusted 12/31/2002
	(Thousands of dollars, except per share data)			
Operating Revenues:				
Electric Utility	$ 5,435,377			$ 5,435,377
Gas Utility	1,397,800			1,397,800
Electric and Gas Trading	8,485			8,485
Nonregulated and Other	2,611,149	(2,212,153)		398,996
Equity Earnings from Investments in Affiliates(f)	71,561	(68,996)		2,565
Total Operating Revenues	9,524,372	(2,281,149)		7,243,223
Operating Expenses:				
Electric Fuel and Purchased Power Utility	2,199,099			2,199,099
Cost of Gas Sold and Transported Utility	851,987			851,987
Cost of Sales Nonregulated and Other	1,361,466	(1,094,795)		266,671
Other Operating and Maintenance Expenses Utility	1,501,602			1,501,602
Other Operating and Maintenance Expenses Nonregulated	787,968	(665,886)		122,082
Depreciation and Amortization	1,037,429	(256,199)		781,230
Taxes (Other Than Income Taxes)	318,641			318,641
Estimated Gain/ Loss on Disposal of Equity Investments	207,290	(196,192)		11,098
Special Charges	2,691,223	(2,656,093)		35,130
Total Operating Expenses	10,956,705	(4,869,165)		6,087,540
Operating Income (Loss)	(1,432,333)	2,588,016		1,155,683
Interest Income	45,863	(16,322)		29,541
Other Non-Operating Income	28,167	2,145		30,312
Other Non-Operating Expense	(30,043)	10,007		(20,036)
Equity in Losses of NRG(f)		(3,464,282)		(3,464,282)
Interest Charges and Financing Costs:				
Interest Charges net of amounts capitalized	879,736	(493,956)		385,780
Distributions on Redeemable Preferred Securities of Subsidiary Trusts	38,344			38,344
Total Interest Charges and Financing Costs	918,080	(493,956)		424,124
Income (Loss) from Continuing Operations Before Income Taxes and Minority Interest	(2,306,426)	(386,480)		(2,692,906)
Income Taxes (Benefit)	(627,985)	165,382		(462,603)
Minority Interest expense (income)	(17,071)	4,759		(12,312)
Income (Loss) from Continuing Operations	(1,661,370)	(556,621)		(2,217,991)

Income (Loss) from Discontinued Operations net of tax(d)		(556,621)		556,621				
Net Income (Loss)		(2,217,991)						(2,217,991)
Dividend Requirements on Preferred Stock		4,241						4,241
Earnings Available for Common Shareholders	$	(2,222,232)	$		$		$	(2,222,232)
Earnings (loss) per share basic and diluted:								
Income (loss) from continuing operations	$	(4.36)	$	(1.46)	$		$	(5.82)
Income (loss) from discontinued operations(d)	$	(1.46)	$	1.46	$		$	
Total earnings (loss) per share diluted	$	(5.82)	$		$		$	(5.82)

See accompanying Notes to Pro-forma Financial Information.

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XCEL ENERGY INC. AND SUBSIDIARIES

PRO-FORMA CONSOLIDATED BALANCE SHEET

	As Reported 12/31/2002(a)	Pro-forma Adjustments for NRG: Apply Equity Accounting(b)	Pro-forma Adjustments for NRG: Adjust Eliminations(c)	Pro-forma Adjusted 12/31/2002
	(Thousands of dollars)			
ASSETS				
Current Assets:				
Cash and cash equivalents	$ 901,273	$ (385,055)		$ 516,218
Restricted cash	305,581	(282,581)		23,000
Accounts receivable net of allowance	961,060	(299,300)	43,213	704,973
Accrued unbilled revenues	390,984			390,984
Materials and supplies inventories at average cost	321,863	(267,924)		53,939
Fuel inventory at average cost	207,200			207,200
Natural gas inventories replacement cost in excess of LIFO	147,306			147,306
Recoverable purchased natural gas and electric energy costs	63,975			63,975
Derivative instruments valuation at market	62,206	(28,791)		33,415
Prepayments and other	267,185	(121,898)		145,287
Current assets held for sale(d)	108,535	(108,535)		
Total Current Assets	3,737,168	(1,494,084)	43,213	2,286,297
Property, Plant and Equipment, at cost:				
Electric utility plant	16,516,790			16,516,790
Nonregulated property and other	8,411,088	(6,844,625)		1,566,463
Natural gas utility plant	2,603,545			2,603,545
Construction work in progress	1,513,807	(623,748)		890,059
Total Property, Plant and Equipment	29,045,230	(7,468,373)		21,576,857
Less accumulated depreciation	(10,303,575)	625,706		(9,677,869)
Nuclear fuel net of accumulated amortization	74,139			74,139
Net Property, Plant and Equipment	18,815,794	(6,842,667)		11,973,127
Other Assets:				
Investments in unconsolidated affiliates(e)	1,001,380	(884,263)		117,117
Notes receivable, including amounts from affiliates	987,714	(985,253)		2,461
Nuclear decommissioning fund and other investments	732,166	(4,617)		727,549
Regulatory assets	576,403			576,403
Derivative instruments valuation at market	93,225	(90,766)		2,459
Prepaid pension asset	466,229			466,229
Goodwill, net	35,538	(27,808)		7,730
Intangible assets, net	68,210	(50,170)		18,040
Other	364,243	(193,871)	(3)	170,369
Noncurrent assets held for sale(d)	379,772	(379,772)		
Total Other Assets	4,704,880	(2,616,520)	(3)	2,088,357

TOTAL ASSETS	$ 27,257,842	$ (10,953,271)	$ 43,210	$ 16,347,781
LIABILITIES AND EQUITY				
Current Liabilities:				
Current portion of long-term debt	$ 7,756,261	$ (7,193,238)		563,023
Short-term debt	1,541,963	(1,030,064)		511,899
Accounts payable	1,399,195	(616,498)	43,210	825,907
Taxes accrued	267,214	(23,191)		244,023
Dividends payable	75,814			75,814
Derivative instruments valuation at market	38,767	(13,439)		25,328
Other	749,521	(408,142)		341,379
Current liabilities held for sale(d)	520,101	(520,101)		
NRG losses in excess of investment(e)		634,452		634,452
Total Current Liabilities	12,348,836	(9,170,221)	43,210	3,221,825
Deferred Credits and Other Liabilities:				
Deferred income taxes	1,283,667	(87,886)		1,195,781
Deferred investment tax credits	169,696			169,696
Regulatory liabilities	518,427			518,427
Derivative instruments valuation at market	102,779	(91,039)		11,740
Benefit obligations and other	722,264	(225,693)		496,571
Asset retirement obligations				
Minimum pension liability	106,897			106,897
Noncurrent liabilities held for sale(d)	155,962	(155,962)		
Total Deferred Credits and Other Liabilities	3,059,692	(560,580)		2,499,112
Minority interest in subsidiaries	34,762	(29,840)		4,922
Commitments and contingencies				
Capitalization:				
Long-term debt	6,550,248	(1,192,630)		5,357,618
Mandatorily redeemable preferred securities of subsidiary trusts	494,000			494,000
Preferred stockholders equity	105,320			105,320
Common stockholders equity(g)	4,664,984			4,664,984
TOTAL LIABILITIES AND EQUITY	$ 27,257,842	$ (10,953,271)	$ 43,210	$ 16,347,781

See accompanying Notes to Pro-forma Financial Information

NOTES TO PRO-FORMA FINANCIAL INFORMATION

The following notes provide additional information for the adjustments made to historical financial statements in determining the accompanying pro-forma financial information.

(a) As Reported amounts for year ended Dec. 31, 2002 were derived from the audited consolidated financial statements included in Xcel Energy s 2002 Annual Report on Form 10-K.

(b) Pro-forma adjustments to As Reported amounts reflect (1) the elimination of NRG s revenues and expenses (as to the Statement of Operations) and assets and liabilities (as to the Balance Sheets) from Xcel Energy s consolidated financial statements; and (2) equity accounting adjustments to reflect NRG s results of operations as a single income/ expense item (Equity in Losses of NRG) and to reflect Xcel Energy s net investment in NRG as a single balance (NRG Losses in Excess of Investment). In addition to NRG s amounts, application of the equity method has also resulted in the reclassification of the minority interest of NRG s stockholders other than Xcel Energy (prior to June 2002) on both the Statement of Operations and the Balance Sheet to be presented as a component of Equity in Losses of NRG and NRG Losses in Excess of Investment, respectively.

(c) Pro-forma adjustments to As Reported Balance Sheet amounts also reflect the reinstatement of Xcel Energy s intercompany balances with NRG, which were previously eliminated under the consolidated method of reporting NRG.

(d) Pro-forma adjustments referred to in (b) above include the elimination of NRG s projects and operations that have been sold in 2002, or were considered held for sale in those periods. Under the equity method of accounting being presented here on a pro-forma basis, the operating results of these NRG projects/ operations, and the related assets and liabilities, are no longer presented as Discontinued Operations and Assets and Liabilities Held for Sale, respectively. In addition, pro-forma adjustments have reclassified NRG s cumulative effect of accounting change into Equity in Losses of NRG.

(e) The pro-forma adjustments to the Balance Sheet referred to in (b) above have adjusted Xcel Energy s net investment in NRG, which would normally be an asset, to a net credit balance, which is presented on a pro-forma basis as a current liability. This presentation assumes that the net liability will be eliminated upon the effectiveness of NRG s plan of reorganization, and the disbursement of agreed-upon settlement payments to NRG s creditors. This negative investment can be reconciled to NRG s stockholders equity as follows (in millions):

December 31, 2002		
Stockholders Equity per NRG 10-K	$	(696)
Less: Xcel Energy Purchase Accounting Adjustments*		62
Less: Settlement Agreement Impacts**		
Less: NRG s Other Comprehensive Income***		
Negative Investment in NRG Liability	$	(634)

* These adjustments resulted from Xcel Energy s purchase accounting for the acquisition of minority shares of NRG in June 2002, and are not reflected in NRG s financial statements. Application of the equity method to Xcel Energy s investment in NRG has resulted in the reclassification of this amount from nonregulated property, prepaid pension, and other noncurrent assets of an intermediate holding company of Xcel Energy to this NRG investment account, which reduces the negative balance.

** Terms of the tentative settlement agreement may require a portion of certain guarantee payments made by Xcel Energy on behalf of NRG to be reclassified from intercompany receivables to a capital contribution, or equity investment amount. These reclassifications are considered immaterial for pro-forma adjustment purposes.

*** Other Comprehensive Income, a component of NRG s stockholder s equity, included unrealized loss amounts of $95 million related to foreign currency translation and derivative financial instrument valuation at Dec. 31, 2002. These amounts will eventually be reclassified on

Xcel Energy s financial statement from stockholders equity to the net investment in NRG at the time of NRG s divestiture (see (g) below). However, divestiture is not assumed in pro-forma adjustments.

NOTES TO PRO-FORMA FINANCIAL INFORMATION (Continued)

(f) The pro-forma adjustments to the Statement of Operations referred to in (b) above have adjusted Xcel Energy s pro-forma Equity In Earnings of Affiliates (now including NRG) to a net debit balance due to losses incurred by NRG. For pro-forma presentation purposes, we have not reported the equity in NRG losses as a negative revenue, but instead have presented them as a nonoperating expense item.

(g) No pro-forma adjustments are required to stockholders equity amounts in the Balance Sheet. NRG s common stock and paid-in capital amounts are not reflected in Xcel Energy s consolidated stockholders equity and therefore do not require adjustment. Also, Xcel Energy s cumulative equity in NRG s losses, even after the pro-forma change in accounting for NRG to the equity method, will still be reported as a component of Xcel Energy s retained earnings and should not be adjusted. The Other Comprehensive Income balance in NRG s stockholders equity reflects unrealized losses related to NRG s foreign currency translation and derivative financial instruments. Under the equity method, these amounts will ultimately be reclassified from stockholders equity to a component of the investment in NRG, but not until divestiture actually occurs. Divestiture is not assumed in pro-forma adjustments.