XCEL ENERGY INC
Form S-1
February 14, 2003

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As filed with the Securities and Exchange Commission on February 14, 2003

Registration No. 333-

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form S-1

REGISTRATION STATEMENT UNDER THE SECURITIES ACT OF 1933

Xcel Energy Inc.

(Exact Name of Registrant as Specified in Its Charter)

MINNESOTA	**4931**	**41-0448030**
(State or Other Jurisdiction of Incorporation or Organization)	*(Primary Standard Industrial Classification Code Number)*	*(I.R.S. Employer Identification Number)*

800 Nicollet Mall
Minneapolis, Minnesota 55402
(612) 330-5500

(Address, Including Zip Code, and Telephone Number, Including Area Code, of Registrant s Principal Executive Offices)

WAYNE H. BRUNETTI	**RICHARD C. KELLY**
President and Chief Executive Officer	Vice President and Chief Financial Officer
Xcel Energy Inc.	Xcel Energy Inc.
800 Nicollet Mall	800 Nicollet Mall
Minneapolis, Minnesota 55402	Minneapolis, Minnesota 55402
(612) 330-5500	(612) 330-5500

(Name, Address, Including Zip Code, and Telephone Number, Including Area Code, of Agent for Service)

Copy to:

ROBERT J. JOSEPH

Jones Day
77 West Wacker Drive
Chicago, Illinois 60601
(312) 269-4176

Approximate date of commencement of proposed sale to the public: From time to time after this registration statement becomes effective.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. þ

If this form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If delivery of the prospectus is expected to be made pursuant to Rule 434, please check the following box. o

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities To Be Registered	Amount To Be Registered	Proposed Maximum Offering Price Per Unit(1)	Proposed Maximum Aggregate Offering Price	Amount of Registration Fee
7 1/2% Convertible Senior Notes due 2007	$230,000,000	$1,211.27	$278,592,100	$25,630.48
Common Stock (par value $2.50 per share)(2)				
Rights to Purchase Common Stock (par value $2.50 per share)(2)				

(1) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(c) under the Securities Act, based on the average of the bid and asked prices of the notes on the Portal System on February 10, 2003 of $1,211.27 per $1,000 aggregate principal amount at maturity of the notes.

(2) Also being registered are an indeterminate number of shares of common stock issuable upon conversion of the notes registered hereby or in connection with a stock split, stock dividend, recapitalization or similar events and one right to purchase common stock pursuant to a stockholder protection rights agreement that trades with each share of common stock, for which no additional registration fee is payable pursuant to Rule 457(i) under the Securities Act.

The registrant hereby amends this registration statement on such date as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until the registration statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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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

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 price of $12.33 per share, which is equal to a conversion rate of approximately 81.1359 shares of our common stock per $1,000 principal amount of notes, 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. 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.

Investing in the notes involves risks. You should consider carefully the risk factors described under the caption Risk Factors beginning on page 7 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 February 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; 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, Notes to Consolidated Financial Statements and Notes to Interim 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 1.3 million electric customers and 0.4 million gas customers in Minnesota, North Dakota and South Dakota;

Public Service Company of Colorado, a Colorado corporation (PSCo), which serves 1.3 million electric customers and 1.2 million gas customers in Colorado;

Southwestern Public Service Company, a New Mexico corporation (SPS), which serves 390,000 electric customers in portions of Texas, New Mexico, Oklahoma and Kansas;

Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin), which serves 230,000 electric customers and 90,000 gas customers in northern Wisconsin and Michigan;

Cheyenne Light, Fuel and Power Company (Cheyenne), a Wyoming corporation, which serves 40,000 electric customers and 30,000 gas customers in and around Cheyenne, Wyoming; and

Black Mountain Gas Company (BMG), an Arizona corporation, which serves 9,300 customers in Arizona.

Our regulated businesses also include Viking Gas Transmission Company (Viking), which we sold on January 17, 2003, and WestGas InterState Inc. (WGI), both interstate natural gas pipelines.

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 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.

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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. Pursuant to the agreement, NBP purchased Viking, including Viking s ownership interest in Guardian, for approximately $152 million, including the assumption of approximately $40 million of outstanding debt.

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. For additional information regarding the terms of the Securities Purchase Agreement and the terms of the 8% senior convertible notes, see Note 10 to our interim consolidated financial statements for the quarter ended September 30, 2002.

On November 12, 2002, we announced that our Board of Directors voted to elect Benjamin G.S. Fowke III to the position of vice president and treasurer. Mr. Fowke, who has 20 years of experience in the energy industry, previously served as vice president and chief financial officer of our commodity trading and marketing business unit.

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 in to 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.

On January 29, 2003, we announced that our preliminary earnings for 2002 were a net loss of $2.0 billion, or $5.26 per share, including NRG results and impacts, compared with net earnings of $791 million, or $2.30 per share, in 2001. Our earnings, excluding NRG s pro forma operating results and other NRG impacts, were $525 million, or $1.38 per share, compared with $591 million, or $1.72 per share, for the year 2001. The earnings are preliminary and unaudited. Consequently they are subject to change until audited results are publicly distributed. The consolidated audit of Xcel Energy, including the audit of NRG, is not expected until early March 2003.

In early November 2002, an NRG restructuring plan was presented to NRG s creditors. The restructuring plan also included a proposal addressing our continuing role and degree of ownership in NRG and obligations of NRG. In mid-December 2002, the NRG bank steering committee submitted a counter-proposal and in January 2003, the bondholder creditor committee issued its counter-proposal to the NRG restructuring plan. The counter-proposals would require substantial additional payments by us.

A new NRG restructuring proposal was presented to NRG s creditors in late January 2003. While we currently anticipate that any financial impact of the proposal will affect only 2003 results, there can be no assurance that the restructuring proposal ultimately agreed to will not impact our final earnings in 2002.

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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 September 30, 2002, after giving effect to the sale of the notes and the use of a portion of the proceeds thereof to redeem the Prior Notes, we would have no secured indebtedness and our unsecured and unsubordinated indebtedness would have been approximately $1.2 billion. 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 September 30, 2002, our subsidiaries had aggregate indebtedness and other liabilities of approximately $21.6 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.

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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 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 sold 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 and unaudited 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.

The consolidated financial statement information summarized in the tables below for 1999, 2000 and 2001 reflect reclassifications from amounts previously reported in our Annual Report on Form 10-K for the year ended December 31, 2001, due to:

changes in the presentation of electric and gas trading revenues and costs, as a result of adopting in 2002 the requirements of Emerging Issues Task Force Issue No. 02-03; and

the impact of discontinued operations for certain components of NRG. These reclassifications are necessary to provide historical information that is comparable and consistent with the amounts shown for the nine months ended September 30, 2002 and 2001 in the tables below.

The reclassifications did not change our earnings or cash flows from amounts previously reported in our Annual Report on Form 10-K for the year ended December 31, 2001.

	Nine months ended September 30,		Year ended December 31,		
	2002(1)	2001	2001	2000	1999(2)
	(unaudited)				(unaudited)
			(Thousands of dollars)		
Consolidated Income Statement Data:					
Operating revenue	$ 7,240,771	$8,979,337	$11,522,647	$9,369,839	$6,876,324
Operating (loss) income	$(1,926,093)	$1,555,026	$ 1,885,232	$1,505,159	$1,196,981
Interest charges and financing costs	$ 669,683	$ 584,530	$ 793,967	$ 674,820	$ 452,144
Net (loss) income	$(1,883,154)	$ 650,070	$ 794,966	$ 526,828	$ 570,933

	September 30, 2002(3)
	(Thousands of dollars) (unaudited)
Consolidated Balance Sheet Data:	
Total assets	$28,405,775
Short-term debt (including current maturities)(4)	$ 9,526,054
Long-term debt(4)	$ 6,889,364
Total debt	$16,415,418
Minority interest	$ 38,837
Mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000
Preferred stockholders equity	$ 105,320
Common stockholders equity	$ 5,247,506
Total capitalization (includes short-term debt and minority interests)	$22,301,081

(1) Results for 2002 include two significant items that are described further in the notes to our interim consolidated financial statements: (a) impairment charges and disposal losses related to NRG s long-lived assets and equity investments, which reduced operating income by

$3.0 billion and net income by $2.9 billion; and (b) income tax benefits related to our investment in NRG, which increased net income

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by $676 million. Excluding these items, 2002 operating income would have been approximately $1.1 billion and 2002 net income would have been approximately $400 million.

(2) The 1999 consolidated financial data was derived from financial statements audited by Arthur Andersen LLP, independent public accountants. We have been unable to obtain the consent of Arthur Andersen LLP to the use of their report in this prospectus. The 1999 amounts, as reclassified, are unaudited.

(3) Actual capitalization amounts are as reported in the notes to our interim consolidated financial statements, which includes reclassification of discontinued operations of NRG. The components of such discontinued operations are segregated on the balance sheet, outside of apparent capitalization components. As a result, $227.7 million of short-term debt is reported as current liabilities held for sale; and $25.1 million of minority interest and $203.1 million of long-term debt are reported in the notes to our interim consolidated financial statements as noncurrent liabilities held for sale.

(4) Based on the defaults under certain NRG debt agreements, and NRG s lenders having the ability to call such debt within twelve months of September 30, 2002, $6.7 billion of NRG s long-term debt has been reclassified to current as of that date.

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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 could be deemed to be insolvent. Many of its subsidiaries are also in default on their debt obligations and could be deemed to be insolvent. If these entities were the subject of voluntary or involuntary bankruptcy proceedings, their creditors 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.

Currently, NRG has failed to make scheduled payments on interest and/or principal on approximately $4.1 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. Under the United States Bankruptcy Code, 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. On December 16, 2002, NRG responded to the involuntary petition, contesting the petitioners claims and filing a motion to dismiss the case. The bankruptcy court has set April 29, 2003 as the evidentiary hearing date to consider the motion to dismiss filed by NRG. 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 so choose, to seek to enforce their remedies at any time, which would likely lead to a bankruptcy filing by NRG.

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.

In early November 2002, an NRG restructuring plan was presented to the creditors of NRG. The restructuring plan includes a proposal addressing our continuing role and degree of ownership in NRG and obligations to NRG. Based on the advice of our financial advisor that NRG could be deemed to be insolvent, and in return for a release of any and all claims against us, the plan proposes that we surrender our equity ownership of NRG and make a lump sum payment to NRG of $300 million. In mid-December 2002, the NRG bank steering committee submitted a counter-proposal to the NRG restructuring plan, which would require substantial additional payments by us. In January 2003, a new restructuring proposal was presented to NRG s creditors, and negotiations among NRG, NRG s creditors and ourselves are on-going.

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

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involuntary proceeding in bankruptcy and, in the case of certain lenders, realization on the collateral for their indebtedness.

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, whether or not NRG becomes subject to a bankruptcy proceeding, it is unlikely that we ultimately will own any equity interest in NRG. As of September 30, 2002, we had contributed approximately $1.9 billion of capital to NRG, including the value of our shares exchanged for minority NRG stockholder shares in June 2002. As of September 30, 2002, the net worth of NRG Energy was a deficit of approximately $135 million.

If NRG does become subject to a 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. If NRG or its creditors were to assert such claims in an NRG bankruptcy proceeding, there can be no assurance as to how a bankruptcy court would resolve the issue. One of the creditors of an NRG project already has filed involuntary bankruptcy proceedings against that project and has included claims against NRG and us. If a bankruptcy court were 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.

If NRG enters or is placed in bankruptcy, we can provide no assurance that a bankruptcy court will not 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 and capital contribution agreement pursuant to which we agreed to provide up to $300 million to NRG under certain circumstances. We may be required to provide NRG with this $300 million.

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 September 30, 2002, the maximum amount stated in our guarantees of obligations of NRG was approximately $234 million. Our aggregate exposure on guarantees of obligations of NRG was approximately $104 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.

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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 were found liable for such payment, we cannot assure you that the amount we would be required to pay would not 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. We cannot assure you that benefits that we would be required to pay NRG current or former employees pursuant to these arrangements would, in the aggregate, not 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, we cannot assure you that the amount of withdrawal liability we would be required to pay would not 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. We cannot assure you that any amounts that we would be required to pay to the IRS would not be material or that such amounts could be recovered from NRG.

We cannot assure you that we will 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

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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.

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 September 30, 2002, given the changing business conditions for NRG and the resolution of its pending restructuring plan. We are unable at this time to determine the possible magnitude of any additional NRG asset impairments, but they could be material.

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For additional information regarding our ownership of NRG and its potential implications on us, see Notes 6 and 7 to our interim 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.

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 September 30, 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.

We cannot assure you that any of our current ratings or those of our affiliates, including NRG, will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency. 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 September 30, 2002, we had guarantees outstanding with a maximum stated amount of approximately $864 million and actual current aggregate exposure of approximately $323 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.

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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.

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.

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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. 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 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 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.

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. 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 Note 10 to our interim consolidated financial statements and 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 and we cannot assure you that such investigations, and any attendant remedial actions, will not materially and adversely affect the financial position and results of operations of NSP-Minnesota.

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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 rate case with CPUC to address increased costs for providing energy to Colorado customers. PSCo has subsequently made revisions to the filing. The net impact of the filings (as currently filed) would increase electric revenue by approximately $233 million annually. This is based on approximately $186 million for fuel and purchased power energy expense and $47 million for the remaining cost of electric service. In addition, PSCo also requested a decrease in natural gas revenue by approximately $21 million to reflect lower wholesale gas costs. PSCo also requested that its authorized rate of return on equity be set at 12 percent for electricity and 12.25 percent for natural gas. Hearings in the case are scheduled for February and March, 2003.

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.

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.

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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 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. in which it bought power from Reliant and simultaneously sold the same quantity back to Reliant. We have received subpoenas from the Commodities Futures 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 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.

We are subject to environmental laws and regulations which could be difficult and costly to comply with.

We are subject to a number of environmental laws and regulations affecting many aspects of our past, present and future operations, including air emissions, water quality, wastewater discharges, and the management of wastes and hazardous substances. These laws and regulations generally require us to obtain and comply with a wide variety of environmental registrations, licenses, permits, inspections and other approvals. Environmental laws and regulations can also require us to perform environmental remediations, including remediations of properties formerly used to manufacture gas, and to install pollution control equipment at our facilities. Both public officials and private individuals may seek to enforce the applicable environmental laws and regulations against us. We cannot assure you that existing environmental laws or regulations will not be revised or that new laws or regulations seeking to protect the environment will not be adopted or become applicable to us or that we will not identify in the future conditions that will result in obligations or liabilities under existing environmental laws and regulations. Revised or additional laws or regulations which result in increased compliance costs or additional operating restrictions, or currently unanticipated costs or restrictions under existing laws or regulations, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our results of operations.

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.

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 connection with corporate-owned life insurance (COLI) policy loans of PSR Investments, Inc. (PSRI), a wholly owned subsidiary of PSCo. 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.

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 potential disallowance of interest expense deductions for the period of 1993 through 2002 is approximately $492 million. Should the IRS ultimately prevail on this issue, the aggregate additional Federal and state taxes and interest (not including penalties or interest on penalties) that would be payable to the IRS and state tax agencies in respect of the 1993-2002 period would be approximately $228 million (as determined on a before-tax basis). Because we are continuing to claim deductions for interest expense 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.

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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 8, 9, 11, 13 and 14 to our interim 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 September 30, 2002, our subsidiaries, other than NRG, had outstanding indebtedness and liabilities (including trade payables) of approximately $9.8 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 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 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.

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.

Deloitte & Touche and PricewaterhouseCoopers did not consent to the inclusion of their reports in this prospectus.

Our consolidated financial statements for the fiscal years ended December 31, 1999, 2000 and 2001 were initially audited by Arthur Andersen LLP, our former independent auditors. Following dismissal of Arthur Andersen as our independent auditors on March 27, 2002, our audited consolidated financial statements for the fiscal years ended December 31, 2000 and 2001, which are included in this prospectus, were reaudited by our new independent auditors, Deloitte & Touche LLP. Our financial statements for the fiscal year ended December 31, 1999 were not reaudited at that time. As a consequence of a change in the presentation of electric and gas trading revenues and costs and the impact of discontinued operations for certain subsidiaries of NRG in 2002, our 1999 financials are subject to restatement. The restated 1999 financial statements have not been reaudited. As a consequence thereof, Deloitte & Touche and PricewaterhouseCoopers LLP (the independent auditors of NRG) have declined to consent to the inclusion in this prospectus of their reports on our (and NRG s) audited financial statements for the fiscal years ended December 31, 2000 and 2001. Because Deloitte & Touche and PricewaterhouseCoopers have not consented to the inclusion of their reports in this prospectus, you may not recover against either one of them under Section 11 of the Securities Act for untrue statements of material fact contained in the financial statements audited by them or any omissions to state a material fact required to be stated in those financial statements. Prior to the date on which this prospectus becomes effective and before any sales of notes or shares of common stock issued upon conversion of notes are made by any selling shareholder hereunder, we expect to file an amendment to the registration statement of which this prospectus is a part that will include consolidated audited financial statements for the fiscal years ended December 31, 2000, 2001 and 2002. We expect that the amendment will include consents from Deloitte & Touche and PricewaterhouseCoopers to the inclusion in the prospectus of their reports on these audited consolidated financial statements.

RATIO OF EARNINGS TO FIXED CHARGES

	Nine months ended September 30,		Year ended December 31,				
	2002(1)	**2001**	**2001**	**2000**	**1999**	**1998**	**1997**
	(unaudited)						
Ratio of Earnings to Fixed Charges	(2.2)	2.8	2.1	1.9	2.4	3.0	2.6

(1) Earnings as defined in the ratio for the nine months ended September 30, 2002 were reduced by NRG asset impairment charges and disposal losses of $3.0 billion. Excluding these items, the ratio for such period would have been 1.8.

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 (through February 10, 2003)	$12.60	$10.76	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 February 10, 2003 the last reported sale price of our common stock on the New York Stock Exchange was $11.21 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. Although, we have preferred stock outstanding, the restrictions do not place any effective limit on our ability to pay dividends.

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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We and some of our subsidiaries have equity compensation plans under which stock options are awarded to key employees. All of the equity compensation plans were approved by our shareholders. As of December 31, 2002, the following options were outstanding:

	Securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options	Securities remaining available for future issuance under equity compensation plans
PSCo Omnibus Incentive Plan	299,351	$21.82	
Xcel Energy Inc. Omnibus Incentive Plan	821,434	26.56	6,347,200
NRG Long Term Incentive Compensation Plan	1,125,276	29.61	1,641,275
NCE Omnibus Incentive Plan	3,235,039	26.36	
NSP Executive Long-Term Incentive Award Stock Plan	3,511,532	23.44	

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CAPITALIZATION

The following table sets forth our consolidated capitalization as of September 30, 2002, (1) on an actual basis and (2) as adjusted for the initial offering of the notes and the application of the net proceeds thereof. 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 September 30, 2002(1)		As of September 30, 2002 (As adjusted)(2)	
	(Thousands of Dollars)	% of Capitalization	(Thousands of Dollars)	% of Capitalization
Short-term debt, including current maturities	$ 9,526,054	42.7%	$ 9,126,054	41.3%
Minority interest	38,837	0.2%	38,837	0.2%
Long-term debt	6,889,364	30.9%	7,112,599	32.1%
Mandatorily redeemable preferred securities of subsidiary trusts	494,000	2.2%	494,000	2.2%
Preferred stockholders equity	105,320	0.5%	105,320	0.5%
Common stockholders equity	5,247,506	23.5%	5,244,904	23.7%
Total capitalization (including short-term debt and minority interest)	$22,301,081	100.0%	$22,121,714	100.0%

(1) Actual capitalization amounts are as reported in our Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, which includes reclassification of discontinued operations of NRG in 2002. The components of such discontinued operations are segregated on the balance sheet, outside of apparent capitalization components. As a result, $227.7 million of short-term debt is reported as current liabilities held for sale; and $25.1 million of minority interest and $203.1 million of long-term debt are reported in the Form 10-Q as noncurrent liabilities held for sale.

(2) As adjusted to give effect to (i) the sale of the Prior Notes and (ii) the initial sale of the notes offered pursuant to this prospectus (not including $30,000,000 pursuant to the overallotment option exercised by the initial purchasers in full) and the use of a portion of the proceeds thereof to redeem the Prior Notes.

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SELECTED CONSOLIDATED FINANCIAL DATA

The following selected consolidated financial data as of December 31, 2001 and 2000, and for the years ended December 31, 2001, 2000 and 1999 have been derived from our audited consolidated financial statements and the related notes. The consolidated financial data as of September 30, 2002 and 2001 have been derived from our unaudited consolidated financial statements. The information set forth below should be read together with Management s Discussion and Analysis of Financial Condition and Results of Operations, our audited and unaudited consolidated financial statements and related notes and other financial information contained this prospectus. The historical financial information may not be indicative of our future performance.

The consolidated financial statement information summarized in the tables below for 1999, 2000 and 2001 reflects reclassifications from amounts previously reported in our Annual Report on Form 10-K for the year ended December 31, 2001, due to (a) changes in the presentation of electric and gas trading revenues and costs, and (b) the impact of discontinued operations for certain components of NRG in 2002. These reclassifications are necessary to provide historical information that is comparable and consistent with the amounts shown for the nine months ended September 30, 2002 and 2001 in the tables below. The reclassifications did not change our earnings or cash flows from amounts previously reported in the Annual Report on Form 10-K for the year ended December 31, 2001.

	Nine months ended September 30,		Year ended December 31,		
	2002(1)	2001	2001	2000	1999(2)
					(unaudited)
	(unaudited)				
	(In millions, except per share data)				
Consolidated Income Statement Data:					
Operating revenue	$ 7,241	$ 8,979	$ 11,522	$ 9,370	$ 6,876
Operating expense	9,167	7,424	9,637	7,865	5,679
Operating income	$ (1,926)	$ 1,555	$ 1,885	$ 1,505	$ 1,197
Interest income and other nonoperating income net of other expenses	39	46	59	18	1
Interest charges and financing costs	670	584	794	675	452
Income taxes (benefits)	(617)	325	330	295	181
Minority interest (income) expense	(39)	57	67	29	1
(Loss) income from continuing operations	(1,901)	635	753	524	564
(Loss) income from discontinued operations, net of tax	18	15	32	22	7
Extraordinary items, net of tax			10	(19)	
Net loss (income)	(1,883)	650	795	527	571
Dividends on preferred stock	3	3	4	4	5
(Loss) earnings available for common shareholders	$ (1,886)	$ 647	$ 791	$ 523	$ 566
Earnings per share diluted:					
(Loss) income before extraordinary items	(5.06)	1.84	2.18	1.54	1.69
Discontinued Operations	0.05	0.04	0.09	0.06	0.01
Extraordinary items			0.03	(0.06)	
Total	$ (5.01)	$ 1.88	$ 2.30	$ 1.54	$ 1.70

(1) Results for 2002 include two significant items that are described further in the notes to our interim consolidated financial statements: (a) impairment charges and disposal losses related to NRG s long-lived assets and equity investments, which increased operating expenses and reduced operating income for the nine month period by $3.0 billion; reduced income from continuing operations, net income and earnings available for common shareholders for the nine month period by $2.9 billion; and reduced

earnings per share from continuing operations and total earnings per share for the nine month period by $7.60; and (b) income tax benefits related to our investment in NRG, which increased income from continuing operations and net income for the nine month period by $676 million, and increased earnings per share from continuing operations and total earnings per share for the nine month period by $1.80.

(2) The 1999 consolidated financial data were derived from financial statements audited by Arthur Andersen LLP, independent public accountants. We have been unable to obtain the consent of Arthur Andersen LLP to the use of their report in this prospectus. The 1999 amounts, as reclassified, are unaudited. Reclassifications as described above have been made to the income statement previously reported in the Annual Report on Form 10-K for the year ended December 31, 2001. These reclassifications reduced revenue by $961 million and operating income by $8 million.

	September 30,	December 31,	
	2002	2001	2000
		(In millions)	
Consolidated Balance Sheet Data:			
Current assets	$ 4,194	$ 3,311	$ 3,128
Property, plant and equipment, at cost	19,136	20,619	15,038
Other assets	5,076	4,805	3,603
Total assets	$28,406	$28,735	$21,769
Current portion of long-term debt(1)	7,522	419	593
Short-term debt	2,004	2,225	1,475
Other current liabilities	2,925	2,806	2,604
Total current liabilities	12,451	5,450	4,672
Deferred credits and other liabilities	3,180	3,965	3,335
Minority interest	39	637	263
Long-term debt(1)	6,889	11,889	7,338
Mandatorily redeemable preferred securities of subsidiary trusts	494	494	494
Preferred stockholders equity	105	105	105
Common stockholders equity	5,248	6,195	5,562
Total liabilities and equity	$28,406	$28,735	$21,769

(1) Based on the defaults under certain NRG debt agreements, and NRG s lenders having the ability to call such debt within twelve months of September 30, 2002, $6.7 billion of NRG s long-term debt has been reclassified to current as of that date.

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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.

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, 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. 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 more fully in the Notes to consolidated financial statements and Liquidity , NRG has recently 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 and loss on disposal 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 being downgraded, NRG is required to post 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. Based on discussions with the construction revolver lenders, it is NRG s understanding that the administrative agent, Credit Suisse First Boston, issued the acceleration notice to preserve certain rights under the construction revolver financing agreements. NRG believes that the administrative agent intends to forbear in the immediate exercise of any rights and remedies against NRG. 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. By reason of these various 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.

NRG prepared and submitted to its, and a number of its subsidiaries various lenders, bondholders and other creditor groups (collectively, NRG s Creditors) a restructuring plan on November 4, 2002. The restructuring plan is expected to serve as a basis for negotiations with NRG s Creditors in a financially-restructured NRG and, among other things, proposes (i) holders of secured (project-level) debt would either

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(a) have their debt reinstated with agreed modifications or (b) receive the collateral securing such debt and a claim or claims to the extent such debt is under-secured; (ii) holders of unsecured debt, holders of secured recourse claims against NRG, and holders of other general unsecured claims against NRG would receive a pro rata share of (a) an aggregate of $500 million of junior secured debt of reorganized NRG and (b) 95% of the common equity of reorganized NRG; and (iii) holders of project-level general unsecured claims that are non-recourse to NRG would receive a pro rata share of the remaining 5% of the common equity of reorganized NRG.

The restructuring plan also includes a proposal addressing our continuing role and degree of ownership in NRG and obligations to NRG. Based on the advice of our financial advisor that NRG may be deemed insolvent and in return for a release of any and all claims against us, the plan proposes that, upon consummation of the restructuring, we would pay $300 million to NRG. The plan separately proposes that we surrender our equity ownership of NRG. The plan does not contemplate any sharing by us with NRG s Creditors of any benefits we might receive in connection with the tax matters described below. We are unable to predict whether NRG will be able to implement any such restructuring plan, or whether, 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. In mid-December 2002, the NRG bank steering committee submitted a counter-proposal and in January 2003, the bondholder creditor committee issued its counter-proposal to the NRG restructuring plan. The counter-proposals would require substantial additional payments by us.

A new NRG restructuring proposal was presented to NRG s creditors in late January, 2003. While we currently anticipate that any financial impact of the proposal would affect only 2003 results, there can be no assurance that the restructuring proposal ultimately agreed to will not also impact our final earnings in 2002.

On November 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG. Under 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 has responded to the involuntary petition, contesting the petitioners claims and filing a motion seeking to have the case dismissed. The court has set April 29, 2003, as the evidentary hearing date to consider the motion to dismiss filed by NRG.

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, 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.

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 audited and interim consolidated financial statements and Notes included in this prospectus.

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Results of Operations

Our earnings per share for the nine months ended September 30, 2002 and 2001 and for each of the three years in the period ended December 31 were as follows:

Contribution to earnings per share

	Nine Months Ended September 30,		Year Ended December 31,		
	2002	**2001**	**2001**	**2000**	**1999**
Total regulated earnings before extraordinary items	$ 1.23	$1.52	$1.87	$ 1.26	$1.51
Total nonregulated/ holding company	(6.29)	0.32	0.31	0.28	0.19
Extraordinary items			0.03	(0.06)	
Discontinued Operations	0.05	0.04	0.09	0.06	0.02
Total earnings per share (diluted)	$(5.01)	$1.88	$2.30	$ 1.54	$1.70

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

Significant Factors that Impacted Nine Months Ended September 30, 2002 Results

Xcel Energy issued 23 million shares of common stock in a public offering in February 2002, as well as 25.7 million in June 2002. Dilution from these issuances reduced the loss per share for the nine-month period ended September 30, 2002, by 42 cents per share. The majority of these dilution impacts are affecting NRG s assets impairment and special charges, as discussed below.

NRG Asset Impairments Earnings have been reduced by NRG asset impairment charges recorded as special charges in the third quarter of 2002, which totaled $2.9 billion before tax and $2.8 billion after tax, or $7.28 per share for the nine months ended September 30, 2002. In addition, results for the nine months ended September 30, 2002 include tax benefits of $1.80 per share related to Xcel Energy investments in NRG.

Special Charges NRG Severance and Restructuring In the second quarter of 2002, NRG expensed a pretax charge of $20 million, or 4 cents per share, for expected severance and related benefits. Additional severance accruals of $6 million, or 1 cent per share, were made in the third quarter of 2002. Through September 30, 2002, severance costs have been recognized for all employees who had been terminated as of that date. Similar charges are expected to be expensed in the future, as further actions are taken, but are not determinable at this time. Another $12 million, or 2 cents per share, of other NRG restructuring costs were recorded in the third quarter of 2002, including financial advisors, legal advisors and consultants.

Special Charges NRG Charges-NEO Project During the second quarter of 2002, NRG expensed a pretax charge of $36 million, or 6 cents per share, related to its NEO Corporation landfill gas generation operations. The charge was related largely to asset impairments based on a revised project outlook. It also reflects the accrued impact of a dispute settlement with Fortistar, a partner with NEO in the landfill gas generation operations.

Special Charges Regulatory Recovery Adjustment In late 2001, SPS, our wholly owned subsidiary, filed an application requesting recovery of costs incurred to comply with transition to retail competition legislation in Texas and New Mexico. During the first quarter of 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, or approximately 1 cent per share.

Special Charges Restaffing Costs During the fourth quarter of 2001, Xcel Energy recorded an estimated liability for expected staff consolidation costs for an estimated 500 employees in several utility operating and corporate support areas of Xcel Energy. In the first quarter of 2002, the identification of affected employees was completed and additional pretax special charges of $9 million, or approximately 1 cent per share, were expensed for the final costs of the utility-related staff consolidations. All 564 of accrued staff terminations have occurred.

Significant Factors that Impacted 2001 Results

Conservation Incentive Recovery Earnings were increased by 7 cents per share due to the reversal of a Minnesota Public Utilities Commission (MPUC) decision.

In June 1999, the MPUC denied NSP-Minnesota recovery of 1998 incentives associated with state-mandated programs for electric energy conservation. We recorded a $35-million charge in 1999, which reduced earnings by 7 cents per share, based on this action. NSP-Minnesota appealed the MPUC decision and in December 2000, the Minnesota Court of Appeals reversed the MPUC decision. In January 2001, the MPUC appealed the lower court decision to the Minnesota Supreme Court. On February 23, 2001, the Minnesota Supreme Court declined to hear the MPUC s appeal. During the second quarter of 2001, NSP-Minnesota filed with the MPUC a plan that carried out, among other things, the court s decision.

On June 28, 2001, the MPUC approved the plan and issued an order to that effect shortly thereafter. 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 for 2001 are now being recorded on a current basis.

Special Charges Postemployment Benefits Earnings 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. For more information, see Note 2 to the audited consolidated financial statements.

Special Charges Restaffing Costs During 2001, we expensed pretax special charges of $39 million, or 7 cents per share, for planned staff consolidation costs. The charges related to severance costs for utility operations resulting from restaffing plans of several operating and corporate support areas of ours. We accrued for 500 staff terminations that occurred mainly in the first quarter of 2002, across all regions of our service territory, but primarily in Minneapolis and Denver. For more information, see Note 2 to the audited consolidated financial statements.

Extraordinary Items Electric Utility Restructuring During early 2001, legislation in both Texas and New Mexico was passed that delayed the planned implementation of restructuring within SPS service territory for at least five years. Accordingly, in the second quarter of 2001, SPS reapplied the provisions of Statement of Financial Accounting Standards (SFAS) No. 71 Accounting for the Effects of Certain Types of Regulation for its generation business. Based on subsequent financing and regulatory activities clarifying the expected ratemaking impacts of restructuring delays in the fourth quarter of 2001, SPS restored certain regulatory assets totaling $17.6 million as of December 31, 2001, and reported related after-tax extraordinary income of $11.8 million, or 3 cents per share. This represents a reversal of a portion of the 2000 write-offs discussed later. Regulatory assets previously written off were restored only for items currently being recovered in rates and items where future rate recovery is considered probable. For more information, see Note 12 to the audited 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. Of these special charges, approximately 44 cents per share were associated with the costs of merging regulated operations and 8 cents per share were associated with merger impacts on nonregulated activities. See Note 2 to the audited consolidated financial statements for more information on these charges.

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Extraordinary Items Electric Utility Restructuring Our earnings for 2000 were reduced by 6 cents per share for two extraordinary items related to the expected discontinuation of regulatory accounting for SPS generation business. Based on expectations at that time for SPS restructuring, during the second quarter of 2000, SPS wrote off its generation-related regulatory assets and other deferred costs for an extraordinary charge of approximately $19.3 million before tax, or $13.7 million after tax. During the third quarter of 2000, SPS recorded an additional extraordinary charge of $8.2 million before tax, or $5.3 million after tax, related to the tender offer and defeasance of approximately $295 million of first mortgage bonds, again based on expected restructuring. For more information, see Note 12 to the audited consolidated financial statements.

Significant Factors that Impacted 1999 Results

Conservation Incentive Recovery Earnings for 1999 were reduced by 7 cents per share due to the disallowance of 1998 conservation incentives for NSP-Minnesota. In June 1999, the MPUC denied NSP-Minnesota recovery of 1998 lost margins, load management discounts and incentives associated with state-mandated programs for electric energy conservation. We recorded a $35-million reduction to pretax income in 1999 based on this action, primarily as a reduction of electric utility revenue. As discussed previously under Significant Factors that Impacted 2001 Results, this decision and the related charge were ultimately reversed.

In addition, based on the 1999 change in the MPUC policy on conservation incentives and regulatory uncertainty, in 1999 and 2000 management did not record conservation incentives until they were approved by the MPUC the following year.

Special Charges During 1999, we expensed pretax special charges of $31 million, or 7 cents per share, stemming from asset impairments related to goodwill and marketable securities associated with nonregulated activities. See Note 2 to the audited consolidated financial statements for more information on these charges.

Contribution to Our Earnings Per Share of Nonregulated Subsidiaries and Holding Company

	Nine Months Ended September 30,		Year Ended December 31,		
	2002	2001	2001	2000	1999
NRG*	$(7.91)	$ 0.50	$ 0.49	$ 0.40	$ 0.15
Holding company tax benefit from investment in NRG	1.80	0.00			
Xcel Energy International, including Yorkshire Power	(0.02)	(0.03)	0.01	0.13	0.13
Eloigne Company	0.02	0.02			
Seren Innovations	(0.04)	(0.06)	(0.08)	(0.07)	(0.03)
Planergy International	(0.01)	(0.02)	(0.04)	(0.08)	(0.06)
e prime	0.00	0.02	0.02	(0.02)	(0.01)
Financing costs and preferred dividends	(0.08)	0.09	(0.11)	(0.07)	(0.03)
Other nonregulated	0.00	0.02	0.02	(0.01)	0.02
Total nonregulated/ holding co earnings per share	$(6.24)	$ 0.36	$ 0.31	$ 0.28	$ 0.17

* NRG s earnings for 2001 and 2000 in this Management s Discussion and Analysis of Financial Condition and Results of Operations exclude earnings of 19 cents per share and 8 cents per share, respectively, related to minority shareholder interests, and earnings of $31.9 million and $21.5 million related to discontinued operations.

NRG NRG s earnings for the nine months ended September 30, 2002 decreased due primarily to lower 2002 power prices in the Northeast, Mid-Atlantic and Central regions of the United States and

favorable market conditions for West Coast Power in 2001. NRG s special charges include estimated losses on sales of certain projects, restructuring costs incurred to date and asset impairment losses, which are discussed in Note 2 to the interim consolidated financial statements, and discontinued operations and loss on disposal of equity investments (other assets held for sale), which are discussed in Note 3 to the interim consolidated financial statements.

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 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 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 s earnings for 2000 reflected increased electric revenues resulting from acquired generation assets. During 2000, NRG increased its megawatt ownership interest in generating facilities in operation by more than 4,000 megawatts. NRG s earnings for 2000 also were influenced by favorable weather conditions that increased demand for electricity in the northeast and western United States, market dynamics, strong performance from existing assets and higher market prices for electricity.

Yorkshire Power In August 2002, we announced that we sold our 5.25-percent interest in Yorkshire Power 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.

During February 2001, we reached an agreement to sell the majority of our investment in Yorkshire Power to Innogy Holdings plc. 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 11 to the audited consolidated financial statements.

Seren Operations of Seren s broadband communications network in Minnesota and California resulted in losses for the nine months ended September 30, 2002. As of December 31, 2002, our investment in Seren was approximately $255 million. Seren projects improvement in its operating results with positive cash flow anticipated in 2005 and an earnings contribution anticipated in 2008.

Construction of Seren s broadband communications network resulted in losses for 2001, 2000 and 1999. 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.

Planergy Planergy s results for the nine months ended September 30, 2002 reflected a loss of approximately 2 cents per share recorded in the second quarter of 2001, which was largely due to lower margins on performance contracts, higher project development expenses and final costs related to the consolidation of Planergy and Energy Masters International (EMI) operations.

Competitive markets and delays in government contracts resulted in continued low margins and losses for Planergy in 2001.

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. As a part of the merger in 2000, Planergy and EMI, both wholly-owned subsidiaries of ours, were combined to form Planergy. As a result of this combination, Planergy reassessed its business model and made a strategic realignment, which resulted in the write-off of $22 million (before tax) of goodwill and project development costs.

In addition, Planergy s results for 1999 were reduced by a special charge of 4 cents per share to write off approximately $17 million (before tax) of goodwill.

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e prime s results for the year ended December 31, 2001, reflect the favorable structure of its contractual portfolio, including gas storage and transportation positions, structured products and proprietary trading in natural gas markets.

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 reevaluations of e prime s energy marketing business.

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

Other Other nonregulated results for 2000, which include the activity of several nonregulated subsidiaries, were reduced by special charges of 2 cents per share recorded during the third quarter. 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 Merger.

In addition, other nonregulated results for 1999 were reduced by special charges of 3 cents per share for a valuation write-down of our investment in the publicly traded common stock of CellNet Data Systems, Inc.

Income Statement Analysis

Electric Utility and Commodity Trading Margins Electric fuel and purchased power expense 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, certain fuel cost recovery mechanisms in various jurisdictions do not allow for complete recovery of all variable production expenses. Therefore, higher costs can result in adverse margin and earnings impacts. 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.

Our commodity trading operations are conducted mainly by PSCo (electric) and e prime (gas), both wholly-owned subsidiaries. Electric trading activity, initially recorded at PSCo, is partially redistributed to NSP-Minnesota and SPS pursuant to a Joint Operating Agreement (JOA) approved by the Federal Energy Regulatory Commission (FERC). Trading revenue and costs do not include the revenue and production costs associated with energy produced from our generation assets or energy and capacity purchased to serve native load. Trading revenue and costs associated with NRG s operations are included in nonregulated margins. Margins from these generating assets for utility operations are included in short-term wholesale amounts, discussed later. Trading margins reflect the impact of sharing certain trading margins under the ICA. The following table details electric utility, short-term wholesale and electric and gas trading revenue and margin.

	Electric Utility	Short-Term Wholesale	Electric Commodity Trading	Gas Commodity Trading	Intercompany Eliminations	Consolidated Totals
			(Millions of dollars)			
9 months ended 9/30/2002						
Electric utility revenue	$ 3,985	$ 132	$	$	$	$ 4,117
Electric and gas trading revenue			1,351	1,511	(57)	2,805
Electric fuel and purchased power-utility	(1,544)	(107)				(1,651)
Electric and gas trading costs			(1,353)	(1,505)	57	(2,801)
Gross margin before operating expenses	$ 2,441	$ 25	$ (2)	$ 6	$	$ 2,470
Margin as a percentage of revenue	61.3%	18.9%	(0.1)%	0.4%		35.7%

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	Electric Utility	Short-Term Wholesale	Electric Commodity Trading	Gas Commodity Trading	Intercompany Eliminations	Consolidated Totals
			(Millions of dollars)			
9 months ended 9/30/2001						
Electric utility revenue	$ 4,335	$ 675	$	$	$	$ 5,010
Electric and gas trading revenue			1,075	1,524	(75)	2,524
Electric fuel and purchased power-utility	(2,043)	(529)				(2,572)
Electric and gas trading costs			(999)	(1,509)	75	(2,433)
Gross margin before operating expenses	$ 2,292	$ 146	$ 76	$ 15	$	$ 2,529
Margin as a percentage of revenue	52.9%	21.6%	7.1%	1.0%		33.6%
12 months ended 12/31/01						
Electric utility revenue	$ 5,607	$ 788	$	$	$	$ 6,395
Electric and gas trading revenue			1,337	1,938	(88)	3,187
Electric fuel and purchased power-utility	(2,559)	(613)				(3,172)
Electric and 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%
12 months ended 12/31/00						
Electric utility revenue	$ 5,107	$ 567	$	$	$	$ 5,674
Electric and gas trading revenue			819	1,297	(54)	2,062
Electric fuel and purchased power-utility	(2,106)	(475)				(2,581)
Electric and 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%
12 months ended 12/31/99						
Electric utility revenue	$ 4,242	$ 680	$	$	$	$ 4,922
Electric and gas trading revenue			534	419	(2)	951
Electric fuel and purchased power-utility	(1,329)	(638)				(1,967)
Electric and gas trading costs			(532)	(417)	2	(947)
Gross margin before operating expenses	$ 2,913	$ 42	$ 2	$ 2	$	$ 2,959
Margin as a percentage of revenue	68.7%	6.2%	0.4%	0.5%		50.4%

Table Note 1 The wholesale and trading margins reflect the impact of the regulatory sharing of certain margins under the ICA in Colorado.

Nine Months Ended September 30, 2002 Comparison to Nine Months Ended September 30, 2001 Electric utility revenues decreased approximately $350 million in the first nine months of 2002, compared with the same period in 2001, due largely to lower fuel and power costs passed through rate recovery mechanisms. Despite the decrease in revenues, electric utility margins increased approximately $149 million for the first nine months of 2002, compared with 2001. The higher electric margins in the first nine months of 2002 reflect lower unrecovered costs, due in part to resetting the base-cost recovery at PSCo in January 2002, sales growth and lower regulatory accruals. Electric utility revenues and margins were both negatively affected in

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2002 due to the 2001 reversal of the disallowed conservation incentive revenues at NSP-Minnesota discussed previously and lower sales of excess capacity in Texas.

Electric and gas commodity trading margins and short-term wholesale margins decreased approximately $208 million for the first nine months of 2002, compared with the first nine months of 2001. The decrease reflects lower power pool prices and other market conditions in 2002.

2001 Comparison to 2000 Electric utility revenue increased by approximately $500 million, or 9.8 percent, in 2001. 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. Temperatures 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, in comparison to approximately $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 gas commodity trading margins, including proprietary (i.e. non-asset based) electric trading 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.

Short-term wholesale margins and electric commodity trading margins for 2002 are not expected to be as strong as margins in 2001 due to declines in energy prices. Margins for the second half of 2001 are more indicative of expected trends in 2002. During 2001, in some Western markets, publicly available power prices ranged from $80 to more than $350 per megawatt-hour on a monthly average. Currently, publicly available forward price information for 2002 for these same areas ranges from $60 to $110 per megawatt-hour on a monthly average.

2000 Comparison to 1999 Electric utility revenue increased by approximately $865 million, or 20.4 percent, in 2000. Electric utility margin increased by approximately $88 million, or 3.0 percent, in 2000. Electric margins reflect the impact of customer sharing due to the ICA mechanism. Weather-normalized retail sales increased by 3.6 percent in 2000, increasing retail revenue by approximately $153 million and retail margin by approximately $88 million. More favorable temperatures during 2000 increased retail revenue by approximately $36 million and retail margin by approximately $22 million. These retail margin increases were partially offset by regulatory adjustments relating to the earnings test in Texas and system reliability and availability in Colorado, and to rate reductions agreed to as part of the merger approval process.

Short-term wholesale margin increased due to the expansion of our wholesale marketing operations and favorable market conditions.

Electric and gas commodity trading revenue increased by a total of approximately $1.2 billion, and the combined trading margin increased by approximately $37 million in 2000. The increase in trading revenue and margin is a result of the expansion of electric and natural gas trading.

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

	Nine Months Ended September 30,		Year Ended December 31,		
	2002	2001	2001	2000	1999
	(Millions of dollars)				
Gas revenue	$ 938	$ 1,577	$ 2,053	$1,469	$1,141
Cost of gas purchased and transported	(559)	(1,200)	(1,518)	(948)	(683)
Gas margin	$ 379	$ 377	$ 535	$ 521	$ 458

Nine Months Ended September 30, 2002 Comparison to Nine Months Ended September 30, 2001 Gas revenue decreased by approximately $639 million, or 40.5 percent, in the first nine months of 2002, compared with the same period in 2001, primarily due to decreases 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. Gas margin increased approximately $2 million for the first nine months of 2002, compared with 2001, due largely to the full-period effect of a rate increase effective February 2001 at PSCo.

2001 Comparison to 2000 Gas 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. Gas margin increased by approximately $14 million, or 2.7 percent, for 2001 due to sales growth and a rate increase in Colorado. These gas revenue and margin increases were partially offset by the impact of warmer temperatures in 2001, which decreased gas revenue by approximately $38 million and gas margin by approximately $16 million.

2000 Comparison to 1999 Gas revenue increased by approximately $328 million, or 28.7 percent, in 2000, primarily due to increases in the cost of natural gas, which are largely recovered through various adjustment clauses in most of the jurisdictions in which we operate. Gas margin increased by approximately $63 million, or 13.8 percent, in 2000. Temperatures during 2000 compared with 1999 increased gas revenue by $82 million and gas margins by $33 million. Customer growth also contributed to margin increases in 2000.

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

	Nine Months Ended:				
	9/30/02	9/30/01	2001	2000	1999
	(Millions of dollars)				
Nonregulated and other revenue	$ 2,108	$ 2,102	$ 2,767	$2,019	$ 703
Earnings from equity investments	73	199	219	166	106
Nonregulated cost of goods sold	(1,137)	(1,132)	(1,361)	(895)	(308)
Nonregulated margin	$ 1,044	$ 1,169	$ 1,625	$1,290	$ 501

Nine Months Ended September 30, 2002 Comparison to Nine Months Ended September 30, 2001 Nonregulated margin decreased for the first nine months of 2002, largely due to lower power prices in both consolidated and equity investment projects. Lower power prices, mainly in the United States, reduced demand for NRG s peaking and merchant power facilities.

2001 Comparison to 2000 Nonregulated revenue and margin increased for 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 the majority of its investment in Yorkshire Power, we did not record any equity earnings from Yorkshire Power after January 2001.

2000 Comparison to 1999 Nonregulated and other revenue increased by approximately $1.3 billion in 2000, largely due to NRG s acquisition of generation facilities during 2000 and the full-year impact of generating assets acquired during 1999. Earnings from equity investments increased by approximately $60 million in 2000, primarily due to increased equity earnings from NRG projects. Nonregulated margin increased by approximately $789 million in 2000, largely due to NRG s acquisition of generation facilities during 2000.

Non-Fuel Operating Expense and Other Items Other utility operating and maintenance expense for the nine months ended September 30, 2002 decreased by approximately $37 million, or 3.3 percent, compared with the nine months ended September 30, 2001. The decreased costs reflect lower incentive compensation and other employee benefit costs, as well as lower staffing levels in corporate areas, partially offset by higher plant outage and property insurance costs.

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 utility operating and maintenance expense for 2000 increased by approximately $69 million, or 5.0 percent, compared with 1999. The increase is largely due to the timing of outages at the Monticello and Prairie Island nuclear plants and at the Sherco coal-fired power plant, increased bad debt reserves related to wholesale and retail customers, higher nuclear operating costs and higher employee-related costs.

Depreciation and amortization expense increased by approximately $120 million, or 17.9 percent, for the nine months ended September 30, 2002, compared with the nine months ended September 30, 2001, primarily due to acquisitions of generating facilities by NRG and capital additions to NRG-owned generation facilities and utility plant additions.

Depreciation and amortization expense increased $148 million, or 18.9 percent, in 2001 and $103 million, or 15.1 percent, in 2000, primarily due to acquisitions of generating facilities by NRG and increased additions to utility plant.

Taxes (other than income taxes) increased largely due to an $8 million Colorado property tax refund in 2001 for calendar year 2000.

Interest expense increased by approximately $85 million, or 15.4 percent, for the nine months ended September 30, 2002, compared with the nine months ended September 30, 2001, primarily due to increased debt levels to fund several asset acquisitions by NRG.

Interest expense increased $119 million, or 19 percent, in 2001 and $222 million, or 53.9 percent, in 2000, primarily due to increased debt levels to finance several asset acquisitions by NRG.

Interest income and other nonoperating income net of other expenses decreased by approximately $8 million, or 16.4 percent, for the nine months ended September 30, 2002, compared with the nine months ended September 30, 2001, primarily due to lower interest income at NRG and lower net gains in the sale of assets.

Interest income and other net increased by approximately $41 million for the year ended December 31, 2001, compared with the same period in 2000. This increase was primarily the result of a credit swap at NRG, NRG mark-to-market gains on foreign debt, NRG interest income due to increased affiliate receivables related to loans to West Coast Power and gains from the sale of PSCo assets.

Income tax expense decreased by approximately $942 million for the nine months ended September 30, 2002, compared with the nine months ended September 30, 2001. Nearly all of this decrease relates to NRG s 2002 losses and the change in tax filing status for NRG in the third quarter of 2002. NRG is now in a tax operating loss carryforward and is no longer assumed to be part of Xcel Energy s consolidated tax group.

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The effective rate for continuing operations (excluding minority interest) was 24.1 percent for the nine months ended September 30, 2002 and 32.1 percent for the nine months ended September 30, 2001. The change 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 from a one-time adjustment to recognize tax benefits from Xcel Energy s investment in NRG.

As discussed in Note 8 to the audited consolidated financial statements, our effective tax rate before extraordinary items was 28.7 percent for the year ended December 31, 2001, and 34.7 percent for the same period in 2000. The change in the effective tax rate reflects changes in the 2001 effective tax rate at NRG and the non-deductibility of certain merger costs in 2000. As discussed previously, NRG s annual effective tax rate for 2001 declined due to higher energy tax 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.

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 the first three quarters of 2002 increased earnings by an estimated 6 cents per share.

weather in 2001 had minimal impact on earnings per share.

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

weather in 1999 decreased earnings by an estimated 9 cents per share.

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 gas service within their respective jurisdictions. In addition, our nonregulated businesses have become a larger part of our operations and a more significant factor in our earnings. The historical and future trends of our operating results have been and are expected to be affected by the following factors:

As discussed more fully in the notes to consolidated financial statements and Liquidity, NRG has recently 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 being 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. 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. By reason of these various 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.

In early November 2002, an NRG restructuring plan was presented to the creditors of NRG. The restructuring plan also includes a proposal addressing our continuing role and degree of ownership in NRG and obligations to NRG. Based on the advice of its financial advisor that NRG may be deemed insolvent, and in return for a release of any and all claims against us, the plan proposes that we surrender our equity ownership of NRG and make a payment to NRG of $300 million. The plan did not contemplate any sharing by us with NRG s creditors of any benefits we might receive in connection with any potential tax benefits. In mid-December 2002, the NRG bank steering committee submitted a counter-proposal and in January 2003,

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the bondholder creditor committee issued its counter-proposal to the NRG restructuring plan. The counter-proposals would require substantial additional payments by us.

A new NRG restructuring proposal was presented to NRG s creditors in late January, 2003. While we currently anticipate that any financial impact of the proposal would affect 2003 results, there can be no assurance that the restructuring proposal made, or ultimately agreed to, will not impact our final earnings in 2002.

On November 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG. Under 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 has responded to the involuntary petition, contesting the petitioners claims and filing a motion seeking to have the case dismissed. The court has set April 29, 2003, as the evidentary hearing date to consider the motion to dismiss filed by NRG. 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 so choose, to seek to enforce their remedies at any time, which would likely lead to a bankruptcy filing by NRG.

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 may decrease the need for additional power supply. We expect the economic conditions to have a significant impact on commodity trading margins, which are not expected to be as strong as those experienced in 2001. In addition, certain operating costs, such as insurance and security, have increased due to the economy and the terrorist attacks of September 11, 2001. We do not believe these events will affect our access to insurance markets. However, we could experience other significant impacts from a weakened economy.

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.

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 its transmission system to MISO in January 2002.

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, a large energy company, have caused delays in industry restructuring.

Major issues that must be addressed include mitigating 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 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. For more information on the delay of restructuring for SPS in Texas and New Mexico, see Note 12 to the audited consolidated financial statements.

In addition, industry restructuring may impact the wholesale power markets in which NRG operates. The independent system operators who oversee most of the wholesale power markets have in the past imposed, and may in the future continue to impose, price limitations and other mechanisms to address some of the volatility in these markets. For example, the independent system operator for the New York Power Pool and

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the California independent system operator have recently imposed price limitations. These types of price limitations and other mechanisms in New York, California, the New England Power Pool and elsewhere may adversely impact the profitability of NRG s generation facilities that sell energy into the wholesale power markets. Finally, the regulatory and legislative changes that have recently been enacted in a number of states in an effort to promote competition are novel and untested in many respects. These new approaches to the sale of electric power have very short operating histories, and it is not yet clear how they will operate in times of market stress or pressure, given the extreme volatility and lack of meaningful long-term price history in many of these markets and the imposition of price limitations by independent system operators.

Enron Impacts Industry changes also may be implemented as a result of the bankruptcy filing of Enron. Such changes may be invoked by various regulatory agencies, including but not limited to the SEC, the FERC or state regulatory agencies. Management is unable to predict the impact of such changes, if any, on any component of the energy industry. See additional discussion in Note 15 to the audited consolidated financial statements.

California Power Market NRG operates in and sells to the wholesale power market in California. During 2000, the inability of certain California utilities to recover rising energy costs through regulated prices charged to retail customers created financial difficulties. The California utilities have appealed to state agencies and regulators for the opportunity to be reimbursed for costs incurred that are not currently recoverable through the existing rate structure. Absent such relief, some of the utilities have indicated they may be unable to continue to service their debt or otherwise pay obligations, or would consider discontinuing energy service to customers to avoid incurring costs that are not recoverable. However, the extent and timing of such financial support that will be made available to California utilities is unknown at this time.

See Note 15 to the audited consolidated financial statements for a description of lawsuits against NRG and other power producers and marketers involving the California electricity markets and a discussion of our and NRG s receivables related to the California power market.

Critical Accounting Policies Preparation of 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 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 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,

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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
Regulatory Mechanisms & 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 of Financial Condition and Results of Operations: Factors Affecting Results of Operations Utility Industry Changes and Restructuring Notes to audited consolidated financial statements Note 1 Note 12 Note 15
Nuclear Plant Decommissioning	Costs of future decommissioning Availability of facilities for waste disposal Approved methods for waste disposal Useful lives of nuclear power plants	Notes to audited consolidated financial statements Note 1 Note 15 Note 16
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 of Financial Condition and Results of Operations: Factors Affecting Results of Operations Environmental Matters Notes to audited consolidated financial statements Note 1 Note 15
Unbilled Revenue	Projecting customer energy usage Estimating impacts of weather and other usage-affecting factors for unbilled period	Notes to audited consolidated financial statements Note 1
Benefit Plan Accounting	Future rate of return on pension and other plan assets Interest rates used in valuing benefit obligation	Notes to audited consolidated financial statements Note 1 Note 10

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Accounting Policy	Judgments/ Uncertainties Affecting Application	See Additional Discussion At
Derivative Financial Instruments	Market conditions in the energy industry, especially the effects of price volatility on contractual commitments Market conditions in foreign countries Regulatory and political environments and requirements	Management s Discussion and Analysis of Financial Condition and Results of Operations: Derivatives, Risk Management and Market Risk Notes to audited consolidated financial statements Note 1 Note 13 Note 14
Income Tax Reserves	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	Management s Discussion and Analysis of Financial Condition and Results of Operations: Factors Affecting Results of Operations Tax Matters Notes to audited consolidated financial statements Note 1 Note 8 Note 15
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 bankruptcy proceedings	Management s Discussion and Analysis of Financial Condition and Results of Operations: Factors Affecting Results of Operations California Power Market Notes to audited consolidated financial statements Note 1 Note 15
Asset Valuation	Regional economic conditions surrounding asset operation and affecting market prices Foreign currency valuation changes Regulatory and political environments and requirements Levels of future market penetration and customer growth	Management s Discussion and Analysis of Financial Condition and Results of Operations: Factors Affecting Results of Operations Impact of Nonregulated Investments Notes to audited consolidated financial statements Note 1

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Regulation We are a registered holding company under the PUHCA. As a result, we, along with 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.

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.

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 ours 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.

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.

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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. See Business Pending Regulatory Matters for more information about the regulatory issues we are facing.

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 its balance sheet. Such changes could have a material adverse effect on our results of operations in the period the write-off is recorded.

At September 30, 2002, we reported on our balance sheet regulatory assets of approximately $570 million and regulatory liabilities of approximately $497 million that would be recognized in the income statement 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 17 to the audited 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, gas and steam rate case in 2002, with new rates effective January 2003;
- cap merger costs associated with the electric operations at $30 million and amortize the merger costs for ratemaking purposes through 2002;
- 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.

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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:
  - a 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
- an ICA that provides for the sharing of energy costs and savings relative to an annual baseline cost per delivered kilowatt-hour. 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 January 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.

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. PSCo has estimated no customer refund obligation for 2002 under the earnings test. The 2001 rate adjustments have not been finalized, with a hearing scheduled for May 2003. PSCo s proposals show no customer sharing for the 2001 plan year.

During 2001, PSCo settled all unresolved issues related to the 1999 and 2000 QSP electric reliability performance measure. An accrual for related customer refunds of $8.2 million was recorded and paid in 2001. PSCo met all 2001 performance benchmarks under the electric QSP, and no customer refunds are required. PSCo estimates no customer refund obligation for the 2002 QSP performance measures.

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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 its 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 is now requesting to increase electric revenue by approximately $233 million annually. This is based on $186 million for fuel and purchased energy expense and $47 million for the remaining cost of electric service. PSCo is requesting a decrease in natural gas revenue by approximately $21 million. PSCo has reached several Settlement Agreements with the CPUC Staff covering the depreciation rates and corrections to the original filing. These Settlement Agreements are the primary reason for the revised requested increase. PSCo s filing has been opposed by many parties. The CPUC Staff has recommended a lower electric revenue increase of approximately $95 million and a greater gas revenue decrease of approximately $45 million. The CPUC Staff has argued for an authorized return on equity of 10.75 percent. The Colorado Office of Consumer Counsel (OCC) has recommended an electric revenue increase of approximately $98 million and a gas revenue decrease of approximately $32 million. The OCC has argued for a return on equity of 9.9 percent. In addition, the CPUC Staff, the OCC and other parties have contested PSCo s proposed electric energy recovery mechanism and many parties have contested the regulatory treatment of the Company s short term off-system electric purchases and sales. Hearings are scheduled for the end of February/ March 2003, with rates expected to be effective at the end of April 2003.

SPS Earnings Test In Texas, until June 2001, SPS operated under an earnings test in which excess earnings were returned to the customer. In May 2000, SPS filed its 1999 Earnings Report with the Public Utilities Commission of Texas (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 s 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 is seeking to recover in a pending case at the PUCT. The PUCT approved the overall settlement on January 10, 2002.

Tax Matters As further discussed in Note 15 to the audited consolidated financial statements, a subsidiary of PSCo is working with the Internal Revenue Service (IRS) to resolve an income-tax dispute regarding deductions for loan interest expense related to company owned life insurance (COLI) of PSR Investments, Inc. (PSRI), one of our wholly-owned subsidiaries. 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 now disallowed the interest expense deductions for the tax years 1993 through 1997.

After consultation with our tax counsel, we continue to believe that the tax deduction of interest expense on the COLI policy loans is in full compliance with the tax law. 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. We intend to challenge the IRS determination, which could require several years to reach final resolution.

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).

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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:

$139 million in 2002

$146 million in 2001

$144 million in 2000

$128 million in 1999

We expect to expense approximately $165 million per year for 2003-2007 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.

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

$108 million in 2002

$136 million in 2001

$57 million in 2000

$126 million in 1999

We expect to incur approximately $948 million 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 15 and 16 to the audited consolidated financial statements for further discussion of our environmental contingencies.

Impact of Nonregulated Investments Our nonregulated businesses may carry a higher level of risk than our 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 XEI, and broadband communications systems through Seren. Management currently intends to hold and operate these investments, but is evaluating their strategic fit in our business portfolio. As of December 31, 2002, our investment in Seren was approximately $255 million. 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.

Some of our nonregulated subsidiaries have project investments (as listed in Note 11 to the audited 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 XEI. See further discussion at Note 15 to the audited consolidated financial statements.

Pending Accounting Changes

SFAS No. 143 In June 2001, the Financial Accounting Standards Board (FASB) approved the issuance of 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 regulatory asset or liability instead, if the criteria for such treatment 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 $661 million of decommissioning obligations and had estimated discounted decommissioning cost obligations of $1,066 million based on approvals from the various state commissions, which used a single scenario. However with the adoption of SFAS 143, a probabilistic view of several decommissioning scenarios were used resulting in an estimated discounted decommissioning cost obligation of $1,574 million.

In our current estimates for adoption of the standard effective January 1, 2003, the initial value of the liability, including cumulative accretion expense through that date, would be approximately $869 million. The liability would be established by reclassifying accumulated depreciation of $661 million and by recording two long-term assets totaling $208 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 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 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 as 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 also will affect Xcel Energy s accrued plant removal costs for other generation, transmission and distribution facilities for its operating utilities. Although SFAS 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 period over which the amounts were accrued and the changing of rates through time, the Company has estimated the amount of removal costs accumulated through historic depreciation expense based on current factors used in the existing depreciation rates. Accordingly, our operating utilities have an estimated amount accrued in accumulated depreciation for future removal costs for the following amounts at December 31, 2002:

Estimated Removal in Accumulated Depreciation (dollars in millions)

NSP-Minnesota	$304
NSP-Wisconsin	70
PSCo	329
SPS	97
Others	9
Total Xcel Energy	$809

SFAS No. 144 On January 1, 2002, we adopted SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets, which supersedes previous guidance for measurement of asset impairments. We 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. 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).

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. Other impacts of SFAS No. 145 are not expected to be material to us.

SFAS No. 146 In July 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.

EITF No. 02-3 and 98-10 During the third quarter of 2002, we adopted Emerging Issues Task Force of the FASB (EITF) Issue No. 02-3 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. 02-3 concluded that all gains and losses related to energy trading activities within the scope of EITF No. 98-10 (whether or not settled physically) be shown net in the statement of income, effective for periods ending after July 15, 2002. We have reclassified revenue from trading activities for all comparable periods. 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 in accordance with EITF No. 02-3 were $2.8 billion and $2.4 billion, respectively for the nine months ended September 30, 2002 and 2001. This reclassification had no material impact on trading margins or reported net income.

On October 25, 2002, the EITF rescinded EITF No. 98-10. With the recission of EITF No. 98-10, energy trading contracts that do not also meet the definition of a derivative under SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities must be accounted 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. We have not yet evaluated the effect of adopting this decision when required in 2003.

FASB Interpretation No. 46 In January 2003, the FASB issued Interpretation No. 46 Consolidation of Variable Interest Entities which requires consolidation of a variable interest entity by the enterprise that holds a controlling financial interest (primary beneficiary), if the risk is not effectively dispersed among parties involved. The Interpretation applies to variable interest entities created after January 31, 2003, and to variable interest entities in which an enterprise obtains an interest after that date. We have not identified any variable interest entities in which we are the primary beneficiary, and do not expect adoption of the Interpretation to have a material impact on future results.

SFAS No. 148 In December 2002, the FASB issued SFAS No. 148 Accounting for Stock-Based Compensation Transition and Disclosure, amends 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 requires disclosure in both annual and interim 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 APB Opinion NO. 25 Accounting for Stock Issued to Employees .

Derivatives, Risk Management and Market Risk

Business and Operational Risk We and our subsidiaries are exposed to commodity price risks in generation, retail distribution and energy trading operations. In certain jurisdictions, purchased power expenses, natural gas costs and certain financial instrument costs are recovered on a dollar-for-dollar basis. However, in other jurisdictions, we are exposed to market price risk for the purchase and sale of electric energy and natural gas. In such jurisdictions, we recover our purchased power expenses and natural gas costs based on fixed price limits or under negotiated 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. Our risk management policy allows us to manage the market price risk within our rate-regulated operations to the extent such exposure exists. Management is limited under the policy to enter into only transactions that reduce 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 we provide to our retail customers even though the regulatory jurisdiction provides dollar-for-dollar recovery of actual costs. This jurisdiction allows us to recover the gains and losses on derivative instruments used to reduce our exposure to market price risk.

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 nonregulated operations. We manage this market price risk by entering into firm power sales agreements for approximately 60 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. Our 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.

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 our equity method investments that own electric operations. We manage 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 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 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 interest rate volatility 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 $12.9 million and $29.9 million, respectively. See Note 13 to the audited consolidated financial statements for a discussion of our and our subsidiaries interest rate swaps.

As a result of various defaults under certain loan agreements, NRG s counterparties have terminated interest rate swaps with NRG, Brazos Valley LP and NRG Finance Company I LLC. Until NRG successfully restructures outstanding debt and returns to credit quality, it will not seek to manage interest rate risk through the use of financial derivatives.

Currency Exchange Risk We and our 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. We manages our 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 18 to the audited consolidated financial statements, we have substantial investments in foreign projects (through NRG and other subsidiaries), which expose us 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 our financial position. As of December 31, 2001, NRG had two foreign currency exchange contracts with notional amounts of $46.3 million. If the contracts had been discontinued on December 31, 2001, NRG would have owed the counterparties approximately $2.4 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 our risk management committee made up of management personnel not involved in the trading operations.

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 known as Value-at-Risk (VaR). VaR expresses the potential loss 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 of five days and three days for electricity and two days for natural gas.

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

		During 2002		
Operations	**Year Ended Dec. 31, 2002**	**Average**	**High**	**Low**
		(Millions of dollars)		
Generation North(a)	0.33	0.60	1.07	0.29
Generation South(b)	6.49	7.39	14.34	3.13
Electric Commodity Trading	0.29	0.62	3.39	0.01
Gas Commodity Trading	0.11	0.35	1.09	0.09
Gas Retail Marketing	0.54	0.47	0.92	0.32
XERS(c)	0.00	0.06	0.57	0.00
NRG Power Marketing(d)	118.58	76.17	132.09	40.10

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(a) Generation North primarily represents NSP-Wholesale book. A regulatory Fuel-Clause Adjustment (FCA) in Minnesota allows for a 100% recovery of fuel and purchased energy costs exceeding the Base Rate.

(b) Generation South primarily represents PSCo Retail and Wholesale books. An Incentive Cost Adjustment (ICA) sharing mechanism in Colorado results in a 50% recovery of costs exceeding the Base Rate.

(c) XERS was established in latter part of December 2001.

(d) NRG VaR is an undiversified VaR.

As of December 31, 2001, the VaRs were:

Operations	Year Ended Dec. 31, 2001	During 2001 Average	High	Low
		(Millions of dollars)		
Generation North	1.00	0.81	1.68	0.09
Generation South	8.11	9.34	13.48	3.10
Electric commodity trading	0.52	1.71	7.37	0.16
Gas commodity trading	0.16	0.15	0.52	0.01
Gas retail marketing	0.69	0.39	0.94	0.13
NRG power marketing	71.70	78.80	126.60	58.60

As of December 31, 2000, the VaRs were:

Operations	Year Ended Dec. 31, 2000	During 2000 Average	High	Low
		(Millions of dollars)		
North(e)	0.68	0.36	2.29	0.01
Electric commodity trading(e)	2.25	0.69	3.53	0.04
Gas commodity trading(e)	0.01	0.11	0.42	0.01
Gas retail marketing(e)	0.21	0.22	0.60	0.04
NRG power marketing	116.00	80.00	125.00	50.00

(e) Amounts have been restated for consistency with December 31, 2001, assuming similar holding periods in the VaR calculations.

Previously, we calculated VaR using a 21-day holding period, as shown below. As markets mature and gain liquidity, shorter holding periods more accurately reflect the risk. In 2001, we changed our holding period for natural gas from 21 days to two days because the gas trading market is mature and traders can liquidate positions in one or two days. The electricity market is still relatively immature and less liquid than the gas market, so we use a five-day holding period in our electricity VaR calculation. Our revised holding periods are generally consistent with current industry standard practice.

As of December 31, 2000, the calculated VaRs were:

Operations	Year Ended Dec. 31, 2000	During 2000 Average	High	Low
		(Millions of dollars)		

Short-term wholesale North	1.40	0.73	4.70	0.01
Electric commodity trading	4.62	1.42	7.23	0.08
Gas commodity trading	0.03	0.35	1.37	0.02
Gas retail marketing	0.69	0.70	1.94	0.12

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-

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performance by a counterparty of its contractual obligations. As we continue to expand our natural gas and power marketing and trading activities, our 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 of our counterparties. We employ additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees and standardized master netting agreements 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. See Note 15 to the audited consolidated financial statements for a discussion of NRG s receivables related to the California power market and a discussion of our exposure to Enron s bankruptcy.

Liquidity and Capital Resources

NRG Credit Rating In December 2001, Moody s placed NRG s long-term senior unsecured debt rating on review for downgrade. In July 2002, Standard & Poor s lowered NRG s corporate credit rating to BB. The secured NRG Northeast Generating LLC bonds and the NRG South Central Generating LLC bonds were also lowered to BB. The senior unsecured bonds of NRG were lowered to B+. All of the NRG debt issues and the corporate credit rating were placed on CreditWatch with negative implications. Continuing throughout the remainder of 2002, the rating agencies have further lowered the NRG credit ratings.

Currently, unsecured bond obligations carry a rating of between CCC and D , depending on both the specific debt issue and the rating agency rating system. Currently, the secured NRG Northeast Generating bonds and the NRG South Central Generating bonds carry a rating of Caa1 from Moody s and D from Standard & Poor s. All credit ratings are not a recommendation to buy, sell or hold securities, and each rating should be evaluated independently of any other rating.

The current credit ratings of NRG have resulted in a significant restriction on its access to the capital markets.

Liquidity Issues 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 Baa3 or BBB- by Moody s or Standard & Poor s, respectively. As a result of the downgrades on July 26 and July 29, NRG estimated that it would be required to post collateral ranging from $1.1 billion to $1.3 billion. Until shortly before the downgrades occurred NRG believed that it could meet the collateral requirements that would result from such an occurrence with available cash, operating cash flows, equity contributions from us, proceeds from asset sales and the issuance of bonds into the capital markets or as a private placement.

On August 19, 2002, NRG executed a Collateral Call Extension Letter (CCEL) with various lender groups in which the lenders agreed to extend until September 13, 2002, the deadline by which NRG was to post its approximately $1.0 billion of cash collateral in connection with certain bank loan agreements.

Subsequently, and effective as of September 13, 2002, NRG and lenders entered into a Second Collateral Call Extension Letter (Second CCEL) that extended until November 15, 2002, the deadline for NRG to post such collateral. Under the Second CCEL, NRG agreed to submit to the lenders a comprehensive restructuring plan. NRG submitted this plan on November 4, 2002 and is working with the lenders on an overall restructuring of its debt (see further discussion below). The November 15, 2002, deadline of the second CCEL has passed and NRG has not posted the required collateral. Because NRG has failed to make principal and interest payments when due, and is in breach of other covenants in various financing agreements, NRG is in default of various debt instruments. By reason of these defaults, the lenders are able, if they so choose, to seek to enforce their remedies, which would likely lead to a bankruptcy filing by NRG.

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

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anticipated that NRG will function independently from us 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. Management concluded that the forecasted free cash flow available to NRG after servicing project-level obligations will be insufficient to service recourse debt obligations. Based on this information and in consultation with us and its financial advisor, NRG prepared and submitted a restructuring plan on November 4, 2002 to various lenders, bondholders and other creditor groups of NRG and its subsidiaries (collectively, NRG s Creditors). The restructuring plan serves as a basis for negotiations with NRG s Creditors in a financial-restructuring of NRG and, among other things, proposed (i) holders of secured (project-level) debt would either (a) have their debt reinstated with agreed modifications or (b) receive the collateral securing such debt and a claim or claims to the extent such debt is under-secured; (ii) holders of unsecured debt, holders of secured recourse claims against NRG, and holders of other general unsecured claims against NRG would receive a pro rata share of (a) an aggregate of $500 million of junior secured debt of reorganized NRG and (b) 95% of the common equity of reorganized NRG; and (iii) holders of project-level general unsecured claims that are non-recourse to NRG would receive a pro rata share of the remaining 5% of the common equity of a reorganized NRG.

The restructuring plan included a proposal addressing our continuing role and degree of ownership in NRG and obligations to NRG in a restructured NRG. Based on the advice of its financial advisor that NRG may be deemed insolvent and in return for a release of any and all claims against us, the plan proposed that, upon consummation of the restructuring, we would pay $300 million to NRG. The plan separately proposed that we surrender our equity ownership of NRG. The plan does not contemplate any sharing by us with NRG s Creditors of any benefits we might receive in connection with the tax matters described in Note 6 to our interim consolidated financial statements. In mid-December 2002, the NRG bank steering committee submitted a counter-proposal to the NRG restructuring plan, which would require substantial additional payments by us. In late January, a new restructuring proposal was presented to NRG s lenders. There can be no assurance that any consensual restructuring plan will be accepted by NRG s Creditors or that any such plan will not be significantly revised as a result of ongoing negotiations.

On November 22, 2002, five former NRG executives filed an involuntary Chapter 11 petition against NRG. Under 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. On December 16, 2002, NRG responded to the involuntary petition, contesting the petitioners claims and filing a motion to dismiss the case. At a scheduling conference on January 23, 200, the bankruptcy court calendared an evidentiary hearing for April 29, 2003, at which time the court will commence a hearing to determine the merits of the involuntary petition and NRG s motion to dismiss. 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 so choose, to seek to enforce their remedies at any time, which would likely lead to a bankruptcy filing by NRG.

Whether NRG does or does not reach 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 is reached with NRG s Creditors on a restructuring plan, it is expected that NRG would commence a Chapter 11 bankruptcy case seek approval of a plan of reorganization based on the agreed restructuring plan. 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 us under the equitable doctrine of substantive consolidation.

As discussed above, NRG is not making any payments of principal or interest on its corporate level debt. 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. However, there can be no assurance that holders of NRG indebtedness, on which interest and principal are not being paid, will not seek to accelerate

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the payment of their indebtedness, which would likely lead to NRG seeking relief under the bankruptcy laws. NRG and we have retained financial advisors to help work through these liquidity issues.

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. 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 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 the issue. One of the creditors of NRG s Pike project in Mississippi (as discussed in Note 4 to our interim consolidated financial statements) has already filed involuntary bankruptcy proceedings against that project and has included claims against both NRG and us. If a bankruptcy court were to allow substantive consolidation of us and NRG, it would have a material adverse effect on us.

NRG has requested that its financial advisor, Kroll Zolfo Cooper, LLC (Zolfo), provide advice to management regarding potential opportunities for, and the general benefits and risks associated with: (a) reducing NRG s cost structure; (b) improving liquidity and cash flow in the short-, medium- and long-term; (c) mitigating the short-term impact on liquidity and cash flow of certain demands and obligations; and (d) liquidating or monetizing certain assets, including contractual relationships that have net present value based on current market prices. One of the specific areas where NRG management has asked for Zolfo s assistance is in relation to cash collateral requests. In addition to collateral requirements under the loan documents described above, cash collateral requests have been made of NRG by various contract counterparties as a result of the ratings downgrade at NRG. Zolfo is working with NRG management to assess the nature and benefit of each such contractual relationship and to identify and evaluate potential strategies for reducing, mitigating or eliminating each cash collateral request. There are no assurances that NRG can be successful in its efforts to mitigate the cash collateral request issue in a manner that preserves sufficient liquidity to operate its businesses effectively. However, as long as NRG s lenders continue to forebear, NRG believes that it has sufficient liquidity to meet its cash collateral calls to support its current activities.

Other areas where Zolfo has been asked to assist management include, but are not limited to: (a) managing the working capital impact of certain vendors who previously sold product or provided services to NRG on reasonable, market credit terms, but who are now requiring NRG to pay cash in advance for such product or services; and (b) controlling the general disbursement and commitment process so as to ensure that cash is utilized in a manner that maximizes value for stakeholders. Zolfo s involvement has helped NRG bring structure to its workout process and institute an appropriate emphasis on short-term liquidity and cash flows.

As explained in Note 10 to the interim consolidated financial statements, we had guaranteed at September 30, 2002, approximately $234 million of power market contracts, primarily of the power-marketing subsidiary of NRG. Exposure under these guarantees is approximately $104 million. As discussed in Note 2 to the interim consolidated financial statements, developments in the third quarter of 2002 resulted in material NRG asset impairments of nearly $3 billion before taxes.

Additional asset impairments may be recorded by NRG in periods subsequent to September 30, 2002, given the changing business conditions and the resolution of the pending restructuring plan. Management is unable to determine the possible magnitude of any additional asset impairments.

NRG may be subject to additional charges and expenses related to the termination of construction and development projects which have not been recorded as of September 30, 2002. Such amounts will be recorded by NRG as they are known and represent a valid claim against the company. NRG is unable to determine the magnitude of these possible charges at this time.

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NRG Debt Covenants and Restrictions

Project Debt Service Substantially all of NRG s operations are conducted by project 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 September 30, 2002, seven of NRG s subsidiaries and project affiliates are restricted from making cash payments to NRG: 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, Crockett Cogeneration and Batesville do not create an event of default and will not allow the lenders to accelerate the project financings, thus these financing are not currently in default. During January 2003, ownership of NRG s interest in Killingholme and Brazos Valley projects was transferred to project lenders, and NRG no longer has any interest in those projects.

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 accounts funding requirements were satisfied by provision of a guarantee from NRG. Following the downgrade, 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.

Other Covenants and Compliance

Defaults Upon Senior Securities On September 16, 2002 NRG failed to make a $14.4 million interest payment due on $350 million of 8.25% senior unsecured notes due in 2010 and a $10.9 million interest payment due on a $250 million bond issued by NRG Pass-Through Trust I trust, which is a wholly-owned special financing entity that is effectively a senior unsecured obligation of NRG with an interest rate of 8.70% that matures in 2005. On October 1, 2002 NRG failed to make a $13.6 million interest payment due on $350 million of 7.75% senior unsecured notes due in 2011 and a $21.6 million interest payment due on $500 million of 8.625% senior unsecured notes due in 2031. On November 1, 2002 NRG failed to make a $9.6 million interest payment due on $240 million of 8.00% senior unsecured notes due in 2013. On December 1, 2002 NRG failed to make an $11.3 million interest payment due on $300 million of 7.50% senior unsecured notes due in 2009. On December 15, 2002 NRG failed to make a $9.4 million interest payment due on $250 million of 7.50% senior unsecured notes due in 2007. On January 15, 2002 NRG failed to make an $11.5 million interest payment due on $340 million of 6.75% senior unsecured notes due in 2006.

The 30-day grace period to make payment, related to each of these individual issues, ended and NRG Energy did not make the required payments. As a result, NRG Energy is in default on these bonds.

On February 1, 2003 NRG failed to make a $4.8 million interest payment due on $125 million of 7.625% senior unsecured notes due in 2006. There is a 30-day grace period to make payment. If NRG Energy does not make the required payments, NRG Energy will be in default on these bonds.

On March 13, 2001, NRG completed the sale of 11.5 million equity units (NRZ) for an initial price of $25 per unit. Net proceeds from this issuance were $278.4 million after deducting underwriting discounts, commissions and estimated offering expenses. 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 our common stock no later than May 18, 2004. Interest payments are payable on the debentures quarterly in arrears on each February 16, May 16, August 16 and November 16. Interest is payable initially at an annual rate of 6.5% of the principal amount of $25 per debenture. On October 29, 2002, NRG announced it would not make the November 16, 2002 quarterly interest payment on the NRG 6.50% senior unsecured debentures due in 2006, which trade with the associated purchase contracts as NRG corporate units (NRZ).

The 30-day grace period to make payment ended December 16, 2002, and NRG did not make payment to the NRZ holders and, as a result, this issue is in default. In the event of an NRG Energy bankruptcy, the obligation to purchase shares of Xcel Energy stock terminates.

Defaults Upon Project Debt In May 2002, NRG s indirect wholly owned subsidiary, LSP-Kendall Energy, LLC received a notice of default from Societe Generale, the administrative agent under LSP-Kendall s Credit and Reimbursement Agreement dated November 12, 1999. The notice asserted that an event of default had occurred under the Credit and Reimbursement Agreement as a result of liens filed against the Kendall project by various subcontractors. In consideration of the borrower s implementation of a plan to remove the liens, and NRG s indemnification pursuant to an Indemnity Agreement dated June 28, 2002, of the lenders to the Kendall project from any claims or damages relating to these liens or any dispute or action involving the project s EPC contractor, the administrative agent, with the consent of the required lenders under the Credit and Reimbursement Agreement, withdrew the notice of default and conditionally waived any default or event of default described therein. Discussions with the administrative agent regarding the liens continue. On January 10, 2003, NRG received a notice of default from LSP Kendall s lenders indicating that certain events of default have taken place and that by issuing this notice of default the lenders have preserved all of their rights and remedies under the Credit Agreement and other Credit Documents.

In June 2002, NRG Peaker Finance Company 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 bear interest at a floating rate based on the 30-day London Interbank Offered Rate. 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. This financing contains a cross-default provision related to the failure by NRG to make payment of principal, interest or other amounts due on debt for borrowed money in excess of $50 million of payment defaults by NRG. This covenant was violated in October 2002. In addition, liens were placed against the Bayou Cove facility resulting in an additional default. As a result of these issues, this facility is in default.

On September 17, 2002, NRG-McClain LLC, an indirect wholly owned subsidiary of NRG, 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 under the Energy Management Services Agreement. In January 2003, NRG consented to the foreclosure of its Brazos Valley project by its lenders. As a consequence of foreclosure, NRG no longer has any interest in the Brazos Valley project, however, NRG may be obligated to infuse additional amounts of 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.

On October 30, 2002 NRG failed to make $3.1 million in payment under certain Non-Operating Interest Acquisition agreements. As a result, NEO Landfill Gas, Inc., an indirect wholly owned subsidiary of NRG, failed to make approximately $1.4 million in payments under the Amended and Restated Construction, Acquisition and Term Loan Agreement, dated July 6, 1998. Also, the subsidiaries of NEO Landfill Gas, Inc. failed to make approximately $2 million in payments pursuant to various Site Development Operations and Coordination Agreements. NRG received an extension until November 19, 2002 to make payment under such agreements. If NRG does not perform certain requirements during the extension period, NRG will be in default under the Non-Operating Interest Acquisition Agreements, and NEO Landfill Gas, Inc. will be in default under the Amended and Restated Construction, Acquisition and Term Loan Agreement, dated July 6, 1998, and the Site Development and Operations Coordination Agreements. All requirements were made during the extension period.

As of December 31, 2002, NEO Landfill Gas, Inc. was in default under the Amended and Restated Construction, Acquisition and Term Loan Agreement dated July 6, 1998 due to the failure to meet the insurance requirements under the loan document.

On January 30, 2003 NRG failed to make $2.7 million in payments under certain Non-Operating Interest Acquisition agreements. As a result, NEO Landfill Gas, Inc. failed to make their payment due on January 30, 2002 under the Amended and Restated Construction Acquisition and Term Loan Agreement dated July 6, 1998 and the subsidiaries of the Company failed to make their payments pursuant to various Site Development and Operations Coordination Agreements.

On December 27, 2002, NRG made the $24.7 million interest payment due on its NRG Northeast Generating LLC bond series and deferred the $53.5 million principal payment. The NRG Northeast Generating LLC bonds include 8.06 percent Series A-1 senior secured bonds due 2004, 8.84 percent Series B-1 senior secured bonds due 2015, and 9.29 percent Series C-1 senior secured bonds due 2024. NRG Northeast Generating LLC bond series are non-recourse to NRG and us.

Cash Flows

	Nine Months Ended September 30,		Year Ended December 31,		
	2002	2001	2001	2000	1999
	(Millions of dollars)				
Net cash provided by operating activities	$1,499	$1,338	$1,584	$1,408	$1,325

Cash provided by operating activities increased during the first nine months of 2002, compared with the first nine months of 2001. This increase was primarily due to improved working capital, mainly at NRG due to NRG s recently implemented cash management procedures. Due to NRG s current liability concerns, payment of certain items has been temporarily suspended, pending the completion of the comprehensive restructuring plan. Cash provided by operating activities increased during 2001, compared with 2000, primarily due to the higher net income, depreciation and improved working capital. Cash provided by operating activities increased during 2000, compared with 1999, primarily due to improved working capital.

	Nine Months Ended September 30,		Year Ended December 31,		
	2002	2001	2001	2000	1999
	(Millions of dollars)				
Net cash used in investing activities	$(2,302)	$(4,623)	$(5,168)	$(3,347)	$(2,953)

Cash used in investing activities decreased for the first nine months of 2002, compared with the first nine months of 2001. This decrease was largely due to decreased levels of nonregulated capital expenditures and asset acquisitions, primarily at NRG. 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 the majority of our investment in Yorkshire Power. Cash used in investing activities increased during 2000, compared with 1999, primarily due to acquisitions of existing generating facilities by NRG.

	Nine Months Ended September 30,		Year Ended December 31,		
	2002	2001	2001	2000	1999
	(Millions of dollars)				
Net cash provided by financing activities	$1,785	$3,364	$3,713	$2,016	$1,668

Cash provided by financing activities decreased for the first nine months of 2002, compared with the first nine months of 2001. This change was largely due to limited financing activities at NRG offset by increased financings at our utility subsidiaries. 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. Cash provided by financing activities increased during 2000, compared with 1999, primarily due to the issuance of debt to finance NRG asset acquisitions in 2000.

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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 Requirements Our utility capital expenditure forecast as of September 30, 2002 is detailed in Note 9 to the interim consolidated financial statements. The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual construction expenditures may vary from the estimates due to changes in market conditions.

NRG Prospective Capital Requirements As of September 30, 2002, NRG had taken definitive steps to scale back and delay certain construction projects so as to enhance its financial position and improve liquidity in the remainder of 2002. See discussion of NRG s capital and operating expenditure forecast as of September 30, 2002 in Note 7 to the interim consolidated financial statements.

NRG s capital expenditure program is subject to continuing review and modification. Actual expenditures may differ significantly depending upon such factors as the success, timing of and level of involvement in projects under construction.

NRG Construction Program Sources NRG has generally financed the acquisition and development of its projects under financing arrangements to be repaid solely from each of its projects cash flows, which are typically secured by the plant s physical assets and equity interests in the project company. Financing needs are subject to continuing review and can change depending on market and business conditions and changes, if any, in the capital requirements of NRG and its subsidiaries. During the nine months ended September 30, 2002, NRG had financed its acquisition and construction activities through a combination of both short- and long-term corporate level and project level financings, cash infusions from us and, to a limited extent, operating cash flows. Additional financing sources include cash proceeds from asset sales, as discussed later.

Capital Expenditures and Nonregulated Investments The estimated cost as of December 31, 2002, of our capital expenditure programs and those of our subsidiaries (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	$ 841	$ 752
Gas utility	110	108	111
Common utility	90	50	37
Total utility	900	999	900
Other nonregulated	32	23	15
Total capital expenditures	932	1,022	915
Sinking funds and debt maturities	563	169	223
Total capital requirements	$1,495	$1,191	$1,138

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 12 and 15 to the audited consolidated financial statements.

NRG is unable to provide an estimate of its near term cash requirements. NRG s near term cash requirement generally includes funds for direct corporate obligations and net requirements for continuing

operations. In general, NRG plans to fund its ongoing liquidity needs with cash on hand and cash proceeds from asset sales.

Our subsidiaries may invest in nonregulated projects in the future. Financing requirements for nonregulated project investments will vary depending on the success, timing and level of involvement in projects currently under consideration. These investments could cause significant changes to the capital requirement estimates for nonregulated projects and property. Long-term financing may be required for such investments. Our investment in exempt wholesale generators and foreign utility companies, which includes NRG and our other subsidiaries, is currently limited to 100 percent of consolidated retained earnings, as a result of the PUHCA restrictions. We cannot make any additional investments in NRG or any EWG or FUCO (other than the potential infusion of the $300 million under the Support Agreement) without the prior approval of the SEC under PUHCA. Infusion of the $300 million is subject to delivery to the SEC of a satisfactory opinion of an independent financial advisor addressing among other things the protection of utility ratepayers.

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 11, 15, 16 and 17 to the audited consolidated financial statements.

	Payments Due by Period as of September 30, 2002				
Contractual Cash Obligations (Unaudited)	**Total**	**Short Term**	**1-3 years**	**4-5 years**	**After 5 years**
			(In thousands)		
Long-term debt	$13,845,236	$7,481,343	$ 384,254	$1,545,053	$4,434,586
Capital lease obligations	665,943	32,551	55,585	54,489	523,318
Operating leases	354,559	83,811	104,383	69,308	97,057
Unconditional purchase obligations	9,612,152	306,073	2,244,547	5,495,532	1,566,000
Other long-term obligations	872,900	4,676	93,742	88,235	686,247

Common Stock Dividends 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. Retained earnings were $115 million at December 31, 2002 assuming no further adjustments to the preliminary NRG results. Xcel Energy has 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. We have outstanding preferred stock, however, the restrictions do not place any effective limit on our ability to pay dividends.

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. We are a registered holding company under the PUHCA. As a result, we, along with 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.

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 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.

Consolidated project-related, nonrecourse debt at the subsidiary level is included in calculating our overall capital structure. 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.

Over the long term, our equity investments in and acquisitions of nonregulated projects may be financed at the nonregulated subsidiary level from internally generated funds or the issuance of subsidiary debt. The financing needs are subject to continuing review and can change depending on market and business conditions and changes, if any, in the construction programs and other capital requirements of us and our subsidiaries.

Short-Term Funding Sources Historically, we have used a number of sources to fulfill short-term funding needs. Primary among these is operating cash flow, but also included are short-term borrowing arrangements such as 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, as discussed previously in Capital Requirements. 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; as well as operational uncertainties that are difficult to predict. See further discussion of such factors under Income Statement Analysis and Factors Affecting Results of Operations.

Short-term borrowing as a source of short-term funding is affected by access to reasonably priced capital markets. This varies based on financial performance and existing debt levels. If current debt levels are

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perceived to be at or higher than standard industry levels or those levels that can be sustained by current operating levels, access to reasonable short-term borrowings could be limited. These factors are evaluated by credit rating agencies that review us and our subsidiary operations on an ongoing basis. As discussed below, NRG s credit situation has affected our credit ratings and our access to short-term funding. As a result of the decline in our credit ratings, we have been unable to utilize the commercial paper market to satisfy any of our short-term funding needs. For additional information on our short-term borrowing arrangements, see Note 3 to the audited consolidated financial statements.

In 2002, we have been experiencing some volatility in our funding sources due largely to the credit issues being faced by NRG, as described in Note 7 to the interim consolidated financial statements.

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 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. See Note 6 to the interim consolidated financial statements for further discussion of the financial restructuring plan for NRG.

Under the proposed plan, owned assets with un-funded debt service reserve accounts would be funded at the project level over time with operating cash from the projects as it becomes available. The following lists amounts currently required to fund such accounts:

NRG Northeast Generating LLC	$ 78.3 million
NRG Peaker Finance Co.	$ 78.7 million
NRG South Central Generating LLC	$ 46.6 million
Mid-Atlantic Generating	$ 23.4 million
Flinders Power Finance Pty	$ 20.3 million
NRG McClain	$ 7.4 million*
Enfield	$ 3.4 million

* Includes both a debt service reserve and maintenance reserve fund.

Going forward, NRG estimates $125 to $150 million for capital spending in 2003. This amount includes capital improvements, minor refurbishments, and extensions of projects in operation. NRG plans to fund these liquidity needs with cash on hand, operating cash from generating assets, a $300 million infusion from us, and the issuance of project level debt. NRG s current financial plan estimates cash from operations of approximately $350 million for 2003.

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 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, however, we have proposed that we will contribute $300 million if the restructuring plan discussed above is approved by the creditors.

In mid-December 2002, the NRG bank steering committee submitted a counter-proposal and in January 2003, the bondholder creditor committee issued its counter-proposal to the NRG restructuring plan. The counter-proposals would request substantial additional payments by us.

A new NRG restructuring proposal was presented to NRG s creditors on or shortly after January 29, 2003. While we currently anticipate that any financial impact of the proposal would affect 2003 results, there can be no assurance that the restructuring proposal made, or ultimately agreed to, will not impact our final earnings in 2002.

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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 it had completed the sale of its ownership interests 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 NRG 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. Polo), in California.

Credit Ratings Short-term borrowings as a source of short-term funding is affected by access to reasonably priced capital markets. This access is 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. As of February 10, 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

Since December 2001, NRG s access to short-term capital has been limited due to tightening credit standards for the independent power sector as a whole. The downgrade of NRG s credit ratings below investment grade in July 2002 has resulted in cash collateral requirements as discussed above and in Note 7 to the interim consolidated financial statements. In addition, lower credit ratings will increase the relative cost of NRG s capital financing compared to historical levels.

In June 2002, our access to commercial paper markets was reduced due to lowered credit ratings (shown above). Management believes these lower credit ratings for entities other than NRG are unwarranted given the separation of NRG s operations and credit risk from our utility operations and corporate financing

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activities. However, until the ratings are raised, we and our utility subsidiaries continue to seek sources of financing (both short- and long-term) other than commercial paper. We and our subsidiaries used cash or existing credit facilities to repay approximately $723 million of commercial paper in July 2002.

Credit Facilities On August 15, 2002, NSP-Minnesota obtained an amended and restated credit facility that replaced its $300 million, 364-day fully drawn credit facility. This credit line is structured as a senior revolving facility and is secured by a new series of bonds issued under its First Mortgage Trust Indenture. The new bonds are secured equally with all other bonds outstanding under the Trust Agreement.

We had a $400 million credit facility that expired on November 8, 2002. We paid down the $400 million, 364-day bank line on November 8, 2002. Funds to pay down the line came from cash at the holding company level and funds from a new financing, as discussed in Note 10 to the interim consolidated financial statements.

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 percent per annum.

Cross Default Provisions On August 5, 2002, we signed agreements with our lenders to eliminate cross-default provisions in our bank credit agreements with respect to NRG. Our bank agreements consist of a five-year credit facility in the amount of $400 million expiring in November 2005. The revised agreements remove key provisions in our credit facilities that would have constrained our ability to access capital due to difficulties faced by NRG in complying with the terms of NRG s credit facilities. The agreements reached with our lenders remove the linkage between NRG s agreements and credit facilities and those at Xcel Energy by removing the cross-default provisions.

Private Securities Offerings On November 8, 2002, we issued $100 million principal amount of 8 percent senior convertible notes (the Prior Notes) pursuant to a Securities Purchase Agreement (the 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 the initial issuance 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 otherwise identical (other than issuance date) to the notes offered pursuant to this prospectus in an aggregate principal amount equal to 25 percent of the aggregate principal amount of the notes.

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.

Registration Statements Our Articles of Incorporation authorize the issuance of 1 billion shares of common stock. As of December 31, 2002, we had 398,714,039 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 September 2000, we filed a $1 billion shelf registration with the SEC to issue debt securities. We have approximately $400 million remaining available under this registration.

In February 2002, we filed a registration statement for the sale of $1 billion of common stock and debt securities. We have approximately $482.5 million remaining available under this registration.

In June 2002, we filed a registration statement with the SEC for the issuance of our stock upon exercise of outstanding NRG options governed by the NRG 2000 Long-Term Incentive Compensation Plan. Upon the exercise of the NRG options, the holders thereof will receive shares of our common stock, and the associated share purchase rights, applying an exchange ratio of ..5 shares of our common stock for each share of NRG common stock, instead of shares of NRG common stock. See further discussion of the NRG exchange offer in Note 5 to the interim consolidated financial statements.

In April 2001, NSP-Minnesota filed a $600-million long-term unsecured debt shelf registration with the SEC.

In November 2002, NSP-Minnesota filed a $450 million first mortgage bond registration with the SEC for an exchange offer of its 8.00 percent first mortgage bonds maturing in 2012 issued in a private placement in August 2002.

PSCo has an effective shelf registration statement with the SEC under which $300 million of senior unsecured debt securities are available for issuance.

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 expects to use the net proceeds for general corporate purposes, which may include the working capital and debt reduction. NRG has approximately $1.5 billion remaining available under this shelf registration.

Xcel Energy Common Stock Issuance In February 2002, we issued 23 million shares of common stock at $22.50 per share. The proceeds were used to fund NRG and to repay short-term debt.

In June 2002, we issued 25.7 million shares of common stock to complete our exchange offer with minority NRG shareholders and acquire 100 percent ownership of NRG (see Note 5 to the interim consolidated financial statements).

NSP-Minnesota Debt Issuances In July 2002, NSP-Minnesota issued $185 million of 8.00 percent unsecured Public Income Notes due in 2042. The proceeds were used to repay short-term indebtedness incurred for general working capital purposes and to meet long-term debt maturity requirements.

In August of 2002, NSP-Minnesota issued $450 million of first mortgage bonds. These bonds carry a fixed interest rate of eight percent and mature in 2012.

In August 2002, in connection with its 364-day, $300 million credit agreement renewal, NSP-Minnesota also issued $308 million of first mortgage bonds, due August 15, 2003, to Wells Fargo Bank, N.A. pursuant to the credit agreement. The obligations under the credit agreement are secured by this series of bonds.

In August 2002, NSP-Minnesota closed on the conversion of several bonds totaling $196 million from variable rate to a fixed rate of 8.5 percent. The first call date on these bonds is August 27, 2012. As part of the conversion, $69 million of the bonds were collateralized with the first mortgage bonds. The remaining bonds were collateralized in 1997.

PSCo Debt Issuances In September 2002, PSCo issued $600 million of first collateral trust bonds at a fixed interest rate of 7.875% and maturing in 2012.

In September 2002, PSCo issued and delivered $530 million of first collateral trust bonds to a certain bank to secure its payment obligations under its $530 million, 364-day credit facility and $48.75 million of first collateral trust bonds to an insurance company to secure insurance obligations related to its 5.1% pollution control bonds, series due January 1, 2019.

NRG Short-Term Borrowings In March 2002, NRG s $500-million recourse revolving credit facility matured and was replaced with a $1.0-billion, 364-day revolving line of credit, which terminates on March 7, 2003. The facility is unsecured. The credit agreement for this facility was amended in April 2002 to revise the interest coverage ratio covenant. As amended, the covenant requires NRG to maintain a minimum interest coverage ratio that varies throughout the year from 1.75 to 1.00 as determined at the end of each fiscal quarter. The facility contains additional covenants that, among other things, restrict the incurrence of liens and require NRG to maintain a net worth of at least $1.5 billion plus 25 percent of NRG s consolidated net income from January 1, 2002, through the determination date. In addition, NRG must maintain a debt to

capitalization ratio, as defined in the credit agreement, of not more than 0.68 to 1.00. The failure to comply with any of these covenants would be an Event of Default under the terms of the credit agreement. At September 30, 2002, NRG had a $1-billion outstanding balance under this credit facility. As of September 30, 2002, the weighted average interest rate of such outstanding advances was 7.7 percent per year. NRG missed the $7.6 million interest payment due on September 30, 2002, and as of September 30, 2002, NRG violated both the minimum net worth covenant and the minimum interest coverage ratio. 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 $1.0-billion, 364-day revolving line of credit. During the second quarter of 2002, the letter of credit facility agreement was amended to incorporate the same covenant revisions and other amendments that had previously been made to the terms and conditions of NRG s $1-billion revolving credit facility, including the addition of an interest coverage ratio covenant. As of September 30, 2002, NRG violated both the minimum net worth covenant and the minimum interest coverage ratio. Accordingly, the facility is in default.

As of December 31, 2001, NRG, through its wholly owned subsidiary NRG South Central Generating LLC, had outstanding approximately $40 million under a project level, non-recourse revolving credit agreement. In June 2002, this facility was paid off and was not renewed.

NRG Peaker Finance Company LLC During the second quarter of 2002, NRG Peaker Finance Company LLC, an indirect wholly-owned subsidiary of NRG, issued $325 million of floating rate senior secured bonds. This issue, rated triple-A by Moody s Investors Service and Standard & Poor s Ratings Services and due in 2019, provided net proceeds of $250 million. SL Capital Assurance Inc. (XLCA), rated triple-A by Moody s Investors Service, Standard & Poor s Ratings Services and Fitch Ratings, will guarantee scheduled principal and interest payments on the bonds. The XLCA guarantee is secured by five Peaker power plants totaling approximately 1,318 megawatts.

NRG Energy Center, Inc. In July 2002, NRG Energy Center, Inc. (NRG Energy Center), an indirect wholly-owned subsidiary of NRG, entered into an agreement allowing it to issue senior promissory notes in the aggregate principal amount of up to $150 million. In July 2002, under this agreement, NRG Energy Center issued $75 million of bonds in a private placement. Two series of notes were issued in July 2002, the $55 million Series A-Notes dated July 3, 2002, which matures on August 1, 2017 and bears an interest rate of 7.25 percent per annum. The $20 million Series B-Notes dated July 3, 2002, which matures on August 1, 2017 and bears an interest rate of 7.12 percent per annum. NRG Thermal Corporation, a wholly-owned subsidiary of NRG, which owns 100 percent of NRG Energy Center, pledged its interests in all of its district heating and cooling investments throughout the United States as collateral. A covenant in this facility requires that Xcel Energy maintain no less than 50 percent indirect ownership interest in NRG Thermal.

See further discussion of NRG credit collateral calls, defaults and debt covenants at Notes 7 and 10 to the interim consolidated financial statements.

Financing Plans The following long-term debt issuances of Xcel Energy s regulated utilities come due during 2003. Depending on cash-on-hand and market conditions, the utilities may refinance this debt with first mortgage bonds, retire debt with cash available at the operating company level or a combination of both.

Issuing Entity	Principal Amount	Interest Rate	Date Due
	(Millions of dollars)		
NSP-M	28	5.375 7.4%	Feb. 1, 2003 May 1, 2003
NSP-M	100	5.875%	March 1, 2003
NSP-M	80	6.375%	April 1, 2003
NSP-W	40	5.750%	Oct. 1, 2003
PSCo.	250	6.000%	April 15, 2003
PSCo.	30	6.450%	Nov. 25, 2003

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.

Short-term debt and financial instruments are discussed in Note 10 to the interim consolidated financial statements.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

During 2000 and 2001, and through the nine months ended September 30, 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 and 2001, and through the nine months ended September 30, 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.

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 18 to the audited 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 0.4 million 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 40,000 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

WGI is subject to the FERC jurisdiction and holds a FERC certificate, which allows it to transport natural gas in interstate commerce pursuant to the provisions of the Natural Gas Act.

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.

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 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 allows 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.

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. In June 2002, SPS filed an application with the PUCT to reconcile fuel costs for calendar years 2000 and 2001.

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.

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.

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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.

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 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.

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Metro 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 (A S 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. NSP-Minnesota does not expect to collect additional revenues under the tariff until late 2003 or early 2004.

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. The MPUC has not yet issued its order.

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.

North Dakota Rate Case In October 2000, NSP-Minnesota filed a request with the NDPSC to increase natural gas rates by approximately 3.3 percent, or $1.4 million, annually. In June 2001, the NDPSC approved an increase of approximately $860,000 annually, effective July 13, 2001.

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

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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;

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 In early 2002, PSCo filed to increase rates under the ICA to recover the projected ICA energy costs through the period ended December 31, 2002 (approximately $148 million). PSCo proposed to increase the ICA rate for 2002 to avoid the significant deferral of costs from 2001 and 2002 ($148 million), which would have resulted in a large rate increase in 2003. The merger Stipulation and Agreement had provided for a rate recovery period of April 1, 2003 to March 31, 2004 for these ICA energy costs.

On May 10, 2002, the CPUC approved a Settlement Agreement between PSCo and other parties to increase the ICA rate to $2.10 per megawatt hour, providing for recovery of the deferred 2001 costs and the projected higher 2002 costs over a 34-month period from June 1, 2002 to March 31, 2005. The prudence review and approval of actual costs incurred and recoverable under the ICA for 2001 and 2002 will be conducted in future proceedings by the CPUC. PSCo is currently projecting its costs for 2002 to be approximately $50 million to $60 million less than the ICA base allowed using the 2001 test year, resulting in an equal sharing of such lower costs between retail customers and PSCo. The mechanism for recovering fuel and energy costs for 2003 and later will be addressed in the 2002 rate case.

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 is now requesting 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 is requesting a decrease in natural gas revenue by approximately $21 million. PSCo has reached several Settlement Agreements with the CPUC Staff covering the depreciation rates and corrections to the original filing. These Settlement Agreements are the primary reason for the revised requested increase. PSCo s filing has been opposed by many parties. The CPUC Staff has recommended a lower electric revenue increase of approximately $95 million and a greater gas revenue decrease of approximately $45 million. The CPUC Staff has argued for an authorized return on equity of 10.75%. The Colorado Office of Consumer Counsel (OCC) has recommended an electric revenue increase of approximately $98 million and a gas revenue decrease of approximately $32 million. The OCC has argued for a return on equity of 9.9%. In addition, the CPUC Staff, the OCC and other parties have contested PSCo s proposed electric energy recovery mechanism and many parties have contested the regulatory treatment of the Company s short term off-system electric purchases and sales. Hearings are scheduled for February/March 2003, with rates expected to be effective at the end of April 2003.

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 review should the CPUC staff file exceptions to the recommended decision, which must be filed by March 3, 2003.

Gas Rate Reduction In September 2002, PSCo filed a request with the CPUC for a $64.6 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

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.

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. 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. Also, PSCo engaged in one trade with Reliant in which PSCo simultaneously bought and sold power without realizing any profit. The purpose of this nonprofit transaction was in consideration of future for-profit transactions. PSCo engaged in these transactions for the proper commercial objective of making a profit, not to inflate volumes or revenues.

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.

SPS

Fuel Recovery At least every three years, SPS is required to file an application for the PUCT to retrospectively review the operations of a utility s electric generation and fuel management activities. 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 commission staff testimony is being reviewed. Hearings commence in March 2003.

SPS Texas Retail Fuel Factor and Fuel Surcharge Application SPS has reported to the PUCT that it has under-collected its fuel costs under the current Texas retail fixed fuel factors. SPS is preparing to file for a fuel cost surcharge.

In December 2001, SPS submitted an application seeking authority to immediately revise its fixed fuel factors on an interim basis to prevent any over-collection of historical under-recoveries due to the rapid and unforeseen decreases in the price of natural gas. SPS also requested that it be allowed to file a supplemental application to revise its fixed fuel factors. On December 19, 2001, the administrative law judge issued an order approving the interim fixed fuel factors and SPS request to file a supplemental application. SPS supplemental application was filed in February 2002 and on March 25, 2002, a unanimous stipulation was filed to reduce SPS fixed fuel factor (effective in the April 2002 billing cycle) to reflect projected lower fuel costs for running the SPS power plants.

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 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.

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 12 to the audited consolidated financial statements.

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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. The FERC issued an order in December 2002, conditionally accepting the revised tariff and related agreements necessary to bring about the proposed business combination. On January 21, 2003, the MISO submitted a filing in compliance with the FERC s December 2002 order, which required certain revisions to the tariff and related agreements. The MISO has requested that the FERC accept the revised MISO tariff and agreements to become effective on the day immediately following the consummation of the business combination between the MISO and the SPP. The MISO will be required to submit an application to the FERC under Section 203 of the Federal Power Act in order to effectuate the business combination with the SPP.

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 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

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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.

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 12 to the audited 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

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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	8,239	8,862
PSCo	5,406	5,644	6,034	5,874
SPS	3,870	4,080	4,214	4,132

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-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 provide for a charge for 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.

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.

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
1999	$1.10	58%	$0.48	38%	$0.88

* 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
1999	$0.90	92%	$2.52	8%	$1.04

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SPS generating plants:	Coal		Gas		Average Fuel Cost
	Cost	Percent	Cost	Percent	
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
1999	$1.41	70%	$2.38	30%	$1.70

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 2005. 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.

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 85 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

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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.

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.

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 16 to the audited 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. NSP-Minnesota has expanded the used nuclear fuel storage facilities at its Monticello plant by replacement of the racks in the storage pool and by shipping 1,058 used fuel assemblies to a General Electric storage facility. The Monticello plant is expected to have sufficient pool storage capacity to the end of its current operating license in 2010.

The Prairie Island spent fuel pool has undergone two storage rack replacements. The on-site storage pool for spent nuclear fuel at Prairie Island was nearly filled and adequate space was no longer available. In 1994, a Minnesota law was enacted authorizing NSP-Minnesota to install 17 spent fuel casks for storage of spent nuclear fuel at Prairie Island. NSP-Minnesota has determined 17 casks will allow facility operation until 2007. As of December 31, 2002, 17 storage casks were loaded and stored on the Prairie Island nuclear generating plant site. The Minnesota Legislature established several energy resource requirements and other commitments for NSP-Minnesota to obtain the Prairie Island temporary nuclear fuel storage facility approval. NSP-Minnesota has implemented programs to meet the legislative commitments.

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 Nuclear Regulatory Commission (NRC) for a national temporary storage site for spent nuclear fuel. The PFS will undertake the development, licensing, construction and operation of a storage facility on the Skull Valley Indian Reservation in Utah. The NRC license review process consists of formal evidentiary hearings and opportunity for public input. Storage cask certification efforts are continuing, with one cask vendor on track to meet the project goals. The interim used fuel storage facility could be operational and able to accept the first shipment of spent nuclear fuel by 2004. However, due to uncertainty regarding regulatory and governmental approvals, it is possible that this interim storage may be delayed or not available at all.

In February 2001, NSP-Minnesota signed a contract with Steam Generating Team Ltd. to perform engineering and construction services for the installation of replacement generators at the Prairie Island nuclear power plant. NSP-Minnesota is evaluating the economics of replacing two 28-year-old 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 has issued a number of regulations, bulletins and orders that require analyses, modification and additional equipment at commercial nuclear power plants. 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.

For further discussion of nuclear issues, see Note 15 and Note 16 to the audited consolidated financial statements.

Electric Operating Statistics (Xcel Energy)

	Year Ended Dec. 31			
	2002	**2001**	**2000**	**1999**
Electric sales (millions of Kwh):				
Residential	23,302	22,113	22,101	20,681
Commercial and industrial	57,815	57,755	57,409	54,336
Public authorities and other	1,143	1,103	1,184	1,111
Total retail	82,260	80,971	80,694	76,128
Sales for resale	23,256	26,104	26,284	21,001
Total energy sold	105,516	107,075	106,978	97,129
Number of customers at end of period:				
Residential	2,756,565	2,722,832	2,691,505	2,640,010
Commercial and industrial	394,620	387,579	380,784	378,960
Public authorities and other	81,341	100,819	98,715	96,098
Total retail	3,232,526	3,211,230	3,171,004	3,115,068
Wholesale	309	305	220	189
Total customers	3,232,835	3,211,535	3,171,224	3,115,257

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.

PSCo has participated fully in state regulatory and legislative efforts to develop a framework for extending unbundling down to the residential and small commercial level. PSCo supported a gas unbundling bill, passed by the Colorado Legislature 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.

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 640,000 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, 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
1999	$2.97	$3.32	$2.85	$2.57

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 $1.0 billion 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. Pursuant to the agreement, Border would purchase Viking and a one-third interest in Guardian Pipeline for approximately $152 million, including the assumption of outstanding debt. The sale closed on January 17, 2003.

Gas Operating Statistics (Xcel Energy)

	Year Ended Dec. 31,			
	2002	**2001**	**2000**	**1999**
Gas deliveries (thousands of Dth):				
Residential	144,038	136,568	137,989	125,694
Commercial and industrial	95,959	97,303	96,370	91,064
Total retail	239,997	233,871	234,359	216,758
Transportation and other	294,640	284,301	297,041	272,757
Total deliveries	534,637	518,172	531,400	489,515
Number of customers at end of period:				
Residential	1,574,489	1,531,589	1,483,114	1,436,455
Commercial and industrial	148,383	146,266	143,568	146,090
Total retail	1,722,872	1,677,855	1,626,682	1,582,545
Transportation and other	3,189	3,054	3,233	3,152
Total customers	1,726,061	1,680,909	1,629,915	1,585,697

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.

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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.

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 September 30, 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 September 30, 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.

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.

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 interim consolidated financial statements. See also Note 3 to the interim consolidated financial statements for discussion of other NRG divestitures that are reported as discontinued operations or assets held for sale as of September 30, 2002.

NRG 2001 Business Developments

In January 2001, NRG purchased from LS Power LLC a 5,339-megawatt portfolio of operating projects and projects in construction and advanced development that are located primarily in the north central and south central United States. Approximately 3,295 megawatts are currently in operation or under construction. 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 megawatts of generation projects developed and offered for sale by LS Power and its partners.

In March 2001, NRG purchased from Cogentrix the remaining 430 megawatts or 51.37 percent interest, in a 837 megawatt natural gas-fired combined-cycle plant located in Mississippi. NRG acquired a 48.63 percent interest in the plant in January 2001 from LS Power.

In June 2001, NRG purchased a 640-megawatt, 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-megawatt, gas-fired power plant in Texas that NRG will build, operate and manage. At the time of the closing, NRG also became the 100 percent owner of the project by purchasing STEAG Power LLC s 50 percent interest in the project. NRG expects the project to begin commercial operation in June 2003.

In June 2001, NRG purchased 1,081 megawatts of interests in power generation plants from a subsidiary of Conectiv. NRG acquired a 100 percent interest in the 784 megawatt, coal-fired Indian River Generating Station, located in Delaware, and in the 170 megawatt, oil-fired Vienna Generating Station, located in Maryland. In addition, NRG acquired 64 megawatts of the 1,711 megawatt, coal-fired Conemaugh Generating Station and 63 megawatts of the 1,711 megawatt, coal-fired Keystone Generating Station, both located near Pittsburgh, Pennsylvania.

In June 2001, NRG increased its interest in Compania Boliviana de Energia Electrica S.A. Bolivian Power Company Ltd. (COBEE) as part of a large portfolio acquisition of assets. NRG now owns 98.9 percent of COBEE. COBEE, with 220 megawatts of predominantly hydroelectric generation, is the second largest electric generator in Bolivia.

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In June 2001, NRG purchased a 389-megawatt, gas-fired power plant and a 116-megawatt, thermal power plant, both of which are located in Hungary, from PowerGen. In April 2001, NRG also purchased PowerGen s interest in Saale Energie GmbH and MIBRAG BV. By acquiring PowerGen s interest in Saale Energie, NRG increased its ownership interest in the 960 megawatt, coal-fired Schkopau power station, located in Germany, from 200 megawatts to 400 megawatts. By acquiring PowerGen s interest in MIBRAG, consisting primarily of two lignite mines and three power stations in Germany, NRG increased its ownership of MIBRAG from 33.3 percent to 50 percent.

In July 2001, NRG acquired approximately 60 percent of Hsin Yu Energy Development Co. Ltd, a Taiwan company, for NT $1.6 billion (approximately $46.7 million at the date of acquisition). Hsin Yu currently owns a 170-megawatt, cogeneration facility. Hsin Yu is developing a 245-megawatt expansion of the facility and has the rights to develop a new 490-megawatt greenfield project in Taiwan.

During 2001, NRG acquired a 30 percent ownership in the Lanco Kondapalli Power Private Limited and 100 percent of Easter Generation (India) Services Limited Private for $27 million. The 355-megawatt gas and oil-fired Kondapalli generating facility is a combined cycle power plant located in India. Eastern Generation Services is the plant operator.

In August 2001, NRG acquired an approximately 2,255 megawatt portfolio of five projects in operation, construction and advanced development that are located in Illinois and upstate New York from Indeck Energy Services, Inc. Approximately 402 megawatts are currently in operation.

In August 2001, NRG acquired Duke Energy s 77 percent interest in the 520 megawatt, natural gas-fired McClain Energy Generating Facility, located in Oklahoma. The Oklahoma Municipal Power Authority owns the remaining 23 percent interest. The McClain facility became operational in June 2001.

In September 2001, NRG acquired a 50 percent interest in TermoRio SA, a 1,040-megawatt gas-fired co-generation facility currently under construction from Petroleos Brasileiros SA located in Brazil. Commercial operation is expected to begin in March 2004.

In September 2001, NRG acquired for $66 million, a 50 percent interest in Saguaro Power Company, L.P. The partnership owns a 105-megawatt natural gas fired cogeneration facility in Nevada. The facility is also capable of generating 50 to 160 thousand pounds per hour of export steam.

In December 2001, NRG acquired a 540-megawatt, natural gas-fired generation facility being developed in Connecticut. The plant has a planned commercial operation date of August 2003.

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, 2001, XEI s primary investments included Yorkshire Power and Xcel Energy Argentina.

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 15 to the audited consolidated financial statements and Note 9 to the interim 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	579
King Bayport, Minnesota	Coal	1968	529
Black Dog Burnsville, Minnesota			
2 Units	Coal	1955-1960	278
2 Units	Natural Gas	2002	270
High Bridge St. Paul, Minnesota			
2 Units	Coal	1956-1959	267
Riverside Minneapolis, Minnesota			
2 Units	Coal	1964-1987	374
Other	Various	Various	1,006
		Total	6,249

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

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			
4 Units	Coal	1950-1955	246
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	3,923

(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

Gas utility mains at December 31, 2002:

Miles	BMG	Cheyenne	NSP-Minnesota	NSP-Wisconsin	PSCo	Viking	WGI
Transmission			115		2,263	671	12
Distribution	415	673	8,608	1,929	18,114		

Listed below are descriptions of NRG s interests in facilities, operations and/or projects under construction at September 30, 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
Meriden Power, Connecticut	ISO-NE	540	100%	Gas/Oil
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 7 Projects	Various	96	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
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
Rockford II, Illinois	MAIN	171	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
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	71.57%	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	Industrials	5	9.33%	Gas/Coal
Other Americas:				
TermoRio, Brazil	Petrobras	520	50%	Gas/Oil
Itiquira Energetica, Brazil	COPEL/ Tradener	154	98.73%	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
Hennepin Co. Energy Center, Minnesota	N/A	Steam: 140 mmBtu/hr. (41 MWt)	N/A	NRG Energy Center Minneapolis 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)	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.

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

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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 Caron 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, property damage, and injury to their dairy herd. The complaint also alleges that NSP-Wisconsin acted willfully and wantonly, entitling plaintiffs to treble damages. The plaintiffs allege farm damages of approximately $3.8 million. The case is in the early stages of discovery. A ten-day trial commencing in April, 2003 has been scheduled.

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. 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 to an environmental project near the plant. The settlement resolves all claims identified in the state s complaint against NSP-Wisconsin.

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. On January 14, 2002, the NYDEC issued NRG NOVs for opacity events, which had occurred since the time NRG assumed ownership of the Huntley, 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. NRG is in negotiations with NYDEC to settle the dispute.

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 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. 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 9th Circuit. Meanwhile, the defendants motion to dismiss all the cases based on federal preemption and the filed rate doctrine is pending in the district court.

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. Under 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 has responded to the involuntary petition, contesting the petitioners claims and filing a motion seeking to have the case dismissed. The court has set April 29, 2003, as the evidentary hearing date to consider the motion to dismiss filed by NRG.

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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 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.

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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 4 to the interim consolidated financial statements, FirstEnergy terminated the purchase agreements pursuant to which NRG had agreed to purchase four 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.

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 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.

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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.

For a discussion of other legal claims and environmental proceedings, see Note 4 and Note 9 to the interim 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

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 Manager of Corporate Communications of PSCo from 1993 to 1996.

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 of Client Services with IBM Global Services and the executive in charge of IBM s account with Xcel Energy since 2000. In his new position he reports to Wayne Brunetti, Xcel Energy chairman, president and chief executive officer.

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 1999 to 2000.

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 the Texas Panhandle. He is President of Monarch Trust Company in Amarillo, Texas, and a director of the

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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 advisory board of the Harvard University Divinity School Center for Values in Public Life. Mr. Hirschfeld is

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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 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.

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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	Years of Service		
Remuneration	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

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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, 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 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. However, the notes are subordinated to any of our secured indebtedness, as to the assets securing such indebtedness. As of September 30, 2002, after giving effect to the initial sale of the notes and the use of the proceeds thereof, we would have no secured indebtedness and our unsecured and unsubordinated indebtedness would have been $1.2 billion.

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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 September 30, 2002, our subsidiaries had aggregate liabilities of $21.6 billion.

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.

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 September 30, 2002, our subsidiaries have $21.6 billion of indebtedness all of which is effectively senior to the notes and some of which is secured by the assets of the respective subsidiaries.

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.

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.

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 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

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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.

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 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) following a Flip-in Date would entitle its holder to purchase $190 worth of 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.

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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 will constitute 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% 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

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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

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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 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.

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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 SandShore 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
TQA Master Fund, Ltd.	$ 4,250,000	1.848%		344,687
TQA Master Plus Fund, Ltd.	$ 3,300,000	1.435%		267,639
TQA Sphinx Fund	$ 600,000	0.260%		48,661
Zurich Institutional Benchmarks Fund Ltd. c/o TQA Investors, LLC	$ 250,000	0.108%		20,275
HFR Master Trust c/o TQA Investors, LLC	$ 350,000	0.152%		28,386
Lexington Vantage Fund Ltd c/o TQA Investors LLC	$ 250,000	0.108%		20,275
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.	$ 1,000,000	0.435%		81,103
RCG Latitude Master Fund, LTD.	$ 1,200,000	0.522%		97,323

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)
RCG Multi Strategy A/C LP	$ 1,400,000	0.609%		113,544
RCG Halifax Master Fund, LTD.	$ 400,000	0.174%		32,441
RCG Baldwin, LP	$ 400,000	0.174%		32,441
Ramius, LP	$ 100,000	0.043%		8,110
Guggenheim Portfolio Co. XU, LLC	$ 500,000	0.217%		40,551
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 Series A-5	$ 840,000	0.365%		68,126
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
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
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
Sunris Partners Limited Partnership	$13,200,000	5.739%	3,500	1,070,559
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

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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)
Wachovia Bank National Association	$ 20,000,000	8.696%		1,622,060
All other holders of notes or future transferees, pledges, donees or successors of any such holders(2)(3)	$ 69,317,000	30.138%		5,621,816
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., except for the consolidated financial statements of NRG Energy, Inc. and its subsidiaries, as of and for the years ended December 31, 2001 and 2000, included in this prospectus have been audited by our independent auditors. The financial statements of NRG Energy, Inc. and its subsidiaries (consolidated with those of Xcel Energy Inc.) and not presented separately in this prospectus have been audited by NRG s independent auditors. Because our financial statements for the fiscal year ended December 31, 1999 have not been reaudited to reflect certain changes in the presentation of electric and gas trading revenues and costs and the impact of discontinued operations for certain companies of NRG, as more specifically discussed below, our and NRG s independent auditors have declined to consent to the inclusion in this prospectus of their reports on our and NRG s audited financial statements for the fiscal years ended December 31, 2000 and 2001. Accordingly, we have not included copies of their reports in this prospectus. Because our and NRG s independent auditors have not consented to the inclusion of their reports in this prospectus, you may not recover against either one of them under Section 11 of the Securities Act for untrue statements of material fact contained in the financial statements audited by them or any omissions to state a material fact required to be stated in those financial statements. Prior to the date on which this prospectus becomes effective and before any sales of notes or shares of common stock issued upon conversion of notes are made by any selling shareholder hereunder, we expect to file an amendment to the registration statement of which this prospectus is a part that will include consolidated audited financial statements for the fiscal years ended December 31, 2000, 2001 and 2002. We expect that the amendment will include consents from our and NRG s independent auditors to the inclusion in the amended prospectus of their reports on these audited consolidated financial statements.

Our consolidated financial statements and schedule as of December 31, 1999 and for the year ended December 31, 1999, included in this prospectus have been audited by Arthur Andersen LLP, independent public accountants, as indicated in their report with respect thereto. In that report, Arthur Andersen LLP states that with respect to NRG as of and for the year ended December 31, 1999 and Northern States Power Co. for the years ended December 31, 1999 and 1998 its opinion is based on the reports of other independent public accountants. For the reasons discussed above, NRG s independent auditor has declined to consent to the inclusion in this prospectus of its report on NRG s financial statements for the fiscal years ended December 31, 1999, 2000 and 2001, and we have not included its report in this prospectus. After reasonable efforts, we have been unable to obtain the consent of Arthur Andersen LLP to the inclusion of their report in this prospectus. In these circumstances, Rule 437a under the Securities Act permits us to file a registration statement without a written consent from Arthur Andersen. Since Arthur Andersen has not consented to the inclusion of their report in this prospectus, you may not be able to recover against Arthur Andersen under Section 11 of the Securities Act for any untrue statements of material fact contained in the financial statements audited by Arthur Andersen or any omissions to state a material fact required to be stated therein. As a result of their conviction on federal obstruction of justice charges arising from the government s investigation of Enron Corporation or other proceedings against them, Arthur Andersen LLP may cease to exist or become insolvent.

Subsequent to the issuance of the audit report of Arthur Andersen on the consolidated financial statements of Xcel Energy referred to above, our consolidated financial statements for 2000 and 2001 have been reaudited by our new independent auditors to account for changes in the presentation of electric and gas trading revenues and costs and the impact of discontinued operations for certain companies of NRG in 2002. Accordingly, you should consider the audit report of Arthur Andersen and our consolidated financial statements for the fiscal years ended December 31, 1999, 2000 and 2001 audited by Arthur Andersen provided only with respect to the financial statements for 1999, which have not been reaudited to address the new accounting standards.

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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INDEX TO FINANCIAL STATEMENTS

* Reports by PricewaterhouseCoopers LLP to be filed by amendment.

2000 and 2001 superseded by unaudited financial statements

** To be filed by amendment

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THE FOLLOWING REPORT IS A COPY OF A PREVIOUSLY ISSUED REPORT OF ARTHUR ANDERSEN LLP AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP.

SUBSEQUENT TO THE ISSUANCE OF THIS REPORT, OUR NEW INDEPENDENT AUDITORS HAVE REAUDITED OUR CONSOLIDATED FINANCIAL STATEMENTS FOR 2000 AND 2001. ACCORDINGLY, YOU SHOULD CONSIDER THE ATTACHED REPORT OF ARTHUR ANDERSEN AND THE CONSOLIDATED FINANCIAL STATEMENTS PRESENTED THEREIN ONLY FOR THE FISCAL YEAR ENDING DECEMBER 31, 1999. THE CONSOLIDATED FINANCIAL STATEMENTS FOR 2000 AND 2001, AS AUDITED BY DELOITTE & TOUCHE LLP, ARE INCLUDED IN THIS PROSPECTUS AT PAGES F-59 TO F-133.

FURTHERMORE, WE HAVE RECLASSIFIED OUR CONSOLIDATED FINANCIAL STATEMENTS FOR 1999 TO REFLECT CERTAIN ACCOUNTING CHANGES. THESE CHANGES ARE NOT COVERED BY THE PREVIOUSLY ISSUED REPORT OF ARTHUR ANDERSEN LLP, A COPY OF WHICH IS PROVIDED BELOW.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Xcel Energy Inc.:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Xcel Energy Inc. (a Minnesota corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, stockholders equity and cash flows for each of the years in the three-year period ended December 31, 2001. 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 did not audit the consolidated financial statements of NRG Energy, Inc. for the years ended December 31, 2001 and 2000, included in the consolidated financial statements of Xcel Energy Inc., which statements reflect total assets and revenues of 45 percent and 18 percent for 2001, respectively, and total assets and revenues of 28 percent and 18 percent for 2000, respectively, of the related consolidated totals. We also did not audit the consolidated financial statements of Northern States Power Co., for the year ended December 31, 1999, included in the consolidated financial statements of Xcel Energy Inc., which statements reflect total revenues of 44 percent of the related consolidated totals. Those statements were audited by other auditors whose reports have been furnished to us, and our opinion, insofar as it relates to the amounts included for NRG Energy, Inc. and Northern States Power Co. for the periods described above, is based solely on the reports of the other auditors.

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

In our opinion, based on our audits and the reports of other auditors, the financial statements referred to above present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 14 to the Consolidated Financial Statements, effective January 1, 2001 Xcel Energy Inc. and subsidiaries adopted Statement of Financial Accounting Standard No. 133, Accounting for Derivative Instruments and Hedging Activity, which changed its method of accounting for certain commodity contracts and other derivatives.

/s/ ARTHUR ANDERSEN LLP

ARTHUR ANDERSEN LLP
Minneapolis, Minnesota
February 21, 2002

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REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

Report by PricewaterhouseCoopers LLP to the Board of Directors and Stockholders of NRG Energy, Inc. to be filed by amendment.

Report by PricewaterhouseCoopers LLP to the Shareholders of Xcel Energy Inc. to be filed by amendment.

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year ended Dec. 31		
	2001	**2000**	**1999**
		(Thousands of Dollars, Except per Share Data)	
Operating revenues:			
Electric utility	$ 6,394,737	$ 5,674,485	$4,921,612
Gas utility	2,052,651	1,468,880	1,141,429
Electric and gas trading	3,186,850	2,061,839	951,490
Nonregulated and other	3,176,896	2,203,878	710,871
Equity earnings from investments in affiliates	217,070	182,714	112,124
Total operating revenues	15,028,204	11,591,796	7,837,526
Operating expenses:			
Electric fuel and purchased power utility	3,171,660	2,580,723	1,967,335
Cost of gas sold and transported utility	1,517,557	948,145	683,455
Electric and gas trading costs	3,097,601	2,020,482	947,144
Cost of sales nonregulated and other	1,656,522	1,006,587	309,553
Other operating and maintenance expenses utility	1,506,039	1,446,122	1,376,690
Other operating and maintenance expenses nonregulated	807,955	636,280	276,146
Depreciation and amortization	949,200	792,395	679,851
Taxes (other than income taxes)	316,492	351,412	360,916
Special charges (see Note 2)	62,230	241,042	31,114
Total operating expenses	13,085,256	10,023,188	6,632,204
Operating income	1,942,948	1,568,608	1,205,322
Interest income and other nonoperating income net of other expenses	72,161	18,639	1,134
Interest charges and financing costs:			
Interest charges net of amounts capitalized	782,399	657,305	414,277
Distributions on redeemable preferred securities of subsidiary trusts	38,800	38,800	38,800
Total interest charges and financing costs	821,199	696,105	453,077
Income before income taxes, minority interest and extraordinary items	1,193,910	891,142	753,379
Income taxes	336,723	304,865	179,673
Minority interest	72,508	40,489	2,773
Income before extraordinary items	784,679	545,788	570,933
Extraordinary items, net of income taxes of $4,807 and ($8,549), respectively (see Note 12)	10,287	(18,960)	0
Net income	794,966	526,828	570,933
Dividend requirements on preferred stock	4,241	4,241	5,292
Earnings available for common shareholders	$ 790,725	$ 522,587	$ 565,641

Weighted average common shares outstanding (in thousands):			
Basic	342,952	337,832	331,943
Diluted	343,742	338,111	332,054
Earnings per share basic:			
Income before extraordinary items	$ 2.28	$ 1.60	$ 1.70
Extraordinary items (see Note 12)	0.03	(0.06)	0.00
Earnings per share	$ 2.31	$ 1.54	$ 1.70
Earnings per share diluted:			
Income before extraordinary items	$ 2.27	$ 1.60	$ 1.70
Extraordinary items (see Note 12)	0.03	(0.06)	0.00
Earnings per share	$ 2.30	$ 1.54	$ 1.70

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended Dec. 31		
	2001	**2000**	**1999**
		(Thousands of Dollars)	
Operating activities:			
Net income	$ 794,966	$ 526,828	$ 570,933
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation and amortization	945,555	828,780	718,323
Nuclear fuel amortization	41,928	44,591	50,056
Deferred income taxes	11,190	62,716	18,161
Amortization of investment tax credits	(12,867)	(15,295)	(14,800)
Allowance for equity funds used during construction	(6,829)	3,848	(1,130)
Undistributed equity in earnings of unconsolidated affiliates	(124,277)	(87,019)	(67,926)
Gain on sale of nonregulated projects	0	0	(37,194)
Special charges not requiring (using) cash	57,391	96,113	31,114
Conservation incentive accrual adjustments	(49,271)	19,248	71,348
Unrealized gain on derivative financial instruments	(9,804)	0	0
Extraordinary items net of tax (see Note 12)	(10,287)	18,960	0
Change in accounts receivable	218,353	(443,347)	(113,521)
Change in inventories	(178,530)	21,933	(44,183)
Change in other current assets	340,478	(484,288)	(164,995)
Change in accounts payable	(325,946)	713,069	214,791
Change in other current liabilities	85,226	129,557	81,056
Change in other assets and liabilities	(193,264)	(27,969)	13,396
Net cash provided by operating activities	1,584,012	1,407,725	1,325,429
Investing activities:			
Nonregulated capital expenditures and asset acquisitions	(4,259,791)	(2,196,168)	(1,620,462)
Utility capital/ construction expenditures	(1,105,989)	(984,935)	(1,178,663)
Allowance for equity funds used during construction	6,829	(3,848)	1,130
Investments in external decommissioning fund	(54,996)	(48,967)	(39,183)
Equity investments, loans, deposits and sales of nonregulated projects	154,845	(93,366)	(240,282)
Collection of loans made to nonregulated projects	6,374	17,039	81,440
Other investments net	84,769	(36,749)	43,136
Net cash used in investing activities	(5,167,959)	(3,346,994)	(2,952,884)
Financing activities:			
Short-term borrowings net	708,335	42,386	1,315,027
Proceeds from issuance of long-term debt	3,777,075	3,565,227	1,215,312
Repayment of long-term debt, including reacquisition premiums	(860,623)	(1,667,335)	(465,045)
Proceeds from issuance of common stock	133,091	116,678	95,317
Proceeds from NRG stock offering	474,348	453,705	0
Dividends paid	(518,894)	(494,992)	(492,456)
Net cash provided by financing activities	3,713,332	2,015,669	1,668,155
Effect of exchange rate changes on cash	(4,566)	360	0
Net increase in cash and cash equivalents	124,819	76,760	40,700
Cash and cash equivalents at beginning of year	216,491	139,731	99,031

Cash and cash equivalents at end of year	$ 341,310	$ 216,491	$ 139,731
Supplemental disclosure of cash flow information:			
Cash paid for interest (net of amounts capitalized)	$ 708,560	$ 610,584	$ 458,897
Cash paid for income taxes (net of refunds received)	$ 327,018	$ 216,087	$ 193,448

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	Dec. 31	
	2001	**2000**
	(Thousands of Dollars)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 341,310	$ 216,491
Restricted cash	161,842	12,135
Accounts receivable net of allowance for bad debts: $57,815 and $41,350, respectively	1,174,828	1,289,724
Accrued unbilled revenues	495,994	683,266
Materials and supplies inventories at average cost	330,363	286,453
Fuel inventory at average cost	250,043	116,990
Gas inventories replacement cost in excess of LIFO: $11,331 and $106,790, respectively	126,563	77,390
Recoverable purchased gas and electric energy costs	52,583	283,167
Derivative instruments valuation at market	59,790	0
Prepayments and other	318,046	162,458
Total current assets	3,311,362	3,128,074
Property, plant and equipment, at cost:		
Electric utility plant	16,099,655	15,304,407
Nonregulated property and other	8,388,261	5,348,976
Gas utility plant	2,493,028	2,376,868
Construction work in progress (utility amounts of $669,895 and $622,494, respectively)	3,682,633	915,486
Total property, plant and equipment	30,663,577	23,945,737
Less: accumulated depreciation	(9,594,775)	(8,759,322)
Nuclear fuel net of accumulated amortization: $1,009,855 and $967,927, respectively	96,315	86,499
Net property, plant and equipment	21,165,117	15,272,914
Other assets:		
Investments in unconsolidated affiliates	1,209,017	1,459,410
Notes receivable, including amounts from affiliates of $202,411 and $76,918, respectively	779,186	92,074
Nuclear decommissioning fund and other investments	695,070	732,908
Regulatory assets	502,442	524,261
Derivative instruments valuation at market	179,683	0
Prepaid pension asset	378,825	225,134
Other	514,360	334,068
Total other assets	4,258,583	3,367,855
Total assets	$28,735,062	$21,768,843

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	Dec. 31	
	2001	**2000**
	(Thousands of Dollars)	
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 682,207	$ 603,611
Short-term debt	2,224,812	1,475,072
Accounts payable	1,378,211	1,608,989
Taxes accrued	246,152	236,837
Dividends payable	130,845	128,983
Derivative instruments valuation at market	83,122	0
Other	704,679	618,316
Total current liabilities	5,450,028	4,671,808
Deferred credits and other liabilities:		
Deferred income taxes	2,289,550	1,794,193
Deferred investment tax credits	184,148	198,108
Regulatory liabilities	483,942	494,566
Derivative instruments valuation at market	57,575	0
Benefit obligations and other	703,836	588,288
Total deferred credits and other liabilities	3,719,051	3,075,155
Minority interest in subsidiaries	654,670	277,335
Capitalization (see Statements of Capitalization):		
Long-term debt	12,117,516	7,583,441
Mandatorily redeemable preferred securities of subsidiary trusts (see Note 6)	494,000	494,000
Preferred stockholders equity	105,320	105,320
Common stockholders equity	6,194,477	5,561,784
Commitments and contingencies (see Note 15)		
Total liabilities and equity	$28,735,062	$21,768,843

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

	Par Value	Premium	Retained Earnings	Shares Held by ESOP	Accumulated Other Comprehensive Income	Total Stockholders Equity
			(Thousands of Dollars)			
Balance at Dec. 31, 1998	$825,395	$2,197,058	$2,173,373	$(18,503)	$ (81,250)	$5,096,073
Net income			570,933			570,933
Recognition of unrealized loss from marketable securities, net of tax of $4,417					6,416	6,416
Currency translation adjustments					(3,587)	(3,587)
Comprehensive income for 1999						573,762
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(5,292)			(5,292)
Common stock			(489,813)			(489,813)
Issuances of common stock net	12,930	92,247				105,177
Pooling of interests business combinations			4,599			4,599
Tax benefit from stock options exercised		58				58
Other	(132)	(1,109)				(1,241)
Repayment of ESOP loan(a)				6,897		6,897
Balance at Dec. 31, 1999	$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	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	$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 14)					(28,780)	(28,780)
After-tax net unrealized gains related to derivatives accounted for as hedges (see Note 14)					43,574	43,574
After-tax net realized losses on derivative transactions reclassified into earnings (see Note 14)					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	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	$864,503	$2,969,589	$2,558,403	$(18,564)	$(179,454)	$6,194,477

(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	
	2001	**2000**
	(Thousands of Dollars)	
Long-Term Debt		
NSP-Minnesota Debt		
First Mortgage Bonds, Series due:		
Dec. 1, 2001 2006, 3.65 4.1%	$ 11,225(a)	$ 13,230(a)
Oct. 1, 2001, 7.875%	0	150,000
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
March 1, 2011, variable rate, 1.8% at Dec. 31, 2001, and 5.05% at Dec. 31, 2000	13,700(b)	13,700(b)
March 1, 2019, variable rate, 2.04% at Dec. 31, 2001, and 4.25% at Dec. 31, 2000	27,900(b)	27,900(b)
Sept. 1, 2019, variable rate 1.76% and 2.04% at Dec. 31, 2001, and 4.36% and 4.61% at Dec. 31, 2000	100,000(b)	100,000(b)
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
Guaranty Agreements, Series due: 2001 May 1, 2003, 5.375% 7.4%	29,200(b)	29,950(b)
Senior Notes due Aug. 1, 2009, 6.875%	250,000	250,000
City of Becker Revenue Bonds-Series due April 1, 2030, 1.85% at Dec. 31, 2001, and 5.1% at Dec. 31, 2000	69,000(b)	69,000(b)
Anoka County Bond-Series due Dec. 1, 2001 2008, 4.15% 5%	16,090(a)	17,990(a)
Employee Stock Ownership Plan Bank Loans due 2001-2007, variable rate	18,564	24,617
Other	390	194
Unamortized discount-net	(5,015)	(5,513)
Total	1,181,054	1,341,068
Less redeemable bonds classified as current (see Note 4)	141,600	141,600
Less current maturities	11,134	161,773
Total NSP-Minnesota long-term debt	$ 1,028,320	$ 1,037,695
PSCo Debt		
First Mortgage Bonds, Series due:		
Jan. 1, 2001, 6%	$ 0	$ 102,667
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)
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%	147,840	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
	190,000	226,500

Secured Medium-Term Notes, due Oct. 22, 2002 March 5, 2007, 6.45% 7.65%		
Other secured long-term debt, 13.25%	0	29,777
PSCCC Unsecured Medium-Term Notes, variable rate 7.4% at Dec. 31, 2000	0	100,000
Unamortized discount	(5,282)	(5,952)
Capital lease obligations, 11.2% due in installments through May 31, 2025	51,921	54,202
Total	1,482,229	1,752,784
Less current maturities	17,174	142,043
Total PSCo long-term debt	$1,465,055	$1,610,741

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31	
	2001	**2000**
	(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	0
Pollution control obligations, securing pollution control revenue bonds due:		
July 1, 2011, 5.2%	44,500	44,500
July 1, 2016, 1.7% at Dec. 31, 2001 and 5.1% at Dec. 31, 2000	25,000	25,000
Sept. 1, 2016, 5.75% series	57,300	57,300
Less funds held by Trustee	0	(168)
Unamortized discount	(1,425)	(126)
Total SPS long-term debt	$725,375	$226,506
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 LaCrosse Resource Recovery Bond Series due Nov. 1, 2021, 6%	18,600(a)	18,600(a)
Fort McCoy System Acquisition due Oct. 31, 2030, 7%	963	996
Senior Notes due Oct. 1, 2008, 7.64%	80,000	80,000
Unamortized discount	(1,475)	(1,562)
Total	313,088	313,034
Less current maturities	34	34
Total NSP-Wisconsin long-term debt	$313,054	$313,000

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31	
	2001	**2000**
	(Thousands of Dollars)	
NRG Debt		
Remarketable or Redeemable Securities due March 15, 2005, 7.97%	$ 232,960	$ 239,386
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	0
April 1, 2011, 7.75%	350,000	0
April 1, 2031, 8.625%	500,000	0
May 16, 2006, 6.5%	284,440	0
NRG Finance Co. I LLC, due May 9, 2006, various rates	697,500	0
NRG debt secured solely by project assets:		
NRG Northeast Generating Senior Bonds, Series due:		
Dec. 15, 2004, 8.065%	180,000	270,000
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%	463,500	488,750
Sept. 15, 2024, 9.479%	300,000	300,000
Mid Atlantic various due Oct. 1, 2005, 3.56%	420,892	0
Sterling Luxembourg#3 Loan due June 30, 2019, variable rate 7.86% at Dec. 31, 2001 and 2000	329,842	346,668
Flinders Power Finance Pty due September 2012, various rates 8.56% at Dec. 31, 2001 and 7.58% at Dec. 31, 2000	74,886	83,820
Brazos Valley due June 30, 2008, 3.44%	159,750	0
Camas Power Boiler, due June 30, 2007 and Aug. 1, 2007, 7.65% and 4.65%	20,909	0
Crockett Corp. LLP debt due Dec. 31, 2014, 8.13%	234,497	245,229
Csepel Aramtermelo due Oct. 2, 2017, 3.79% and 4.846%	169,712	0
Hsin Yu Energy Development due November 2006 April 2012, 4% to 6.475%	89,964	0
LSP Batesville due Jan. 15, 2014, 7.164% and July 15, 2025, 8.16%	321,875	0
LSP Kendall Energy due Sept. 1, 2005, 3.154%	499,500	0
McClain due Dec. 31, 2005, 3.43%	159,885	0
NEO due 2005 2008, 9.35%	23,956	27,185
NRG Energy Center, Inc. Senior Secured Notes, Series due June 15, 2013, 7.31%	62,408	65,762
PERC due 2017 2018, 5.2%	33,220	0
Audrain Capital Lease Obligation due Dec. 31, 2023, 10%	239,930	0
Saale Energie GmbH Schkopau Capital Lease due May 2021, various rates	311,867	0
Various debt due 2001-2007, 0.0%-20.8%	148,121	33,738
Other	0	1,307
Total	8,344,614	3,796,845
Less current maturities	500,155	145,504

Total NRG long-term debt	$7,844,459	$3,651,341

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31	
	2001	2000
	(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, 1.8% and 4.95% at Dec. 31, 2001 and 2000	17,000	17,000
Viking Gas Transmission Co. Senior Notes Series due:		
Oct. 31, 2008 Sept. 30, 2014, 6.65% 8.04%	45,181	49,941
Various Eloigne Co. Affordable Housing Project Notes due 2002 2027, 0.3% 9.91%	47,856	51,309
Other	34,981	30,414
Total	157,018	160,664
Less current maturities	12,110	12,657
Total other subsidiaries long-term debt	$ 144,908	$ 148,007
Xcel Energy Inc. Debt		
Unsecured Senior Notes due Dec. 1, 2010, 7%	$ 600,000	$ 600,000
Unamortized discount	(3,655)	(3,849)
Total Xcel Energy Inc. debt	$ 596,345	$ 596,151
Total long-term debt	$ 12,117,516	$ 7,583,441
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: 2001, 1,049,800; 2000, 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
Premium 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: 2001, 345,801,028; 2000, 340,834,147	$ 864,503	$ 852,085
Premium on common stock	2,969,589	2,607,025
Retained earnings	2,558,403	2,284,220
Leveraged common stock held by ESOP shares at cost: 2001, 783,162; 2000, 1,041,180	(18,564)	(24,617)
Accumulated other comprehensive income (loss)	(179,454)	(156,929)
Total common stockholders equity	$ 6,194,477	$ 5,561,784

(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, NSP and 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.

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. Xcel Energy s regulated businesses also include Viking and WGI.

Xcel Energy also owns or has an interest in a number of nonregulated businesses, the largest of which is NRG Energy, Inc., a publicly traded independent power producer. At Dec. 31, 2001, Xcel Energy indirectly owned approximately 74 percent of NRG. 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. See Note 19 to the Financial Statements for further discussion of potential changes in NRG ownership.

In addition to NRG, Xcel Energy s nonregulated subsidiaries include Utility Engineering (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.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

subtracting foreign income taxes, if applicable. In the consolidation process, we eliminate all significant intercompany transactions and balances.

Revenue Recognition Xcel Energy records utility revenues based on a calendar month, but reads meters and bills customers according to a cycle that doesn t necessarily correspond with the calendar month s end. To compensate, we record unbilled revenues for an estimate of the energy usage from the monthly meter-reading dates to the month s end.

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.

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. SPS rates in Texas have fixed fuel factor and periodic fuel filing, reconciling and reporting requirements, which provide cost recovery. In New Mexico, SPS has recently reinstituted a monthly fuel and purchased power cost recovery factor. 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.

Trading Operations Beginning with year-end 2000 reporting, Xcel Energy changed its policy for the presentation of energy trading operating results. Previously, trading margins were recorded net of costs in electric and natural gas revenues. Xcel Energy currently reports trading revenues separately from trading costs. 1999 results have been reclassified for consistency with the 2000 and 2001 presentation.

Xcel Energy s trading operations are conducted mainly by PSCo (electric) and e prime (gas). The results of the electric trading activity are initially recorded at PSCo. Pursuant to a Joint Operating Agreement, approved by the FERC as a part of the merger, the activity is then 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 generation assets or results from NRG. PSCo s trading results include the impacts of the ICA rate-sharing mechanism. For more information, see Notes 13 and 14 to the 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 3.1 percent for the year ended Dec. 31, 2001, and 3.3 percent for the years ended Dec. 31, 2000 and 1999.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

based on its weighted average cost of debt in accordance with a Colorado Public Utilities Commission (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 $56 million in 2001, $23 million in 2000 and $19 million in 1999.

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 16 to the Financial Statements.

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. 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, except NRG, file consolidated federal and combined and separate state income tax returns. Due to NRG s 2001 public equity offering, NRG and its subsidiaries will file a federal income tax return separate from Xcel Energy for the period March 13, 2001 through Dec. 31, 2001. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss. In accordance with the PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive taxable income of each company in the consolidated federal or combined state returns. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax basis of assets and liabilities. We use 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 17 to the Financial Statements. We discuss our income tax policy for international operations in Note 8 to the 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 component of Other Nonoperating Income.

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 commodity price risk. 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 Statement of Financial Accounting Standard (SFAS) No. 133 Accounting for Derivative Instruments and Hedging Activity, as amended by SFAS No. 137 and SFAS No. 138 (collectively referred to as SFAS No. 133). For more information on the impact of SFAS No. 133, see Note 14 to the Financial Statements.

For further discussion of Xcel Energy s risk management and derivative activities, see Note 13 and Note 14 to the 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 and funds held in trust accounts to satisfy the requirements of certain debt agreements. Restricted cash is classified as a current asset as all restricted cash is designated for interest and principal payments due within one year.

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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 the restriction lapses or the stock is forfeited. For more information, see Note 9 to the Financial Statements.

NRG Development Costs As NRG develops projects, it expenses the development costs it incurs (for professional services, permits, etc.) until a sales agreement or letter of intent is signed and the project has received NRG board approval. NRG capitalizes additional costs incurred at that point. When a project begins to operate, NRG amortizes the capitalized costs over either the life of the project s related assets or the revenue contract period, whichever is less. If a project is terminated without becoming operational, NRG expenses the capitalized costs in the period of the termination.

Intangible Assets and Deferred Financing Costs Goodwill results when Xcel Energy purchases an entity at a price higher than the underlying fair value of the net assets. At Dec. 31, 2001, Xcel Energy had unamortized intangible assets of $166 million, including $69 million of goodwill, mainly at its nonregulated subsidiaries. The majority of these intangible assets is associated with energy contracts and will be amortized over the contract terms. Effective Jan. 1, 2002, Xcel Energy implemented SFAS No. 142. These amounts and all intangible assets and goodwill acquired in the future will be accounted for under the new accounting standard. The new accounting can be expected to initially increase earnings due to the elimination of amortization expense, but periodically causes reductions in earnings when impairment write-downs of goodwill and/or intangible assets are required.

Other assets also included deferred financing costs, net of amortization, of approximately $154 million at Dec. 31, 2001. We are amortizing these financing costs over the remaining maturity periods of the related debt.

Reclassifications We reclassified certain items in the 1999 and 2000 income statements and the 2000 balance sheet to conform to the 2001 presentation. These reclassifications had no effect on net income or earnings per share. Reported amounts for periods prior to the merger have been restated to reflect the merger as if it had occurred as of Jan. 1, 1999. The reclassifications were primarily to conform the presentation of all consolidated Xcel Energy subsidiaries to a standard corporate presentation.

2. Special Charges

2001 Restaffing During the fourth quarter of 2001, Xcel Energy expensed pretax special charges of $39 million, or 7 cents per share, for expected staff consolidation costs. The charges related to severance costs for utility operations resulting from the restaffing plans of several operating and corporate support areas of Xcel Energy relate primarily to nonbargaining positions. We accrued costs for 500 staff terminations, which are expected to occur, mainly in the first quarter of 2002, across all regions of Xcel Energy s service territory, but primarily in Minneapolis and Denver. As of Jan. 31, 2002, 239 of these terminations had occurred.

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. PSCo appealed this decision to the Denver District Court. In 1998, the CPUC deferred the final determination of the regulatory treatment of the electric jurisdictional costs pending the outcome of PSCo s appeal on the natural gas rate case. On Dec. 16, 1999, the Denver District Court affirmed the decision by the CPUC.

On July 2, 2001, the Colorado Supreme Court affirmed the District Court decision. Accordingly, PSCo has written off $23 million pretax, representing 4 cents per share, of regulatory assets related to deferred postemployment benefit costs as of June 30, 2001, since all means of regulatory recovery have been denied.

2000 Merger Costs Upon consummation of the merger in 2000, Xcel Energy expensed pretax special charges totaling $241 million. These special charges reduced Xcel Energy s 2000 earnings by 52 cents per share. Of these pretax special charges, $201 million, or 43 cents per share, was recorded during the third quarter of 2000, and $40 million, or 9 cents per share, was recorded during the fourth quarter of 2000.

The pretax charges included $199 million, or 44 cents per share, 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 pretax charges also included $42 million, or 8 cents per share, of asset impairments and other costs resulting from the post-merger strategic alignment of Xcel Energy s nonregulated businesses. 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 transition costs include approximately $77 million for severance and related expenses associated with staff reductions of 721 employees, 706 of whom were released through Jan. 31, 2002. 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.

Accrued Special Charges The following table summarizes activity related to accrued special charges in 2001 and 2000.

	Expensed 2000	Payments Through Dec. 31, 2000	Dec. 31, 2000 Liability*	Expensed 2001	Payments 2001	Dec. 31, 2001 Liability*
	(Millions of dollars)					
Employee severance and related costs	$ 77	$ (29)	$ 48	$ 39	$ (50)	$ 37
Regulatory transition costs	12	(7)	5	0	(5)	0
Other transition and integration costs	58	(56)	2	0	(2)	0
Total accrued special charges	$ 147	$ (92)	$ 55	$ 39	$ (57)	$ 37

* Reported on the balance sheet in other current liabilities.

1999 EMI Goodwill In 1999, Xcel Energy expensed pretax special charges of approximately $17 million, or 4 cents per share, to write off all goodwill that was recorded by its subsidiary EMI for its acquisitions of Energy Masters Corp. in 1995 and Energy Solutions International in 1997. This charge reflected a revised business outlook based on the levels of contract signings by EMI.

1999 Loss on Marketable Securities During 1999, Xcel Energy expensed pretax special charges of approximately $14 million, or 3 cents per share, for valuation write-downs on its investment in the publicly traded common stock of CellNet Data Systems, Inc. In October 1999, CellNet announced it was

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experiencing financial difficulties and in February 2000, filed for Chapter 11 bankruptcy protection. CellNet s assets were subsequently acquired by another company.

3. Short-Term Borrowings

Notes Payable and Commercial Paper Information regarding notes payable and commercial paper for the years ended Dec. 31, 2001 and 2000 is:

	2001	2000
	(Millions of dollars, except interest rates)	
Notes payable to banks	$ 835	$ 20
Commercial paper	1,390	1,455
Total short-term debt	$2,225	$1,475
Weighted average interest rate at year end	3.41%	6.48%

Bank Lines of Credit and Compensating Bank Balances At Dec. 31, 2001, we and our subsidiaries had approximately $6.9 billion and DEM 203.6 million in credit facilities with several banks. We pay for these lines of credit with a combination of fee payments and compensating balances.

	Period Beginning	Term	Credit Line
Xcel Energy	November 2001	364 days	$400 million
Xcel Energy	November 2000	5 years	$400 million
NSP-Minnesota	August 2001	364 days	$300 million
PSCo	June 2001	364 days	$600 million
SPS	February 2001	364 days	$300 million
NRG total			$4.8 billion and DEM 203.6 million
Other subsidiaries	Various	Various	$118 million

The lines of credit for companies other than NRG provide short-term financing in the form of bank loans and letters of credit, but their primary purpose is support for commercial paper borrowings. At Dec. 31, 2001, there were no loans outstanding under these lines of credit. The borrowing rate under these lines of credit is based on the 90-day London Interbank Offered Rate (LIBOR), a euro dollar rate margin, and the amount of money borrowed. The rate that would have applied at Dec. 31, 2001, if we had loans outstanding, would have been between 2.18 percent and 2.505 percent.

At Dec. 31, 2001, NRG had three credit facilities for short-term financing:

a $500-million recourse revolving credit facility under a commitment fee arrangement that matures in March 2002. This facility provided short-term financing in the form of bank loans. At Dec. 31, 2001, NRG had $170 million outstanding under this facility. In March 2002, the revolving credit facility will terminate. During the period ended Dec. 31, 2001, the facility bore interest at a floating rate based on LIBOR and prime rates throughout the period and had a weighted average interest rate of 5.89 percent,

a $40-million revolving credit facility that matures in March 2002. This is a facility of NRG s South Central project and is nonrecourse to NRG. At Dec. 31, 2001, NRG South Central had $40 million outstanding under this facility at 4.46 percent and

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

a $600-million unsecured term loan facility, which terminates on June 21, 2002. At Dec. 31, 2001, the aggregate amount outstanding under this facility was $600 million at a weighted average interest rate of 3.94 percent.

NRG s other credit facilities are used for long-term financing. See discussion in Note 4 to the Financial Statements.

4. 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 addition, certain SPS payments under its pollution-control obligations are pledged to secure obligations of the Red River Authority of Texas.

There are annual sinking-fund requirements in our utility subsidiaries first mortgage indentures, in the amounts necessary to redeem 1 to 6.7 percent of the highest principal amount of each series of first mortgage bonds at any time outstanding, excluding series issued for pollution control and resource recovery financings and certain other series totaling $1.7 billion. NSP-Minnesota, NSP-Wisconsin, PSCo and Cheyenne expect to satisfy substantially all of their sinking fund obligations in accordance with the terms of their respective indentures through the application of property additions. SPS has no significant sinking fund requirements.

NSP-Minnesota s 2011 series bonds are redeemable upon seven-days notice at the option of the bondholder. NSP-Minnesota also is potentially liable for repayment of the 2019 series when the bonds are tendered, which occurs each time the variable interest rates change. 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.

NRG has several credit facilities used for long-term financing:

Facility	Available line of credit	Recourse to NRG	End date	Outstanding Dec. 31, 2001	Rate at Dec. 31, 2001
			(Currency in Thousands)		
Revolving lines of credit:					
NRG Finance Co. I LLC	$2,000,000	Yes	May 2009	$697,500	4.83%
Term loan facilities:					
MidAtlantic	$580,000	No	November 2005	$420,892	3.56%
LSP Kendall Energy	$554,200	No	September 2005	$499,500	3.15%
Csepel	$78,500 and	No	October 2017	$169,712	3.79-4.85%
	DEM $203,600				
Brazos Valley	$180,000	No	June 2008	$159,750	3.44%
McClain	$296,000	No	December 2005	$159,885	3.43%

The NRG Finance Co. I LLC facility is 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 non-recourse to NRG other than its obligation to contribute equity at certain times in respect of projects and turbines financed under the facility.

On March 13, 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 $25 NRG senior debenture (6.5 percent notes due May 16, 2006) and an obligation to acquire shares of NRG common stock no later than May 18, 2004 at a price ranging from $27.00 to $32.94 per share.

The $240 million NRG senior notes due Nov. 1, 2013 are Remarketable or Redeemable Securities (ROARS). At certain dates the notes must either be tendered to and purchased by Credit Suisse Financial

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Products or 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.

NRG s $250 million issue of 8.7 percent ROARS due March 15, 2005 may be remarketed by Bank of America, N.A. at a fixed rate of interest through the maturity date or at a floating rate of interest for up to one year and then at a fixed rate of interest through 2020.

Maturities and sinking fund requirements of long-term debt are:

2002	$ 682 million
2003	$ 719 million
2004	$ 335 million
2005	$ 1,140 million
2006	$ 1,832 million

5. Preferred Stock

At Dec. 31, 2001, we had six series of preferred stock outstanding, which were callable at our option at prices ranging from $102 to $103.75 per share plus accrued dividends.

The holders of our $3.60 series preferred stock are entitled to three votes for each share held. The holders of our 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 our 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
NRG Energy, Inc.	200,000,000	$ 0.01	None
PS Colorado Credit Corp.	25,000,000	$ 1.00	None

6. Mandatorily Redeemable Preferred Securities of Subsidiary Trusts

In 1996, SPS Capital I, a wholly owned, special-purpose subsidiary trust of SPS, issued $100 million of 7.85 percent trust preferred securities 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.

In 1997, NSP Financing I, a wholly owned, special-purpose subsidiary trust of NSP-Minnesota, issued $200 million of 7.875 percent trust preferred securities 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In 1998, PSCo Capital Trust I, a wholly owned, special-purpose subsidiary trust of PSCo, issued $194 million of 7.60 percent trust preferred securities 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 Income along with interest charges.

7. Joint Plant Ownership

The investments by Xcel Energy s subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2001, are:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
		(Thousands of dollars)		
NSP-Minnesota-Sherco Unit 3	$609,382	$271,874	$1,158	59.0
PSCo:				
Hayden Unit 1	$ 84,032	$ 37,664	$ 223	75.5
Hayden Unit 2	79,197	40,864	63	37.4
Hayden Common Facilities	28,044	2,715	156	53.1
Craig Units 1 & 2	59,799	30,593	0	9.7
Craig Common Facilities Units 1, 2 & 3	26,052	8,816	0	6.5-9.7
Transmission Facilities, including Substations	84,760	28,689	125	42.0-73.0
Total PSCo.	$361,884	$149,341	$ 567	
NRG:				
McClain	$276,589	$ 3,836	$ 0	77.0
Big Cajun II Unit 3	177,359	7,838	2,249	58.0
Conemaugh	60,237	1,497	695	3.7
Keystone	51,906	1,291	1,022	3.7
Total NRG	$566,091	$ 14,462	$3,966	

NSP-Minnesota is part owner of Sherco 3, an 860-megawatt, coal-fired 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Income Taxes

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:

	2001	2000	1999
Federal statutory rate	35.0 %	35.0 %	35.0 %
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	2.5 %	5.8 %	2.1 %
Life insurance policies	(1.9)%	(2.4)%	(2.3)%
Tax credits recognized	(6.6)%	(10.2)%	(6.0)%
Equity income from unconsolidated affiliates	(1.7)%	(2.3)%	(5.5)%
Income from foreign consolidated affiliates	(0.8)%	(0.4)%	0.0 %
Regulatory differences utility plant items	1.8 %	2.3 %	1.9 %
Deferred tax expense on Yorkshire investment	0.0 %	2.3 %	0.0 %
Nondeductible merger costs	0.0 %	2.9 %	0.0 %
Other net	0.1 %	1.8 %	(1.3)%
Effective income tax rate including extraordinary items	28.4 %	34.8 %	23.9 %
Effective income tax rate excluding extraordinary items	28.0 %	35.8 %	23.9 %

Income taxes comprise the following expense (benefit) items:

	(Thousands of dollars)		
Current federal tax expense	$373,891	$205,718	$175,461
Current state tax expense	26,927	63,428	26,949
Current foreign tax expense	6,510	(625)	4,040
Current federal tax credits	(66,179)	(71,270)	(30,137)
Deferred federal tax expense	(24,114)	103,258	27,380
Deferred state tax expense	18,702	12,547	(2,352)
Deferred foreign tax expense	13,969	7,104	(6,868)
Deferred investment tax credits	(12,983)	(15,295)	(14,800)
Income tax expense excluding extraordinary items	336,723	304,865	179,673
Tax expense (benefit) on extraordinary items	4,807	(8,549)	0
Total income tax expense	$341,530	$296,316	$179,673

Xcel Energy management intends to reinvest the earnings from NRG s foreign operations to the extent the earnings are subject to current U.S. income taxes. Accordingly, U.S. income taxes and foreign withholding taxes have not been provided on a cumulative amount of unremitted earnings of foreign subsidiaries of approximately $345 million and $238 million at Dec. 31, 2001 and 2000. The additional U.S. income tax and foreign withholding tax on the unremitted foreign earnings, if repatriated, would be offset in part by foreign tax credits. Thus, it is not practicable to estimate the amount of tax that might be payable.

Xcel Energy management also intends to reinvest the earnings of the Argentina operations of Xcel Energy International, and therefore has not provided deferred taxes for the effects of the currency devaluation discussed in Note 15 to the Financial Statements. However, as a result of management s revised strategic plan for Yorkshire Power to begin repatriation of earnings to the United States, Xcel Energy provided deferred taxes of $20 million on unremitted earnings of $55 million at Dec. 31, 2000. Due to the sale of the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

majority of its interest in Yorkshire Power during 2001, Xcel Energy now accounts for its remaining investment under the cost method.

The components of Xcel Energy s net deferred tax liability (current and noncurrent portions) at Dec. 31 were:

	2001	2000
	(Thousands of dollars)	
Deferred tax liabilities:		
Differences between book and tax basis of property	$2,195,323	$1,754,928
Regulatory assets	155,587	168,380
Partnership income/loss	53,955	70,266
Unrealized gains and losses on mark-to-market transactions	45,701	411
Tax benefit transfer leases	14,765	18,839
Other	73,437	97,852
Total deferred tax liabilities	$2,538,768	$2,110,676
Deferred tax assets:		
Differences between book and tax basis of contracts	$ 82,972	$ 0
Deferred investment tax credits	72,345	76,133
Regulatory liabilities	66,507	88,817
Foreign tax loss carryforwards	23,630	25,063
Employee benefits and other accrued liabilities	(16,559)	14,675
Other	87,387	62,053
Total deferred tax assets	$ 316,282	$ 266,741
Net deferred tax liability	$2,222,486	$1,843,935

9. Common Stock and Incentive Stock Plans

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 includes 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.

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Stock Options and Performance Awards at Dec. 31:

	2001		2000		1999	
	Awards	Average Price	Awards	Average Price	Awards	Average Price
			(Thousands of dollars)			
Outstanding at beginning of year	14,259	$25.35	8,490	$25.12	6,156	$26.15
Granted	2,581	25.98	6,980	25.31	2,545	22.64
Exercised	(1,472)	23.00	(453)	20.33	(90)	18.72
Forfeited	(142)	27.08	(704)	25.70	(111)	30.10
Expired	(12)	24.07	(54)	22.62	(10)	25.64
Outstanding at end of year	15,214	25.65	14,259	25.35	8,490	25.12
Exercisable at end of year	7,154	24.78	8,221	24.46	5,301	25.84

	Range of Exercise Prices		
At Dec. 31, 2001	$16.60 to $21.75	$21.76 to $27.99	$28.00 to $31.01
Options Outstanding:			
Number outstanding	2,544,374	11,261,229	1,408,857
Weighted average remaining contractual life (years)	6.8	8.0	6.5
Weighted average exercise price	$19.87	$26.33	$30.66
Options Exercisable:			
Number exercisable	2,334,841	3,459,896	1,359,376
Weighted average exercise price	$19.86	$25.79	$30.67

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. We granted 21,774 restricted shares in 2001, 58,690 restricted shares in 2000 and 52,688 restricted shares in 1999. 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 did not constitute 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 reduced by approximately 1 cent per share for 2001, 2 cents per share for 2000 and 1 cent per share for 1999.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes Option Pricing Model with the following assumptions:

	2001	2000	1999

Expected option life	3-5 years	3-5 years	5-10 years
Stock volatility	18%	15%	15-21%
Risk-free interest rate	3.8-4.8%	5.3-6.5%	4.7-6.4%
Dividend yield	4.9-5.8%	5.4-7.5%	5.4%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Dividend Restrictions The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Xcel Energy has outstanding preferred stock. It could have paid nearly $2 billion in additional common stock dividends before restrictions would apply.

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, 2001.

Stockholder Protection Rights Agreement On June 28, 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.

10. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its benefit employees. Approximately 44 percent of benefit employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2001, NSP-Minnesota and NSP-Wisconsin had 2,563 union employees covered under a collective-bargaining agreement, which expires at the end of 2004. PSCo had 1,979 union employees covered under a collective-bargaining agreement, which expires in May 2003. SPS had 742 union employees covered under a collective-bargaining agreement, which expires in October 2002.

Pension Benefits Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all utility 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

A comparison of the actuarially computed pension benefit obligation and plan assets at Dec. 31, 2001 and 2000, for Xcel Energy plans on a combined basis is presented in the following table.

	2001	2000
	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at Jan. 1	$2,254,138	$ 2,170,627
Service cost	57,521	59,066
Interest cost	172,159	172,063
Acquisitions	0	52,800
Plan amendments	2,284	2,649
Actuarial (gain) loss	108,754	1,327
Benefit payments	(185,670)	(204,394)
Obligation at Dec. 31	$2,409,186	$ 2,254,138
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	$3,689,157	$ 3,763,293
Actual return on plan assets	(235,901)	91,846
Acquisitions	0	38,412
Benefit payments	(185,670)	(204,394)
Fair value of plan assets at Dec. 31	$3,267,586	$ 3,689,157
Funded Status at Dec. 31		
Net asset	$ 858,400	$ 1,435,019
Unrecognized transition (asset) obligation	(9,317)	(16,631)
Unrecognized prior-service cost	242,313	228,436
Unrecognized (gain) loss	(712,571)	(1,421,690)
Prepaid pension asset recorded	$ 378,825	$ 225,134
Significant assumptions		
Discount rate for year-end valuation	7.25%	7.75%
Expected average long-term increase in compensation level	4.5%	4.5%
Expected average long-term rate of return on assets	9.5%	8.5-10.0%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of net periodic pension cost (credit) for Xcel Energy plans are:

	2001	2000	1999
		(Thousands of dollars)	
Service cost	$ 57,521	$ 59,066	$ 63,674
Interest cost	172,159	172,063	154,619
Expected return on plan assets	(325,635)	(292,580)	(259,074)
Curtailment	1,121	0	0
Amortization of transition asset	(7,314)	(7,314)	(7,314)
Amortization of prior-service cost	20,835	19,197	17,855
Amortization of net gain	(72,413)	(60,676)	(40,217)
Net periodic pension cost (credit) under SFAS No.87	$(153,726)	$(110,244)	$ (70,457)
Credits not recognized due to effects of regulation	76,509	49,697	36,469
Net benefit cost (credit) recognized for financial reporting	$ (77,217)	$ (60,547)	$ (33,988)

NRG also offers other noncontributory, defined benefit pension plans that are sponsored by NRG and its affiliates. For the year ended Dec. 31, 2001, the total assets of such plans were $16 million and benefit obligations were $37 million. The net recorded pension liabilities for these plans were $19 million and annual pension costs were $4 million.

Additionally, Xcel Energy 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 $29 million in 2001, $23 million in 2000 and $21 million in 1999.

Xcel Energy has a leveraged employee stock ownership plan (ESOP) that covers substantially all employees of NSP-Minnesota and NSP-Wisconsin. Xcel Energy makes contributions to this noncontributory, defined contribution plan to the extent it realizes tax savings from dividends paid on certain ESOP shares. ESOP contributions have no material effect on Xcel Energy earnings because the contributions are essentially offset by the tax savings provided by the dividends paid on ESOP shares. Xcel Energy allocates leveraged ESOP shares to participants when it repays ESOP loans with dividends on stock held by the ESOP.

Xcel Energy s leveraged ESOP held 10.5 million shares of Xcel Energy common stock at the end of 2001, 12.0 million shares of Xcel Energy common stock at the end of 2000 and 11.3 million shares of Xcel Energy common stock at the end of 1999. Xcel Energy excluded the following uncommitted leveraged ESOP shares from earnings per share calculations: 0.9 million in 2001, 0.7 million in 2000 and 0.5 million in 1999.

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 NSP plan was terminated for nonbargaining employees retiring after 1998 and for bargaining employees retiring after 1999.

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 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Additionally, certain state agencies, which regulate Xcel Energy s utility subsidiaries, have 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 and Cheyenne are 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 require 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.

A comparison of the actuarially computed benefit obligation and plan assets at Dec. 31, 2001 and 2000, for all Xcel Energy postretirement health care plans is presented in the following table.

	2001	2000
	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at Jan. 1	$ 576,727	$ 533,458
Service cost	6,160	5,679
Interest cost	46,579	43,477
Acquisitions	3,212	16,445
Plan participants contributions	3,517	4,358
Plan amendments	(278)	0
Actuarial (gain) loss	100,386	10,501
Benefit payments	(48,848)	(37,191)
Obligation at Dec. 31	$ 687,455	$ 576,727
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	$ 223,266	$ 201,767
Actual return on plan assets	(3,701)	10,069
Plan participants contributions	3,517	4,358
Employer contributions	68,569	44,263
Benefit payments	(48,848)	(37,191)
Fair value of plan assets at Dec. 31	$ 242,803	$ 223,266
Funded Status at Dec. 31		
Net obligation	$ 444,652	$ 353,461
Unrecognized transition asset (obligation)	(186,099)	(202,871)
Unrecognized prior-service cost	12,812	13,789
Unrecognized gain (loss)	(134,225)	(11,126)
Accrued benefit liability recorded	$ 137,140	$ 153,253
Significant assumptions:		
Discount rate for year end valuation	7.25%	7.75%
Expected average long-term rate of return on assets	9.0%	8.0-9.5%

The assumed health care cost trend rate for 2001 is approximately 8.0 percent, decreasing gradually to 5.5 percent in 2007 and remaining level thereafter. A 1-percent increase in the assumed health care cost trend rate would increase the estimated total accumulated benefit obligation for Xcel Energy by approximately

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$72.3 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately $5.8 million. A 1-percent decrease in the assumed health care cost trend rate would decrease the estimated total accumulated benefit obligation for Xcel Energy by approximately $60.2 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately $4.7 million.

The components of net periodic postretirement benefit cost of all Xcel Energy s plans are:

	2001	2000	1999
	(Thousands of dollars)		
Service cost	$ 6,160	$ 5,679	$ 4,680
Interest cost	46,579	43,477	35,583
Expected return on plan assets	(18,920)	(17,902)	(15,003)
Amortization of transition obligation	16,771	16,773	17,461
Amortization of prior-service cost (credit)	(1,235)	(1,211)	(1,803)
Amortization of net loss (gain)	1,457	915	(5)
Net periodic postretirement benefit costs under SFAS No. 106	50,812	47,731	40,913
Additional cost recognized due to effects of regulation	3,738	6,641	4,029
Net cost recognized for financial reporting	$ 54,550	$ 54,372	$ 44,942

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Equity Investments and Asset Acquisitions

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	Geographic Area	Dec. 31, 2001 Economic Interest
Loy Yang Power A	Australia	25.37%
Enfield Energy Centre	Europe	25.00%
Gladstone Power Station	Australia	37.50%
COBEE (Bolivian Power Co. Ltd.)	South America	49.45%
MIBRAG GmbH	Europe	50.00%
Cogeneration Corp. of America	USA	20.00%
Schkopau Power Station	Europe	41.90%
West Coast Power	USA	50.00%
Energy Developments Limited	Australia	25.10%
Scudder Latin American Power	Latin America	25.00%
Lanco Kondapalli Power	India	30.00%
ECK Generating	Czech Republic	44.50%
Rocky Road Power	USA	50.00%
Mustang	USA	25.00%
Sabine River Works Cogeneration	USA	50.00%
Quixx Linden L.P.	USA	50.00%
Borger Energy L.P.	USA	45.00%
Denver City Energy Associates, L.P.	USA	50.00%
Various independent power production facilities	USA	9%-70%
Various affordable housing limited partnerships	USA	20%-99.9%

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

	2001	2000	1999
		(Millions of dollars)	
Operating revenues	$3,583	$4,664	$4,087
Operating income	442	464	516
Net income (losses)	422	447	290
Xcel Energy s equity earnings of unconsolidated affiliates	217	183	112

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Position

	2001	2000
	(Millions of dollars)	
Current assets	$1,478	$ 1,590
Other assets	7,396	10,939
Total assets	$8,874	$12,529
Current liabilities	$1,229	$ 1,833
Other liabilities	4,841	6,806
Equity	2,804	3,890
Total liabilities and equity	$8,874	$12,529
Xcel Energy s share of undistributed retained earnings	$ 93	$ 96

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 has 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.

NRG Asset Acquisitions During the year ended Dec. 31, 2001, NRG completed numerous acquisitions of project assets and related liabilities. These acquisitions have been recorded using the purchase method of accounting. Accordingly, the purchase prices of each acquisition have been preliminarily allocated to assets acquired and liabilities assumed based on their estimated fair values at the various dates of acquisition. These estimates will be adjusted based upon completion of certain procedures, including third party valuations. Operations of the acquired projects have been included in Xcel Energy s results of operations since the respective dates of each acquisition.

The following is a summary of the projects acquired in 2001:

Project Acquired	Total Plant Megawatt (MW)	NRG Ownership	Operations
LS Power (USA)	5,633 (1,697 in operation or under construction)	100%	
Indeck (USA)	2,255 (402 in operation)	100%	
Conectiv (USA)	4,340	100% of 918 MW; 4% of remainder	
Termo Rio (Brazil)	1,040	50%	Operations beginning in 2004
Schkopau (Germany)	960	Increased from 21% to 42%	
Audrain (USA)	640	100%	
Fort Bend (USA)	633	100%	Operations beginning in 2003
Csepel (Hungary)	505	100%	
McClain (USA)	500	77%	
Cogentrix (USA)	837	100%	
MIBRAG (Germany)	233	Increased from 33% to 50%	
Various other	372 in operation	various	

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The respective purchase prices of these 2001 acquisitions have been allocated to the net assets of the acquired NRG projects as follows:

	(Thousands of dollars)
Current assets	$ 307,654
Property, plant and equipment	4,173,509
Noncurrent 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 noncurrent assets and liabilities	(181,473)
Total purchase price	2,935,897
Less cash balances acquired	(122,780)
Net purchase price	$ 2,813,117

12. Electric Utility Restructuring 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 2007. This legislation amended the 1999 legislation, Senate Bill No. 7 (SB-7), which provided for retail electric competition to begin 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. SPS restructuring and rate unbundling proceedings in Texas have been terminated. In addition, under the legislation, SPS is entitled to recover all reasonable and necessary expenditures made or incurred before Sept. 1, 2001, to comply with SB-7. As required, SPS filed an application during the fourth quarter of 2001, requesting a rate rider to recover these costs incurred preparing for customer choice. These proceedings are pending.

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 Texas and New Mexico, SPS previous plans to implement restructuring, including the divestiture of

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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). In the second quarter of 2001, SPS did not restore any regulatory assets or other costs previously written off due to the uncertainty of various regulatory issues, including transition plans to address future rate recovery of SPS restructuring costs.

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 has 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, as previously discussed. These nonfinancing restructuring costs have been deferred and will be amortized in the future consistent with rate recovery. Management believes it will be allowed full recovery of its prudently incurred costs. Based on these fourth-quarter events 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.

13. Financial Instruments

Fair Values

The estimated Dec. 31 fair values of Xcel Energy s recorded financial instruments are as follows:

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of dollars)			
Mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000	$ 486,270	$ 494,000	$ 481,270
Long-term investments	619,976	620,703	625,616	624,989
Notes receivable, including current portion	782,079	782,079	99,557	99,557
Long-term debt, including current portion	12,799,723	12,788,749	8,187,052	8,131,139

For cash, cash equivalents and short-term investments, the carrying amount 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 and variable rate notes (interest rates ranging from 4.75 percent to 19.5 percent and maturities ranging from 2001 to 2024). Notes receivable include a $319-million direct financing lease related to a long-term sales agreement for NRG s Schkopau project, and other notes related to projects at NRG 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, 2001 and 2000. These fair value estimates have not been comprehensively revalued for purposes of these financial statements since that date and current estimates of fair values may differ significantly from the amounts presented herein.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Guarantees

Xcel Energy had the following guarantees outstanding as of Dec. 31, 2001:

Guarantor	Guarantee Amount	Nature of Guarantee
	(Millions of dollars)	
NRG	$721.7	Obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries. Xcel Energy is not obligated under these agreements.
Xcel Energy	343.1	Guarantee performance and payment of surety bonds for itself and its subsidiaries.
Various Subsidiaries	336.9	Guarantee performance and payment of surety bonds for those subsidiaries. Xcel Energy is not obligated under these agreements.
Xcel Energy	270.7	Guarantees made to facilitate e prime s natural gas acquisition, marketing and trading operations.
Xcel Energy	60.0	Guarantee on the payments on notes issued by Guardian Pipeline LLC, of which Viking Gas Transmission Co. is one of three partners. The guarantee will terminate on the in-service date of the pipeline, which is expected to be March 2003.
Xcel Energy	28.5	Three guarantees benefiting Cheyenne to guarantee the payment obligations under gas and power purchase agreements.
Xcel Energy	25.0	Construction contract guarantee that assures Quixx s performance under its engineering, procurement and construction contract with Borger Energy Associates, LP (BEA). Quixx, which owns 45 percent of BEA, has constructed a 230-megawatt, cogeneration facility at a Phillips Petroleum site near Borger, Texas. The guarantee will remain in effect until no later than July 2003.
SPS	22.9	Guarantee for certain obligations of a customer in connection with an agreement for the sale of electric power. These obligations relate to the construction of certain utility property that, in the event of default by the customer, would revert to SPS.
Xcel Energy	17.9	Guarantees related to energy conservation projects in which Planergy has guaranteed certain energy savings to the customer. As energy savings are realized each year due to these projects, the value of the guarantee decreases until it reaches zero in 2024.
Xcel Energy	17.0	Guarantees payments for XERS Inc., a nonregulated subsidiary of Xcel Energy, under a Master Power Purchase and Sale Agreement and a Qualified Scheduling Entity Services Agreement. This guarantee was terminated and replaced with a $10-million guarantee in January 2002.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Guarantor	Guarantee Amount	Nature of Guarantee
	(Millions of dollars)	
NSP-Minnesota	11.6	NSP-Minnesota sold a portion of its receivables to a third party. The portion of the receivables sold consisted of customer loans to local and state government entities for energy efficiency improvements under various conservation programs offered by NSP-Minnesota. Under the sales agreements, NSP-Minnesota is required to guarantee repayment to the third party of the remaining loan balances. Based on prior collection experience of these loans, losses under the loan guarantees, if any, are not believed to have a material impact on the results of operations.
Xcel Energy	5.0	Guarantee on behalf of BNP Paribas in connection with a letter of credit provided by BNP Paribas at the request of SPS. The letter of credit is required to indemnify former SPS board of directors.
Xcel Energy	4.5	Guarantee for e prime Energy Marketing, Inc. s performance of obligations under a supply agreement and for payments of energy and capacity transactions.
Xcel Energy	3.0	Guarantee resulting from noncompletion of certain milestone achievements within required dates in connection with the Quixx Linden cogeneration plant. The milestones have been achieved as of December 2001. The guarantee is required to remain six months upon completion of these milestones. Therefore, the guarantee will be released June 2002 assuming contract requirements are met.
Xcel Energy	4.1	Combination of guarantees benefiting various Xcel Energy subsidiaries.

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, 2001. For more detailed information regarding derivative financial instruments and the related risks, see Note 14 to the Financial Statements.

Interest Rate Swaps 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.

As of Dec. 31, 2000, Xcel Energy had several interest rate swaps converting project financing from variable-rate debt to fixed-rate debt with a notional amount of approximately $598 million. The fair value of the swaps as of Dec. 31, 2000 was a liability of approximately $36 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Xcel Energy has recorded its physical trading transactions on total contract purchases and total contract sales known as the gross accounting method. 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 Statement of Income in Electric and Gas Trading Revenues.

The fair value of Xcel Energy s trading contracts as of Dec. 31, 2001 is as follows:

	Total Fair Value
	(Millions of dollars)
Fair value of trading contracts outstanding at Jan. 1, 2001	$ 8.6
Contracts realized or settled during 2001	(87.0)
Fair value of trading contract additions and changes during the year	96.2
Fair value of contracts outstanding at Dec. 31, 2001*	$ 17.8

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

The future maturities of Xcel Energy s trading contracts are as follows:

Source of Fair Value	Maturity Less than 1 Year	Maturity 1 to 3 Years	Total Fair Value
		(Millions of dollars)	
Prices actively quoted	$15.3	$1.0	$16.3
Prices based on models and other valuation methods (including prices quoted from external sources)	1.2	0.3	1.5

Regulated Operations Xcel Energy s regulated energy marketing operation uses a combination of energy and gas purchase for resale futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2001, the notional value of these contracts was approximately $83.8 million. The fair value of these contracts as of Dec. 31, 2001, was a liability of approximately $24 million.

Nonregulated Operations Xcel Energy s nonregulated operations uses a combination of energy futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2001, the notional value of these contracts was approximately $1.0 billion. The fair value of these contracts as of Dec. 31, 2001, was an asset of approximately $242.2 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, 2001 and 2000, the net notional amount of these contracts was approximately $46.3 million and $8.8 million, respectively. The fair value of these contracts as of Dec. 31, 2001 and 2000 was a liability of approximately $2.4 million and $0.7 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, 2001, there were $221.7 million in letters of credit outstanding, including $169.7 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. Derivative Valuation and Financial Impacts

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, we 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 negotiated 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 its rate-regulated operations to the extent such exposure exists. Management is limited under the policy to enter into only transactions that reduce 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 we provide to our retail customers even though the regulatory jurisdiction provides dollar-for-dollar recovery of actual costs. This jurisdiction allows us to recover the gains and losses on derivative instruments used to reduce our exposure to market price risk.

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 60 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 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 is mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility 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.

Foreign Currency 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Accounting Change On Jan. 1, 2001, Xcel Energy adopted SFAS No. 133. 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 income statement, 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 formally documents its 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 also formally assesses, 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.

The adoption of SFAS No. 133 on Jan. 1, 2001, resulted in an earnings impact of less than $1 million, which is not being reported separately as a cumulative effect of accounting change due to immateriality. In addition, upon adoption of SFAS No. 133, Xcel Energy recorded a net transition loss of approximately $28.8 million in Other Comprehensive Income.

The components of SFAS No. 133 impacts 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	$ 34.2

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of the gain for SFAS No. 133 impacts on Xcel Energy s income statement for the year ended Dec. 31, 2001, are detailed in the following table. The amounts below exclude our gains and losses from trading activities.

	(Millions of dollars, except per share data)
Increase (decrease) in income:	
Nonregulated and other revenues	$ (8.1)
Equity earnings from investment in affiliates	4.6
Electric fuel and purchased power utility	0.1
Cost of goods sold nonregulated and other	17.5
Other income (deductions)	0.2
Total increase before minority interest and income tax	$ 14.3
Net-of-tax increase in net income	$ 9.8
Increase in EPS (diluted)	$ 0.03

Xcel Energy records the fair value of its derivative instruments in its Consolidated Balance Sheet as separate line items noted as Derivative Instruments Valuation for assets and liabilities as well as current and noncurrent.

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 our 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 into 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 operations are considered normal.

Normal purchases and normal sales contracts are accounted for as executory contracts as required under other generally accepted accounting principles.

Cash Flow Hedges

Xcel Energy and its subsidiaries enter into derivative instruments to manage our 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, 2001, Xcel Energy had various commodity related contracts extending through 2018. Earnings on these cash flow hedges are recorded as the hedged purchase or sales transaction is completed. This could include the physical sale of electric energy or the usage of natural gas to generate electric energy. Xcel Energy expects to reclassify into earnings during 2002 net gains from Other Comprehensive Income of approximately $18.0 million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2002 net losses from Other Comprehensive Income of approximately $5.6 million.

Xcel Energy records hedge effectiveness 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 are recorded as a component of interest expense.

The net gain (loss) recognized in earnings for derivative instruments that have been designated and qualify as cash flow hedging instruments are detailed in the following table.

	Hedge Ineffectiveness	Derivatives Excluded from Assessment of Hedge Effectiveness	Firm Commitments No Longer Qualifying as Cash Flow Hedges
		(Millions of dollars)	
Year ended Dec. 31, 2001:			
Energy and energy-related commodities	$27.9	$ 0	$ 0
Interest rates	0	0	0

Fair Value Hedges and 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. Xcel Energy expects to reclassify into earnings during 2002 net losses from Other Comprehensive Income of approximately $2.2 million.

Derivatives Not Qualifying for Hedge Accounting

Xcel Energy and its subsidiaries have various trading operations that enter into derivative instruments. These derivative instruments are accounted for on a mark-to-market basis in the Consolidated Statements of Income. All financial derivative instruments are recorded at the amount of the gain or loss from the transaction within Operating Revenues on the Consolidated Statements of Income.

In order to preserve the U.S. dollar value of projected foreign currency cash flows from European trading operations, we enter into various foreign currency exchange contracts that are not designated as accounting hedges but are considered economic hedges. Accordingly, the changes in fair value of these derivatives are reported in Other Nonoperating Income in the Consolidated Statements of Income.

15. 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, 2001, NSP-Minnesota had loaded 14 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Capital Commitments As discussed in Liquidity and Capital Resources under Management s Discussion and Analysis, the estimated cost, as of Dec. 31, 2001, of the capital expenditure programs of Xcel Energy and its subsidiaries and other capital requirements is approximately $2.8 billion in 2002, $2.6 billion in 2003 and $2.7 billion in 2004.

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.

Xcel Energy s capital expenditures include approximately $1.6 billion in 2002 for NRG construction activity, excluding asset acquisitions. NRG s future capital requirements may vary significantly. For 2002, NRG will require additional capital of approximately $1.8 billion for expected acquisitions of existing generation facilities, including the generating assets of FirstEnergy Corp. and the Conectiv fossil assets. See further discussion in Note 19 to the Financial Statements.

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 $605 million and $55 million at Dec. 31, 2001 and 2000, 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 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 $58 million, $56 million and $57 million for 2001, 2000 and 1999, respectively.

Future commitments under operating and capital leases are:

	Operating Leases	Capital Leases
	(Millions of dollars)	
2002	$ 54	$ 77
2003	50	75
2004	50	73
2005	48	71
2006	45	69
Thereafter		1,073
Total minimum obligation		$ 1,438
Interest		(834)
Present value of minimum obligation		$ 604

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,

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

although there are financial penalties for early termination. In 2001, we paid IBM $130 million under the contract. 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 2002 and 2025. In total, Xcel Energy is committed to the minimum purchase of approximately $2.8 billion of coal, $122.3 million of nuclear fuel and $1.3 billion of natural gas and related 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 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. 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 10 percent of NSP-Minnesota s 2001 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, 2001, 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)
2002	$ 507,095
2003	513,979
2004	590,109
2005	658,976
2006 and thereafter	4,135,048
Total	$6,405,207

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2001, 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 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, 2001, our liability for the cost of remediating sites for which an estimate was possible was $51 million, including $13 million in current liabilities. 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 $19 million of the long-term liability and $4 million of the current liability relate to a DOE 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 16 to the 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 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

We proposed, and the EPA and WDNR have approved, an interim action (a 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 will install monitor wells in the deep aquifer to better characterize the extent and degree of contaminants in that aquifer while the free-product recovery system is operational.

On Dec. 1, 2000, in response to a citizen petition, the EPA proposed the Ashland site for inclusion on the National Priorities List (NPL) of hazardous sites requiring cleanup. NSP-Wisconsin submitted comments in the Administrative Record concerning the proposed listing on Jan. 30, 2001. It is anticipated that the site will be listed on the NPL sometime in 2002.

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 recovered cost of remediating that site, $2.9 million, 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.

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 the fall of 2001, PSCo took its Leyden natural gas storage facility out of commercial storage operation and began final withdrawal of gas as part of the process to permanently close the facility. PSCo is closing the Leyden facility because it is no longer compatible with surrounding land use, which has experienced considerable residential and commercial development in recent years. Through Dec. 31, 2001, $4 million of costs have been incurred. PSCo has deferred expensing these closing costs because it believes that it will be able to recover them from its ratepayers. We will request recovery of the closing costs as part of the rate case to be filed in 2002. Any costs that are not recoverable from customers will be expensed.

Plant Emissions 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 its allegations.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NRG estimates capital expenditures over the next five years related to resolving environmental concerns at the Indian River Generating Station, which are centered around possible closure of the existing landfill and construction of a new cell to replace it, possible addition of a cooling tower, and the addition of controls to reduce nitrogen oxide (NOx) emissions. Currently, cost estimates for addressing the first two items vary widely pending the results of negotiations with the Delaware Natural Resources and Environment Commission (DNREC). If ash sales are poor, it is estimated that NRG could spend up to $11 million over the five-year timeframe to close/ construct sections of the landfill; if sales are robust, expenditures related to closure/construction are expected to be minimal. In the unlikely event NRG is unable to reach agreement with DNREC on extension of a variance, NRG estimates a $40-million cooling tower could be required; if negotiations are successful, a cooling tower can be avoided.

NRG also estimates $39 million of capital expenditures at its Encina Generating Station to install emission-control equipment required by California regulation passed in late 2001. Installation is expected to be completed in the spring of 2003.

The Commonwealth of Massachusetts is seeking additional emissions reductions beyond current requirements. The Massachusetts Department of Environmental Protection (MDEP) has issued proposed regulations that would require significant emissions reductions from certain coal-fired power plants in the state, including NRG s Somerset facility. The MDEP has proposed that such facilities comply with stringent limits on emissions of NOx and on sulfur dioxide (SO2) commencing in December 2003, with further reductions required by December 2005, and on carbon dioxide (CO2) by December 2005. In addition to output-based limits (a standard that limits emissions to a certain rate per net megawatt-hour), the proposed regulations also would limit, by December 2003, the total emissions of NOx and SO2 at the Somerset facility to no more than 75 percent of the average annual emissions of the Somerset facility for the years 1997 through 1999. Finally, the proposed regulations require the MDEP to evaluate, by December 2002, the technological and economic feasibility of controlling or eliminating mercury emissions by the year 2010, and to propose mercury emission standards within 18 months of completion of the feasibility evaluation. Compliance with these proposed regulations, if such regulations become effective, could have a material impact on the operation of NRG s Somerset facility. The annual average CO2 emission rate identified in the proposed regulations cannot be met by the Somerset facility. NRG has submitted an emission control plan, with respect to the NOx and SO2 requirements, and is conducting ongoing discussions with the MDEP regarding finalization of the plan.

Nuclear Insurance NSP-Minnesota s public liability for claims resulting from any nuclear incident is limited to $9.5 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 $9.3 billion of exposure is funded by the Secondary Financial Protection Program, 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 $3 million for business interruption insurance and $10 million for property damage insurance if losses exceed accumulated reserve funds.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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 certain private plaintiff class actions filed in the Superior Court of the State of California for the County of San Diego in San Diego, Calif. in November 2000. NRG has also been named in another suit filed in January 2001 in San Diego County and brought by three California water districts, as consumers of electricity, and in two suits filed in San Francisco County, one brought by the San Francisco City Attorney on behalf of the people of the State of California and one brought by Pier 23 Restaurant as a class action. Certain NRG affiliates in NRG s West Coast power partnership with Dynegy (Cabrillo I and II, Long Beach Generation and El Segundo Power) have been named as defendants in a state court action in Los Angeles County.

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 and assigned to the presiding judge of the San Diego County Superior Court, and a pretrial conference has been scheduled for March 2002. While it is too soon to speculate on the outcome of these cases it could have a material adverse effect on NRG s results of operations and financial condition if they were ultimately resolved adversely to the defendants.

Other Litigation In January 2002 the New York Attorney General and the New York Department of Environmental Control filed suit in the western district of New York against NRG and Niagara Mohawk Power Corporation, 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 July 2001, Niagara Mohawk Power Corporation 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 Corporation requests a declaration by the Court that, pursuant to the terms of the Asset Sales Agreement (the ASA) under which NRG

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 Corporation, and the parties have exchanged discovery requests.

Other Contingencies

California Power Market NRG s California generation assets include a 57.67-percent interest in Crockett Cogeneration (Crockett), a 39.5-percent interest in the Mt. Poso facility and a 50-percent interest in the West Coast Power partnership with Dynegy.

In March 2001, the California Power Exchange (PX) filed for bankruptcy under Chapter 11 of the Bankruptcy Code, and in April 2001, Pacific Gas & Electric Co. (PG&E) also filed for bankruptcy under Chapter 11. PG&E s filing delayed collection of receivables owed to the Crockett facility. In September 2001, PG&E filed a proposed plan of reorganization. Under the terms of the proposed plan, which is subject to challenge by interested parties, unsecured creditors such as NRG s California affiliates would receive 60 percent of the amounts owed upon approval of the plan. The remaining 40 percent would be paid in negotiable debt with terms from 10 to 30 years. The California PX s ability to repay its debt is dependent on the extent to which it receives payments from PG&E and Southern California Edison Co. On Dec. 21, 2001, the California bankruptcy court affirmed the Mt. Poso and Crockett power purchase agreements with PG&E and, in respect of the Crockett power purchase agreement, approved a twelve-month repayment schedule of all past due amounts totaling, $49.6 million, plus interest. The first payment of $6.2 million, including accrued interest, was received on Dec. 31, 2001.

NRG s share of the net amounts owed to West Coast Power by the California Independent System Operator (ISO) and PX totaled approximately $85.1 million as of Dec. 31, 2001, compared with $101.8 million at Dec. 31, 2000. These amounts reflect NRG s share of total amounts owed to West Coast Power less amounts that are currently treated as disputed revenues and are not recorded as accounts receivable in the financial statements of West Coast Power, and reserves taken against accounts receivable that have been recorded in the financial statements. The decrease is primarily attributed to cash collections from the California ISO during the fourth quarter of 2001.

The FERC has set for investigation the justness and reasonableness of the rates of wholesale sellers into the California ISO and PX markets and is making such rates subject to refund effective November 2001. The effect of the FERC s action is to make certain transactions of PSCo and NRG in California subject to refund. Xcel Energy believes that PSCo s refund exposure is immaterial. NRG has estimated potential refunds in the calculation of the reserves taken against its related accounts receivable.

Enron Xcel Energy, through its subsidiaries (excluding NRG as discussed later), has entered into agreements with Enron and its subsidiaries. However, pursuant to netting/set-off rights provisions of the industry standard agreements that Xcel Energy and Enron have utilized, Xcel Energy generally has a net liability to Enron. Therefore, we will owe Enron termination payments under these agreements for such services. The most significant of these agreements is between Enron and e prime. e prime will owe Enron a termination payment of approximately $12 million, representing the net of a $69-million receivable and an $81-million payable. As a result of the netting/set-off provisions, no provision for loss has been recorded in connection with these transactions agreements. Xcel Energy does not expect a material impact to the results of its operations as a direct result of the bankruptcy filing of Enron.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

During 2001, NRG s power marketing operation recorded a net after-tax expense of $6.7 million related to Enron s bankruptcy. This amount includes a $14.2 million, after-tax charge to establish bad debt reserves, which was partially offset by a $7.5-million, after-tax gain on a credit swap agreement entered into as part of NRG s credit risk management program. NRG has fully provided for its exposure to Enron; however, as with any receivable, NRG will pursue collection of all amounts outstanding through the ordinary course of business.

In addition, an Enron subsidiary, NEPCO, is serving as the construction contractor for two of NRG s greenfield development projects, the Kendall and Nelson projects currently under construction in Illinois. Enron guaranteed NEPCO s obligations under the construction contracts. To date, the actual construction and engineering work on both projects has continued without disruption, and NRG expects the projects to achieve commercial operations on schedule. NRG believes overall construction costs will increase by no more than $50 million, which represents less than 5 percent of the expected construction costs.

Tax Matters The IRS had 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. 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.

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 2001 are estimated to total approximately $240 million. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2001, would reduce earnings by an estimated $197 million (after tax), or 57 cents per Xcel Energy share.

Seren At Dec. 31, 2001, Xcel Energy s investment in Seren was approximately $232 million. Seren had capitalized $190 million for plant in service and had incurred another $60 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 is evaluating the strategic fit in its business portfolio.

Loy Yang NRG owns a 25.37-percent interest in Loy Yang Power, which owns and operates the 2,000-megawatt Loy Yang A brown coal-fired thermal power station and the adjacent Loy Yang coal mine located in Victoria, Australia. Energy prices in the Victoria region of the National Electricity Market of Australia into which the Loy Yang facility sells its power have been significantly lower than NRG expected when it acquired its interest in the facility. Prices improved during 2001 resulting in a 14-percent revenue increase. Despite this improvement, a significant unplanned outage, beginning in late December 2001 and expected to last until April 2002, will result in a reduction in 2002 revenues and cash flows. Such reduction may cause the Loy Yang project company to fail its required coverage ratios under its loan agreements during the next 12 months, which would constitute an event of default. In the case of default, the project company s lenders would be allowed to accelerate the project company s indebtedness. The ultimate financial

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

impact of the outage is subject to continuing investigation and is also subject to several events, including the receipt and timing of insurance proceeds, the cost and timing of repairs to the damaged unit and electricity market conditions. Project management is actively pursuing each of these options to mitigate the impact of the outage. However, in the event all factors are unfavorable, NRG may be required to either infuse more cash or write off all or a portion of its $250-million investment in this project as a result of such acceleration. In its current circumstances, Loy Yang Power is prohibited by its loan agreements from making equity distributions to the project owners.

Xcel Energy International At Dec. 31, 2001, Xcel Energy s investment in Argentina through Xcel Energy International was $102 million. Given the political and economic climate in Argentina, Xcel Energy continues to closely monitor the investment for asset impairment. Due to the declining value of the Argentine peso, a currency translation adjustment was recorded in the amount of $38 million as an adjustment to Other Comprehensive Income. Currently, management intends to hold and operate the investment and believes that no asset impairment exists.

16. 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 $11 million in 2001, $12 million in 2000 and $12 million in 1999. In total, NSP-Minnesota had paid approximately $296 million to the DOE through Dec. 31, 2001. 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.

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 2001 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 $25 million at Dec. 31, 2001, as a regulatory asset.

Plant Decommissioning Decommissioning of NSP-Minnesota s nuclear facilities is planned for the years 2010-2022, 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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

accruals in Accumulated Depreciation. Consequently, the total decommissioning cost obligation and corresponding assets currently are not recorded in Xcel Energy s financial statements.

In June 2001, the FASB approved the issuance of 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 useful life, the recorded liability differs from the actual obligations paid, a gain or loss will be recognized at that time.

SFAS No. 143 will also affect our accrued plant removal costs for other generation, transmission and distribution facilities for our utility subsidiaries. We expect that these costs, which have yet to be estimated, will be reclassified from Accumulated Depreciation to Regulatory Liabilities based on the recoverability of these costs in rates. We plan to adopt SFAS No. 143, as required, on Jan. 1, 2003.

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. 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 and related nuclear plant depreciation capital recovery request in April 2000, using 1999 cost data. 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, 2001, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

At Dec. 31, 2001, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of $623 million. The following table summarizes the funded status of NSP-Minnesota s decommissioning obligation at Dec. 31, 2001:

	2001
	(Thousands of dollars)
Estimated decommissioning cost obligation from most recently approved study (1999 dollars)	$ 958,266
Effect of escalating costs to 2001 dollars (at 4.35 percent per year)	85,183
Estimated decommissioning cost obligation in current dollars	1,043,449
Effect of escalating costs to payment date (at 4.35 percent per year)	850,825
Estimated future decommissioning costs (undiscounted)	1,894,274
Effect of discounting obligation (using risk-free interest rate)	(1,016,206)
Discounted decommissioning cost obligation	878,068
Assets held in external decommissioning trust	596,113
Discounted decommissioning obligation in excess of assets currently held in external trust	$ 281,955

Decommissioning expenses recognized include the following components:

	2001	2000	1999
	(Thousands of dollars)		
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	$ 51,433	$ 51,433	$33,178
Internally funded (including interest costs)	(17,396)	(16,111)	1,595
Interest cost on externally funded decommissioning obligation	4,535	5,151	4,191
Earnings from external trust funds	(4,535)	(5,151)	(4,191)
Net decommissioning accruals recorded	$ 34,037	$ 35,322	$34,773

Decommissioning and interest accruals are included with Accumulated Depreciation on the balance sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Nonoperating Income on the income statement.

Negative accruals for internally funded portions in 2000 and 2001 reflect the impacts of the 2000 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. Regulatory Assets and Liabilities

Our regulated businesses prepare their financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the 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 Ref.	Remaining Amortization Period	2001	2000
		(Thousands of dollars)		
AFDC recorded in plant(a)		Plant Lives	$149,591	$159,406
Conservation programs(a)(d)		Up to 5 Years	65,825	52,444
Losses on reacquired debt	1	Term of Related Debt	95,394	85,688
Environmental costs	15,16	To be determined	20,169	19,372
Unrecovered gas costs(b)	1	1-2 Years	11,316	24,719
Deferred income tax adjustments	1	Mainly Plant Lives	17,799	0
Nuclear decommissioning costs(e)		Up to 8 Years	68,484	82,490
Employees postretirement benefits other than pension	10	11 Years	42,942	46,680
Employees postemployment benefits	2	2-3 Years	119	23,223
Renewable resource costs		To be determined	17,500	10,500
State commission accounting adjustments(a)		Plant Lives	7,578	7,614
Other		Various	5,725	12,125
Total regulatory assets			$502,442	$524,261
Investment tax credit deferrals			$117,257	$119,060
Unrealized gains from decommissioning investments	16		149,041	171,736
Pension costs-regulatory differences	10		215,687	139,178
Conservation programs(c)			0	40,679
Deferred income tax adjustments			0	12,416
Fuel costs, refunds and other			1,957	11,497
Total regulatory liabilities			$483,942	$494,566

(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 $22 million and $13 million for 2001 and 2000, respectively.

(c) Represents estimated refund for 1998 incentives; ultimately reversed in 2001.

(d) 2001 amount includes accrued conservation incentives expected to be approved for 2001 and 2000. Due to regulatory uncertainty, such incentives were not accrued in 2000.

(e) 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. Segment and Related Information

Xcel Energy has the following reportable segments: Electric Utility, Gas Utility and two of its nonregulated energy businesses, NRG and e prime. During February 2001, Xcel Energy reached an agreement to sell the majority of its investment in Yorkshire Power. As a result of this sales agreement, Xcel International (Yorkshire Power was Xcel International s most significant holding) is no longer a reportable segment. Prior periods have been restated for comparability.

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 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.

e prime trades and markets natural gas throughout 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 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 Financial Statements. Xcel Energy evaluates performance by each legal entity based on profit or loss generated from the product or service provided.

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Business Segments

	Electric Utility	Gas Utility	NRG	e prime	All Other	Reconciling Eliminations	Consolidated Total
				(Thousands of dollars)			
2001							
Operating revenues from external customers(a)	$7,731,640	$2,051,199	$2,803,073	$1,848,969	$373,823	$	$14,808,704
Intersegment revenues	978	4,501	1,859	88,475	89,636	(183,019)	2,430
Equity in earnings (losses) of unconsolidated affiliates			208,613	1,376	7,081		217,070
Total revenues	$7,732,618	$2,055,700	$3,013,545	$1,938,820	$470,540	$(183,019)	$15,028,204
Depreciation and amortization	$ 617,320	$ 92,989	$ 212,493	$ 247	$ 26,151	$	$ 949,200
Financing costs, mainly interest expense	265,285	49,108	450,729	277	107,855	(52,055)	821,199
Income tax expense (credit)	351,181	41,077	33,477	5,150	(94,162)		336,723
Segment income (loss) before extraordinary items	$ 535,182	$ 81,562	$ 265,204	$ 8,547	$ (65,426)	$ (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	$ 8,547	$ (66,960)	$ (40,390)	$ 794,966
2000							
Operating revenues from external customers(a)	$6,492,194	$1,466,478	$2,014,757	$1,269,506	$162,566	$	$11,405,501
Intersegment revenues	1,179	5,761	2,256	53,928	78,419	(137,962)	3,581
Equity in earnings (losses) of unconsolidated affiliates			142,086	1,203	39,425		182,714
Total revenues	$6,493,373	$1,472,239	$2,159,099	$1,324,637	$280,410	$(137,962)	$11,591,796
Depreciation and amortization	$ 574,018	$ 85,353	$ 123,404	$ 569	$ 9,051	$	$ 792,395
Financing costs, mainly interest expense	333,512	60,755	295,917	200	65,501	(59,780)	696,105
Income tax expense (credit)	261,942	36,962	92,474	(3,995)	(82,518)		304,865
Segment income (loss) before extraordinary items	$ 340,634	$ 57,911	$ 182,935	$ (6,158)	$ (13,925)	$ (15,609)	$ 545,788
Extraordinary items, net of tax	(18,960)						(18,960)
Segment net income (loss)	$ 321,674	$ 57,911	$ 182,935	$ (6,158)	$ (13,925)	$ (15,609)	$ 526,828
1999							
Operating revenues from external customers(a)	$5,454,958	$1,141,294	$ 427,567	$ 564,045	$136,570	$	$ 7,724,434
Intersegment revenues	1,303	11,785	963	2,102	119,546	(134,731)	968
Equity in earnings (losses) of unconsolidated affiliates			68,947	1,467	41,710		112,124
Total revenues	$5,456,261	$1,153,079	$ 497,477	$ 567,614	$297,826	$(134,731)	$ 7,837,526
Depreciation and amortization	$ 546,794	$ 82,206	$ 37,026	$ 3,762	$ 14,187	$	$ 683,975
Financing costs, mainly interest expense	300,108	53,217	92,570	226	25,976	(19,020)	453,077
Income tax expense (credit)	272,129	24,081	(26,416)	(2,984)	(73,002)	(14,135)	179,673
Segment net income (loss)	$ 431,510	$ 49,175	$ 57,195	$ (4,765)	$ 50,939	$ (13,121)	$ 570,933

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(a) All operating revenues are from external customers located in the United States, except $764 million and $290 million of NRG operating revenues in 2001 and 2000, respectively, which came from external customers outside of the United States. However, Xcel Energy International and NRG also have significant equity investments for nonregulated projects outside the United States. NRG s equity in earnings of unconsolidated affiliates, primarily independent power projects, includes $54.1 million in 2001, $19.2 million in 2000 and $38.6 million in 1999 from nonregulated projects located outside of the United States. NRG s equity investments in projects outside of the United States were $519 million in 2001, $566 million in 2000 and $606 million in 1999. All Other equity in earnings of unconsolidated affiliates includes $1 million in 2001, $35.3 million in 2000 and $44.9 million in 1999 from outside of the United States, primarily related to Yorkshire Power. All Other equity investments and projects outside of the United States were $36.9 million in 2001, $383 million in 2000 and $367 million in 1999. In addition, NRG s wholly owned foreign assets ($2.8 billion in 2001 and $796 million in 2000) contributed earnings of $49.2 million in 2001, $30.1 million in 2000 and $0 in 1999.

19. Subsequent Event NRG Tender Offer (Unaudited)

Numerous factors have recently led to significant erosion in the market valuations within the independent power production sector, and resulted in a fundamental shift in market perception that has increased the cost of capital for these companies in 2002. As discussed in Management s Discussion and Analysis, since December 2001, NRG has experienced tightening credit standards and has been notified by certain credit rating agencies that NRG s corporate securities have been placed under review for possible downgrade. In response to these developments, Xcel Energy s board of directors and management have been reviewing their options with respect to NRG s funding and structure.

On Feb. 14, 2002, Xcel Energy s board of directors approved plans to commence an exchange offer by which Xcel Energy would acquire all of the outstanding publicly held shares of NRG, representing an approximately 26-percent minority ownership. In the offer, NRG shareholders would receive 0.4846 shares of Xcel Energy common stock in a tax-free exchange for each outstanding share of NRG common stock. Based on the Feb. 14, 2002 closing prices of Xcel Energy and NRG common stock, the exchange ratio represents a 15-percent premium. In addition, following completion of the transaction, shareholders would be entitled to Xcel Energy s current annual dividend of $1.50 per share.

NRG s board of directors must review the proposed transaction, consider whether independent financial and legal advisors are necessary and communicate with NRG s minority shareholders. In order to meet the conditions of the offer, enough shares will need to be tendered so that Xcel Energy s ownership level of NRG reaches 90 percent. Based on the number of shares of NRG common stock outstanding on Feb. 14, 2002, this would require the tender of at least 60 percent of the shares of NRG common stock. As this report went to press, it was not known what NRG s board of directors would recommend, or how many minority shares of NRG would be tendered. Xcel Energy anticipates that the exchange offer will proceed and be completed promptly.

In addition to the exchange offer, on Feb. 15, 2002, Xcel Energy also announced other plans for NRG in 2002:

- Infusing $600 million of equity into NRG, including an estimated $400 million from Xcel Energy common stock issuances under existing shelf registrations;
- Placing approximately $1.9 billion of existing NRG generating assets onto the market for possible sale;
- Canceling approximately $700 million of planned NRG projects, and deferring about $900 million of other NRG projects;
- Selling unassigned turbines currently under order by NRG;

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Reducing NRG s business development and administrative and general expenses by about $45 million per year in comparison to current levels; and

Consolidating NRG s trading and marketing organizations, and integrating NRG s power plant management into the Xcel Energy system.

On Feb. 15, 2002, eight separate civil actions were filed in the Court of Chancery of the State of Delaware by owners of NRG common stock against Xcel Energy, NRG and NRG s directors. The complaints contain a number of allegations, but the basic claim is that Xcel Energy proposes to acquire the remaining ownership of NRG for inadequate consideration and without full and complete disclosure of all material information, in breach of defendants fiduciary duties. The complaints request the court to enjoin the proposed transaction and, in the event the exchange offer is consummated, to award damages to defendants.

20. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
	March 31, 2001	June 30, 2001(a)	Sept. 30, 2001	Dec. 31, 2001(a)
	(Thousands of dollars, except per share amounts)			
Revenue	$4,230,568	$3,698,557	$3,763,474	$3,335,605
Operating income(c)	492,306	433,765	658,379	358,498
Income before extraordinary items	209,310	167,857	272,903	134,609
Extraordinary items	0	0	0	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 before extraordinary items:				
Basic	$ 0.61	$ 0.49	$ 0.79	$ 0.39
Diluted	$ 0.61	$ 0.49	$ 0.79	$ 0.38
Earnings per share extraordinary items basic & diluted	$ 0.00	$ 0.00	$ 0.00	$ 0.03
Earnings per share after extraordinary items:				
Basic	$ 0.61	$ 0.49	$ 0.79	$ 0.42
Diluted	$ 0.61	$ 0.49	$ 0.79	$ 0.41

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Quarter Ended			
	March 31, 2000	June 30, 2000	Sept. 30, 2000(b)	Dec. 31, 2000(b)
	(Thousands of dollars, except per share amounts)			
Revenue	$2,335,709	$2,461,752	$3,100,398	$3,693,937
Operating income(c)	361,749	429,728	402,595	374,536
Income before extraordinary items	153,331	156,741	97,916	137,800
Extraordinary items	0	(13,658)	(5,302)	0
Net income	153,331	143,083	92,614	137,800
Earnings available for common shareholders	152,271	142,022	91,554	136,740
Earnings per share before extraordinary items:				
Basic	$ 0.45	$ 0.46	$ 0.29	$ 0.40
Diluted	$ 0.45	$ 0.46	$ 0.29	$ 0.40
Earnings per share extraordinary items basic & diluted	$ 0.00	$ (0.04)	$ (0.02)	$ 0.00
Earnings per share after extraordinary items:				
Basic	$ 0.45	$ 0.42	$ 0.27	$ 0.40
Diluted	$ 0.45	$ 0.42	$ 0.27	$ 0.40

(a) 2001 results include special charges and unusual items in the second and fourth quarters, as discussed in Notes 2 and 17 to the 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 postemployment benefits. Fourth quarter results were decreased by $39 million, or 7 cents per share, for a special charge related to employee restaffing costs.

(b) 2000 results include special charges related to merger costs and strategic alignment, as discussed in Note 2 to the Financial Statements. Third quarter results were reduced by approximately $201 million, or 43 cents per share. Fourth quarter results were reduced by approximately $40 million, or 9 cents per share.

(c) Certain items in the 2000 and 2001 quarterly income statements have been reclassified to conform to the 2001 annual presentation. These reclassifications, primarily related to items formerly presented as nonoperating revenues and expenses, had no effect on net income or earnings per share.

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REAUDITED FINANCIAL STATEMENTS 2000-2001

INDEPENDENT AUDITORS   REPORT

Report by Deloitte & Touche LLP to Xcel Energy Inc. to be filed by amendment.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

Report by PricewaterhouseCoopers LLP to the Board of Directors and Stockholders of NRG Co. Energy, Inc. to be filed by amendment.

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year ended Dec. 31	
	2001	2000
	(Thousands of Dollars, Except per Share Data)	
Operating revenues:		
Electric utility	$ 6,394,737	$ 5,674,485
Gas utility	2,052,651	1,468,880
Electric and gas trading margin	89,249	41,357
Nonregulated and other	2,766,699	2,019,085
Equity earnings from investments in affiliates	219,311	166,032
Total operating revenues	11,522,647	9,369,839
Operating expenses:		
Electric fuel and purchased power utility	3,171,660	2,580,723
Cost of gas sold and transported utility	1,517,557	948,145
Cost of sales nonregulated and other	1,360,801	894,716
Other operating and maintenance expenses utility	1,506,039	1,446,122
Other operating and maintenance expenses nonregulated	775,701	623,039
Depreciation and amortization	929,488	781,679
Taxes (other than income taxes)	313,939	349,214
Special charges (see Note 2)	62,230	241,042
Total operating expenses	9,637,415	7,864,680
Operating income	1,885,232	1,505,159
Interest income and other nonoperating income net of other expenses	59,486	18,327
Interest charges and financing costs:		
Interest charges net of amounts capitalized	755,167	636,020
Distributions on redeemable preferred securities of subsidiary trusts	38,800	38,800
Total interest charges and financing costs	793,967	674,820
Income from continuing operations before income taxes and minority interest	1,150,751	848,666
Income taxes	330,781	294,355
Minority interest	67,155	29,994
Income from continuing operations	752,815	524,317
Income from discontinued operations, net of tax (see Note 19)	31,864	21,471
Income before extraordinary items	784,679	545,788
Extraordinary items, net of income taxes of $4,807 and ($8,549), respectively (see Note 12)	10,287	(18,960)
Net income	794,966	526,828
Dividend requirements on preferred stock	4,241	4,241

Earnings available for common shareholders	$ 790,725	$ 522,587
Weighted average common shares outstanding (in thousands):		
Basic	342,952	337,832
Diluted	343,742	338,111
Earnings per share basic:		
Income from continuing operations	$ 2.19	$ 1.54
Discontinued operations (see Note 19)	0.09	0.06
Extraordinary items (see Note 12)	0.03	(0.06)
Earnings per share	$ 2.31	$ 1.54
Earnings per share diluted:		
Income from continuing operations	$ 2.18	$ 1.54
Discontinued operations (see Note 19)	0.09	0.06
Extraordinary items (see Note 12)	0.03	(0.06)
Earnings per share	$ 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	
	2001	**2000**
	(Thousands of Dollars)	
Operating activities:		
Net income	794,966	$ 526,828
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	945,555	828,780
Nuclear fuel amortization	41,928	44,591
Deferred income taxes	11,190	62,716
Amortization of investment tax credits	(12,867)	(15,295)
Allowance for equity funds used during construction	(6,829)	3,848
Undistributed equity in earnings of unconsolidated affiliates	(124,277)	(87,019)
Special charges not requiring (using) cash	57,391	96,113
Conservation incentive accrual adjustments	(49,271)	19,248
Unrealized gain on derivative financial instruments	(9,804)	0
Extraordinary items net of tax (see Note 12)	(10,287)	18,960
Change in accounts receivable	218,353	(443,347)
Change in inventories	(178,530)	21,933
Change in other current assets	340,478	(484,288)
Change in accounts payable	(325,946)	713,069
Change in other current liabilities	85,226	129,557
Change in other assets and liabilities	(193,264)	(27,969)
Net cash provided by operating activities	1,584,012	1,407,725
Investing activities:		
Nonregulated capital expenditures and asset acquisitions	(4,259,791)	(2,196,168)
Utility capital/ construction expenditures	(1,105,989)	(984,935)
Allowance for equity funds used during construction	6,829	(3,848)
Investments in external decommissioning fund	(54,996)	(48,967)
Equity investments, loans, deposits and sales of nonregulated projects	154,845	(93,366)
Collection of loans made to nonregulated projects	6,374	17,039
Other investments net	84,769	(36,749)
Net cash used in investing activities	(5,167,959)	(3,346,994)
Financing activities:		
Short-term borrowings net	708,335	42,386
Proceeds from issuance of long-term debt	3,777,075	3,565,227
Repayment of long-term debt, including reacquisition premiums	(860,623)	(1,667,335)
Proceeds from issuance of common stock	133,091	116,678
Proceeds from NRG stock offering	474,348	453,705
Dividends paid	(518,894)	(494,992)
Net cash provided by financing activities	3,713,332	2,015,669
Effect of exchange rate changes on cash	(4,566)	360
Net increase in cash and cash equivalents	124,819	76,760

Cash and cash equivalents at beginning of year	216,491	139,731
Cash and cash equivalents at end of year	341,310	$ 216,491
Cash and cash equivalents discontinued operations	63,954	8,653
Cash and cash equivalents continuing operations	277,356	207,838
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	708,560	$ 610,584
Cash paid for income taxes (net of refunds received)	327,018	$ 216,087

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	Dec. 31	
	2001	**2000**
	(Thousands of Dollars)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 277,356	$ 207,838
Restricted cash	143,009	7,236
Accounts receivable net of allowance for bad debts: $57,815 and $41,350, respectively	1,092,553	1,218,881
Accrued unbilled revenues	495,994	683,266
Materials and supplies inventories at average cost	323,505	286,379
Fuel inventory at average cost	250,043	116,990
Gas inventories replacement cost in excess of LIFO: $11,331 and $106,790, respectively	126,563	77,390
Recoverable purchased gas and electric energy costs	52,583	283,167
Derivative instruments valuation at market	59,790	0
Prepayments and other	307,777	160,385
Current assets held for sale	182,189	86,542
Total current assets	3,311,362	3,128,074
Property, plant and equipment, at cost:		
Electric utility plant	16,099,655	15,304,407
Nonregulated property and other	7,783,994	5,072,718
Gas utility plant	2,493,028	2,376,868
Construction work in progress (utility amounts of $669,895 and $622,494, respectively)	3,682,619	915,471
Total property, plant and equipment	30,059,296	23,669,464
Less: accumulated depreciation	(9,536,854)	(8,718,179)
Nuclear fuel net of accumulated amortization: $1,009,855 and $967,927, respectively	96,315	86,499
Net property, plant and equipment	20,618,757	15,037,784
Other assets:		
Investments in unconsolidated affiliates	1,209,017	1,459,410
Notes receivable, including amounts from affiliates of $202,411 and $76,918, respectively	779,186	92,074
Nuclear decommissioning fund and other investments	695,070	732,908
Regulatory assets	502,442	524,261
Derivative instruments valuation at market	179,683	0
Prepaid pension asset	378,825	225,134
Other	476,050	292,651
Non current assets held for sale	584,670	276,547
Total other assets	4,804,943	3,602,985
Total assets	$28,735,062	$21,768,843

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Continued)

	Dec. 31	
	2001	2000
	(Thousands of Dollars)	
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 419,335	$ 592,879
Short-term debt	2,224,812	1,475,072
Accounts payable	1,336,637	1,566,153
Taxes accrued	246,152	236,837
Dividends payable	130,845	128,983
Derivative instruments valuation at market	83,122	0
Other	698,315	616,477
Current liabilities held for sale	310,810	55,407
Total current liabilities	5,450,028	4,671,808
Deferred credits and other liabilities:		
Deferred income taxes	2,271,313	1,793,505
Deferred investment tax credits	184,148	198,108
Regulatory liabilities	483,942	494,566
Derivative instruments valuation at market	42,444	0
Benefit obligations and other	703,836	588,288
Non current liabilities held for sale	279,289	260,870
Total deferred credits and other liabilities	3,964,972	3,335,337
Minority interest in subsidiaries	636,847	262,650
Capitalization (see Statements of Capitalization):		
Long-term debt	11,889,418	7,337,944
Mandatorily redeemable preferred securities of subsidiary trusts (see Note 6)	494,000	494,000
Preferred stockholders equity	105,320	105,320
Common stockholders equity	6,194,477	5,561,784
Commitments and contingencies (see Note 15)		
Total liabilities and equity	$28,735,062	$21,768,843

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

	Par Value	Premium	Retained Earnings	Shares Held by ESOP	Accumulated Other Comprehensive Income	Total Stockholders Equity
			(Thousands of Dollars)			
Balance at Dec. 31, 1999	$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	13,892	102,785				116,677
Tax benefit from stock options exercised		53				53
Other			16			16
Gain 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	$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 14)					(28,780)	(28,780)
After-tax net unrealized gains related to derivatives accounted for as hedges (see Note 14)					43,574	43,574
After-tax net realized losses on derivative transactions reclassified into earnings (see Note 14)					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	12,418	120,673				133,091
Other			(27)			(27)
Gain from NRG stock offering		241,891				241,891
Repayment of ESOP loan(a)				6,053		6,053
Balance at Dec. 31, 2001	$864,503	$2,969,589	$2,558,403	$(18,564)	$(179,454)	$6,194,477

(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	
	2001	**2000**
	(Thousands of Dollars)	
Long-Term Debt		
NSP-Minnesota Debt		
First Mortgage Bonds, Series due:		
Dec. 1, 2001-2006, 3.65-4.1%	$ 11,225(a)	$ 13,230(a)
Oct. 1, 2001, 7.875%	0	150,000
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
March 1, 2011, variable rate, 1.8% at Dec. 31, 2001, and 5.05% at Dec. 31, 2000	13,700(b)	13,700(b)
March 1, 2019, variable rate, 2.04% at Dec. 31, 2001, and 4.25% at Dec. 31, 2000	27,900(b)	27,900(b)
Sept. 1, 2019, variable rate 1.76% and 2.04% at Dec. 31, 2001, and 4.36% and 4.61% at Dec. 31, 2000	100,000(b)	100,000(b)
July 1, 2025, 7.125%	250,000	250,000
March 1, 2028, 6.5%	150,000	150,000
Guaranty Agreements, Series due: 2001-May 1, 2003, 5.375%-7.4%	29,200(b)	29,950(b)
Senior Notes due Aug. 1, 2009, 6.875%	250,000	250,000
City of Becker Revenue Bonds-Series due April 1, 2030, 1.85% at Dec. 31, 2001, and 5.1% at Dec. 31, 2000	69,000(b)	69,000(b)
Anoka County Bond-Series due Dec. 1, 2001-2008, 4.15%-5%	16,090(a)	17,990(a)
Employee Stock Ownership Plan Bank Loans due 2001-2007, variable rate	18,564	24,617
Other	390	194
Unamortized discount-net	(5,015)	(5,513)
Total	1,181,054	1,341,068
Less redeemable bonds classified as current (see Note 4)	141,600	141,600
Less current maturities	11,134	161,773
Total NSP-Minnesota long-term debt	$ 1,028,320	$ 1,037,695
PSCo Debt		
First Mortgage Bonds, Series due:		
Jan. 1, 2001, 6%	$ 0	$ 102,667
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)
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%	147,840	147,840

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31	
	2001	2000
	(Thousands of Dollars)	
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 Oct. 22, 2002-March 5, 2007, 6.45%-7.65%	190,000	226,500
Other secured long-term debt, 13.25%	0	29,777
PSCCC Unsecured Medium-Term Notes, variable rate 7.4% at Dec. 31, 2000	0	100,000
Unamortized discount	(5,282)	(5,952)
Capital lease obligations, 11.2% due in installments through May 31, 2025	51,921	54,202
Total	1,482,229	1,752,784
Less current maturities	17,174	142,043
Total PSCo long-term debt	$1,465,055	$1,610,741
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	0
Pollution control obligations, securing pollution control revenue bonds due:		
July 1, 2011, 5.2%	44,500	44,500
July 1, 2016, 1.7% at Dec. 31, 2001 and 5.1% at Dec. 31, 2000	25,000	25,000
Sept. 1, 2016, 5.75% series	57,300	57,300
Less funds held by Trustee	0	(168)
Unamortized discount	(1,425)	(126)
Total SPS long-term debt	$ 725,375	226,506
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 LaCrosse Resource Recovery Bond Series due Nov. 1, 2021, 6%	18,600(a)	18,600(a)
Fort McCoy System Acquisition due Oct. 31, 2030, 7%	963	996
Senior Notes due Oct. 1, 2008, 7.64%	80,000	80,000
Unamortized discount	(1,475)	(1,562)
Total	313,088	313,034
Less current maturities	34	34
Total NSP-Wisconsin long-term debt	$ 313,054	$ 313,000
NRG Debt		

Remarketable or Redeemable Securities due March 15, 2005, 7.97%	$ 232,960	$ 239,386
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

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31	
	2001	2000
	(Thousands of Dollars)	
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	0
April 1, 2011, 7.75%	350,000	0
April 1, 2031, 8.625%	500,000	0
May 16, 2006, 6.5%	284,440	0
NRG Finance Co. I LLC, due May 9, 2006, various rates	697,500	0
NRG debt secured solely by project assets:		
NRG Northeast Generating Senior Bonds, Series due:		
Dec. 15, 2004, 8.065%	180,000	270,000
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%	463,500	488,750
Sept. 15, 2024, 9.479%	300,000	300,000
Mid Atlantic various due Oct. 1, 2005, 3.56%	420,892	0
Sterling Luxembourg #3 Loan due June 30, 2019, variable rate 7.86% at Dec. 31, 2001 and 2000	329,842	346,668
Flinders Power Finance Pty due September 2012, various rates 8.56% at Dec. 31, 2001 and 7.58% at Dec. 31, 2000	74,886	83,820
Brazos Valley due June 30, 2008, 3.44%	159,750	0
Camas Power Boiler, due June 30, 2007 and Aug. 1, 2007, 7.65% and 4.65%	20,909	0
Crockett Corp. LLP debt due Dec. 31, 2014, 8.13%	234,497	245,229
Csepel Aramtermelo due Oct. 2, 2017, 3.79% and 4.846%	169,712	0
Hsin Yu Energy Development due November 2006-April 2012, 4% to 6.475%	89,964	0
LSP Batesville due Jan. 15, 2014, 7.164% and July 15, 2025, 8.16%	321,875	0
LSP Kendall Energy due Sept. 1, 2005, 3.154%	499,500	0
McClain due Dec. 31, 2005, 3.43%	159,885	0
NEO due 2005-2008, 9.35%	23,956	27,185
NRG Energy Center, Inc. Senior Secured Notes, Series due June 15, 2013, 7.31%	62,408	65,762
PERC due 2017-2018, 5.2%	33,220	0
Audrain Capital Lease Obligation due Dec. 31, 2023, 10%	239,930	0
Saale Energie GmbH Schkopau Capital Lease due May 2021, various rates	311,867	0
Various debt due 2001-2007, 0.0%-20.8%	148,121	33,738
Other	0	1,307
Total	8,344,614	3,796,845

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31 2001	Dec. 31 2000
	(Thousands of Dollars)	
Less current maturities continuing operations	237,282	134,772
Less discontinued operations	490,971	256,229
Total NRG long-term debt	7,616,361	$3,405,844
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, 1.8% and 4.95% at Dec. 31, 2001 and 2000	17,000	17,000
Viking Gas Transmission Co. Senior Notes Series due: Oct. 31, 2008-Sept. 30, 2014, 6.65%-8.04%	45,181	49,941
Various Eloigne Co. Affordable Housing Project Notes due 2002-2027, 0.3%-9.91%	47,856	51,309
Other	34,981	30,414
Total	157,018	160,664
Less current maturities	12,110	12,657
Total other subsidiaries long-term debt	144,908	$ 148,007
Xcel Energy Inc. Debt		
Unsecured Senior Notes due Dec. 1, 2010, 7%	600,000	$ 600,000
Unamortized discount	(3,655)	(3,849)
Total Xcel Energy Inc. debt	596,345	$ 596,151
Total long-term debt	11,889,418	$7,337,944
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: 2001, 1,049,800; 2000, 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
Premium on preferred stock	340	340

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Continued)

	Dec. 31	
	2001	**2000**
	(Thousands of Dollars)	
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: 2001, 345,801,028; 2000, 340,834,147	$ 864,503	$ 852,085
Premium on common stock	2,969,589	2,607,025
Retained earnings	2,558,403	2,284,220
Leveraged common stock held by ESOP shares at cost: 2001, 783,162; 2000, 1,041,180	(18,564)	(24,617)
Accumulated other comprehensive income (loss)	(179,454)	(156,929)
Total common stockholders equity	$6,194,477	$5,561,784

(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 Public Utility Holding Act of 1935 (PUHCA).

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 Northern States Power Co., a Minnesota corporation (NSP-Minnesota); Northern States Power Co., a Wisconsin corporation (NSP-Wisconsin); Public Service Co. of Colorado, a Colorado corporation (PSCo); Southwestern Public Service Co., a Wyoming corporation (SPS); Black Mountain Gas Co., an Arizona corporation (BMG); and Cheyenne Light, Fuel and Power Co., a Wyoming corporation (Cheyenne). Their service territories include portions of Arizona, Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, Wisconsin and Wyoming. Xcel Energy s regulated businesses also include Viking Gas Transmission Co. (Viking) and WestGas InterState, Inc. (WGI), both interstate natural gas pipeline companies.

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. At Dec. 31, 2001, Xcel Energy indirectly owned approximately 74 percent of NRG. 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. On June 3, 2002, Xcel Energy acquired the 26 percent of NRG owned by other shareholders.

In addition to NRG, Xcel Energy s nonregulated subsidiaries include Utility Engineering (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 Xcel Energy records utility revenues based on a calendar month, but reads meters and bills customers according to a cycle that doesn t necessarily correspond with the calendar month s end. To compensate, we record unbilled revenues for an estimate of the energy usage from the monthly meter-reading dates to the month s end.

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.

PSCo s electric rates in Colorado are adjusted under the incentive cost adjustment (ICA) mechanism, which takes into account changes in energy costs and certain trading revenues and expenses that are shared with the customer. SPS rates in Texas have fixed fuel factor and periodic fuel filing, reconciling and reporting requirements, which provide cost recovery. In New Mexico, SPS has recently reinstituted a monthly fuel and purchased power cost recovery factor. 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.

Trading Operations Xcel Energy s trading operations are conducted mainly by PSCo (electric) and e prime (gas). The results of the electric trading activity are initially recorded at PSCo. Pursuant to a Joint Operating Agreement, approved by the FERC as a part of the merger, the activity is then apportioned to the other operating utilities of Xcel Energy. Trading margins do not include the revenue and production costs associated with energy produced from generation assets or results from NRG. PSCo s trading results include the impacts of the ICA rate-sharing mechanism. For more information, see Notes 13 and 14 to the Financial Statements.

In June 2002 the Emerging Issues Task Force of the Financial Accounting Standards Board (EITF) issued a consensus decision for EITF Issue No. 02-3 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. 02-3 requires that all gains and losses related to energy trading activities within the scope of EITF No. 98-10 (whether or not settled physically) be shown net in the statement of income. Although the decision requires reclassification of comparable prior periods reported and is applicable for financial statement periods ending after July 15, 2002, the accompanying financial statements reflect early adoption and accordingly, the applicable 2001 and 2000 trading activities are reported herein on a net basis. Such energy trading activities previously reported 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 in accordance with EITF No. 02-3 were $3.1 billion and $2.0 billion for 2001 and 2000, respectively. This reclassification had no impact on trading margins and reported net income.

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 3.1 percent for the year ended Dec. 31, 2001, and 3.3 percent for the year ended Dec. 31, 2000.

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 Colorado Public Utilities Commission (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 $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 16 to the Financial Statements.

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. 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, except NRG, file consolidated federal and combined and separate state income tax returns. Due to NRG s 2001 public equity offering, NRG and its

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

subsidiaries will file a federal income tax return separate from Xcel Energy for the period March 13, 2001 through Dec. 31, 2001. Income taxes for consolidated or combined subsidiaries are allocated to the subsidiaries based on separate company computations of taxable income or loss. In accordance with the PUHCA requirements, the holding company also allocates its own net income tax benefits to its direct subsidiaries based on the positive taxable income of each company in the consolidated federal or combined state returns. Xcel Energy defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax basis of assets and liabilities. We use 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 17 to the Financial Statements. We discuss our income tax policy for international operations in Note 8 to the 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 component of Other Nonoperating Income.

Derivative Financial Instruments Xcel Energy and its subsidiaries utilize a variety of derivatives to manage commodity, foreign exchange and interest rate risk, including interest rate swaps and locks, foreign currency hedges and energy contracts. 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 Statement of Financial Accounting Standard (SFAS) No. 133 Accounting for Derivative Instruments and Hedging Activity, as amended by SFAS No. 137 and SFAS No. 138 (collectively referred to as SFAS No. 133). For more information on the impact of SFAS No. 133, see Note 14 to the Financial Statements.

For further discussion of Xcel Energy s risk management and derivative activities, see Note 13 and Note 14 to the 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 and funds held in trust accounts to satisfy the requirements of certain debt agreements. Restricted cash is classified as a current asset as all restricted cash is designated for interest and principal payments due within one year.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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 the restriction lapses or the stock is forfeited. For more information, see Note 9 to the Financial Statements.

Development Costs As we develop projects, we expense the development costs incurred (for professional services, permits, etc.) until a sales agreement or letter of intent is signed and the project has received board approval. We capitalize additional costs incurred at that point. When a project begins to operate, we amortize the capitalized costs over either the life of the project s related assets or the revenue contract period, whichever is less. If a project is terminated without becoming operational, we expense the capitalized costs in the period of the termination.

Intangible Assets and Deferred Financing Costs Goodwill results when Xcel Energy purchases an entity at a price higher than the underlying fair value of the net assets. At Dec. 31, 2001, Xcel Energy had unamortized intangible assets of $166 million, including $69 million of goodwill, mainly at its nonregulated subsidiaries. The majority of these intangible assets is associated with energy contracts and will be amortized over the contract terms. Effective Jan. 1, 2002, Xcel Energy implemented SFAS No. 142. These amounts and all intangible assets and goodwill acquired in the future will be accounted for under the new accounting standard.

The new accounting can be expected to initially increase earnings due to the elimination of amortization expense, but periodically causes reductions in earnings when impairment write-downs of goodwill and/or intangible assets are required.

Other assets also included deferred financing costs, net of amortization, of approximately $154 million at Dec. 31, 2001. We are amortizing these financing costs over the remaining maturity periods of the related debt.

Impairment of Long Lived Assets Long-lived assets and intangibles are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the assets to the future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less the cost to sell.

Reclassifications We reclassified certain items in the 2000 income statement and balance sheet to conform to the 2001 presentation. These reclassifications had no effect on net income or earnings per share. Reported amounts for periods prior to the merger have been restated to reflect the merger as if it had

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

occurred as of Jan. 1, 2000. The reclassifications were primarily to conform the presentation of all consolidated Xcel Energy subsidiaries to a standard corporate presentation.

New Accounting Pronouncements

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 plan, if existing debt agreements are ultimately renegotiated. Other impacts of SFAS 145 are not expected to be material to Xcel Energy.

SFAS No. 146 In July 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 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.

2. Special Charges

*2001 Restaffing*During the fourth quarter of 2001, Xcel Energy expensed pretax special charges of $39 million, or 7 cents per share, for expected staff consolidation costs. The charges related to severance costs for utility operations resulting from the restaffing plans of several operating and corporate support areas of Xcel Energy relate primarily to nonbargaining positions. We accrued costs for 500 staff terminations, which occurred mainly in the first quarter of 2002, across all regions of Xcel Energy s service territory, but primarily in Minneapolis and Denver. As of June 30, 2002, all of these terminations had occurred.

*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. PSCo appealed this decision to the Denver District Court. In 1998, the CPUC deferred the final determination of the regulatory treatment of the electric jurisdictional costs pending the outcome of PSCo s appeal on the natural gas rate case. On Dec. 16, 1999, the Denver District Court affirmed the decision by the CPUC.

On July 2, 2001, the Colorado Supreme Court affirmed the District Court decision. Accordingly, PSCo has written off $23 million pretax, representing 4 cents per share, of regulatory assets related to deferred postemployment benefit costs as of June 30, 2001, since all means of regulatory recovery have been denied.

*2000 Merger Costs*Upon consummation of the merger in 2000, Xcel Energy expensed pretax special charges totaling $241 million. These special charges reduced Xcel Energy s 2000 earnings by 52 cents per share. Of these pretax special charges, $201 million, or 43 cents per share, was recorded during the third quarter of 2000, and $40 million, or 9 cents per share, was recorded during the fourth quarter of 2000.

The pretax charges included $199 million, or 44 cents per share, 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 pretax charges also included $42 million, or 8 cents per share, of asset impairments and other

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

costs resulting from the post-merger strategic alignment of Xcel Energy s nonregulated businesses. 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 transition costs include approximately $77 million for severance and related expenses associated with staff reductions of 721 employees, all of whom were released through June 30, 2002. 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.

Accrued Special Charges The following table summarizes activity related to accrued special charges in 2001 and 2000.

	Expensed 2000	Payments Through Dec. 31, 2000	Dec. 31, 2000 Liability*	Expensed 2001	Payments 2001	Dec. 31, 2001 Liability*
	(Millions of dollars)					
Employee severance and related costs	$ 77	$(29)	$ 48	$ 39	$(50)	$ 37
Regulatory transition costs	12	(7)	5	0	(5)	0
Other transition and integration costs	58	(56)	2	0	(2)	0
Total accrued special charges	$147	$(92)	$ 55	$ 39	$(57)	$ 37

* Reported on the balance sheet in other current liabilities.

3. Short-Term Borrowings

Notes Payable and Commercial Paper Information regarding notes payable and commercial paper for the years ended Dec. 31, 2001 and 2000 is:

	2001	2000
	(Millions of dollars, except interest rates)	
Notes payable to banks	$ 835	$ 20
Commercial paper	1,390	1,455
Total short-term debt	$2,225	$1,475
Weighted average interest rate at year end	3.41%	6.48%

At June 30, 2002, Xcel Energy and its subsidiaries had approximately $2.5 billion of short-term debt outstanding at a weighted average interest rate of approximately 3.32 percent.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Bank Lines of Credit At Dec. 31, 2001, we and our subsidiaries had approximately $6.9 billion and DEM 203.6 million in credit facilities with several banks.

	Period Beginning	Term	Credit Line
Xcel Energy	November 2001	364 days	$400 million
Xcel Energy	November 2000	5 years	$400 million
NSP-Minnesota	August 2001	364 days	$300 million
PSCo	June 2001	364 days	$600 million
SPS	February 2001	364 days	$300 million
NRG total			$4.8 billion and DEM 203.6 million
Other subsidiaries	Various	Various	$118 million

The lines of credit for companies other than NRG provide short-term financing in the form of bank loans and letters of credit, but their primary purpose is support for commercial paper borrowings. At Dec. 31, 2001, there were no loans outstanding under these lines of credit. The borrowing rate under these lines of credit is based on the 90-day London Interbank Offered Rate (LIBOR), a euro dollar rate margin, and the amount of money borrowed. The rate that would have applied at Dec. 31, 2001, if we had loans outstanding, would have been between 2.18 percent and 2.505 percent.

At Dec. 31, 2001, NRG had three credit facilities for short-term financing:

a $500-million recourse revolving credit facility under a commitment fee arrangement that matures in March 2002. This facility provided short-term financing in the form of bank loans. At Dec. 31, 2001, NRG had $170 million outstanding under this facility. In March 2002, the revolving credit facility will terminate. During the period ended Dec. 31, 2001, the facility bore interest at a floating rate based on LIBOR and prime rates throughout the period and had a weighted average interest rate of 5.89 percent,

a $40-million revolving credit facility that matures in March 2002. This is a facility of NRG s South Central project and is nonrecourse to NRG. At Dec. 31, 2001, NRG South Central had $40 million outstanding under this facility at 4.46 percent and

a $600-million unsecured term loan facility, which terminates on June 21, 2002. At Dec. 31, 2001, the aggregate amount outstanding under this facility was $600 million at a weighted average interest rate of 3.94 percent.

NRG s other credit facilities are used for long-term financing. See discussion in Note 4 to the Financial Statements.

4. 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 addition, certain SPS payments under its pollution-control obligations are pledged to secure obligations of the Red River Authority of Texas.

There are annual sinking-fund requirements in our utility subsidiaries first mortgage indentures, in the amounts necessary to redeem 1 to 6.7 percent of the highest principal amount of each series of first mortgage bonds at any time outstanding, excluding series issued for pollution control and resource recovery financings and certain other series totaling $1.7 billion. NSP-Minnesota, NSP-Wisconsin, PSCo and Cheyenne expect to satisfy substantially all of their sinking fund obligations in accordance with the terms of their respective indentures through the application of property additions. SPS has no significant sinking fund requirements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NSP-Minnesota s 2011 series bonds are redeemable upon seven-days notice at the option of the bondholder. NSP-Minnesota also is potentially liable for repayment of the 2019 series when the bonds are tendered, which occurs each time the variable interest rates change. 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.

NRG has several credit facilities used for long-term financing:

Facility	Available line of credit	Recourse to NRG	End date	Outstanding Dec. 31, 2001	Rate at Dec. 31, 2001
			(Currency in Thousands)		
Revolving lines of credit:					
NRG Finance Co.I LLC	$ 2,000,000	Yes	May 2009	$ 697,500	4.83%
Term loan facilities:					
MidAtlantic	$ 580,000	No	November 2005	$ 420,892	3.56%
LSP Kendall Energy	$ 554,200	No	September 2005	$ 499,500	3.15%
Csepel	$ 78,500 and DEM 203,600	No	October 2017	$ 169,712	3.79-4.85%
Brazos Valley	$ 180,000	No	June 2008	$ 159,750	3.44%
McClain	$ 296,000	No	December 2005	$ 159,885	3.43%

The NRG Finance Co. I LLC facility is 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 non-recourse to NRG other than its obligation to contribute equity at certain times in respect of projects and turbines financed under the facility.

On March 13, 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 $25 NRG senior debenture (6.5 percent notes due May 16, 2006) and an obligation to acquire shares of NRG common stock no later than May 18, 2004 at a price ranging from $27.00 to $32.94 per share.

The $240 million NRG senior notes due Nov. 1, 2013 are Remarketable or Redeemable Securities (ROARS). At certain dates the notes must either be tendered to and purchased by Credit Suisse Financial Products or 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.

NRG s $250 million issue of 8.7 percent ROARS due March 15, 2005 may be remarketed by Bank of America, N.A. at a fixed rate of interest through the maturity date or at a floating rate of interest for up to one year and then at a fixed rate of interest through 2020.

Maturities and sinking fund requirements of long-term debt are:

2002	$ 682 million
2003	$ 719 million
2004	$ 335 million
2005	$ 1,140 million
2006	$ 1,832 million

On Aug. 5, 2002, Xcel Energy signed agreements with its lenders to eliminate certain cross-default provisions in its bank credit agreements that were tied to the performance by NRG of its credit agreements. Xcel Energy s bank agreements consist of a 364-day credit facility in the amount of $400 million expiring in November 2002 and a five-year credit facility in the amount of $400 million expiring in November 2005. The agreements remove key provisions in Xcel Energy s credit facilities that would have constrained Xcel Energy s

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ability to access capital due to difficulties faced by its NRG subsidiary in complying with the terms of its own credit facilities. NRG s debt was downgraded recently to below investment grade by two major rating agencies. Absent waivers or modifications, NRG s inability to meet the cash collateral demands following the downgrade would result in defaults under various agreements and credit facilities at the NRG level, which, in turn, could have resulted in a cross-default under Xcel Energy s $800 million bank facilities. The agreements reached with Xcel Energy s lenders remove this linkage between NRG s agreements and credit facilities. In particular, cross-default provisions of Xcel Energy s credit facilities were amended such that default by NRG in respect of its indebtedness will not constitute an event of default under Xcel Energy s credit agreements. As part of its agreements with its lenders, Xcel Energy has agreed that its board of directors will review its dividend policy. While the board could decide to alter the dividend, currently the board has made no decision.

NSP-MN Debt Issuance In July 2002, NSP-MN issued $185 million of 8 percent Public Income Notes due in 2042. The proceeds were used to repay short-term indebtedness incurred for general working capital purposes and to meet long-term debt maturity requirements.

On Aug. 15, 2002 NSP-Minnesota signed agreements for an amended and restated credit facility that will replace its $300-million, 364-day fully drawn credit facility scheduled to expire Aug. 15, 2002. This credit line is structured as a senior revolving facility and is secured by a new series on bonds issued under its First Mortgage Trust Indenture. The new bonds are secured with all other bonds outstanding under the Trust Agreement.

On Aug. 27, 2002, NSP-Minnesota issued $127.9 million in secured bonds maturing in 2019 and $69 million in secured bonds maturing in 2030 bearing interest at 8 percent. Proceeds were used to redeem a comparable series of callable bonds.

On Aug. 29, 2002, NSP-Minnesota issued $450 million in first mortgage bonds maturing in 2012 bearing interest at 8 percent. Proceeds were used to repay short-term debt and for general corporate purposes, including working capital and capital expenditures.

5. Preferred Stock

At Dec. 31, 2001, we had six series of preferred stock outstanding, which were callable at our option at prices ranging from $102 to $103.75 per share plus accrued dividends.

The holders of our $3.60 series preferred stock are entitled to three votes for each share held. The holders of our 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 our 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
NRG Energy, Inc.	200,000,000	$ 0.01	None
PS Colorado Credit Corp.	25,000,000	$ 1.00	None

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Mandatorily Redeemable Preferred Securities of Subsidiary Trusts

In 1996, SPS Capital I, a wholly owned, special-purpose subsidiary trust of SPS, issued $100 million of 7.85 percent trust preferred securities 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.

In 1997, NSP Financing I, a wholly owned, special-purpose subsidiary trust of NSP-Minnesota, issued $200 million of 7.875 percent trust preferred securities 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.

In 1998, PSCo Capital Trust I, a wholly owned, special-purpose subsidiary trust of PSCo, issued $194 million of 7.60 percent trust preferred securities 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 Income along with interest charges.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Joint Plant Ownership

The investments by Xcel Energy s subsidiaries in jointly owned plants and the related ownership percentages as of Dec. 31, 2001, are:

	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Ownership %
		(Thousands of dollars)		
NSP-Minnesota-Sherco Unit 3	$609,382	$271,874	$1,158	59.0
PSCo:				
Hayden Unit 1	$ 84,032	$ 37,664	$ 223	75.5
Hayden Unit 2	79,197	40,864	63	37.4
Hayden Common Facilities	28,044	2,715	156	53.1
Craig Units 1 & 2	59,799	30,593	0	9.7
Craig Common Facilities Units 1, 2 & 3	26,052	8,816	0	6.5-9.7
Transmission Facilities, including Substations	84,760	28,689	125	42.0-73.0
Total PSCo	$361,884	$149,341	$ 567	
NRG:				
McClain	$276,589	$ 3,836	$ 0	77.0
Big Cajun II Unit 3	177,359	7,838	2,249	58.0
Conemaugh	60,237	1,497	695	3.7
Keystone	51,906	1,291	1,022	3.7
Total NRG	$566,091	$ 14,462	$3,966	

NSP-Minnesota is part owner of Sherco 3, an 860-megawatt, coal-fired 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.

8. Income Taxes

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:

	2001	2000
Federal statutory rate	35.0%	35.0%
Increases (decreases) in tax from:		
State income taxes, net of federal income tax benefit	2.5%	5.8%
Life insurance policies	(1.9)%	(2.4)%
Tax credits recognized	(6.6)%	(10.2)%
Equity income from unconsolidated affiliates	(1.7)%	(2.3)%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2001	2000
Income from foreign consolidated affiliates	(0.8)%	(0.4)%
Regulatory differences utility plant items	1.8%	2.3%
Deferred tax expense on Yorkshire investment	0.0%	2.3%
Nondeductible merger costs	0.0%	2.9%
Other net	0.1%	1.8%
Total effective income tax rate	28.4%	34.8%
Effective income tax rate from continuing operations	28.7%	34.7%

Income taxes comprise the following expense (benefit) items:

	(Thousands of dollars)	
Current federal tax expense	$368,219	$195,309
Current state tax expense	26,927	63,428
Current foreign tax expense	6,219	(784)
Current federal tax credits	(66,179)	(71,270)
Deferred federal tax expense	(24,114)	103,258
Deferred state tax expense	18,702	12,547
Deferred foreign tax expense	13,990	7,162
Deferred investment tax credits	(12,983)	(15,295)
Income tax expense from continuing operations	330,781	294,355
Tax expense (benefit) on extraordinary items	4,807	(8,549)
Tax expense on discontinued operations	5,942	10,510
Total income tax expense	$341,530	$296,316

Xcel Energy management intends to reinvest the earnings from NRG s foreign operations to the extent the earnings are subject to current U.S. income taxes Accordingly, U.S. income taxes and foreign withholding taxes have not been provided on a cumulative amount of unremitted earnings of foreign subsidiaries of approximately $345 million and $238 million at Dec. 31, 2001 and 2000. The additional U.S. income tax and foreign withholding tax on the unremitted foreign earnings, if repatriated, would be offset in part by foreign tax credits. Thus, it is not practicable to estimate the amount of tax that might be payable.

Xcel Energy management also intends to reinvest the earnings of the Argentina operations of Xcel Energy International, and therefore has not provided deferred taxes for the effects of the currency devaluation discussed in Note 15 to the Financial Statements. However, as a result of management s revised strategic plan for Yorkshire Power to begin repatriation of earnings to the United States, Xcel Energy provided deferred taxes of $20 million on unremitted earnings of $55 million at Dec. 31, 2000. Due to the sale of the majority of its interest in Yorkshire Power during 2001, Xcel Energy now accounts for its remaining investment under the cost method.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of Xcel Energy s net deferred tax liability (current and noncurrent portions) at Dec. 31 were:

	2001	2000
	(Thousands of dollars)	
Deferred tax liabilities:		
Differences between book and tax basis of property	$2,195,323	$1,754,928
Regulatory assets	155,587	168,380
Partnership income/loss	53,955	70,266
Unrealized gains and losses on mark-to-market transactions	45,701	411
Tax benefit transfer leases	14,765	18,839
Other	73,437	97,852
Total deferred tax liabilities	$2,538,768	$2,110,676
Deferred tax assets:		
Differences between book and tax basis of contracts	$ 82,972	$ 0
Deferred investment tax credits	72,345	76,133
Regulatory liabilities	66,507	88,817
Foreign tax loss carryforwards	23,630	25,063
Employee benefits and other accrued liabilities	(16,559)	14,675
Other	87,387	62,053
Total deferred tax assets	$ 316,282	$ 266,741
Net deferred tax liability	$2,222,486	$1,843,935

9. Common Stock and Incentive Stock Plans

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 includes 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.

Stock Options and Performance Awards at Dec. 31:

	2001		2000	
	Awards	Average Price	Awards	Average Price
	(Shares in thousands)			
Outstanding at beginning of year	14,259	$25.35	8,490	$25.12
Granted	2,581	25.98	6,980	25.31
Exercised	(1,472)	23.00	(453)	20.33
Forfeited	(142)	27.08	(704)	25.70
Expired	(12)	24.07	(54)	22.62

Outstanding at end of year	15,214	25.65	14,259	25.35
Exercisable at end of year	7,154	24.78	8,221	24.46

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Range of Exercise Prices		
At Dec. 31, 2001	$16.60 to $21.75	$21.76 to $27.99	$28.00 to $31.01
Options Outstanding:			
Number outstanding	2,544,374	11,261,229	1,408,857
Weighted average remaining contractual life (years)	6.8	8.0	6.5
Weighted average exercise price	$19.87	$26.33	$30.66
Options Exercisable:			
Number exercisable	2,334,841	3,459,896	1,359,376
Weighted average exercise price	$19.86	$25.79	$30.67

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. We granted 21,774 restricted shares in 2001 and 58,690 restricted shares in 2000. 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 did not constitute 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 reduced by approximately 1 cent per share for 2001 and 2 cents per share for 2000.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes Option Pricing Model with the following assumptions:

	2001	2000
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%

Dividend Restrictions The Articles of Incorporation of Xcel Energy place restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. Xcel Energy has outstanding preferred stock. At Dec. 31, 2001, an additional $2 billion in common stock dividends could have been paid before restrictions would apply.

Certain financing agreements of Xcel Energy s utility subsidiaries restrict the amount of dividends such subsidiaries can pay to Xcel Energy. Xcel Energy currently does not expect these restrictions to limit the ability of Xcel Energy s subsidiaries to pay dividends at historic levels if declared.

Stockholder Protection Rights Agreement On June 28, 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Xcel Energy Common Stock Issuance In February 2002, Xcel Energy issued 23 million shares of common stock at $22.50 per share. The proceeds were used to fund NRG and to repay short-term debt.

In June 2002, Xcel Energy issued 25.7 million shares of common stock to complete its exchange offer with minority NRG shareholders and acquire 100 percent ownership of NRG.

10. Benefit Plans and Other Postretirement Benefits

Xcel Energy offers various benefit plans to its benefit employees. Approximately 44 percent of benefit employees are represented by several local labor unions under several collective-bargaining agreements. At Dec. 31, 2001, NSP-Minnesota and NSP-Wisconsin had 2,563 union employees covered under a collective-bargaining agreement, which expires at the end of 2004. PSCo had 1,979 union employees covered under a collective-bargaining agreement, which expires in May 2003. SPS had 742 union employees covered under a collective-bargaining agreement, which expires in October 2002.

Pension Benefits Xcel Energy has several noncontributory, defined benefit pension plans that cover almost all utility 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.

A comparison of the actuarially computed pension benefit obligation and plan assets at Dec. 31, 2001 and 2000, for Xcel Energy plans on a combined basis is presented in the following table.

	2001	2000
	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at Jan. 1	$2,254,138	$2,170,627
Service cost	57,521	59,066
Interest cost	172,159	172,063
Acquisitions	0	52,800
Plan amendments	2,284	2,649
Actuarial (gain) loss	108,754	1,327
Benefit payments	(185,670)	(204,394)
Obligation at Dec. 31	$2,409,186	$2,254,138
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	$3,689,157	$3,763,293
Actual return on plan assets	(235,901)	91,846
Acquisitions	0	38,412
Benefit payments	(185,670)	(204,394)
Fair value of plan assets at Dec. 31	$3,267,586	$3,689,157

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2001	2000
	(Thousands of dollars)	
Funded Status at Dec. 31		
Net asset	$ 858,400	$ 1,435,019
Unrecognized transition (asset) obligation	(9,317)	(16,631)
Unrecognized prior-service cost	242,313	228,436
Unrecognized (gain) loss	(712,571)	(1,421,690)
Prepaid pension asset recorded	$ 378,825	$ 225,134
Significant assumptions		
Discount rate for year-end valuation	7.25%	7.75%
Expected average long-term increase in compensation level	4.5%	4.5%
Expected average long-term rate of return on assets	9.5%	8.5-10.0%

The components of net periodic pension cost (credit) for Xcel Energy plans are:

	2001	2000
	(Thousands of dollars)	
Service cost	$ 57,521	$ 59,066
Interest cost	172,159	172,063
Expected return on plan assets	(325,635)	(292,580)
Curtailment	1,121	0
Amortization of transition asset	(7,314)	(7,314)
Amortization of prior-service cost	20,835	19,197
Amortization of net gain	(72,413)	(60,676)
Net periodic pension cost (credit) under SFAS No. 87	$(153,726)	$(110,244)
Credits not recognized due to effects of regulation	76,509	49,697
Net benefit cost (credit) recognized for financial reporting	$ (77,217)	$ (60,547)

NRG also offers other noncontributory, defined benefit pension plans that are sponsored by NRG and its affiliates. For the year ended Dec. 31, 2001, the total assets of such plans were $16 million and benefit obligations were $37 million. The net recorded pension liabilities for these plans were $19 million and annual pension costs were $4 million.

Additionally, Xcel Energy 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 $29 million in 2001 and $23 million in 2000.

Xcel Energy has a leveraged employee stock ownership plan (ESOP) that covers substantially all employees of NSP-Minnesota and NSP-Wisconsin. Xcel Energy makes contributions to this noncontributory, defined contribution plan to the extent it realizes tax savings from dividends paid on certain ESOP shares. ESOP contributions have no material effect on Xcel Energy earnings because the contributions are essentially offset by the tax savings provided by the dividends paid on ESOP shares. Xcel Energy allocates leveraged ESOP shares to participants when it repays ESOP loans with dividends on stock held by the ESOP.

Xcel Energy s leveraged ESOP held 10.5 million shares of Xcel Energy common stock at the end of 2001 and 12.0 million shares of Xcel Energy common stock at the end of 2000. Xcel Energy excluded the following

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

uncommitted leveraged ESOP shares from earnings per share calculations: 0.9 million in 2001 and 0.7 million in 2000.

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.

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 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.

Additionally, certain state agencies, which regulate Xcel Energy s utility subsidiaries, have 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 and Cheyenne are 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 require 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.

A comparison of the actuarially computed benefit obligation and plan assets at Dec. 31, 2001 and 2000, for all Xcel Energy postretirement health care plans is presented in the following table.

	2001	2000
	(Thousands of dollars)	
Change in Benefit Obligation		
Obligation at Jan. 1	$576,727	$533,458
Service cost	6,160	5,679
Interest cost	46,579	43,477
Acquisitions	3,212	16,445
Plan participants contributions	3,517	4,358
Plan amendments	(278)	0
Actuarial (gain) loss	100,386	10,501
Benefit payments	(48,848)	(37,191)
Obligation at Dec. 31	$687,455	$576,727
Change in Fair Value of Plan Assets		
Fair value of plan assets at Jan. 1	$223,266	$201,767
Actual return on plan assets	(3,701)	10,069
Plan participants contributions	3,517	4,358
Employer contributions	68,569	44,263
Benefit payments	(48,848)	(37,191)
Fair value of plan assets at Dec. 31	$242,803	$223,266

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	2001	2000
	(Thousands of dollars)	
Funded Status at Dec. 31		
Net obligation	$ 444,652	$ 353,461
Unrecognized transition asset (obligation)	(186,099)	(202,871)
Unrecognized prior-service cost	12,812	13,789
Unrecognized gain (loss)	(134,225)	(11,126)
Accrued benefit liability recorded	$ 137,140	$ 153,253
Significant assumptions:		
Discount rate for year end valuation	7.25%	7.75%
Expected average long-term rate of return on assets	9.0%	8.0-9.5%

The assumed health care cost trend rate for 2001 is approximately 8.0 percent, decreasing gradually to 5.5 percent in 2007 and remaining level thereafter. A 1-percent increase in the assumed health care cost trend rate would increase the estimated total accumulated benefit obligation for Xcel Energy by approximately $72.3 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately $5.8 million. A 1-percent decrease in the assumed health care cost trend rate would decrease the estimated total accumulated benefit obligation for Xcel Energy by approximately $60.2 million, and the service and interest cost components of net periodic postretirement benefit costs by approximately $4.7 million.

The components of net periodic postretirement benefit cost of all Xcel Energy s plans are:

	2001	2000
	(Thousands of dollars)	
Service cost	$ 6,160	$ 5,679
Interest cost	46,579	43,477
Expected return on plan assets	(18,920)	(17,902)
Amortization of transition obligation	16,771	16,773
Amortization of prior-service cost (credit)	(1,235)	(1,211)
Amortization of net loss (gain)	1,457	915
Net periodic postretirement benefit costs under SFAS No.106	50,812	47,731
Additional cost recognized due to effects of regulation	3,738	6,641
Net cost recognized for financial reporting	$ 54,550	$ 54,372

11. Equity Investments and Asset Acquisitions

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2001 Economic Interest
Loy Yang Power A	Partnership	None	Australia	25.37%
Enfield Energy Centre	Partnership	None	Europe	25.00%
Gladstone Power Station	Joint Venture	Operator	Australia	37.50%
COBEE (Bolivian Power Co. Ltd.)	Corporation	None	South America	49.45%
MIBRAG GmbH	Partnership	None	Europe	50.00%
Cogeneration Corp. of America	Partnership	None	USA	20.00%
Schkopau Power Station	Tenants in Common	None	Europe	41.90%
West Coast Power	Partnership	Operator	USA	50.00%
Energy Developments Limited	Corporation	None	Australia	25.10%
Scudder Latin American Power	Partnership/ Corporation/ Trust	None	Latin America	25.00%
Lanco Kondapalli Power	Partnership	Operator	India	30.00%
ECK Generating	Partnership	Operator	Czech Republic	44.50%
Rocky Road Power	Partnership	Operator	USA	50.00%
Mustang	Joint Venture	None	USA	50.00%
Sabine River Works Cogeneration	Partnership	None	USA	50.00%
Quixx Linden L.P.	Limited Partnership	None	USA	50.00%
Borger Energy L.P.	Limited Partnership	None	USA	45.00%
Various independent power production facilities	Various	Various	USA	9%-70%
Various affordable housing limited partnerships	Limited Partnerships	Various	USA	20%-99.9%

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

	2001	2000
	(Millions of dollars)	
Operating revenues	$3,583	$4,664
Operating income	442	464
Net income	422	447
Xcel Energy s equity earnings of unconsolidated affiliates	216	182

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Position

	2001	2000
	(Millions of dollars)	
Current assets	$1,478	$ 1,590
Other assets	7,396	10,939
Total assets	$8,874	$12,529
Current liabilities	$1,229	$ 1,833
Other liabilities	4,841	6,806
Equity	2,804	3,890
Total liabilities and equity	$8,874	$12,529
Xcel Energy s share of undistributed retained earnings	$ 449	$ 325

West Coast Power Xcel Energy has a significant investment in West Coast Power LLC (through NRG), as defined by applicable SEC regulations, and accounts for its investment using the equity method. The following is summarized pretax financial information for West Coast Power:

Results of Operations

	Year ended Dec. 31	
	2001	2000
	(Millions of dollars)	
Operating revenues	$1,562	$875
Operating income	$ 345	$278
Net income	$ 326	$245

Financial Position

	Dec. 31	
	2001	2000
	(Millions of dollars)	
Current assets	$ 401	$322
Other assets	659	526
Total assets	$1,060	$848
Current liabilities	$ 138	$230
Other liabilities	269	194
Equity	653	424

Total liabilities and equity	$ 1,060	$ 848

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 has 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NRG Asset Acquisitions During the year ended Dec. 31, 2001, NRG completed numerous acquisitions of project assets and related liabilities. These acquisitions have been recorded using the purchase method of accounting. Accordingly, the purchase prices of each acquisition have been preliminarily allocated to assets acquired and liabilities assumed based on their estimated fair values at the various dates of acquisition. These estimates will be adjusted based upon completion of certain procedures, including third party valuations. Operations of the acquired projects have been included in Xcel Energy s results of operations since the respective dates of each acquisition.

The following is a summary of the projects acquired in 2001:

Project Acquired	Total Plant Megawatt (MW)	NRG Ownership	Operations
LS Power (USA)	5,633 (1,697 in operation or under construction)	100%	
Indeck (USA)	2,255 (402 in operation)	100%	
Conectiv (USA)	4,340	100% of 918 MW; 4% of remainder	
Termo Rio (Brazil)	1,040	50%	Operations beginning in 2004
Schkopau (Germany)	960	Increased from 21% to 42%	
Audrain (USA)	640	100%	
Fort Bend (USA)	633	100%	Operations beginning in 2003
Csepel (Hungary)	505	100%	
McClain (USA)	500	77%	
Cogentrix (USA)	837	100%	
MIBRAG (Germany)	233	Increased from 33% to 50%	
Various other	372 in operation	various	

The respective purchase prices of these 2001 acquisitions have been allocated to the net assets of the acquired NRG projects as follows:

	(Thousands of dollars)
Current assets	$ 307,654
Property, plant and equipment	4,173,509
Noncurrent 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 noncurrent assets and liabilities	(181,473)
Total purchase price	2,935,897
Less cash balances acquired	(122,780)
Net purchase price	$ 2,813,117

12. Electric Utility Restructuring 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2007. This legislation amended the 1999 legislation, Senate Bill No. 7 (SB-7), which provided for retail electric competition to begin 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. SPS restructuring and rate unbundling proceedings in Texas have been terminated. In addition, under the legislation, SPS is entitled to recover all reasonable and necessary expenditures made or incurred before Sept. 1, 2001, to comply with SB-7. As required, SPS filed an application during the fourth quarter of 2001, requesting a rate rider to recover these costs incurred preparing for customer choice. These proceedings are pending.

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 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). In the second quarter of 2001, SPS did not restore any regulatory assets or other costs previously written off due to the uncertainty of various regulatory issues, including transition plans to address future rate recovery of SPS restructuring costs.

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 has 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, as previously discussed. These nonfinancing restructuring costs have been deferred and will be amortized in the future consistent with rate recovery. Management believes it will be allowed full recovery of its prudently incurred costs. Based on these fourth-quarter events 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.

In late 2001, SPS filed an application with the PUCT to recover $20.3 million in costs related to transition to retail competition from the Texas retail customers. 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

13. Financial Instruments

Fair Values

The estimated Dec. 31 fair values of Xcel Energy s recorded financial instruments are as follows:

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Thousands of dollars)			
Mandatorily redeemable preferred securities of subsidiary trusts	$ 494,000	$ 486,270	$ 494,000	$ 481,270
Long-term investments	619,976	620,703	625,616	624,989
Notes receivable, including current portion	782,079	782,079	99,557	99,557
Long-term debt, including current portion	12,799,723	12,788,749	8,187,052	8,131,139

For cash, cash equivalents and short-term investments, the carrying amount 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 and variable rate notes (interest rates ranging from 4.75 percent to 19.5 percent and maturities ranging from 2001 to 2024). Notes receivable include a $319-million direct financing lease related to a long-term sales agreement for NRG s Schkopau project, and other notes related to projects at NRG 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, 2001 and 2000. These fair value estimates have not been comprehensively revalued for purposes of these financial statements since that date and current estimates of fair values may differ significantly from the amounts presented herein.

Guarantees

Xcel Energy had the following guarantees outstanding as of Dec. 31, 2001:

Guarantor	Guarantee Amount	Nature of Guarantee
	(Millions of dollars)	
NRG	$721.7	Obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries. Xcel Energy is not obligated under these agreements.
Xcel Energy	343.1	Guarantee performance and payment of surety bonds for itself and its subsidiaries.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Guarantor	Guarantee Amount	Nature of Guarantee
	(Millions of dollars)	
Various Subsidiaries	336.9	Guarantee performance and payment of surety bonds for those subsidiaries. Xcel Energy is not obligated under these agreements.
Xcel Energy	270.7	Guarantees made to facilitate e prime s natural gas acquisition, marketing and trading operations.
Xcel Energy	60.0	Guarantee on the payments on notes issued by Guardian Pipeline LLC, of which Viking Gas Transmission Co. is one of three partners. The guarantee will terminate on the in-service date of the pipeline, which is expected to be March 2003.
Xcel Energy	28.5	Three guarantees benefiting Cheyenne to guarantee the payment obligations under gas and power purchase agreements.
Xcel Energy	25.0	Construction contract guarantee that assures Quixx s performance under its engineering, procurement and construction contract with Borger Energy Associates, LP (BEA). Quixx, which owns 45 percent of BEA, has constructed a 230-megawatt, cogeneration facility at a Phillips Petroleum site near Borger, Texas. The guarantee will remain in effect until no later than July 2003.
SPS	22.9	Guarantee for certain obligations of a customer in connection with an agreement for the sale of electric power. These obligations relate to the construction of certain utility property that, in the event of default by the customer, would revert to SPS.
Xcel Energy	17.9	Guarantees related to energy conservation projects in which Planergy has guaranteed certain energy savings to the customer. As energy savings are realized each year due to these projects, the value of the guarantee decreases until it reaches zero in 2024.
Xcel Energy	17.0	Guarantees payments for XERS Inc., a nonregulated subsidiary of Xcel Energy, under a Master Power Purchase and Sale Agreement and a Qualified Scheduling Entity Services Agreement. This guarantee was terminated and replaced with a $10-million guarantee in January 2002.
NSP-Minnesota	11.6	NSP-Minnesota sold a portion of its receivables to a third party. The portion of the receivables sold consisted of customer loans to local and state government entities for energy efficiency improvements under various conservation programs offered by NSP-Minnesota. Under the sales agreements, NSP-Minnesota is required to guarantee repayment to the third party of the remaining loan balances. Based on prior collection experience of these loans, losses under the loan guarantees, if any, are not believed to have a material impact on the results of operations.
Xcel Energy	5.0	Guarantee on behalf of BNP Paribas in connection with a letter of credit provided by BNP Paribas at the request of SPS. The letter of credit is required to indemnify former SPS board of directors.
Xcel Energy	4.5	Guarantee for e prime Energy Marketing, Inc. s performance of obligations under a supply agreement and for payments of energy and capacity transactions.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Guarantor	Guarantee Amount	Nature of Guarantee
	(Millions of dollars)	
Xcel Energy	3.0	Guarantee resulting from noncompletion of certain milestone achievements within required dates in connection with the Quixx Linden cogeneration plant. The milestones have been achieved as of December 2001. The guarantee is required to remain six months upon completion of these milestones. Therefore, the guarantee will be released June 2002 assuming contract requirements are met.
Xcel Energy	4.1	Combination of guarantees benefiting various Xcel Energy subsidiaries.

As of July 31, 2002, Xcel Energy s exposure under these guarantees totaled approximately $330 million.

Of the aggregate exposure of Xcel Energy under guarantees outstanding as of July 31, 2002, approximately $90 million relate to obligations of NRG s power marketing subsidiary (which includes power marketing obligations, fuel purchasing transactions and hedging activities), approximately $30 million relate to obligations of e prime (relating to trading and hedging activities) and approximately $60 million relate to obligations of Viking Gas (relating to the Guardian pipeline project which terminates on the in-service of the project, which is expected to be March 2003). The remaining exposure of Xcel Energy under the guarantees is estimated to be between $60 million and $110 million.

The guarantees issued by Xcel Energy guaranty 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. The majority of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. The aggregate maximum liability of Xcel Energy under the guarantees was approximately $779 million and $878 million as of Dec. 31, 2001 and July 31, 2002, respectively. Of this maximum, approximately $247 million support obligations of NRG s power marketing subsidiary, approximately $329 million relate to e prime, and approximately $60 million relate to Viking Gas. Xcel Energy entered into the NRG guarantees after the NRG exchange offer, which was completed in the second quarter of 2002.

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 and Poors or Moodys downgrade Xcel Energy s credit rating below investment grade.

In the event of a downgrade, Xcel Energy would expect to meet its obligations under the above guarantees with some combination of cash on hand, availability under its credit facilities and the issuance of securities in the capital markets.

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, 2001. For more detailed information regarding derivative financial instruments and the related risks, see Note 14 to the Financial Statements.

Interest Rate Swaps 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.

As of Dec. 31, 2000, Xcel Energy had several interest rate swaps converting project financing from variable-rate debt to fixed-rate debt with a notional amount of approximately $598 million. The fair value of the swaps as of Dec. 31, 2000 was a liability of approximately $36 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Trading Operations Xcel Energy participates in the trading of electricity and gas 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.

The fair value of Xcel Energy s trading contracts as of Dec. 31, 2001 is as follows:

	(Millions of dollars)
Fair value of trading contracts outstanding at Jan. 1, 2001	$ 8.6
Contracts realized or settled during 2001	(87.0)
Fair value of trading contract additions and changes during the year	96.2
Fair value of contracts outstanding at Dec. 31, 2001*	$ 17.8

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

The future maturities of Xcel Energy s trading contracts are as follows:

Source of Fair Value	Maturity Less than 1 Year	Maturity 1 to 3 Years	Total Fair Value
		(Millions of dollars)	
Prices actively quoted	$15.3	$1.0	$16.3
Prices based on models and other valuation methods (including prices quoted from external sources)	1.2	0.3	1.5

Regulated Operations Xcel Energy s regulated energy marketing operation uses a combination of energy and gas purchase for resale futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2001, the notional value of these contracts was approximately $83.8 million. The fair value of these contracts as of Dec. 31, 2001, was a liability of approximately $24 million.

Nonregulated Operations Xcel Energy s nonregulated operations uses a combination of energy futures and forward contracts, along with physical supply, to hedge market risks in the energy market. At Dec. 31, 2001, the notional value of these contracts was approximately $1.0 billion. The fair value of these contracts as of Dec. 31, 2001, was an asset of approximately $242.2 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, 2001 and 2000, the net notional amount of these contracts was approximately $46.3 million and $8.8 million, respectively. The fair value of these contracts as of Dec. 31, 2001 and 2000 was a liability of approximately $2.4 million and $0.7 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, 2001, there were $221.7 million in letters of credit outstanding, including $169.7 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.

14. Derivative Valuation and Financial Impacts

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, we 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 negotiated 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 its rate-regulated operations to the extent such exposure exists. Management is limited under the policy to enter into only transactions that reduce 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 we provide to our retail customers even though the regulatory jurisdiction provides dollar-for-dollar recovery of actual costs. This jurisdiction allows us to recover the gains and losses on derivative instruments used to reduce our exposure to market price risk.

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 annual 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 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 is mitigated by entering into derivative instruments known as interest rate swaps, caps, collars and put or call options. These contracts reduce exposure to interest rate volatility 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.

Foreign Currency 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Accounting Change On Jan. 1, 2001, Xcel Energy adopted SFAS No. 133. 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 income statement, 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 formally documents its 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 also formally assesses, 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.

The adoption of SFAS No. 133 on Jan. 1, 2001, resulted in an earnings impact of less than $1 million, which is not being reported separately as a cumulative effect of accounting change due to immateriality. In addition, upon adoption of SFAS No. 133, Xcel Energy recorded a net transition loss of approximately $28.8 million in Other Comprehensive Income.

The components of SFAS No. 133 impacts 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	$ 34.2

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The components of the gain for SFAS No. 133 impacts on Xcel Energy s income statement for the year ended Dec. 31, 2001, are detailed in the following table. The amounts below exclude our gains and losses from trading activities.

	(Millions of dollars, except per share data)
Increase (decrease) in income:	
Nonregulated and other revenues	$ (8.1)
Equity earnings from investment in affiliates	4.6
Electric fuel and purchased power utility	0.1
Cost of goods sold nonregulated and other	17.5
Other income (deductions)	0.2
Total increase before minority interest and income tax	$ 14.3
Net-of-tax increase in net income	$ 9.8
Increase in EPS (diluted)	$ 0.03

Xcel Energy records the fair value of its derivative instruments in its Consolidated Balance Sheet as separate line items noted as Derivative Instruments Valuation for assets and liabilities as well as current and noncurrent.

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 our 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 into 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 operations are considered normal.

Normal purchases and normal sales contracts are accounted for as executory contracts as required under other generally accepted accounting principles.

Cash Flow Hedges

Xcel Energy and its subsidiaries enter into derivative instruments to manage our 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, 2001, Xcel Energy had various commodity related contracts extending through 2018. Earnings on these cash flow hedges are recorded as the hedged purchase or sales transaction is completed. This could include the physical sale of electric energy or the usage of natural gas to generate electric energy. Xcel Energy expects to reclassify into earnings during 2002 net gains from Other Comprehensive Income of approximately $18.0 million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2002 net losses from Other Comprehensive Income of approximately $5.6 million.

Xcel Energy records hedge effectiveness 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 are recorded as a component of interest expense.

The net gain (loss) recognized in earnings for derivative instruments that have been designated and qualify as cash flow hedging instruments are detailed in the following table.

	Hedge Ineffectiveness	Derivatives Excluded from Assessment of Hedge Effectiveness	Firm Commitments No Longer Qualifying as Cash Flow Hedges
		(Millions of dollars)	
Year ended Dec. 31, 2001:			
Energy and energy-related commodities	$27.9	$ 0	$ 0
Interest rates	0	0	0

Fair Value Hedges and 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. Xcel Energy expects to reclassify into earnings during 2002 net losses from Other Comprehensive Income of approximately $2.2 million.

Derivatives Not Qualifying for Hedge Accounting

Xcel Energy and its subsidiaries have various trading operations that enter into derivative instruments. These derivative instruments are accounted for on a mark-to-market basis in the Consolidated Statements of Income. All financial derivative instruments are recorded at the amount of the gain or loss from the transaction within Operating Revenues on the Consolidated Statements of Income.

In order to preserve the U.S. dollar value of projected foreign currency cash flows from European trading operations, we enter into various foreign currency exchange contracts that are not designated as accounting hedges but are considered economic hedges. Accordingly, the changes in fair value of these derivatives are reported in Other Nonoperating Income in the Consolidated Statements of Income.

15. 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, 2001, NSP-Minnesota had loaded 14 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Capital Commitments Xcel Energy has reviewed its construction program and significantly revised its capital expenditure forecast. The new forecast reflects a reduction in capital expenditures of approximately $1.0 billion in 2003 and $1.3 billion in 2004 at NRG and approximately $200 million per year in 2003 and 2004 for Xcel Energy s utility operations. The capital expenditure forecast is detailed in the following table ($ in millions).

	2002	2003	2004
Total utility	$1,017	$ 922	$ 930
NRG	1,436	548	257
Other nonregulated	66	27	30
Total capital expenditures	$2,519	$1,497	$1,217

NRG has an ownership interest in U.S. projects currently under construction, which remain in the capital expenditure forecast and are scheduled for operation before the end of 2004.

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.

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 $605 million and $55 million at Dec. 31, 2001 and 2000, 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 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 $58 million and $56 million for 2001 and 2000, respectively.

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Future commitments under operating and capital leases are:

	Operating Leases	Capital Leases
	(Millions of dollars)	
2002	$ 54	$ 77
2003	50	75
2004	50	73
2005	48	71
2006	45	69
Thereafter		1,073
Total minimum obligation		$1,438
Interest		(834)
Present value of minimum obligation		$ 604

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 2001, we paid IBM $130 million under the contract. 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 2002 and 2025. In total, Xcel Energy is committed to the minimum purchase of approximately $2.8 billion of coal, $122.3 million of nuclear fuel and $1.3 billion of natural gas and related 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 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. 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 10 percent of NSP-Minnesota s 2001 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. In August 2002, Xcel Energy replaced the existing contract that was to expire in 2005 with a 10-year contract to purchase approximately $1 billion of electricity from Manitoba Hydro between 2005 and 2015. The contract is subject to approval from regulators.

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At Dec. 31, 2001, 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)
2002	$ 507,095
2003	513,979
2004	590,109
2005	658,976
2006 and thereafter	4,135,048
Total	$6,405,207

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, 2001, 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 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, 2001, our liability for the cost of remediating sites for which an estimate was possible was $51 million, including $13 million in current liabilities. 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.

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Approximately $19 million of the long-term liability and $4 million of the current liability relate to a DOE 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 16 to the 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 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. 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.

We proposed, and the EPA and WDNR have approved, an interim action (a 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 will install monitor wells in the deep aquifer to better characterize the extent and degree of contaminants in that aquifer while the free-product recovery system is operational.

On Dec. 1, 2000, in response to a citizen petition, the EPA proposed the Ashland site for inclusion on the National Priorities List (NPL) of hazardous sites requiring cleanup. NSP-Wisconsin submitted comments in the Administrative Record concerning the proposed listing on Jan. 30, 2001. On Sept. 5, 2002, the site was listed in the NPL.

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 recovered cost of remediating that site, $2.9 million, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 the fall of 2001, PSCo took its Leyden natural gas storage facility out of commercial storage operation and began final withdrawal of gas as part of the process to permanently close the facility. PSCo is closing the Leyden facility because it is no longer compatible with surrounding land use, which has experienced considerable residential and commercial development in recent years. Through Dec. 31, 2001, $4 million of costs have been incurred. PSCo has deferred expensing these closing costs because it believes that it will be able to recover them from its ratepayers. We will request recovery of the closing costs as part of the rate case to be filed in 2002. Any costs that are not recoverable from customers will be expensed.

Plant Emissions 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 its allegations.

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 United States 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 Xcel Energy 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. Xcel Energy disagrees with the assertions contained in the NOV and intends to vigorously defend its 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 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. The ultimate financial impact to Xcel Energy is not determinable at this time.

NRG estimates capital expenditures over the next five years related to resolving environmental concerns at the Indian River Generating Station, which are centered around possible closure of the existing landfill and construction of a new cell to replace it, possible addition of a cooling tower, and the addition of controls to reduce nitrogen oxide (NOx) emissions. Currently, cost estimates for addressing the first two items vary widely pending the results of negotiations with the Delaware Natural Resources and Environment Commission (DNREC). If ash sales are poor, it is estimated that NRG could spend up to $11 million over the five-year timeframe to close/ construct sections of the landfill; if sales are robust, expenditures related to closure/ construction are expected to be minimal. In the unlikely event NRG is unable to reach agreement with

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DNREC on extension of a variance, NRG estimates a $40-million cooling tower could be required; if negotiations are successful, a cooling tower can be avoided.

NRG also estimates $39 million of capital expenditures at its Encina Generating Station to install emission-control equipment required by California regulation passed in late 2001. Installation is expected to be completed in the spring of 2003.

The Commonwealth of Massachusetts is seeking additional emissions reductions beyond current requirements. The Massachusetts Department of Environmental Protection (MDEP) has issued proposed regulations that would require significant emissions reductions from certain coal-fired power plants in the state, including NRG s Somerset facility. The MDEP has proposed that such facilities comply with stringent limits on emissions of NOx and on sulfur dioxide (SO2) commencing in December 2003, with further reductions required by December 2005, and on carbon dioxide (CO2) by December 2005. In addition to output-based limits (a standard that limits emissions to a certain rate per net megawatt-hour), the proposed regulations also would limit, by December 2003, the total emissions of NOx and SO2 at the Somerset facility to no more than 75 percent of the average annual emissions of the Somerset facility for the years 1997 through 1999. Finally, the proposed regulations require the MDEP to evaluate, by December 2002, the technological and economic feasibility of controlling or eliminating mercury emissions by the year 2010, and to propose mercury emission standards within 18 months of completion of the feasibility evaluation. Compliance with these proposed regulations, if such regulations become effective, could have a material impact on the operation of NRG s Somerset facility. The annual average CO2 emission rate identified in the proposed regulations cannot be met by the Somerset facility. NRG has submitted an emission control plan, with respect to the NOx and SO2 requirements, and is conducting ongoing discussions with the MDEP regarding finalization of the plan.

NRG became part of an opacity consent order as a result of acquiring its Huntley, Dunkirk and Oswego plants from Niagara Mohawk. At the time of financial close on these assets, a consent order was being negotiated between Niagara Mohawk and the NYDEC; it required Niagara Mohawk to pay a stipulated penalty for each opacity event at these facilities. On Jan. 14, 2002, the NYDEC issued NRG NOVs for opacity events, which had occurred since the time NRG assumed ownership of the Huntley, Dunkirk and Oswego generating stations. The NOVs allege that a total of 7,231 events had occurred where the average opacity during a six-minute block of time had exceeded 20 percent. The NYDEC proposed a penalty associated with the NOVs at $900,000.

Nuclear Insurance NSP-Minnesota s public liability for claims resulting from any nuclear incident is limited to $9.5 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 $9.3 billion of exposure is funded by the Secondary Financial Protection Program, 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

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approximately $3 million for business interruption insurance and $10 million for property damage insurance if losses exceed accumulated reserve funds.

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.

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 certain private plaintiff class actions filed in the Superior Court of the State of California for the County of San Diego in San Diego, Calif. in November 2000. NRG has also been named in another suit filed in January 2001 in San Diego County and brought by three California water districts, as consumers of electricity, and in two suits filed in San Francisco County, one brought by the San Francisco City Attorney on behalf of the people of the State of California and one brought by Pier 23 Restaurant as a class action. Certain NRG affiliates in NRG s West Coast power partnership with Dynegy (Cabrillo I and II, Long Beach Generation and El Segundo Power) have been named as defendants in a state court action in Los Angeles County.

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. The plaintiffs in these six consolidated civil actions filed a master amended complaint reiterating the allegations contained in their complaints and alleging that 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 federal court. Now pending for hearing in September 2002 are the plaintiffs motion to remand the cases to state court and motions by the cross-defendants to dismiss the cases against them.

On March 20, 2002 the Attorney General of California filed at the FERC a complaint against specific named generators and marketers (including Dynegy Power Marketing, Inc., which serves as the scheduling coordinator for certain NRG affiliates) and against all other public utility sellers of energy and ancillary services into markets operated by the California Power Exchange and California Independent System Operator. The complaint alleges that defendants have violated the FERC s grant of market-based rate authority by failing to file their rates, as required by Section 205(c) of the Federal Power Act and numerous FERC orders requiring the filing of transaction-specific information about defendants sales and purchases at market-based rates. The plaintiff seeks injunctive relief to compel defendants prospective compliance with

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Section 205 of the Federal Power Act, as well as refunds on behalf of California purchasers to the extent prior transactions are found to exceed just and reasonable price levels.

On March 29, 2002, the Attorney General of California entered into an agreement to toll the statute of limitations for two threatened lawsuits against Xcel Energy, NRG, Dynegy, Inc., Dynegy Power Marketing, Inc., and certain NRG affiliates. The agreement applies to threatened actions similar to two sets of cases filed in April 2002 by the Attorney General of California; one set, filed in federal court against Mirant and Reliant under Section 7 of the federal Clayton Act and Section 17200 (Unfair Competition Act) of the California Business and Professions Code, alleges that those companies acquired an excessive number of California power plants, which allowed them to illegally exercise market power, limit competition and raise prices. The other set of cases was filed in California state court against Reliant, Mirant, Williams, Powerex and Coral Power, alleging that these power companies made thousands of illegally priced energy sales, in violation of California s Unfair Competition Act, and seeking penalties of up to $2,500 per violation. The defendants removed these state court actions to federal court and filed motions to dismiss, while the Attorney General filed motions to remand the cases to state court.

In addition, several class actions and other state court actions have been filed in 2002 requesting various relief and damages in relation to alleged violations regarding California power generation. All of these state court cases have been removed to various federal courts. The defendants are now seeking to have all these removed cases treated as related cases before Judge Walker in San Francisco, and defendants will then seek to have the federal Multidistrict Litigation Panel assign these cases to Judge Whaley, sitting in San Diego.

Fortistar Litigation and NEO Charges 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 entered into a binding, conditional settlement of the litigation, pending certain approvals and final agreement on the terms of the settlement. The settlement also encompasses litigation between the parties with respect to Minnesota Methane LLC.

During the second quarter of 2002, NRG expensed a pre-tax charge of $36 million related to its NEO Corporation landfill gas operations. The charge was related largely to asset impairments based on a revised project outlook developed in 2002. It also reflects the accrued impact of the 2002 dispute settlement with Fortistar, a partner with NEO in the Minnesota Methane LLC landfill gas operations.

Class Action Lawsuit On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of Xcel Energy common stock between Jan. 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, vice president and chief financial officer and former chairman, James J. Howard as defendants. Among other things, the complaint alleges 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 Xcel Energy s and its subsidiary, NRG s, credit agreements with lenders. Since the filing of the lawsuit on July 31, 2002, several additional lawsuits have been filed with similar allegations. The defendants deny any liability and maintain they have made disclosures fully compliant with applicable laws and reporting requirements.

Other Litigation In January 2002 the New York Attorney General and the New York Department of Environmental Control filed suit in the western district of New York against NRG and Niagara Mohawk Power Corporation, 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

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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 July 2001, Niagara Mohawk Power Corporation 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 Corporation requests a declaration by the Court that, pursuant to the terms of the Asset Sales Agreement (the 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 Corporation, and the parties have exchanged discovery requests.

Other Contingencies

California Power Market NRG s California generation assets include a 57.67-percent interest in Crockett Cogeneration (Crockett), a 39.5-percent interest in the Mt. Poso facility and a 50-percent interest in the West Coast Power partnership with Dynegy.

In March 2001, the California Power Exchange (PX) filed for bankruptcy under Chapter 11 of the Bankruptcy Code, and in April 2001, Pacific Gas & Electric Co. (PG&E) also filed for bankruptcy under Chapter 11. PG&E s filing delayed collection of receivables owed to the Crockett facility. In September 2001, PG&E filed a proposed plan of reorganization. Under the terms of the proposed plan, which is subject to challenge by interested parties, unsecured creditors such as NRG s California affiliates would receive 60 percent of the amounts owed upon approval of the plan. The remaining 40 percent would be paid in negotiable debt with terms from 10 to 30 years. The California PX s ability to repay its debt is dependent on the extent to which it receives payments from PG&E and Southern California Edison Co. On Dec. 21, 2001, the California bankruptcy court affirmed the Mt. Poso and Crockett power purchase agreements with PG&E and, in respect of the Crockett power purchase agreement, approved a twelve-month repayment schedule of all past due amounts totaling, $49.6 million, plus interest. The first payment of $6.2 million, including accrued interest, was received on Dec. 31, 2001. Through June 2002, Crockett received $24.8 million (excluding interest) from PG&E. The net outstanding amount due from PG&E at June 30, 2002 is $28.6 million.

NRG s share of the net amounts owed to West Coast Power by the California Independent System Operator (ISO) and PX totaled approximately $85.1 million as of Dec. 31, 2001, compared with $101.8 million at Dec. 31, 2000. These amounts reflect NRG s share of total amounts owed to West Coast Power less amounts that are currently treated as disputed revenues and are not recorded as accounts receivable in the financial statements of West Coast Power, and reserves taken against accounts receivable that have been recorded in the financial statements. The decrease is primarily attributed to cash collections from the California ISO during the fourth quarter of 2001. NRG s share of the net amounts owed to West Coast Power by the California ISO and PX totaled approximately $58.2 million as of June 30, 2002 compared to $85.1 million at Dec. 31, 2001.

The FERC has set for investigation the justness and reasonableness of the rates of wholesale sellers into the California ISO and PX markets and is making such rates subject to refund effective November 2001. The

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effect of the FERC s action is to make certain transactions of PSCo and NRG in California subject to refund. Xcel Energy believes that PSCo s refund exposure is immaterial. NRG has estimated potential refunds in the calculation of the reserves taken against its related accounts receivable.

Enron Xcel Energy, through its subsidiaries (excluding NRG as discussed later), has entered into agreements with Enron and its subsidiaries. However, pursuant to netting/set-off rights provisions of the industry standard agreements that Xcel Energy and Enron have utilized, Xcel Energy generally has a net liability to Enron. Therefore, we will owe Enron termination payments under these agreements for such services. The most significant of these agreements is between Enron and e prime. e prime will owe Enron a termination payment of approximately $12 million, representing the net of a $69-million receivable and an $81-million payable. As a result of the netting/set-off provisions, no provision for loss has been recorded in connection with these transactions agreements. Xcel Energy does not expect a material impact to the results of its operations as a direct result of the bankruptcy filing of Enron.

During 2001, NRG s power marketing operation recorded a net after-tax expense of $6.7 million related to Enron s bankruptcy. This amount includes a $14.2 million, after-tax charge to establish bad debt reserves, which was partially offset by a $7.5-million, after-tax gain on a credit swap agreement entered into as part of NRG s credit risk management program. NRG has fully provided for its exposure to Enron; however, as with any receivable, NRG will pursue collection of all amounts outstanding through the ordinary course of business.

In addition, an Enron subsidiary, NEPCO, is serving as the construction contractor for two of NRG s greenfield development projects, the Kendall and Nelson projects currently under construction in Illinois. Enron guaranteed NEPCO s obligations under the construction contracts. To date, the actual construction and engineering work on both projects has continued without disruption, and NRG expects the projects to achieve commercial operations on schedule. NRG believes overall construction costs will increase by no more than $50 million, which represents less than 5 percent of the expected construction costs.

FERC Investigation As discussed in Xcel Energy s Current Report on Form 8-K filed May 24, 2002, on May 8, 2002, the FERC ordered all sellers of wholesale electricity and/or ancillary services to the California Independent System Operator or Power Exchange, including Xcel Energy and NRG, to respond to data requests, including requests for admissions with respect to certain trading strategies in which the companies may have engaged. The investigation is in response to memoranda prepared by Enron Corporation that detail certain trading strategies engaged in 2000 and 2001. On May 22, 2002, Xcel Energy reported to the FERC that it had not engaged directly in any of the trading strategies identified in the May 8th inquiry. On May 22, 2002, NRG responded that it had not engaged in any trading activities outlined in the FERC request.

On May 13, 2002, Xcel Energy independently and not in direct response to any regulatory inquiry announced that PSCo had engaged in certain trading transactions, initiated by Reliant Resources, that had immaterial income effects in 1999 and 2000.

To supplement the May 8th request, on May 21, 2002, the FERC ordered 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, Xcel Energy reported to the FERC that it had not engaged in so-called round trip electricity trading identified in the May 21st inquiry.

Xcel Energy did report, as previously announced on May 13, 2002, that PSCo had engaged in a group of transactions in 1999 and 2000 with the trading arm of Reliant Resources in which PSCo bought a quantity of 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. Also, PSCo engaged in one trade with Reliant in which PSCo simultaneously bought and sold power at the same price without realizing any profit. The purpose of this nonprofit transaction was in consideration of future for-profit transactions. PSCo engaged in these transactions with Reliant for the proper

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commercial objective of making a profit. It did not enter into these transactions to inflate volumes or revenues.

Xcel Energy and PSCo have received subpoenas from the Commodity Futures Trading Commission for documents and other information concerning these so-called round trip trades and other trading in electricity and natural gas for the period Jan. 1, 1999 to the present involving Xcel Energy or any of its subsidiaries.

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

Tax Matters The IRS had 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. 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.

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 2001 are estimated to total approximately $240 million. Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2001, would reduce earnings by an estimated $197 million (after tax), or 57 cents per Xcel Energy share.

Seren At Dec. 31, 2001, Xcel Energy s investment in Seren was approximately $232 million. Seren had capitalized $190 million for plant in service and had incurred another $60 million for construction work in progress for these systems. Operations 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 is evaluating the strategic fit of Seren in its business portfolio and may make a decision later in 2002.

Loy Yang NRG owns a 25.37-percent interest in Loy Yang Power, which owns and operates the 2,000-megawatt Loy Yang A brown coal-fired thermal power station and the adjacent Loy Yang coal mine located in Victoria, Australia. Energy prices in the Victoria region of the National Electricity Market of Australia into which the Loy Yang facility sells its power have been significantly lower than NRG expected when it acquired its interest in the facility. Prices improved during 2001 resulting in a 14-percent revenue increase. Despite this improvement, a significant unplanned outage, beginning in late December 2001 and expected to last until April 2002, will result in a reduction in 2002 revenues and cash flows. Such reduction may cause the Loy Yang project company to fail its required coverage ratios under its loan agreements

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during the next 12 months, which would constitute an event of default. In the case of default, the project company s lenders would be allowed to accelerate the project company s indebtedness. The ultimate financial impact of the outage is subject to continuing investigation and is also subject to several events, including the receipt and timing of insurance proceeds, the cost and timing of repairs to the damaged unit and electricity market conditions. Project management is actively pursuing each of these options to mitigate the impact of the outage. However, in the event all factors are unfavorable, NRG may be required to either infuse more cash or write off all or a portion of its $250-million investment in this project as a result of such acceleration. In its current circumstances, Loy Yang Power is prohibited by its loan agreements from making equity distributions to the project owners.

Xcel Energy International At Dec. 31, 2001, Xcel Energy s investment in Argentina through Xcel Energy International was $102 million. Given the political and economic climate in Argentina, Xcel Energy continues to closely monitor the investment for asset impairment. Due to the declining value of the Argentine peso, a currency translation adjustment was recorded in the amount of $38 million as an adjustment to Other Comprehensive Income. At Dec. 31, 2001, management intended to hold and operate the investment and believes that no asset impairment exists. Xcel Energy is evaluating the strategic fit of Argentina in its business portfolio and may make a decision later in 2002.

PUHCA Equity Ratio Limit In accordance with an order of the SEC granting Xcel Energy authority to finance, Xcel Energy cannot currently issue any securities or guarantees if its common equity ratio is below 30 percent. On Aug. 2, 2002, Xcel Energy filed a proposal with the SEC, seeking authorization to engage in financing transactions at a time when Xcel Energy s ratio of common equity to total capitalization is less than 30 percent. The proposal provided that the common equity of Xcel Energy, as reflected on its most recent Form 10-K or Form 10-Q and as adjusted to reflect subsequent events that affect capitalization, be at least 24 percent of total capitalization. In addition, Xcel Energy proposed not to engage in any financing transactions after June 30, 2003, unless at such time Xcel Energy has an equity ratio of at least 30 percent. Xcel Energy expects that any reduction of its common equity ratio below 30 percent would be temporary, as discussed below.

Xcel Energy is evaluating the business of NRG and its other non-regulated businesses and is considering certain alternatives. Alternatives under consideration by Xcel Energy management will require approval of the board of directors and include the possible sale of selected generating assets of NRG and exiting other non-regulated businesses, which do not fit strategically with Xcel Energy. Xcel Energy may be required to record losses from such sales or divestitures as a result of future board actions prior to the period in which the asset sale occurs. Such losses may result in the common equity of Xcel Energy temporarily falling below 30 percent of its capitalization.

16. 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 $11 million in 2001 and $12 million in 2000. In total, NSP-Minnesota had paid approximately $296 million to the DOE through Dec. 31, 2001. 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

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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.

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 2001 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 $25 million at Dec. 31, 2001, as a regulatory asset.

Plant Decommissioning Decommissioning of NSP-Minnesota s nuclear facilities is planned for the years 2010-2022, 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 financial statements.

In June 2001, the FASB approved the issuance of 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 useful life, the recorded liability differs from the actual obligations paid, a gain or loss will be recognized at that time.

SFAS No. 143 will also affect our accrued plant removal costs for other generation, transmission and distribution facilities for our utility subsidiaries. We expect that these costs, which have yet to be estimated, will be reclassified from Accumulated Depreciation to Regulatory Liabilities based on the recoverability of these costs in rates. We plan to adopt SFAS No. 143, as required, on Jan. 1, 2003.

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. 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 and related nuclear plant depreciation capital recovery request in April 2000, using 1999 cost data. 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

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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, 2001, 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, 2001, NSP-Minnesota had recorded and recovered in rates cumulative decommissioning accruals of $623 million. The following table summarizes the funded status of NSP-Minnesota s decommissioning obligation at Dec. 31, 2001:

	2001
	(Thousands of dollars)
Estimated decommissioning cost obligation from most recently approved study (1999 dollars)	$ 958,266
Effect of escalating costs to 2001 dollars (at 4.35 percent per year)	85,183
Estimated decommissioning cost obligation in current dollars	1,043,449
Effect of escalating costs to payment date (at 4.35 percent per year)	850,825
Estimated future decommissioning costs (undiscounted)	1,894,274
Effect of discounting obligation (using risk-free interest rate)	(1,016,206)
Discounted decommissioning cost obligation	878,068
Assets held in external decommissioning trust	596,113
Discounted decommissioning obligation in excess of assets currently held in external trust	$ 281,955

Decommissioning expenses recognized include the following components:

	2001	2000
	(Thousands of dollars)	
Annual decommissioning cost accrual reported as depreciation expense:		
Externally funded	$ 51,433	$ 51,433
Internally funded (including interest costs)	(17,396)	(16,111)
Interest cost on externally funded decommissioning obligation	4,535	5,151
Earnings from external trust funds	(4,535)	(5,151)
Net decommissioning accruals recorded	$ 34,037	$ 35,322

Decommissioning and interest accruals are included with Accumulated Depreciation on the balance sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Nonoperating Income on the income statement.

Negative accruals for internally funded portions in 2000 and 2001 reflect the impacts of the 2000 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.

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17. Regulatory Assets and Liabilities

Our regulated businesses prepare their financial statements in accordance with the provisions of SFAS No. 71, as discussed in Note 1 to the 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 Ref.	Remaining Amortization Period	2001	2000
		(Thousands of dollars)		
AFDC recorded in plant(a)		Plant Lives	$149,591	$159,406
Conservation programs(a)(d)		Up to 5 Years	65,825	52,444
Losses on reacquired debt	1	Term of Related Debt	95,394	85,688
Environmental costs	15, 16	To be determined	20,169	19,372
Unrecovered gas costs(b)	1	1-2 Years	11,316	24,719
Deferred income tax adjustments	1	Mainly Plant Lives	17,799	0
Nuclear decommissioning costs(e)		Up to 8 Years	68,484	82,490
Employees postretirement benefits other than pension	10	11 Years	42,942	46,680
Employees postemployment benefits	2	2-3 Years	119	23,223
Renewable resource costs		To be determined	17,500	10,500
State commission accounting adjustments(a)		Plant Lives	7,578	7,614
Other		Various	5,725	12,125
Total regulatory assets			$502,442	$524,261
Investment tax credit deferrals			$117,257	$119,060
Unrealized gains from decommissioning investments	16		149,041	171,736
Pension costs-regulatory differences	10		215,687	139,178
Conservation programs(c)			0	40,679
Deferred income tax adjustments			0	12,416
Fuel costs, refunds and other			1,957	11,497
Total regulatory liabilities			$483,942	$494,566

(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 $22 million and $13 million for 2001 and 2000, respectively.

(c) Represents estimated refund for 1998 incentives; ultimately reversed in 2001.

(d) 2001 amount includes accrued conservation incentives expected to be approved for 2001 and 2000. Due to regulatory uncertainty, such incentives were not accrued in 2000.

(e) 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.

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18. Segment and Related Information

Xcel Energy has the following reportable segments: Electric Utility, Gas Utility and two of its nonregulated energy businesses, NRG and e prime. During February 2001, Xcel Energy reached an agreement to sell the majority of its investment in Yorkshire Power. As a result of this sales agreement, Xcel International (Yorkshire Power was Xcel International s most significant holding) is no longer a reportable segment. Prior periods have been restated for comparability.

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 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.

e prime trades and markets natural gas throughout 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 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 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	Gas Utility	NRG	e prime	All Other	Reconciling Eliminations	Consolidated Total
				(Thousands of dollars)			
2001							
Operating revenues from external customers(a)	$6,463,401	$2,051,199	$2,392,876	$19,607	$373,823	$	$11,300,906
Intersegment revenues	978	4,501	1,859		89,636	(94,544)	2,430
Equity in earnings (losses) of unconsolidated affiliates			210,854	1,376	7,081		219,311
Total revenues	$6,464,379	$2,055,700	$2,605,589	$20,983	$470,540	$(94,544)	$11,522,647

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	Electric Utility	Gas Utility	NRG	e prime	All Other	Reconciling Eliminations	Consolidated Total
	(Thousands of dollars)						
Depreciation and amortization	$ 617,320	$ 92,989	$ 192,781	$ 247	$ 26,151	$	$ 929,488
Financing costs, mainly interest expense	265,285	49,108	423,497	277	107,855	(52,055)	793,967
Income tax expense (credit)	351,181	41,077	27,535	5,150	(94,162)		330,781
Segment income (loss) from continuing operations	$ 535,182	$ 81,562	$ 233,340	$ 8,547	$ (65,426)	$ (40,390)	$ 752,815
Discontinued operations, net of tax			31,864				31,864
Extraordinary items, net of tax	11,821				(1,534)		10,287
Segment net income (loss)	$ 547,003	$ 81,562	$ 265,204	$ 8,547	$ (66,960)	$ (40,390)	$ 794,966
2000							
Operating revenues from external customers(a)	$ 5,704,683	$ 1,466,478	$ 1,829,964	$ 9,979	$ 189,122	$	$ 9,200,226
Intersegment revenues	1,179	5,761	2,256		78,419	(84,034)	3,581
Equity in earnings (losses) of unconsolidated affiliates			125,404	1,203	39,425		166,032
Total revenues	$ 5,705,862	$ 1,472,239	$ 1,957,624	$ 11,182	$ 306,966	$ (84,034)	$ 9,369,839
Depreciation and amortization	$ 574,018	$ 85,353	$ 112,688	$ 569	$ 9,051	$	$ 781,679
Financing costs, mainly interest expense	333,512	60,755	274,632	200	65,501	(59,780)	674,820
Income tax expense (credit)	261,942	36,962	81,964	(3,995)	(82,518)		294,355
Segment income (loss) from continuing operations	$ 340,634	$ 57,911	$ 161,464	$ (6,158)	$ (13,925)	$ (15,609)	$ 524,317
Discontinued operations, net of tax			21,471				21,471
Extraordinary items, net of tax	(18,960)						(18,960)
Segment net income (loss)	$ 321,674	$ 57,911	$ 182,935	$ (6,158)	$ (13,925)	$ (15,609)	$ 526,828

(a) All operating revenues are from external customers located in the United States, except $757 million and $290 million of NRG operating revenues in 2001 and 2000, respectively, which came from external customers outside of the United States. However, Xcel Energy International and NRG also have significant equity investments for nonregulated projects outside the United States. NRG s equity in earnings of unconsolidated affiliates, primarily independent power projects, includes $53.2 million in 2001 and $18.4 million in 2000 from nonregulated projects located outside of the United States. NRG s equity investments in projects outside of the United States were $519 million in 2001 and $566 million in 2000. All Other equity in earnings of unconsolidated affiliates includes $1 million in 2001 and $35.3 million in 2000 from outside of the United States, primarily related to Yorkshire Power. All Other equity investments and projects outside of the United States were $36.9 million in 2001 and $383 million in 2000. In addition, NRG s wholly owned foreign assets

($2.8 billion in 2001 and $796 million in 2000) contributed earnings of $47.5 million in 2001 and $29.1 million in 2000.

19. Subsequent Events Discontinued Operations

As of September 30, 2002, four projects (Bulo Bulo, Cspel, Entrade, and Crockett Cogeneration Project) were classified as held for sale pursuant to the requirements of SFAS No. 144. SFAS No. 144 requires that assets held for sale to be valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. NRG Energy recorded a write-down of approximately $17.1 million (pre-tax) in 2002 related to

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the four projects and reported the projects as discontinued operations in its quarterly report on Form 10-Q for the quarter ended Sept. 30, 2002. Accordingly, 2001 and 2000 consolidated statements of income have been reclassified to report the projects as discontinued operations in the accompanying financial statements.

Bulo Bulo In June 2002, NRG began negotiations for the sale of its 60-percent interest in Companie Electrica Central Bulo Bulo S.A. (Bulo Bulo), a Bolivian corporation, to its 40 percent partner, Pan American Energy LLC. As a result of entering into these negotiations in the second quarter of 2002, NRG classified Bulo Bulo as held for sale and recognized an after-tax loss of approximately $9.7 million (net of $0 taxes) as discontinued operations. The transaction is expected to reach financial close in fourth quarter 2002.

Crockett Cogeneration Project In September 2002, NRG announced that it had reached an agreement to sell its 57.7-percent interest in Crockett Cogeneration Project, a 240-megawatt, natural gas-fueled cogeneration plant near San Francisco, Calif., to an undisclosed buyer. Upon closing of the sale of Crockett, NRG expects to realize net cash proceeds of approximately $70 million and expects to reduce balance sheet debt and credit obligations by approximately $240 million. Crockett has been classified as held-for-sale and an estimated loss of approximately $7.4 million has been reported as a loss on discontinued operations during the third quarter of 2002 in connection with the decision to sell this interest.

Hungarian and Czech Assets In September 2002, NRG announced it had reached agreement to sell its Csepel power generating facilities, and its interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland. NRG expects to close the sale in the first quarter 2003. The transaction, which requires approval by competition authorities, is expected to close before year-end and is expected to result in a gain of approximately $20 million, net of transaction fees. This gain will not be recognized until closing occurs.

Located on Csepel Island in Budapest, Hungary, Csepel I is a 116-megawatt thermal plant, and Csepel II is a 389-megawatt gas turbine power generating station. Based in Prague, Entrade markets and trades electricity in Central and Eastern Europe.

The following is a summary of the components of discontinued operations (in thousands):

	Year Ended Dec. 31,	
	2001	2000
Operating Revenues	$407,956	$201,475
Operating & Other Expenses	370,150	169,494
Income before taxes	37,806	31,981
Income tax expense	5,942	10,510
Net income from discontinued operations	$ 31,864	$ 21,471

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In addition, assets and liabilities for these four projects now considered discontinued operations have been reclassified and reported in the accompanying financial statements as follows:

	Dec. 31	
	2001	2000
	(Thousands of dollars)	
Cash and cash equivalents	$ 63,954	$ 8,653
Restricted cash	18,833	4,899
Customer A/ R Net	82,275	70,843
Other current assets	17,127	2,147
Total current assets held for sale	$ 182,189	$ 86,542
Property, Plant and Equipment	546,360	$ 235,130
Other	38,310	41,417
Total non-current assets held for sale	$ 584,670	$ 276,547
Total current liabilities	$ (310,810)	$ (55,407)
Long-term debt	$ (228,098)	$ (245,497)
Minority interest and other	(51,191)	(15,373)
Total long-term liabilities	$ (279,289)	(260,870)
Net assets held for sale	$ 176,760	$ 46,812

20. Summarized Quarterly Financial Data (Unaudited)

	Quarter Ended			
	March 31, 2001	June 30, 2001(a)	Sept. 30, 2001	Dec. 31, 2001(a)
	(Thousands of dollars, except per share amounts)			
Revenue	3,216,353	2,781,345	2,981,639	2,543,310
Operating income(c)	476,770	440,671	637,585	330,206
Income from continuing operations	200,797	177,217	259,375	115,426
Income (loss) from discontinued operations	8,513	(9,360)	13,528	19,183
Income before extraordinary items	209,310	167,857	272,903	134,609
Extraordinary items				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:				
Basic	$ 0.58	$ 0.52	$ 0.75	$ 0.33
Diluted	$ 0.58	$ 0.52	$ 0.75	$ 0.32
Earnings per share discontinued operations:				
Basic & Diluted	$ 0.03	$ (0.03)	$ 0.04	$ 0.06
Earnings per share before extraordinary items:				
Basic	$ 0.61	$ 0.49	$ 0.79	$ 0.39

Diluted	$ 0.61	$ 0.49	$ 0.79	$ 0.38

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Quarter Ended			
	March 31, 2001	June 30, 2001(a)	Sept. 30, 2001	Dec. 31, 2001(a)
	(Thousands of dollars, except per share amounts)			
Earnings per share extraordinary items:				
Basic & Diluted	$0.00	$0.00	$0.00	$0.03
Earnings per share after extraordinary items:				
Basic	$0.61	$0.49	$0.79	$0.42
Diluted	$0.61	$0.49	$0.79	$0.41

	Quarter Ended			
	March 31, 2000	June 30, 2000	Sept. 30, 2000(b)	Dec. 31, 2000(b)
	(Thousands of dollars, except per share amounts)			
Revenue	$2,088,420	$2,075,771	$2,503,095	$2,702,553
Operating income(c)	350,103	417,473	385,498	352,085
Income from continuing operations	150,010	153,232	91,382	129,693
Income from discontinued operations	3,321	3,509	6,534	8,107
Income before extraordinary items	153,331	156,741	97,916	137,800
Extraordinary items	0	(13,658)	(5,302)	0
Net income	153,331	143,083	92,614	137,800
Earnings available for common shareholders	152,271	142,022	91,554	136,740
Earnings per share from continuing operations:				
Basic	$ 0.44	$ 0.45	$ 0.27	$ 0.37
Diluted	$ 0.44	$ 0.45	$ 0.27	$ 0.37
Earnings per share discontinued operations:				
Basic & Diluted	$ 0.01	$ 0.01	$ 0.02	$ 0.03
Earnings per share before extraordinary items:				
Basic	$ 0.45	$ 0.46	$ 0.29	$ 0.40
Diluted	$ 0.45	$ 0.46	$ 0.29	$ 0.40
Earnings per share extraordinary items:				
Basic & Diluted	$ 0.00	$ (0.04)	$ (0.02)	$ 0.00
Earnings per share after extraordinary items:				
Basic	$ 0.45	$ 0.42	$ 0.27	$ 0.40
Diluted	$ 0.45	$ 0.42	$ 0.27	$ 0.40

(a) 2001 results include special charges and unusual items in the second and fourth quarters, as discussed in Notes 2 and 17 to the 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

share, for a special charge related to postemployment benefits. Fourth quarter results were decreased by $39 million, or 7 cents per share, for a special charge related to employee restaffing costs.

(b) 2000 results include special charges related to merger costs and strategic alignment, as discussed in Note 2 to the Financial Statements. Third quarter results were reduced by approximately $201 million, or 43 cents per share. Fourth quarter results were reduced by approximately $40 million, or 9 cents per share.

(c) Certain items in the 2000 and 2001 quarterly income statements have been reclassified to conform to the 2001 annual presentation. These reclassifications, primarily related to items formerly presented as nonoperating revenues and expenses, had no effect on net income or earnings per share.

21. Subsequent Events NRG Going Concern Issues
Credit Ratings

In December 2001, Moody s placed NRG s long-term senior unsecured debt rating on review for downgrade. In July 2002, NRG s credit rating was downgraded below investment grade. On July 26, 2002, Standard & Poor s Ratings Services announced it had lowered NRG s corporate credit rating to BB. The secured NRG Energy Northeast Generating LLC bonds and the NRG Energy South Central Generating LLC bonds were also lowered to BB. The senior unsecured bonds of NRG were lowered to B-plus. All of the NRG debt issues and the corporate credit rating were placed on credit watch with negative implications. On July 29, 2002, Moody s Investors Service lowered NRG s senior unsecured debt rating from Baa3 to B1 and assigned a Senior Implied rating of Ba3 to NRG. On Aug. 7, 2002, Standard & Poor s Ratings Services lowered the corporate credit rating of NRG to B-plus from double BB, stating the rating now reflects NRG s stand-alone credit quality. On Sept. 5, 2002, Moody s Investors Service lowered NRG s senior unsecured debt rating from B1 to Caa1 and assigned a Senior Implied rating of B3 to NRG. The secured NRG Energy Northeast Generating LLC bonds and the NRG Energy South Central Generating LLC bonds were also lowered to B3. Finally, the secured LSP Energy Limited Partnership bonds were lowered to B1. Other debt issuances were placed under review for possible downgrade. NRG s rating remains on Credit Watch with negative implications.

The downgrade in NRG s credit ratings has resulted in increased collateral requirements in 2002, as discussed later.

Liquidity Issues

In 2002, NRG has been experiencing some volatility in its funding sources due largely to the credit issues, as described previously.

NRG s operating cash flows have been impacted by lower operating margins as a result of low power pool 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. With a successful financial improvement plan for NRG, management expects to improve operating cash flow by lowering financing costs (due to reduction in NRG s debt levels from application of asset sale proceeds) and lowering operating costs (due to cost reductions from combining portions of NRG s business activities with Xcel Energy s). However, asset sales may have a partially mitigating effect on operating cash flows as the projects are sold. In addition, the credit contingencies being faced by NRG may limit the ability to distribute project cash flows and use such funds to service NRG corporate debt.

Since December 2001, NRG s access to short-term capital has deteriorated significantly due to tightening credit standards for the independent power sector as a whole. The downgrade of NRG s credit ratings below

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

investment grade in July 2002 has resulted in cash collateral requirements as discussed later. In addition, lower credit ratings will increase the relative cost of NRG s capital financing compared to historical levels.

Collateral Requirements. NRG has significant amounts debt and other obligations that currently require that they be supported with letters of credit or cash collateral within 5 to 30 days of a ratings downgrade by Moody s or Standard & Poor s.

As a result of the recent downgrades, NRG estimates that it will be required to post collateral ranging from $1.1 billion to $1.3 billion. Of the collateral to be posted, approximately $215 million is required to fund debt service reserve and other guarantees at the project level, $75 million is required to fund trading operations, $10 million is required to fund remaining equity commitments to complete construction of the Brazos Valley plant in Texas; and between $825 million and $975 million is required to fund equity guarantees associated with the $2 billion construction and acquisition revolver depending on various options being pursued. NRG is working with its lenders to obtain waivers to delay the posting of this collateral until the fourth quarter of 2002. To date NRG has been successful in working with its lenders concerning these issues. NRG obtained waivers to delay the posting of the remaining collateral until Sept. 13, 2002.

NRG may be unable to post the required collateral by Sept. 13, 2002, or delay the posting requirement by obtaining waivers. The failure to post the required collateral will result in defaults unless waivers are extended. If NRG is unable to obtain waivers or modifications of these collateral requirements and the underlying obligations are accelerated, NRG would need to refinance or restructure its obligations and, if unsuccessful in these efforts, to consider all other options including a restructuring under the bankruptcy laws, as discussed later. Pending the resolution of NRG credit and liquidity contingencies and the timing of possible asset sales, $4.0 billion of NRG s long-term debt obligations at Dec. 31, 2001 may be callable by lenders under the terms and conditions of the agreements.

In addition to the collateral requirements, NRG must continue to meet its ongoing operational and construction funding requirements. Since NRG s downgrade, its cost of borrowing and access to the capital markets has deteriorated significantly. As a consequence, NRG is developing an updated business plan and evaluating its options with respect to the continuation and funding of its ongoing construction projects. NRG is also continuously re-evaluating its asset sale program to maximize its net proceeds, given current market conditions. NRG believes that its current funding requirements under its already reduced construction program may be unsustainable given the difficulties involved in raising cash through the capital markets and the uncertainties involved in obtaining additional equity funding from Xcel Energy. NRG and Xcel Energy have retained financial advisors to help work through these liquidity issues in an effort to avoid defaults on NRG debt and other obligations. Because only a short amount of time has passed since NRG was downgraded, NRG is unsure as to the resolution of all issues. NRG s initial priorities are obtaining waivers or delay of its collateral calls and avoiding the acceleration of its debt obligations. Once these collateral issues are resolved and additional decisions relating to asset sales are made, NRG plans to finalize a revised business plan in respect of ongoing operations of NRG.

Assuming the waiver of cash collateral requirements, and with aggressive cost management, near term asset sales, selective cost deferrals and the application of other viable liquidity stabilization measures, NRG expects to have cash available for operations until Oct. 31, 2002. This forecast does not assume further investment by Xcel Energy or modification of NRG s current debt obligations.

At the present time and based on conversations with various lenders, Xcel Energy management does not believe the appropriate course of action would be filing by NRG to seek relief under the bankruptcy laws. Rather it believes that the implementation of its plans for NRG, coupled with waivers from lenders is the appropriate course of action to restore NRG s financial strength. In the event that NRG is unable to work through the issues as described above and is unable to obtain adequate financing on terms acceptable to NRG, there would be substantial doubt as to NRG s ability to continue as a going concern. NRG s inability to obtain timely waivers and avoid defaults on their credit obligations could lead to involuntary bankruptcy proceedings at NRG.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Obligations and Commitments. The following is a table outlining the current status of the projects that NRG has under construction and an estimate of the expected costs to be incurred through 2004 for such projects. As previously disclosed, NRG is reevaluating its commitments under these agreements and over the remainder of 2002 will be making determinations as to which projects will be disposed of or abandoned.

Project (Unaudited)	July - Dec. 2002 Forecasted Expenditures (in millions)	2003 Forecasted Capital Expenditures (in millions)	2004 Forecasted Capital Expenditures (in millions)	Status
Bayou Cove	$ 15			3 of 4 Units Complete
Brazos Valley	$ 48	$ 32		In Construction
Itiquira	$ 26			In Construction
Flinders	$ 24			In Construction
Nelson	$132	$154		In Construction
Pike	$ 76			Pending Sale
Rockford II	$ 11			Substantially Completed
Meriden	$ 50	$ 36	$ 35	Delayed
Kendall	$ 35			Substantially Completed
Other Construction and Turbine Expenditures	$127	$143	$ 85	
Total	$544	$365	$120	

LSP Pike Energy, LLC In response to its credit rating downgrade in July 2002, NRG has been evaluating its ability and willingness to meet capital requirements for projects under construction given potentially limited financing capabilities.

On Aug. 4, 2002, The Shaw Group and NRG tentatively entered into an agreement for the sale of NRG s interest in LSP Pike Energy, LLC (Pike) in exchange for $43 million of cash and the forgiveness of approximately $75 million owed to The Shaw Group as contractor for Pike. In addition to the cash received, the sale of the Pike project is expected to improve NRG s liquidity position by reducing its ongoing construction funding needs by approximately $142 million in 2002 through 2003.

The Pike project is a 1,200-megawatt combined cycle gas turbine plant currently under construction in Mississippi. Construction is approximately one-third completed. The sale of the Pike project to Shaw would include all assets, free of all liens, and would require the consent of all construction lenders and General Electric, which holds a lien against the turbines. In addition, the Xcel Energy board of directors must approve the transaction. None of these required approvals has yet been received.

NRG s construction lenders have been unwilling to provide the consent required under the letter of intent. However, as they have not rejected the offer outright, NRG is working with lenders under the terms of the letter of intent in order to secure lender approval.

Assuming all required consents and approvals are received, completion of the sale to Shaw would result in an estimated pretax loss of approximately $500 million. In addition, NRG is responsible for the repayment of related debt of $294 million and a turbine payment of approximately $50 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NRG has a variety of contractual obligations and other commercial commitments that represent prospective cash requirements in addition to its capital expenditure programs. The following is a summarized table of contractual obligations.

	Payments due by period as of June 30, 2002 (In thousands)				
Contractual Cash Obligations (Unaudited)	**Total**	**Short Term**	**1-3 Years**	**4-5 Years**	**After 5 years**
Long term debt	$ 8,615,504	$ 459,158	$274,914	$2,052,963	$5,828,469
Capital lease obligations	557,256	25,031	45,010	45,010	442,205
Operating leases	87,779	10,742	19,111	16,311	41,615
Short term debt	1,020,409	1,020,409			
Total contractual cash obligations	$10,280,948	$1,515,340	$339,035	$2,114,284	$6,312,289

	Amount of commitment expiration per period As of June 30, 2002 (In thousands)				
Other Commercial Commitments (Unaudited)	**Total Amounts Committed**	**Short Term**	**1-3 Years**	**4-5 Years**	**After 5 years**
Lines of credit	$2,075,100	$1,000,000	$	$	$1,075,100
Stand by letters of credit	179,759	179,759			
Guarantees	805,406	210,390	89,803	105,593	399,620
Total commercial commitments	$3,060,265	$1,390,149	$89,803	$105,593	$1,474,720

FirstEnergy Assets NRG signed purchase agreements in 2001 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 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 require FirstEnergy to protect the City of Cleveland in the event the generating assets are taken out of service. On July 16, 2002, the FERC clarified that the condition requires NRG to provide notice to the City of Cleveland and FirstEnergy if the generating assets are taken out of service and that other obligations remain with FirstEnergy.

On Aug. 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. FirstEnergy also notified NRG that it is reserving the right to pursue legal action against NRG and Xcel Energy for damages, based on the alleged anticipatory breach. NRG continues to evaluate the implications of the cancellation and its potential exposure.

Project Debt Service 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 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 June 30, 2002, six of NRG s subsidiaries and project affiliates are restricted from making cash payments to NRG. Loy Yang, Killingholme, Energy Center Kladno, LSP Energy (Batesville) and Louisiana Generating do not currently meet the minimum debt service coverage ratios required for these projects to make payments to NRG; Crockett Cogeneration is limited in its ability to make distributions to NRG and its other partners.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NRG believes the situations at Louisiana Generating, Energy Center Kladno, Batesville and Killingholme do not create an event of default and do not permit the lenders to accelerate the project financings. The forced outage of one 500-megawatt unit at Loy Yang, combined with current market prices, may lead to an event of default and the possible acceleration of the Loy Yang project debt in the fourth quarter of 2002. The unit has been repaired and, if insurance claims are paid and forecasted revenues and costs are achieved, default is expected to be avoided. If an event of default were to occur at one or more of the projects and any accelerated financings were not paid, the project lenders could foreclose on the projects in question and NRG could lose its equity investment in the projects. NRG s equity investment in these six projects was approximately $1.1 billion at June 30, 2002.

Other Covenants and Compliance The bankruptcy of Pacific Gas & Electric (PG&E) creates the potential for a covenant default that would result in the acceleration of the debt at Crockett if not resolved with the lenders. Management has engaged in active discussions with the lenders of Crockett since PG&E filed for bankruptcy in April 2001; additionally, Crockett is being paid each month by PG&E since the bankruptcy filing. PG&E and the Bankruptcy Court have affirmed the long-term power purchase agreement and PG&E is paying down the outstanding receivable over a 12-month period ending Dec. 1, 2002. Thus NRG believes that an acceleration of the Crockett debt is unlikely. However, as of Dec. 31, 2001, NRG has reflected the entire balance of the Crockett debt as a current obligation of $234.5 million.

In May 2002, NRG s indirect wholly owned subsidiary, LSP-Kendall Energy, LLC received a notice of default from Societe Generale, the administrative agent under LSP-Kendall s Credit and Reimbursement Agreement dated Nov. 12, 1999. The notice asserted that an event of default had occurred under the Credit and Reimbursement Agreement as a result of liens filed against the Kendall project by various subcontractors. In consideration of NRG s indemnification of LSP-Kendall, the administrative agent and the lenders to the Kendall project from any claims or damages relating to these liens or any dispute or action involving the project s EPC contractor pursuant to an Indemnity Agreement dated as of June 28, 2002, the administrative agent, with the consent of the required lenders under the Credit and Reimbursement Agreement, withdrew the notice of default and waived any default or event of default described therein.

2002 Financing Activities During the second quarter of 2002, NRG s $125-million syndicated letter of credit facility was amended to incorporate the same covenant revisions and other amendments that had previously been made to the terms and conditions of NRG s $1-billion revolving credit facility, including the addition of an interest coverage ratio covenant.

In March 2002, NRG s $500 million recourse revolving credit facility matured and was replaced with a $1.0 billion 364-day revolving line of credit, which terminates on March 7, 2003. The facility is unsecured and provides for borrowings of Base Rate Loans and Eurocurrency Loans . The Base Rate Loans bear interest at the greater of the Administrative Agent s prime rate or the sum of the prevailing per annum rates for overnight funds plus 0.5 percent per annum, plus an additional margin which varies from 0.375 percent to 0.50 percent based upon NRG s utilization of the facility and its then-current senior debt credit rating. The Eurocurrency loans bear interest at an adjusted rate based on LIBOR plus an adjustment percentage, which varies depending on NRG s senior debt credit rating and the amount outstanding under the facility. The credit agreement for this facility was amended in April 2002 to revise the interest coverage ratio covenant. As amended, the covenant requires NRG to maintain a minimum interest coverage ratio of 1.75 to 1, as determined at the end of each fiscal quarter. The facility contains additional covenants that, among other things, restrict the incurrence of liens and require NRG to maintain a net worth of at least $1.5 billion plus 25 percent of NRG s consolidated net income from Jan. 1, 2002 through the determination date. In addition, NRG must maintain a debt to capitalization ratio of not more than 0.68 to 1.00 as defined in the credit agreement. The failure to comply with any of these covenants would be an Event of Default under the terms of the credit agreement. Based on current forecasts, NRG believes that, unless the covenant is waived, it is likely that it will breach the minimum interest coverage ratio when the Sept. 30, 2002 calculation is performed. At June 30, 2002, NRG had a $1.0 billion outstanding balance under this credit facility. As of June 30, 2002, the weighted average interest rate on such outstanding advances was 3.38 percent per year.

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As of Dec. 31, 2001, NRG, through its wholly owned subsidiary, NRG Energy South Central Generating LLC, had outstanding approximately $40 million under a project level, non-recourse revolving credit agreement scheduled to mature in March 2002. In March 2002, the facility was renewed for an additional 90 days, with substantially similar terms and conditions. In June 2002, this facility was paid off and was not renewed.

In February 2002, NRG issued a $300 million subordinated convertible note to its majority shareholder, Xcel Energy, to evidence a loan from Xcel Energy to NRG in the amount of $300 million. The $300 million subordinated convertible note bore interest at a per annum rate equal to 30-day LIBOR plus 0.90 percent. Payments on unpaid principal, together with interest, were due quarterly in arrears, NRG did not make any payments of principal or interest on the note. In April and May 2002, NRG issued an additional $300 million of subordinated convertible notes to Xcel Energy, to evidence further loans from Xcel Energy to NRG. As of June 30, 2002, NRG has received $500 million under these loans. In June 2002, Xcel Energy cancelled these notes effectively converting them, including accrued interest into permanent equity.

In June 2002, NRG Peaker Finance Company 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 bear interest at a floating rate equal to three-months USD-LIBOR BBA plus 1.07 percent. Interest on the bonds is payable on March 10, June 10, September 10 and December 10 of each year, commencing on Sept. 10, 2002. Scheduled principal payments of $5.6 million, $8.0 million, $10.5 million, $4.3 million, $6.8 million, $11.2 million and $278.6 million are due on Dec. 10 of 2002, 2003, 2004, 2005, 2006, 2007 and thereafter through June 2019, respectively. The final scheduled repayment of principal will be made on June 10, 2019. The bonds may be redeemed at any time prior to maturity at a price that, in certain circumstances, will include a redemption premium. The initial bond proceeds of $250 million were used to make loans to affiliates which own natural-gas fired peaker electric generating projects located in either Louisiana or Illinois. The project owners used the proceeds of the loans to (1) reimburse NRG for construction and/or acquisition costs for the peaker projects previously paid by NRG, (2) pay to XL Capital Assurance (XLCA) the premium for the Bond Policy, (3) provide funds to NRG Peaker to collateralize a portion of NRG s contingent guaranty obligations and (4) pay transaction costs incurred in connection with the offering of the bonds (including reimbursement of NRG for the portion of such costs previously paid by NRG). The Bond Policy is a financial guaranty insurance policy that unconditionally and irrevocably guaranties payment of scheduled principal and interest payments on the Bonds. The Bond Policy does not, however, guaranty the payment of principal of or interest on the bonds prior to the applicable scheduled payment dates, unless XLCA elects to make such payments. The bonds are secured by a pledge of membership interests in NRG Peaker and a security interest in all of its assets, which initially consist of notes evidencing loans to the affiliate project owners. The project owners jointly and severally guaranty 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.

NRG Peaker has also entered into an interest rate swap agreement pursuant to which it agreed to make fixed rate interest payments and receive floating rate interest payments. The interest rate swap counter-party will have a security interest in the collateral for the bonds and the collateral for the project owner guaranties. Net payments to be made by NRG Peaker under the interest rate swap agreement will be guaranteed pursuant to a separate financial guaranty insurance policy, the issuer of which will have a security interest in the collateral for the bonds and the collateral for the project owner guaranties.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In July 2002, NRG Energy Center, an indirect wholly owned subsidiary of NRG, entered into an agreement allowing it to issue senior secured promissory notes in the aggregate principal amount of up to $150 million. In July 2002, under this agreement, NRG Energy Center, Inc. issued $75 million of bonds in a private placement. Two series of notes were issued in July 2002, the $55 million Series A-Notes dated July 3, 2002, which matures on Aug. 1, 2017 and bears an interest rate of 7.25 percent per annum and the $20 million Series B-Notes dated July 3, 2002, which matures on Aug. 1, 2017 and bears an interest rate of 7.12 percent per annum. NRG Thermal Corporation, a wholly owned subsidiary of NRG, which owns 100 percent of NRG Energy Center, pledged its interests in all of its district heating and cooling investments throughout the United States as collateral.

Financial Improvement Plan

In response to tightening credit standards experienced by NRG and the independent power production sector, on Feb. 17, 2002, Xcel Energy announced a financial improvement plan for NRG. The announced plan included an initial step of acquiring 100 percent of NRG through a tender offer to exchange all of the outstanding shares of NRG common stock with Xcel Energy common shares. In addition, the 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 NRG functions with Xcel Energy s system and organization.

Xcel Energy Support On June 3, 2002, Xcel Energy completed its exchange offer for the 26 percent of NRG s shares that had been previously publicly held. Xcel Energy offered NRG shareholders 0.50 shares of Xcel Energy common stock for each outstanding share of NRG common stock. As part of its exchange offer, Xcel Energy committed to take aggressive steps to strengthen NRG s balance sheet and eliminate overhead costs associated with running NRG as an independent company. Through June 30, 2002, Xcel Energy provided NRG with $500 million of cash infusions. Under PUHCA limitations, as of June 30, 2002, Xcel Energy could invest an additional $400 million into NRG. In May 2002, Xcel Energy and NRG entered into a support and capital subscription agreement pursuant to which Xcel Energy agreed, under certain circumstances, to provide up to $300 million to NRG. Xcel Energy has not, to date, provided funds to NRG under this agreement. Xcel Energy currently is evaluating the circumstances under which it would make any further investment in NRG.

Asset Marketing In the first quarter of 2002, management identified NRG assets and groups of assets to be marketed for sale. The assets are being marketed in four regional bundles: Latin America, the United Kingdom, Continental Europe and Asia-Pacific. Select North American assets, including those in the South Central United States, have also been identified for potential sale.

In the second quarter of 2002, invitations were sent to prospective bidders on such assets, with indicative bids due during June 2002. Xcel Energy management reviewed the results of the indicative bids received with the Xcel Energy board of directors and discussed the process by which assets would be considered, recommended, and approved for sale. The board determined at their August 2002 meeting that NRG s Board of Directors approval was necessary for material asset sales. NRG s Board of Directors is comprised of Xcel Energy senior management.

The remaining asset-marketing timetable for 2002 and 2003 is generally as follows:

- Final bids were received in August 2002;
- Negotiation of sale and purchase agreements is expected in September 2002; and

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial close is expected to be completed in September-December 2002, with financial close of some projects in the first half of 2003.

Several projects have an accelerated sales timetable. At the NRG June 2002 board meeting, one material NRG asset sale (Bulo Bulo) was approved. One additional project, which was not a material asset sale (Collinsville), was classified as held for sale in the second quarter of 2002. In addition, it is expected that several other sales of small NRG assets will be completed during the third quarter of 2002.

Indicative bids received and discussed with the Xcel Energy board in June 2002 for NRG s international projects, if ultimately proceeding to a sale at the bid price, would generate net proceeds of approximately $800 million to $1.3 billion of cash, compared with a book value (of equity investments in such projects) of approximately $1.5 billion resulting in material losses. While bids for certain NRG domestic projects were not presented in detail to the Xcel Energy Board at their June meeting, management anticipates that bids on domestic projects could generate an additional $500 million to $900 million of cash from sale proceeds. Material losses could also result from the sale of domestic projects. Proceeds from asset sales are expected to be used to pay down debt at NRG.

Because it is not known at this time which sales of projects the NRG Board of Directors will approve, nearly all NRG assets being marketed are not currently considered held for sale. For projects ultimately determined to be held for sale, any excess of carrying value of the project assets over fair value would need to be recognized as a loss at the time the board commits to a plan to sell.

In assessing any potential impairment issues associated with NRG assets being marketed for sale, NRG considered these assets to be held for use until final approval of the NRG Board of Directors is completed for the respective NRG asset sales.

Differences between indicative bids and the carrying value of the respective NRG assets being marketed can be attributed to the economic downturn in the independent power market as well as other recent negative developments in the energy industry in general. Management does not believe these bids are indicative of the fair value of the NRG assets under a held for use model. Since the assets are considered held for use, NRG has reviewed the carrying value of the assets being marketed for sale pursuant to the guidance in SFAS No. 144. That model compares expected undiscounted cash flows from operations of the assets to their carrying values. NRG concluded that no impairment losses should be recognized pursuant to SFAS No. 144 at June 30, 2002.

Capital Spending NRG has reviewed its construction program and significantly revised its capital expenditure forecast. The new forecast reflects a reduction in NRG construction spending of approximately $1.0 billion in 2003 and $1.3 billion in 2004 (See Note 15). In addition, NRG s acquisition expenditures are also expected to be reduced. The Conectiv acquisition originally scheduled for 2002 has been canceled. The FirstEnergy acquisition planned for 2002 has been canceled by FirstEnergy due to the alleged anticipatory breach of the related purchase agreement of NRG.

Other Activities Management changes have occurred at NRG. Xcel Energy and NRG have begun to combine portions of NRG s energy marketing and power plant management functions with corresponding Xcel Energy functions. In addition, NRG s corporate and administrative support functions are also being combined into comparable areas of Xcel Energy.

In the second quarter of 2002, NRG expensed a pretax charge of $20 million, or 4 cents per share, for severance costs associated with employees who had been terminated as of June 30, 2002. Additional charges are expected to be expensed in the future, as further actions are taken, but are not determinable at this time.

Xcel Energy Impacts

Xcel Energy does not believe that the ultimate resolution of NRG s going concern uncertainty will affect Xcel Energy s ability to continue as a going concern. Xcel Energy is not dependent on cash flows from NRG,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 operations and current 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 has access to additional debt and equity financing. On Nov. 8, 2002, Xcel Energy entered into a Securities Purchase Agreement with certain investors. Proceeds from this agreement were used to repay Xcel Energy s line of credit which expired in November of 2002.

22. Subsequent Events Third Quarter 2002 NRG Asset Impairments and NRG Restructuring Plan (Unaudited)

As a result of events occurring subsequent to June 30, 2002 related to NRG s credit ratings, defaults on certain debt securities, cash collateral requirements, and liquidity constraints, NRG conducted impairment reviews of a number of NRG assets as of September 30, 2002. These reviews resulted in NRG recording pretax impairment charges against the carrying value of certain long-lived assets and investments in the amount of approximately $2.9 billion in the third quarter of 2002.

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 anticipates that NRG will 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. Management concluded that the forecasted free cash flow available to NRG after servicing project-level obligations will 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 on November 4, 2002 to various lenders, bondholders and other creditor groups (collectively, NRG s Creditors) of NRG and its subsidiaries. The restructuring plan is expected to serve as a basis for negotiations with NRG s Creditors in a financially-restructured NRG and, among other things, proposes (i) holders of secured (project-level) debt would either (a) have their debt reinstated with agreed modifications or (b) receive the collateral securing such debt and a claim or claims to the extent such debt is under-secured; (ii) holders of unsecured debt, holders of secured recourse claims against NRG, and holders of other general unsecured claims against NRG would receive a pro rata share of (a) an aggregate of $500 million of junior secured debt of reorganized NRG and (b) 95% of the common equity of reorganized NRG; and (iii) holders of project-level general unsecured claims that are non-recourse to NRG would receive a pro rata share of the remaining 5% of the common equity of a reorganized NRG.

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(Thousands of Dollars, Except Per Share Data)

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
	2002	**2001**	**2002**	**2001**
Operating revenues:				
Electric utility	$ 1,556,942	$1,818,812	$ 4,117,497	$5,010,201
Gas utility	138,268	216,589	937,814	1,577,159
Electric and gas trading margin	2,127	9,341	4,472	91,333
Nonregulated and other	810,782	825,876	2,107,849	2,102,118
Equity earnings from investments in affiliates	27,970	111,021	73,139	198,526
Total operating revenues	2,536,089	2,981,639	7,240,771	8,979,337
Operating expenses:				
Electric fuel and purchased power utility	618,442	947,914	1,650,961	2,572,456
Cost of gas sold and transported utility	58,115	135,734	559,347	1,199,888
Cost of sales nonregulated and other	454,505	379,636	1,137,133	1,132,376
Other operating and maintenance expenses utility	352,863	382,299	1,088,337	1,124,971
Other operating and maintenance expenses nonregulated	197,369	200,778	571,862	463,389
Depreciation and amortization	270,899	243,797	792,118	671,818
Taxes (other than income taxes)	87,538	53,894	255,143	236,395
Special charges (see Note 2)	2,908,347		2,978,828	23,018
Writedowns and disposal losses from investments (see Notes 2 and 3)	128,967		133,135	
Total operating expenses	5,077,045	2,344,052	9,166,864	7,424,311
Operating income (loss)	(2,540,956)	637,587	(1,926,093)	1,555,026
Interest and other nonoperating income net of other expenses	5,394	19,926	38,679	46,273
Interest charges and financing costs:				
Interest charges net of amounts capitalized	236,141	203,653	640,925	555,430
Distributions on redeemable preferred securities of subsidiary trusts	9,586	9,700	28,758	29,100
Total interest charges and financing costs	245,727	213,353	669,683	584,530
Income (loss) from continuing operations before income taxes and minority interest	(2,781,289)	444,160	(2,557,097)	1,016,769
Income taxes (benefit)	(687,955)	148,131	(616,934)	324,573
Minority interest (income) expense	(26,129)	37,210	(39,184)	57,108
Income (loss) from continuing operations	(2,067,205)	258,819	(1,900,979)	635,088
Income (loss) from discontinued operations, net of tax (see Note 3)	(6,755)	14,084	17,825	14,982
Net income (loss)	(2,073,960)	272,903	(1,883,154)	650,070
Dividend requirements on preferred stock	1,060	1,060	3,180	3,180

Earnings (loss) available for common shareholders	$(2,075,020)	$ 271,843	$(1,886,334)	$ 646,890
Weighted average common shares outstanding (in thousands):				
Basic	397,405	343,770	376,565	342,378
Diluted	397,405	344,385	376,565	343,188
Earnings per share basic Income (loss) from continuing operations	$ (5.20)	$ 0.75	$ (5.06)	$ 1.85
Discontinued Operations	(0.02)	0.04	0.05	0.04
Earnings per share basic	$ (5.22)	$ 0.79	$ (5.01)	$ 1.89
Earnings per share diluted Income (loss) from continuing operations	$ (5.20)	$ 0.75	$ (5.06)	$ 1.84
Discontinued Operations	(0.02)	0.04	0.05	0.04
Earnings per share diluted	$ (5.22)	$ 0.79	$ (5.01)	$ 1.88

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(Thousands of Dollars)

	Nine Months Ended Sept. 30	
	2002	**2001**
Operating activities:		
Net (loss) income	$(1,883,154)	$ 650,070
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	800,648	715,493
Nuclear fuel amortization	37,208	31,843
Deferred income taxes	(849,327)	(34,193)
Amortization of investment tax credits	(10,285)	(9,684)
Allowance for equity funds used during construction	(5,125)	(6,373)
Undistributed equity in earnings of unconsolidated affiliates	(14,544)	(170,900)
Write-downs and losses from investments and disposal of discontinued operations	150,234	
Non-cash special charges primarily asset impairment write-downs	2,961,454	
Gain on sale of property	(6,785)	
Unrealized (gain) loss on derivative financial instruments	15,106	13,942
Change in accounts receivable	(32,686)	155,090
Change in inventories	32,981	(123,826)
Change in other current assets	146,473	354,756
Change in accounts payable	81,847	(495,896)
Change in other current liabilities	150,831	258,220
Change in other assets and liabilities	(75,943)	(994)
Net cash provided by operating activities	1,498,933	1,337,548
Investing activities:		
Nonregulated capital expenditures and asset acquisitions	(1,443,999)	(3,901,094)
Utility capital/construction expenditures	(696,092)	(753,572)
Proceeds from sale of property	40,465	
Allowance for equity funds used during construction	5,125	6,373
Investments in external decommissioning fund	(175,356)	(46,865)
Equity investments, loans, deposits and sales of nonregulated projects	(129,464)	82,194
Collection of loans made to nonregulated projects	21,081	3,821
Other investments net	76,086	(14,205)
Net cash used in investing activities	(2,302,154)	(4,623,348)
Financing activities:		
Short-term borrowings net	(172,047)	737,880
Proceeds from issuance of long-term debt	2,318,152	2,854,213
Repayment of long-term debt, including reacquisition premiums	(510,899)	(422,936)
Proceeds from issuance of common stock	570,242	108,609
Proceeds from NRG stock offering		474,348
Dividends paid	(420,560)	(388,491)

Net cash provided by financing activities	1,784,888	3,363,623
Effect of exchange rates on cash and cash equivalents	5,979	8,173
Net increase in cash and cash equivalents	987,646	85,996
Cash and cash equivalents at beginning of year	277,356	216,491
Cash and cash equivalents at end of period	$ 1,265,002	$ 302,487

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(Thousands of Dollars)

	Sept. 30, 2002	Dec. 31, 2001
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,265,002	$ 277,356
Restricted cash	208,277	143,009
Accounts receivable net of allowance for bad debts of $48,142 and $46,815, respectively	1,049,330	1,075,686
Accrued unbilled revenues	359,937	495,994
Materials and supplies inventories at average cost	333,719	323,505
Fuel inventory at average cost	196,328	250,043
Gas inventories replacement cost in excess of (below) LIFO: $(41,165) and $11,331, respectively	140,101	126,563
Recoverable purchased gas and electric energy costs	65,782	52,583
Derivative instruments valuation at market	79,839	59,790
Prepayments and other	303,838	309,554
Current assets held for sale	192,135	180,413
Total current assets	4,194,288	3,294,496
Property, plant and equipment, at cost:		
Electric utility plant	16,375,000	16,099,655
Nonregulated property and other	8,751,511	7,783,994
Gas utility plant	2,568,036	2,493,028
Construction work in progress (utility amounts of $890,841 and $669,895, respectively)	1,533,727	3,682,619
Total property, plant and equipment	29,228,274	30,059,296
Less: accumulated depreciation	(10,145,971)	(9,536,854)
Nuclear fuel net of accumulated amortization of $1,047,063 and $1,009,855, respectively	53,295	96,315
Net property, plant and equipment	19,135,598	20,618,757
Other assets:		
Investments in unconsolidated affiliates	1,141,107	1,209,017
Notes receivable, including amounts from affiliates of $201,268 and $202,411, respectively	812,370	779,186
Nuclear decommissioning fund and other investments	732,363	690,734
Regulatory assets	569,840	502,442
Derivative instruments valuation at market	255,606	179,683
Prepaid pension asset	509,122	378,825
Goodwill net (See Note 1)	40,150	63,925
Intangible assets net (See Note 1)	62,027	53,369
Other	402,417	363,551
Noncurrent assets held for sale	550,887	584,211
Total other assets	5,075,889	4,804,943
Total assets	$ 28,405,775	$ 28,718,196

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED) (Continued)

(Thousands of Dollars)

	Sept. 30, 2002	Dec. 31, 2001
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 7,521,934	$ 419,335
Short-term debt	2,004,120	2,224,812
Accounts payable	1,408,852	1,319,770
Taxes accrued	377,951	246,152
Dividends payable	75,982	130,845
Derivative instruments valuation at market	48,422	83,122
Other	716,395	698,315
Current liabilities held for sale	296,929	310,810
Total current liabilities	12,450,585	5,433,161
Deferred credits and other liabilities:		
Deferred income taxes	1,407,927	2,270,854
Deferred investment tax credits	172,816	184,148
Regulatory liabilities	497,274	483,942
Derivative instruments valuation at market	119,303	42,445
Benefit obligations and other	741,948	703,836
Noncurrent liabilities held for sale	240,895	279,748
Total deferred credits and other liabilities	3,180,163	3,964,973
Minority interest in subsidiaries	38,837	636,847
Capitalization:		
Long-term debt	6,889,364	11,889,418
Mandatorily redeemable preferred securities of subsidiary trusts	494,000	494,000
Preferred stockholders equity authorized 7,000,000 shares, of $100 par value; outstanding shares: 1,049,800	105,320	105,320
Common stockholders equity authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: 2002, 398,714,039; 2001, 345,801,028	5,247,506	6,194,477
Commitments and Contingent Liabilities (see Note 9)		
Total Liabilities and Equity	$28,405,775	$28,718,196

See Notes to Consolidated Financial Statements

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CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY (UNAUDITED)

Three Months Ended Sept. 30, 2002 and 2001

(Thousands of Dollars)

	Par Value	Premium	Retained Earnings	Shares Held by ESOP	Accumulated Other Comprehensive Income	Total Stockholders Equity
Balance at June 30, 2001	$860,211	$2,924,429	$ 2,401,727	$(21,502)	$(141,000)	$ 6,023,865
Net income			272,903			272,903
Currency translation adjustments					39,066	39,066
After-tax net unrealized losses related to derivatives accounted for as hedges (see Note 11)					(39,068)	(39,068)
After-tax net unrealized losses on derivative transactions reclassified into earnings (see Note 11)					12,358	12,358
Comprehensive income for the period						285,259
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(1,060)			(1,060)
Common stock			(129,343)			(129,343)
Issuances of common stock net	2,076	22,894				24,970
Other			17			17
Repayment of ESOP loan(a)				1,444		1,444
Balance at Sept. 30, 2001	$862,287	$2,947,323	$ 2,544,244	$(20,058)	$(128,644)	$ 6,205,152
Balance at June 30, 2002	$992,186	$4,019,732	$ 2,459,374	$(16,881)	$ (82,125)	$ 7,372,286
Net income			(2,073,960)			(2,073,960)
Currency translation adjustments					(31,515)	(31,515)
After-tax net unrealized gains related to derivatives accounted for as hedges (see Note 11)					54,284	54,284
After-tax net unrealized gains on derivative transactions reclassified into earnings (see Note 11)					(17,707)	(17,707)
Unrealized gain-marketable securities					(1)	(1)
Comprehensive income for the period						(2,068,899)
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(1,060)			(1,060)
Common stock			(74,813)			(74,813)
Issuances of common stock net	4,435	15,274				19,709
Other			90		(8)	82
Repayment of ESOP loan(a)				201		201

Balance at Sept. 30, 2002	$996,621	$4,035,006	$ 309,631	$(16,680)	$ (77,072)	$ 5,247,506

(a) Did not affect cash flows

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY (UNAUDITED)

Nine Months Ended Sept. 30, 2002 and 2001

(Thousands of Dollars)

	Par Value	Premium	Retained Earnings	Shares Held by ESOP	Accumulated Other Comprehensive Income	Total Stockholders Equity
Balance at Dec. 31, 2000	$852,085	$2,607,025	$ 2,284,220	$(24,617)	$(156,929)	$ 5,561,784
Net income			650,070			650,070
Currency translation adjustments					17,604	17,604
Cumulative effect of accounting change -SFAS 133					(28,780)	(28,780)
After-tax net unrealized gains related to derivatives accounted for as hedges (see Note 11)					7,230	7,230
After-tax net unrealized losses on derivative transactions reclassified into earnings (see Note 11)					32,231	32,231
Comprehensive income for the period						678,355
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(3,180)			(3,180)
Common stock			(386,840)			(386,840)
Issuances of common stock net	10,202	98,407				108,609
Other			(26)			(26)
Gain recognized from NRG stock offering		241,891				241,891
Repayment of ESOP loan(a)				4,559		4,559
Balance at Sept. 30, 2001	$862,287	$2,947,323	$ 2,544,244	$(20,058)	$(128,644)	$ 6,205,152
Balance at Dec. 31, 2001	$864,503	$2,969,589	$ 2,558,403	$(18,564)	$(179,454)	$ 6,194,477
Net income			(1,883,154)			(1,883,154)
Currency translation adjustments					16,982	16,982
After-tax net unrealized gains related to derivatives accounted for as hedges (see Note 11)					69,186	69,186
After-tax net unrealized gains on derivative transactions reclassified into earnings (see Note 11)					(11,921)	(11,921)
Unrealized gain-marketable securities					(29)	(29)
						(1,808,936)

Comprehensive income for the period						
Dividends declared:						
Cumulative preferred stock of Xcel Energy			(3,180)			(3,180)
Common stock			(362,601)			(362,601)
Issuances of common stock net	67,706	510,195				577,901
Acquisition of NRG minority common shares	64,412	555,222			28,150	647,784
Other			163		14	177
Repayment of ESOP loan(a)				1,884		1,884
Balance at Sept. 30, 2002	$996,621	$4,035,006	$ 309,631	$(16,680)	$ (77,072)	$ 5,247,506

(a) Did not affect cash flows

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

In the opinion of management, the accompanying, unaudited consolidated financial statements contain all adjustments necessary to present fairly the financial position of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) as of Sept. 30, 2002, and Dec. 31, 2001, the results of its operations and stockholders equity for the three months and nine months ended Sept. 30, 2002 and 2001, and its cash flows for the nine months ended Sept. 30, 2002 and 2001. Due to the seasonality of Xcel Energy s electric and gas sales and variability of nonregulated operations, quarterly results are not necessarily an appropriate base from which to project annual results.

The accounting policies followed by Xcel Energy are set forth in Note 1 to the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2001 and its Current Report on Form 8-K filed Sept. 16, 2002. The following notes should be read in conjunction with such policies and other disclosures in the Form 10-K and Form 8-K.

Certain items in the 2001 income statement and balance sheet have been reclassified to conform to the 2002 presentation. These reclassifications had no effect on stockholders equity, net income or earnings per share as previously reported.

1. Accounting Policies and Changes

Intangible Assets During the first quarter of 2002, Xcel Energy adopted Statement of Financial Accounting Standard (SFAS) No. 142- Goodwill and Other Intangible Assets , which requires new accounting for intangible assets, including 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 $40 million at Sept. 30, 2002, which will not be amortized, consisting of project-related goodwill at NRG Energy, Inc. (NRG) and Utility Engineering. At June 30, 2002, Xcel Energy had initially recorded $62 million of goodwill related to the acquisition of NRG s minority shares (see Note 5), which was subsequently reallocated to fixed assets related to projects where the fair value of the fixed assets was higher than the carrying value as of June 2002 and to prepaid pension assets. During the first nine months of 2002, Xcel Energy performed impairment tests of its intangible assets. Tests completed to date have concluded that no write-down of these intangible assets is necessary.

With respect to those intangible assets that will continue to be amortized, aggregate amortization expense recognized in the three and nine months ended Sept. 30, 2002, was $2.0 million and $3.9 million, respectively. The annual aggregate amortization expense for each of the five succeeding years is expected to approximate $3.5 million. Intangible assets consisted of the following:

	Sept. 30, 2002		Dec. 31, 2001	
Class of Intangible Asset	**Gross Carrying Amount**	**Accumulated Amortization**	**Gross Carrying Amount**	**Accumulated Amortization**
	(Millions of dollars)			
Not Amortized:				
Goodwill	$47.9	$ 7.7	$74.7	$10.8
Amortized:				
Service contracts	$73.2	$17.1	$90.9	$19.8
Trademarks	$ 5.1	$ 0.5	$ 5.0	$ 0.4
Other (primarily franchises)	$ 1.8	$ 0.5	$ 1.9	$ 0.3

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XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

The following table summarizes the pro forma impact of implementing SFAS No. 142 at Jan. 1, 2001, 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.

	3 Months Ended		9 Months Ended	
	Sept. 30, 2002	Sept. 30, 2001	Sept. 30, 2002	Sept. 30, 2001
	(Millions of dollars)			
Reported net income (loss)	$(2,074.0)	$272.9	$(1,883.2)	$650.1
Add back: Goodwill amortization (after tax)		0.9		2.4
Adjusted net income (loss)	$(2,074.0)	$273.8	$(1,883.2)	$652.5
Diluted earnings (loss) per share	$ (5.22)	$ 0.79	$ (5.01)	$ 1.89

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.

Trading Operations In June 2002, the Emerging Issues Task Force (EITF) of the Financial Accounting Standards Board (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 income, 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 $1.0 billion and $679 million for the third quarter of 2002 and 2001, respectively. Such reclassifications for the nine months ended Sept. 30, 2002 and 2001 were $2.8 billion and $2.4 billion, respectively. This reclassification had no impact on trading margins 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 Accounting for Derivative Instruments and Hedging Activities must be accounted 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 has not yet evaluated the effect of adopting this decision when required in 2003.

Diluted Earnings Per Share Diluted earnings per share is based on the weighted average common stock and common equivalent shares outstanding each period. However, no common equivalent shares shall be included in the computation of any diluted per-share amounts when a loss from continuing operations exists due to their antidilutive effect. Therefore, common equivalent shares of approximately 5.8 million and 2.0 million were excluded from the diluted earnings per share computations for the three and nine months ended Sept. 30, 2002, respectively.

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XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

2. Special Charges and Asset Impairments

Special charges included in Operating Expenses include the following:

	3 Months Ended		9 Months Ended	
	Sept. 30, 2002	Sept. 30, 2001	Sept. 30, 2002	Sept. 30, 2001
NRG Asset Impairments	$2,891	$	$2,891	$
NRG Restructuring Costs	18		38	
NEO Charges (NRG)			36	
Regulatory Recovery Adjustment (SPS)			5	
Restaffing (Utility and Service Companies)			9	
Postemployment Benefits (PSCo)				23
Total Special Charges	$2,909	$	$2,979	$ 23

NRG Asset Impairments As discussed further in Note 7, during the third quarter of 2002, NRG experienced credit rating downgrades, defaults under certain credit agreements, increased collateral requirements and reduced liquidity. These events resulted in impairment reviews of a number of NRG assets. NRG completed an analysis as of Sept. 30, 2002 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 were significantly affected by NRG s credit rating downgrade at the end of July 2002. 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 the third quarter of 2002 and should be written down to fair market value. In applying those provisions NRG management considered cash flow analyses, bids and offers related to those

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projects. The resulting impairments were recognized as Special Charges in the third quarter of 2002 as follows:

	Status	Pretax Charge	Fair Value Basis
		(Millions of dollars)	
Projects In Construction or Development			
Nelson	Terminated	$ 620	Similar asset prices
Pike	Terminated; in bankruptcy	529	Similar asset prices
Bourbonnais	Terminated	270	Similar asset prices
Meriden	Terminated	180	Similar asset prices
Brazos Valley	Foreclosure in process	103	Projected cash flows
Kendall & Batesville expansion and other	Terminated	147	Similar asset prices
Langage (UK)	Terminated	44	Estimated market price
Turbines & other costs	Equipment being sold	309	Similar asset prices
Total		$2,202	
Operating Projects			
Killingholme (UK)	Foreclosure in process	$ 478	Projected cash flows
Audrain	Operating at a loss	66	Projected cash flows
Hsin Yu (Taiwan)*	Funding discontinued; operating at a loss	122	Projected cash flows
Other	Operating at a loss	23	Projected cash flows
Total		$ 689	
Total NRG Impairment Charges		$2,891	

* Excluding minority interest impact, which would reduce pretax cost by $21 million.

All of these impairment charges relate to assets considered held for use under SFAS 144. For fair values determined by similar asset prices, the fair value represents NRG s current estimate of recoverability from expected marketing of project assets. 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 (using rates of 8-10 percent) 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.

The Loy Yang project is an equity method investment, not subject to SFAS No. 144 impairment provisions. In the second quarter of 2002, NRG began marketing this investment for sale with the condition that it would only sell the investment if it could recover its current carrying value. Since the Company has not received an offer to recover its carrying amount, NRG will continue to hold its investment as long as it has the capability to do so. However, if the Company had elected to sell this investment as of Sept. 30, 2002, it would be required under generally accepted accounting principles to recognize any foreign currency adjustments recorded as a component of accumulated other comprehensive income into income rather than as a component of equity. As of Sept. 30, 2002, foreign currency adjustments of $89 million were deferred in

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OCI that would be recognized as a loss if the Company had elected to sell this investment. Based on market appraisals received in the second and third quarters, it was determined in the third quarter of 2002 that there has been a decline in Loy Yang s fair value that is considered by the Company to be other than temporary. Accordingly, an impairment charge of approximately $54 million has been recognized at Sept. 30, 2002.

Additional asset impairments may be recorded by NRG in periods subsequent to Sept. 30, 2002, given the changing business conditions and the resolution of the pending restructuring plan. Management is unable to determine the possible magnitude of any additional asset impairments.

NRG Severance and Restructuring In the second quarter of 2002, NRG expensed a pretax charge of $20 million, or 4 cents per share, for expected severance and related benefits. Additional severance accruals of $6 million, or 1 cent per share, were made in the third quarter of 2002. Through Sept. 30, 2002, severance costs have been recognized for all employees who had been terminated as of that date. Similar charges are expected to be expensed in the future, as further actions are taken, but are not determinable at this time. Another $12 million, or 2 cents per share, of other NRG restructuring costs were recorded in the third quarter of 2002, including financial advisors, legal advisors and consultants. See Note 6 for further discussion of NRG restructuring activities and developments.

NRG Charges-NEO Project During the second quarter of 2002, NRG expensed a pretax charge of $36 million, or 6 cents per share, related to its NEO Corporation landfill gas generation operations. The charge was related largely to asset impairments based on a revised project outlook. It also reflects the accrued impact of a dispute settlement with Fortistar, a partner with NEO in the landfill gas generation operations.

Regulatory Recovery Adjustment In late 2001, Southwestern Public Service (SPS), a wholly owned subsidiary of Xcel Energy, filed an application requesting recovery of costs incurred to comply with transition to retail competition legislation in Texas and New Mexico. During the first quarter of 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, or approximately 1 cent per share.

2002 Restaffing During the fourth quarter of 2001, Xcel Energy recorded an estimated liability for expected staff consolidation costs for an estimated 500 employees in several utility operating and corporate support areas of Xcel Energy. In the first quarter of 2002, the identification of affected employees was completed and additional pretax special charges of $9 million, or approximately 1 cent per share, were expensed for the final costs of the utility-related staff consolidations. All 564 of accrued staff terminations have occurred.

The following table summarizes the activity related to accrued special charges for restaffing in the first nine months of 2002.

	Dec. 31, 2001 Liability	Accrued Special Charges	Payments	Sept. 30, 2002 Liability
		(Millions of dollars)		
Utility and corporate employee severance*	$ 37	$ 9	$(31)	$ 15
NRG employee severance**		26	(5)	$ 21
Total accrued special charges	$ 37	$ 35	$(36)	$ 36

* Reported on the balance sheet in other current liabilities.

** $18.5 million reported on the balance sheet in other current liabilities and $2.5 million reported in benefit obligations and other.

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Postemployment Benefits Earnings for the second quarter of 2001 were reduced by 4 cents per share due to a Colorado Supreme Court decision that resulted in a 2001 pretax write-off of $23 million of regulatory assets related to deferred postemployment benefit costs at Public Service Company of Colorado (PSCo), a wholly owed utility subsidiary of Xcel Energy.

3. Discontinued Operations and Assets Held for Sale

In the second and third quarters of 2002, NRG applied the provisions of SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets, to certain of its assets, which were held for sale. 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 considered cash flow analyses, bids and offers, related to those businesses. As a result, NRG recorded an estimated losses of $86 million on disposal for assets held for sale. A portion of this amount is included as Income (loss) from discontinued operations for consolidated projects and the majority is reported as Estimated loss from disposal of equity investments for equity method projects in the accompanying Consolidated Statements of Income. In accordance with the provisions of SFAS No. 144, the assets classified as assets held for sale will not be depreciated commencing the beginning of the month in which they were classified as such.

Discontinued Operations NRG

As of Sept. 30, 2002, four projects of NRG (Bulo Bulo, Csepel, Entrade and Crockett Cogeneration Project) that were consolidated on NRG s financial statements had been classified as held for sale. The operating results and estimated losses on disposal for these projects have been separately classified and reported as discontinued operations in the accompanying financial statements.

Bulo Bulo In June 2002, NRG began negotiations for the sale of its 60-percent interest in Companie Electrica Central Bulo Bulo S.A. (Bulo Bulo), a Bolivian corporation, to its 40 percent partner, Pan American Energy LLC. During the second quarter of 2002, NRG classified Bulo Bulo as held for sale and recognized an estimated disposal loss of approximately $9.7 million as discontinued operations. The transaction is expected to reach financial close in fourth quarter 2002.

Crockett Cogeneration Project In September 2002, NRG announced that it had reached an agreement to sell its 57.7-percent interest in Crockett Cogeneration Project, a 240-megawatt, natural gas-fueled cogeneration plant near San Francisco, Calif., to an undisclosed buyer. Upon closing of the sale of Crockett, NRG expects to realize net cash proceeds of approximately $70 million and expects to reduce balance sheet debt and credit obligations by approximately $240 million. Crockett has been classified as held-for-sale and a loss of approximately $7 million has been reported in discontinued operations in the third quarter of 2002.

Hungarian and Czech Assets In September 2002, NRG announced it had reached agreement to sell its Csepel power generating facilities, its 44.5-percent interest in ECKG power station and its interest in Entrade, an electricity trading business, to Atel, an independent energy group headquartered in Switzerland. NRG expects to realize net cash proceeds of approximately $200 million from the sale with closing anticipated in first quarter 2003. The transaction, which requires approval by competition authorities, is expected to close before year-end and is expected to result in a gain, net of transaction fees. This gain will not be recognized until closing occurs.

Located on Csepel Island in Budapest, Hungary, Csepel I is a 116-megawatt thermal plant, and Csepel II is a 389-megawatt gas turbine power generating station. ECKG, a 343-megawatt coal- and gas-fueled power station and a 173-megawatt thermal plant, is located in Kladno, Czech Republic. Based in Prague, Entrade markets and trades electricity in Central and Eastern Europe.

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The following is a summary of the components of discontinued operations:

	3 Months Ended Sept. 30		9 Months Ended Sept. 30	
	2002	2001	2002	2001
Operating Revenues	$121,976	$103,100	$373,080	$280,203
Operating & Other Expenses	121,308	87,247	338,158	263,416
Estimated Loss on Disposal	(7,423)		(17,097)	
Income (loss) before taxes	(6,755)	15,853	17,825	16,787
Income tax expense		1,769		1,805
Net income (loss) from discontinued operations	$ (6,755)	$ 14,084	$ 17,825	$ 14,982

Other Assets Held for Sale NRG

As of Sept. 30, 2002, five significant projects of NRG (Collinsville, ECKG, Energy Development Limited, SRW Cogeneration and Mt. Poso) that were reflected as equity investments on NRG s financial statements had been classified as held for sale. In the accompanying financial statements, the operating results of these projects are classified in revenue as Equity earnings from investments in affiliates, and the estimated losses on disposal for these projects have been classified and reported as a component of Estimated loss from disposal of equity investments for equity method projects. For the nine months ended Sept. 30, 2002, NRG had recorded charges of $117.9 million to write-down the carrying value of equity investments due to losses expected from sales.

Energy Development Limited On July 25, 2002, NRG announced it had agreed to the sale of its ownership interests in an Australian energy company, Energy Development Limited (EDL). EDL is engaged in the development and management of an international portfolio of projects with a particular focus on renewable and waste fuels. In October 2002, NRG received proceeds of $78.5 million (AUS), or approximately $43.9 million (USD), from the sale in exchange for its ownership interest in EDL with the closing of the transaction. During the second quarter of 2002, NRG recognized an estimated loss on the sale of approximately $14.3 million in the third quarter of 2002.

Collinsville Power Station In August 2002, NRG announced it had entered into an agreement for the sale of its 50-percent interest in the 192-megawatt Collinsville Power Station in Australia to an existing partner, a subsidiary of Transfield Services Limited for $8.6 million (AUS), or approximately $4.8 million (USD). NRG recognized an estimated loss on the sale of approximately $4.1 million (USD) during the second quarter of 2002.

Sabine River In September 2002, NRG agreed to transfer its indirect 50 percent interest in SRW Cogeneration LP (SRW), which owns a cogeneration facility in Orange County, Texas, to Conoco, in consideration for Conoco s agreement to terminate or assume all of the obligations of NRG in relation to SRW including all of NRG s obligations under the Tolling Agreement with SRW. The sale closed on Nov. 5, 2002 and resulted in a loss of approximately $49 million which was accrued in the third quarter of 2002.

Mount Poso In September 2002, NRG agreed to sell its 39.5 percent indirect partnership interest in Mt. Poso Cogeneration Company, a California limited partnership (Mt. Poso), which owns a 49.5 megawatt coal-fired cogeneration power plant and thermally enhanced oil recovery factory in California, to Red Hawk Energy, LLC of $10 million less financial advisors fees of $200,000. This sale is expected to close in November 2002 and is expected to result in a loss to NRG of approximately $400,000, which was accrued in the third quarter of 2002.

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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 Statement of Income.

4. Business Developments

NRG Divestitures and Project Terminations

Conectiv In April 2002, NRG terminated its agreement with a subsidiary of Conectiv, pursuant to which NRG was 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.

On Aug. 8, 2002, FirstEnergy notified NRG that the 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 Xcel Energy for damages, based on the alleged anticipatory breach. At this time, NRG cannot predict the effect on NRG of any legal action that might be brought. NRG continues to evaluate the implications of the cancellation and its potential exposure to FirstEnergy.

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) to Shaw. Pike is 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. Pike, NRG and the Pike Project lenders have not approved the agreement and are not expected to in the near term.

On Oct. 17, 2002, Shaw filed an involuntary petition for liquidation of Pike in the U.S. District Court for the Southern District of Mississippi under Chapter 7 of the U.S. Bankruptcy Code. Shaw also filed suit against Xcel Energy, NRG, certain NRG subsidiaries, Wayne Brunetti and Richard Kelly. The suit seeks recovery of approximately $130 million, as a result of what Shaw asserts are multiple breaches of contract and under various other liability theories, including that the corporate veils between Xcel Energy, NRG and Pike should be ignored. Defendants expect to challenge the allegations vigorously. The carrying value of NRG s Pike assets has been reduced substantially as a result of the asset impairments reflected as Special Charges. See discussion in Note 2.

Discontinued Operations and Assets Held for Sale See Note 3 for discussion of other NRG divestitures that are reported as discontinued operations or assets held for sale as of Sept. 30, 2002.

Other Developments

TRANSLink Transmission Company, LLC (TRANSLink) In September 2001, Xcel Energy and several other electric utilities applied to the Federal Energy Regulatory Commission (FERC) to integrate operations of their electric transmission systems into a single system through the formation of TRANSLink, a

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for-profit, independent transmission-only company. The utilities will participate in TRANSLink through a combination of divestiture, leases and operating agreements. The applicants are: Alliant Energy s Iowa company (Interstate Power and Light Co.), Corn Belt Power Cooperative, MidAmerican Energy Co., Nebraska Public Power District, Omaha Public Power District and Xcel Energy. The participants believe TRANSLink is the most cost-effective option available to manage transmission and to comply with regulations issued by the FERC in 1999, known as Order No. 2000, that require investor-owned electric utilities to transfer operational control of their transmission system to an independent regional transmission organization (RTO).

Under the proposal, TRANSLink will be responsible for planning, managing and operating both local and regional transmission assets. TRANSLink also will construct and own new transmission system additions. TRANSLink will collect revenue for the use of Xcel Energy s 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. The participants also have entered into a memorandum of understanding with the Midwest Independent Transmission Operator, Inc. (MISO) in which they agree that TRANSLink will contract with the MISO for certain other required RTO functions and services. In May 2002, the partners 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. Eleven intervenors had requested that the FERC clarify or reconsider elements of the TRANSLink decision. On Nov. 1, 2002, the FERC issued its order supporting the approval of the formation of TRANSLink. The FERC also clarified several issues covered in its April 2002 order. Several state approvals also would be required to implement the proposal, as well as SEC approval. Subject to receipt of required regulatory approvals, TRANSLink is expected to begin operations in the third quarter of 2003.

Viking Gas Transmission Company On Nov. 7, 2002, Xcel Energy reached an agreement to sell its wholly owned subsidiary, Viking Gas Transmission Company (Viking) and Viking s share of Guardian Pipeline to Border Viking Company (Border) whose ultimate parent is Northern Border Partners L.P. Pursuant to the agreement, Border would purchase Viking and a one-third interest in Guardian Pipeline for approximately $152 million, including the assumption of outstanding debt. The purchase is expected to close in the first quarter of 2003, subject to receipt of all necessary approvals.

5. Acquisition of Minority NRG Common Shares

During the second quarter of 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 $650 million as of June 30, 2002. Due to the acquisition occurring near quarter-end, additional

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acquisition costs recorded in the third quarter of 2002 increased the purchase price as of Sept. 30, 2002, to $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 was initially completed during the third quarter and resulted in approximately $62 million of amounts preliminarily reported as goodwill which have subsequently been reallocated to fixed assets related to projects where the fair values were in excess of carrying values and to prepaid pension assets. The preliminary purchase price allocation is subject to change as the final purchase price allocation and asset valuation process is completed.

6. NRG Restructuring Plan

Since mid-August, 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 anticipates that NRG will function independent 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 the forecasted cash flow information included in the business plan. Management concluded that the forecasted free cash flow available to NRG after servicing project-level obligations will be insufficient to service recourse debt obligations. Based on this information in conjunction with Xcel Energy and its financial advisor, NRG prepared and submitted to its, and a number of its subsidiaries various lenders, bondholders and other creditor groups (collectively, NRG s Creditors) a restructuring plan on Nov. 4, 2002. The restructuring plan is expected to serve as a basis for negotiations with NRG s Creditors in a financially-restructured NRG and, among other things, proposes (i) holders of secured (project-level) debt would either (a) have their debt reinstated with agreed modifications or (b) receive the collateral securing such debt and a claim or claims to the extent such debt is under-secured; (ii) holders of unsecured debt, holders of secured recourse claims against NRG, and holders of other general unsecured claims against NRG would receive a pro rata share of (a) an aggregate of $500 million of junior secured debt of reorganized NRG and (b) 95% of the common equity of reorganized NRG; and (iii) holders of project-level general unsecured claims that are non-recourse to NRG would receive a pro rata share of the remaining 5% of the common equity of reorganized NRG.

The restructuring plan also includes a proposal addressing Xcel Energy s continuing role and degree of ownership in NRG and obligations to NRG. Based on the advice of its financial advisor that NRG is likely insolvent and in return for a release of any and all claims against Xcel Energy, the plan proposes that, upon consummation of the restructuring, Xcel Energy would pay $300 million to NRG. The plan separately proposes that Xcel Energy surrender its equity ownership of NRG. The plan does not contemplate any sharing by Xcel Energy with NRG s Creditors of any benefits Xcel Energy might receive in connection with the tax matters described below. There can be no assurance that the restructuring plan submitted by NRG will be accepted by NRG s Creditors or that it will not be significantly revised as a result of ongoing negotiations. Furthermore, there can be no assurance that NRG s Creditors ultimately will accept any consensual restructuring plan. Xcel Energy is unable to predict whether NRG will be able to implement any such restructuring plan, or whether, 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. On Nov. 6, 2002, lenders to NRG accelerated approximately $1.1. billion of NRG s debt under a construction revolver financing facility, rendering the debt due and payable. Based on discussions with the lenders, it is NRG s understanding that the administrative agent issued the acceleration notice to preserve certain rights under the construction revolver financing agreements.

Whether NRG does or does not reach 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

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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. See Potential NRG Bankruptcy under Note 9.

Since the acquisition of 100 percent ownership of NRG in June 2002, Xcel Energy has been operating under the following assumptions related to income tax attributes assignable to NRG: (a) NRG is a going concern; (b) Xcel Energy retains a controlling interest in NRG; and (c) NRG will rejoin Xcel Energy s consolidated group for federal income tax purposes effective June 2002 and will, again, become a party to Xcel Energy s Tax Allocation Agreement. Under this Tax Allocation Agreement, subsidiaries are paid for taxable losses used by the consolidated group and likewise remit taxable income. To date, no formal election has been made by Xcel Energy to reconsolidate NRG for federal income tax purposes, and NRG has not become a signatory to the Tax Allocation Agreement. Consistent with the foregoing assumptions, Xcel Energy included NRG in its third quarter 2002 estimated income tax payment calculation as if it were included in Xcel Energy s consolidated federal income tax group for 2002. In addition, Xcel Energy applied the Tax Allocation Agreement as if NRG were included in Xcel Energy s Consolidated federal income tax group for 2002 and, therefore, made a cash payment of $24 million to NRG in September 2002 for tax benefits expected to be provided by NRG to the Xcel Energy consolidated tax group for the period from and after the acquisition of 100 percent ownership of NRG in June 2002. Based on changed circumstances subsequent to Sept. 30, 2002, it is likely, though not certain, that Xcel Energy will eventually decide not to consolidate NRG for income tax purposes for 2002 when Xcel Energy files its 2002 consolidated income tax returns in 2003. Xcel Energy s decision in this regard will depend on a variety of factors, including the outcome of ongoing negotiations with NRG s Creditors. If Xcel Energy does not consolidate NRG on its 2002 federal income tax return, such action may be contested by NRG s Creditors.

7. NRG Liquidity & Related Credit Contingencies

NRG Credit Rating In December 2001, Moody s placed NRG s long-term senior unsecured debt rating on review for downgrade. In response to this threat to NRG s investment grade rating, on Feb. 17, 2002, Xcel Energy announced a financial improvement plan for NRG, which included an initial step of acquiring 100 percent of NRG through a tender offer to exchange all of the outstanding shares of NRG common stock for Xcel Energy common shares. In addition, the plan included financial support to NRG from Xcel Energy; marketing certain NRG generating assets for possible sale; cancelling and deferring capital spending for NRG projects; and combining certain of NRG s functions with Xcel Energy s system and organization. On June 3, 2002, Xcel Energy completed its exchange offer for the 26 percent of NRG s shares that had been previously publicly held. Xcel Energy offered NRG shareholders 0.50 shares of Xcel Energy common stock for each outstanding share of NRG common stock (see Note 5). Throughout this period of time, NRG was in discussions with credit agencies and believed that its actions were sufficient to avoid a downgrade.

However, even with NRG s efforts to avoid a downgrade, unexpectedly on July 26, 2002, Standard & Poors downgraded NRG s senior unsecured bonds below investment grade, and three days later Moody s Investors Services 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 and the secured NRG South Central Generating LLC 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, depending on both the specific debt issue and the

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rating agency rating system. Credit ratings are not a recommendation to buy, sell or hold securities, and each rating should be evaluated independently of any other rating.

The current credit ratings of NRG have resulted in its inability to access the capital markets.

NRG Liquidity Issues As a result of the credit rating agencies unexpectedly downgrading NRG s credit rating below investment grade, NRG is required to post estimated collateral ranging from approximately $1.1 billion to $1.3 billion. NRG previously believed it could meet the collateral requirements that would result from such an occurrence with available cash, operating cash flows, equity contributions from Xcel Energy, proceeds from asset sales and the issuance of bonds into the capital markets or as a private placement.

NRG obtained an agreement with various lenders to extend, until Nov. 15, 2002, the deadline by which it must post this cash collateral. This deadline has passed and NRG has not posted the required collateral. The extension agreement called for NRG to submit a comprehensive restructuring plan to its lenders and bondholders by late October (see Note 6). The extension agreement did not waive other events of default, including failure to make principal and/or interest payments when due or failure to comply with financial covenants. Nor did the extension agreement waive the rights of the bank group or the bondholders to pursue any rights and remedies in respect of such other defaults.

On Nov. 6, 2002, lenders to NRG accelerated approximately $1.1 billion of NRG s debt under a construction revolver financing facility, rendering the debt immediately due and payable. This action terminated the collateral call extension letter (CCEL) in effect between NRG and its major lenders. The extension letter was previously scheduled to expire Nov. 15, 2002. Based on discussions with the construction revolver lenders it is NRG s understanding that the administrative agent, Credit Suisse First Boston, issued the acceleration notice to preserve certain rights under the construction revolver financing agreements. NRG believes that the administrative agent intends to forbear in the immediate exercise of any rights and remedies against NRG.

NRG has missed several scheduled payments of interest and principal on some of its bonds as discussed later and in Part II, Item 3. Consequently, NRG is, and expects to continue to be, in default under various debt instruments. By reason of these various defaults, the lenders are able to seek to enforce their remedies and that would likely lead to a bankruptcy filing by NRG.

In addition, NRG South Central LLC, a wholly owned subsidiary of NRG, has not made approximately $47 million in combined principal and interest payments on 8.962 percent series A-1 senior secured bonds due 2016 and 9.479 percent series B-1 senior secured bonds due 2024. As discussed above, pending agreement on a restructuring plan, NRG does not expect to make any further payments of principal or interest on its debt.

As discussed in Note 6, NRG continues to work with its lenders on a comprehensive restructuring plan that would address the collateral requirements and its debt and other obligations. Absent an agreement on this restructuring plan, NRG will continue to be in default under its debt and other obligations because it does not have sufficient funds to meet the requirements and obligations. There can be no assurance that NRG will be able to effect a consensual restructuring or otherwise satisfactorily resolve these issues soon, or at all. It is unlikely that Xcel Energy ultimately will own any equity interest in a restructured NRG.

In addition to the collateral requirements and its debt payment obligations, NRG must continue to meet its ongoing operational and construction funding requirements. Since NRG s downgrade, its cost of borrowing has increased and it has no access to the capital markets. As a consequence, NRG has developed an updated business plan and, in October 2002 and early November 2002, presented this plan along with a comprehensive restructuring plan to its lenders and bondholders (see Note 6). NRG believes that its current funding requirements under its already reduced construction program may be unsustainable given its inability to raise cash through the capital markets and the uncertainties involved in obtaining additional equity funding from

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Xcel Energy. NRG and Xcel Energy have retained financial advisors to help work through these issues. NRG is unsure as to the resolution of all issues. NRG s initial priorities have been obtaining waivers to delay its collateral calls and developing of a restructuring plan.

As discussed earlier, NRG is not making any payments of principal and interest on its corporate level debt and neither NRG nor any subsidiary is making payment of principal or interest on publicly-held bonds and certain project-level credit facilities. 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. However, there can be no assurance that holders of NRG indebtedness on which interest and principal are not being paid will not seek to enforce their remedies, which would likely lead to NRG seeking relief under bankruptcy laws.

At the present time and based on conversations with various lenders, Xcel Energy management believes that the appropriate course of action is to seek a consensual restructuring of NRG with NRG Creditors. Following an agreement on the restructuring with NRG s Creditors and as described in Note 6 above, it is expected that NRG would commence a Chapter 11 bankruptcy proceeding and immediately seek approval of a prenegotiated plan of reorganization. If a consensual restructuring cannot be reached, substantial doubt would exist as to NRG s ability to continue as a going concern and, the likelihood of NRG being subject to a protracted voluntary or involuntary bankruptcy proceeding is increased. Although there is a substantial likelihood that NRG will be the subject of a bankruptcy proceeding, if a consensual restructuring of NRG cannot be obtained and NRG remains outside of a bankruptcy proceeding, NRG is expected to continue selling assets to reduce its debt and improve its liquidity.

NRG Debt Covenants and Restrictions

As a consequence of NRG s credit rating downgrades, defaults under certain agreements, including collateral requirements, reduced liquidity and asset impairments (discussed in Note 2) that occurred during the third quarter of 2002, a portion of NRG s long term debt obligations have been classified as a current liability on the accompanying balance sheets due to the lenders having the ability to call such debt, including $3.1 billion that is in default. As of Sept. 30, 2002, approximately $6.7 billion of NRG s long term debt has been reclassified to current from long term.

Short-term Credit Facility Covenants In May 2001, NRG s wholly-owned subsidiary, NRG Finance Company I LLC, entered into a $2-billion revolving credit facility. The facility terminates on May 8, 2006, and is non-recourse to NRG other than its obligation to contribute equity at certain times in respect of projects and turbines financed under the facility. As of Sept. 30, 2002, the aggregate amount outstanding under this facility was $1.1 billion, and NRG estimates the obligation to contribute equity to be approximately $819 million. Interest and fees due on Sept. 30, 2002 were not paid and supporting construction and other contracts associated with Pike and Nelson were violated by NRG in September 2002 and October 2002, respectively. Supporting construction and other contracts associated with NRG s Pike and Nelson projects were violated by NRG in September and October 2002, respectively. Thus this facility is currently in default. See additional discussion regarding this facility and other short-term credit facility defaults in Note 10.

NRG Defaults Upon Senior Securities On Sept. 16, 2002, NRG failed to make a $14.4-million interest payment due on $350 million of 8.25 percent senior unsecured notes due in 2010 and a $10.9-million interest payment due on a $250 million bond issued by NRG Pass-Thru Trust I trust, which is a wholly owned special financing entity that is effectively a senior unsecured obligation of NRG with an interest rate of 8.70 percent that matures in 2005. The 30-day grace period to make payment ended Oct. 16, 2002, and NRG did not make the required payments. As a result, NRG is in default on these bonds.

On Oct. 1, 2002, NRG failed to make a $13.6-million interest payment due on $350 million of 7.75 percent senior unsecured notes due in 2011 and a $21.6-million interest payment due on $500 million of

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8.625 percent senior unsecured notes due in 2031. The 30-day grace period to make payment ended Oct. 31, 2002, and NRG did not make the required payments. As a result, NRG is in default on these bonds.

On Nov. 1, 2002 NRG failed to make a $9.6 million interest payment due on $240 million of 8.00 percent senior unsecured notes due in 2013. The 30-day grace period to make payment ends Dec. 1, 2002 and if NRG does not make the required payments, NRG will be in default on these bonds.

In addition, if certain creditors exercise rights of acceleration against $20 million or $50 million of NRG senior indebtedness, depending on the governing indenture, cross-default provisions place the following NRG senior unsecured debt in default: $300 million of 7.50 percent senior due 2009 (with a $11.3 million interest payment due on Dec. 1, 2002); $250 million of 7.50 percent senior notes due 2007 (with a $9.4 million interest payment due on Dec. 15, 2002); $340 million of 6.75 percent senior notes due 2006 (with a $11.5 million interest payment due on January 15, 2003); $125 million of a 7.625 percent due 2006 (with an interest payment of $4.8 million due Feb. 1, 2003).

On March 13, 2001, NRG completed the sale of 11.5 million equity units (NRZ) 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 Xcel Energy common stock no later than May 18, 2004. On Oct. 29, 2002, NRG announced it would not make the Nov. 16, 2002 quarterly interest payment on the NRG 6.5 percent senior unsecured debentures due in 2006, which trade with the associated purchase contracts as NRG corporate units (NRZ). The 30-day grace period to make payment ends Dec. 16, 2002, and if NRG does not make payment to the NRZ holders, this issue will be in default. In the event of an NRG bankruptcy, the obligation to purchase shares of Xcel Energy terminates.

Project Debt Service Substantially all of NRG s operations are conducted by project 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 Sept. 30, 2002, seven of NRG s subsidiaries and project affiliates are restricted from making cash payments to NRG: 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. Additionally, Crockett Cogeneration is limited in its ability to make distributions to NRG and its other partners. 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, Crockett Cogeneration and Batesville do not create an event of default and will not allow the lenders to accelerate the project financings, thus these financing are not currently in default.

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 accounts funding requirements were satisfied by provision of a guarantee from NRG. Following the downgrade, 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. NRG expects that the Killingholme and Brazos Valley projects will be foreclosed upon by the lenders.

Other Covenants and Compliance The bankruptcy of Pacific Gas & Electric (PG&E) creates the potential for a covenant default that would result in the acceleration of the debt at Crockett if not resolved with the lenders. Management has engaged in active discussions with the lenders of Crockett since PG&E filed for bankruptcy in April 2001; additionally, Crockett is being paid each month by PG&E since the bankruptcy filing. PG&E and the Bankruptcy Court have affirmed the long-term power purchase agreement

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and PG&E is paying down the outstanding receivable over a 12-month period ending Dec. 1, 2002. Thus, NRG believes that an acceleration of the Crockett debt is unlikely. However, as of Dec. 31, 2001, NRG has reflected the entire balance of the Crockett debt as a current obligation in the amount of $234.5 million. As of Sept. 30, 2002, the outstanding balance of the Crockett debt has been reclassified as a current liability held for sale due to the pending sale of NRG s interest in the project. For additional information regarding the pending sale of NRG s interest in Crockett Cogeneration, see Note 3.

In May 2002, NRG s indirect wholly owned subsidiary, LSP-Kendall Energy, LLC received a notice of default from Societe Generale, the administrative agent under LSP-Kendall s Credit and Reimbursement Agreement dated Nov. 12, 1999. The notice asserted that an event of default had occurred under the Credit and Reimbursement Agreement as a result of liens filed against the Kendall project by various subcontractors. In consideration of the borrower s implementation of a plan to remove the liens, and NRG s indemnification pursuant to an Indemnity Agreement dated June 28, 2002, of the lenders to the Kendall project from any claims or damages relating to these liens or any dispute or action involving the project s EPC contractor, the administrative agent, with the consent of the required lenders under the Credit and Reimbursement Agreement, withdrew the notice of default and conditionally waived any default or event of default described therein. Discussions with the administrative agent regarding the liens continue.

In June 2002, NRG Peaker Finance Company LLC (NRG Peaker), an indirect wholly owned subsidiary of NRG Energy, completed the issuance of $325 million of Series A Floating Rate Senior Secured Bonds due 2019. The bonds bear interest at a floating rate based on the 30-day London Interbank Offered Rate. 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. This financing contains a cross-default provision related to the failure by NRG to make payment of principal, interest or other amounts due on debt for borrowed money in excess of $50 million of payment defaults by NRG. This covenant was violated in October 2002. In addition, liens were placed against the Bayou Cove facility resulting in an additional default. As a result of these issues, this facility is in default.

On Sept. 17, 2002, NRG-McClain LLC, an indirect wholly owned subsidiary of NRG, 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 under the Energy Management Services Agreement.

Brazos Valley Energy, LP, an indirect wholly owned subsidiary of NRG, is party to a credit facility that provides for borrowings of base rate loans and Eurocurrency loans and is secured by mortgages and security agreements in respect of the assets of the projects financed under the facility and pledges of the equity interests in the subsidiaries or affiliates of the borrower that own such projects.

On Sept. 30, 2002, Brazos Valley failed to make approximately $1.2 million in interest payments on the facility. Brazos Valley had five days to make interest payments to the lenders to avoid an event of default on the facility. The five-day grace period to make payment expired and Brazos Valley did not make the required payments. In addition, NRG has suspended equity contributions to the project. As a result, Brazos Valley is in default on this loan.

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On Oct. 30, 2002 NRG failed to make $3.1 million in payment under certain Non-Operating Interest Acquisition agreements. As a result, NEO Landfill Gas, Inc., an indirect wholly owned subsidiary of NRG, failed to make approximately $1.4 million in payments under the Amended and Restated Construction, Acquisition and Term Loan Agreement, dated July 6, 1998. Also, the subsidiaries of NEO Landfill Gas, Inc. failed to make approximately $2 million in payments pursuant to various Site Development Operations and Coordination Agreements. NRG received an extension until Nov. 19, 2002 to make payment under such agreements. If NRG does not perform certain requirements during the extension period, NRG will be in default under the Non-Operating Interest Acquisition Agreements, and NEO Landfill Gas, Inc. will be in default under the Amended and Restated Construction, Acquisition and Term Loan Agreement, dated July 6, 1998, and the Site Development and Operations Coordination Agreements.

Electric Wholesale Generator (EWG) Approval In April 2002, NRG discovered that filings with the FERC to exempt NRG s Big Cajun Peaking facility in Louisiana from regulation by the SEC under the Public Utility Holding Company Act (PUHCA), and to sell power from the facility at market-based rates, had not been made. NRG has since discussed the situation with the FERC and the SEC and made those filings. EWG status was granted by the FERC, effective April 17, 2002. Although NRG does not expect any material legal or regulatory action to be taken by those agencies, the failure to have made these filings could be viewed as an event of default under certain of NRG s debt facilities, including the $2 billion construction and acquisition revolving credit facility and the $1 billion unsecured corporate revolving line of credit. Accordingly, NRG sought and has received from its construction and acquisition revolving credit facility lenders a waiver of any event of default occurring as a result of Big Cajun Peaking Power s failure to file for exemption from regulation under PUCHA, and has sought and received from its corporate revolver lenders an amendment to its corporate revolving line of credit to provide that such failure to obtain or maintain exemption from regulation under PUHCA will not cause an event of default under that facility. While the construction and acquisition revolver waiver and the corporate revolver amendment were being discussed and finalized with its lenders, NRG did not borrow under either of these credit facilities. The waiver under the construction and acquisition facility continues indefinitely unless a default arising out of any possible PUHCA violation relating to Big Cajun s temporary failure to make these filings occurs. No fines or refunds have been asserted against NRG or any of its subsidiaries or affiliates by the FERC as a result of these missed filings.

Xcel Energy Impacts

Xcel Energy does not believe that the ultimate resolutions of NRG s going concern uncertainty will affect Xcel Energy s ability to continue as a going concern. Xcel Energy is not dependent 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 operations and current 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 has access to additional debt and equity financing that is not conditioned upon the outcome of NRG s financial restructuring plan.

8. Rates and Regulation

Colorado

Merger Agreements Under the Stipulation and Agreement approved by the Colorado Public Utilities Commission (CPUC) in connection with the Xcel Energy merger, PSCo agreed to 1) file a combined electric, gas and steam rate case in 2002 with new rates effective in January 2003, 2) extend its electric incentive cost adjustment (ICA) mechanism through Dec. 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, 3) continue the Performance Based Regulatory Plan and the Quality of Service Plan through 2006 with an electric department earnings cap of 10.5 percent return on equity for 2002, 4) reduce electric rates annually by $11 million for the period August

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2000 to July 2002 and 5) cap merger costs associated with electric operations at $30 million and amortize such costs through 2002.

Incentive Cost Adjustment In early 2002, PSCo filed to increase rates under the ICA to recover the undercollection of electric supply costs through the period ended Dec. 31, 2001 (approximately $14.5 million, which went into effect on June 1, 2002) and to increase the ICA base rate for the recovery of 2002 costs which are projected to be substantially higher than the $12.78 per megawatt hour currently being recovered. PSCo s actual ICA base costs for 2001 were approximately $19 per megawatt hour. PSCo proposed to increase the ICA base in 2002 to avoid the significant deferral of costs and a large rate increase in 2003, although the Stipulation and Agreement provided for a rate recovery period of April 1, 2003, to March 31, 2004.

On May 10, 2002, the CPUC approved a Settlement Agreement between PSCo and other parties to increase the ICA base rate to $14.88 per megawatt hour, providing for recovery of the deferred 2001 costs and the projected higher 2002 costs over a 34-month period from June 1, 2002, to March 31, 2005. The prudency review and approval of actual costs incurred and recoverable under the ICA for 2001 and 2002 will be conducted in future rate proceedings by the CPUC. PSCo is currently projecting its costs for 2002 to be approximately $50 million to $60 million less than the ICA base allowed using the 2001 test year, resulting in an equal sharing of the difference between retail customers and PSCo. The mechanism for recovering fuel and energy costs for 2003 and later will be addressed in the pending 2002 rate case (discussed below).

General Rate Case In May 2002, PSCo filed a combined general rate case with the CPUC to address increased costs for providing energy to Colorado customers. The net impact of the filings would increase electric revenue by approximately $220 million annually. This is based on $127 million for fuel and purchased power (including amounts deferred under the ICA) and $93 million for cost of electric service. In addition, PSCo also requested a decrease in natural gas revenue by approximately $13 million to reflect lower wholesale gas costs. PSCo also requested that its authorized rate of return on equity be set at 12 percent for electricity and 12.25 percent for natural gas.

The current schedule for the rate case, as approved by the CPUC, is as follows:

November 2002 intervenor testimony;
January 2003 company rebuttal testimony;
February/ March 2003 hearings; and
April/ May 2003 rates effective.

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 in July 2002. A decision is expected in late 2002.

Texas

Transition to Competition Cost Recovery Application In December 2001, SPS filed an application with the Public Utility Commission of Texas (PUCT) to recover $20.3 million in costs related to transition to retail competition from the Texas retail customers. 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 request to $13 million to reflect the PUCT approval of SPS using 1999 over-earnings to offset the claims for reimbursement of transition to competition costs. 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.

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Fuel Clause Adjustment Mechanisms The PUCT s regulations require periodic examination of SPS fuel and purchased power costs, the efficiency of the use of such fuel and purchase power, fuel acquisition and management policies and purchase power commitments. SPS is required to file an application for the PUCT to retrospectively review, at least every three years, the operations of a utility s electricity generation and fuel management activities.

In June 2002, SPS filed its fuel reconciliation to review costs recorded for calendar years 2000 and 2001 in the amount of $608 million. A pre-hearing conference was held in October 2002 and discovery in this case is in process. Hearings are scheduled for March 2003.

Minnesota

Metro Emissions Reduction Program In July 2002, NSP-Minnesota filed for approval by the Minnesota Public Utilities Commission (MPUC) a proposal to invest in existing NSP-Minnesota generation facilities to reduce emissions under the terms of legislation adopted by the 2001 Minnesota Legislature. The proposal includes the installation of state-of-the-art pollution control equipment at the A.S. King plant and conversion from coal to natural gas at the High Bridge and Riverside plants. Under the proposal, major construction would start in 2005 and be completed in 2009. 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. 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.

Renewable Cost Recovery Tariff In April 2002, NSP-Minnesota 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, and is proposed to be effective Jan. 1, 2003. In July 2002, the Minnesota Department of Commerce filed comments supporting approval of the tariff mechanism, subject to certain modifications that are generally acceptable to Xcel Energy.

Minnesota Financial and Service Quality Investigation On Aug. 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 Oct. 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. In addition, the order requires a number of reporting requirements regarding financial information and work with interested parties on various issues to ensure NSP-Minnesota s commitments are fulfilled. In addition, the order imposes restrictions on NSP-Minnesota s ability to seek rate increases, encumber utility property, provide intercompany loans and calculate cost of capital. The Minnesota Department of Commerce and Office of Attorney General also have begun their own investigation. There is no scheduled date for completion.

Federal Energy Regulatory Commission

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 rulemaking 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

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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. RTOs or Independent Transmission Providers will administer the market. RTOs will also be responsible for creating 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 are due in the fourth quarter of 2002 and first quarter of 2003. The FERC recently extended the comment period but anticipates that the final rules will be in place in 2003 and the contemplated market changes will take place in 2003 and 2004.

Standards of Conduct Rulemaking In October 2001, the FERC issued a Notice of Proposed Rulemaking proposing to adopt new standards of conduct rules applicable to all jurisdictional electric and natural gas transmission providers. The proposed rules would replace the current rules governing the electric transmission and wholesale electric functions of the Xcel Energy utility subsidiaries and NRG, respectively; and the rules governing the natural gas transportation and wholesale gas supply functions of Viking Gas, e prime and the Xcel Energy utility subsidiaries, respectively. The proposed rules would expand the definition of affiliate and further limit communications between transmission functions and supply functions, and could materially increase operating costs of Xcel Energy. In April 2002, the FERC staff issued a reaction paper, generally rejecting the comments of parties opposed to the proposed rules. Though final rules were expected by year-end 2002, they may be delayed while the FERC pursues development of its Standard Market Design Rulemaking.

FERC Investigation On May 8, 2002, the FERC ordered all sellers of wholesale electricity and/or ancillary services to the California Independent System Operator or Power Exchange, including Xcel Energy and NRG, to respond to data requests, including requests for admissions with respect to certain trading strategies in which the companies may have engaged. The investigation is in response to memoranda prepared by Enron Corporation that detail certain trading strategies engaged in 2000 and 2001, which may have violated market rules. On May 22, 2002, Xcel Energy reported to the FERC that it had not engaged directly in any of the trading strategies identified in the May 8th inquiry. On May 22, 2002, NRG responded that it had not engaged in any trading activities outlined in the FERC request.

However, Xcel Energy also reported that at times during 2000 and 2001, its regulated operations did sell energy to another energy company that may then have re-sold 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 Xcel Energy made sales to the other electricity provider of approximately 8,000 megawatt-hours in the California intra-day market, which resulted in revenues to Xcel Energy of approximately $1.5 million. Xcel Energy cannot determine from its records what part of such sales were associated with overschedules.

To supplement the May 8th request, on May 21, 2002, the FERC ordered 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, Xcel Energy reported to the FERC that it had not engaged in so-called round trip electricity trading identified in the May 21st inquiry.

On May 13, 2002, Xcel Energy reported that PSCo had engaged in a group of transactions in 1999 and 2000 with the trading arm of Reliant Resources in which PSCo bought a quantity of 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. Also, PSCo engaged in one trade with Reliant in which PSCo simultaneously bought and sold power at the same price without realizing any profit. The purpose of this nonprofit transaction was in consideration of future for-profit transactions.

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PSCo engaged in these transactions with Reliant for the proper commercial objective of making a profit. It did not enter into these transactions to inflate volumes or revenues.

In addition, the FERC is assessing whether to set for hearing the justness and reasonableness of rates charged in the Pacific Northwest from Dec. 25, 2000, through June 20, 2001. The FERC directed that an administrative law judge hold a hearing and make a preliminary assessment as to whether it should undertake such an investigation. On Sept. 25, 2001, an administrative law judge concluded that no further proceedings should be held. Various parties have sought rehearing of that order and have requested that the record be reopened in light of the disclosure of the Enron trading strategies. The proceeding is pending before the FERC.

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 Xcel Energy for certain information and documents. Xcel Energy is complying with the request.

SPS Commitment and Dispatch Agreement Golden Spread Electric Power Cooperative, Inc. (Golden Spread) and SPS are parties to a commitment and dispatch agreement pursuant to which SPS commits and dispatches the combined resources of both entities to meet their combined load requirements. Under this agreement, SPS purchases a significant amount of energy from Golden Spread at rates designed to share the savings between both parties. Golden Spread has filed a complaint at the FERC contending that SPS has underpaid it for the power it has supplied under the agreement by not providing it with an appropriate share of the savings that SPS has achieved. SPS in turn has filed a complaint at the FERC contending that Golden Spread has improperly inflated various cost components of the rate calculation. FERC has set both complaints for investigation and hearing, but has deferred the hearing pending settlement proceedings. The matter is now before a settlement judge. Even if SPS is required to pay more to Golden Spread for power purchased under this agreement, it believes that the amounts will likely be recoverable from customers under applicable fuel clauses.

Securities and Exchange Commission/ Commodity Futures Trading Commission

Temporary Modification of PUHCA Equity Ratio Limit In accordance with an order from the SEC granting Xcel Energy authority to finance, Xcel Energy cannot currently issue any securities or guarantees if its common equity ratio is below 30 percent.

On Aug. 2, 2002, Xcel Energy filed a proposal with the SEC seeking authorization to engage in financing transactions at a time when Xcel Energy s ratio of common equity to total capitalization is less than 30 percent. The proposal provided that the common equity of Xcel Energy, as reflected on its most recent Form 10-K, or Form 10-Q and as adjusted to reflect subsequent events that affect capitalization, be at least 24 percent of total capitalization. In addition, Xcel Energy proposed not to engage in any financing transactions after June 30, 2003, unless at such time Xcel Energy has an equity ratio of at least 30 percent. Xcel Energy expects that any reduction of its common equity ratio below 30 percent would be temporary pending resolution of the NRG restructuring.

On Nov. 7, 2002, the SEC issued an order authorizing Xcel Energy to engage in certain financing transactions through Mar. 31, 2003 so long as its common equity ratio, as reported in its 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 its total capitalization. At Sept. 30, 2002, and as adjusted for pending subsequent items that affect capitalization, Xcel Energy s common equity ratio was at least 24 percent. Financings of Xcel Energy authorized by the SEC included the issuance of debt (including convertible debt) to refinance or replace Xcel Energy s $400-million credit facility that expired on Nov. 8, 2002, issuance of $450 million of stock (less any amounts issued as part of the refinancing of the $400-million credit facility) and the renewal of

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guarantees for various trading obligations of NRG s power marketing subsidiary. The SEC reserved authorizing additional securities issuances by Xcel Energy through June 30, 2003 while its common equity ratio is below 30 percent. Xcel Energy also has the authority, under PUHCA, to issue approximately $100 million of debt securities with maturities of not more than nine months. In the event NRG were to seek protection under bankruptcy laws and Xcel Energy ceased to have control over NRG, NRG would cease to be a consolidated subsidiary of Xcel Energy for financial reporting purposes and Xcel Energy s common equity ratio under the SEC s method of calculation would exceed 30 percent.

SEC and CFTC Subpoenas Xcel Energy has received a subpoena from the SEC for documents concerning round trip trades, as defined in the SEC subpoena, in electricity and natural gas with Reliant Resources, Inc. for the period Jan. 1, 1999, to the present. The SEC subpoena is issued pursuant to a formal order of private investigation that does not name Xcel Energy. Based upon accounts in the public press, management believes that similar subpoenas in the same investigations have been served on other industry participants. Xcel Energy and PSCo are cooperating with the regulators and taking steps to assure satisfactory compliance with the subpoenas.

Xcel Energy and PSCo have also received subpoenas from the Commodity Futures Trading Commission for documents and other information concerning these so-called round trip trades and other trading in electricity and natural gas for the period Jan. 1, 1999, to the present involving Xcel Energy or any of its subsidiaries.

9. Commitments and Contingent Liabilities

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition of them.

Xcel Energy and its subsidiaries have been or are currently involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, Xcel Energy is pursuing or intends to pursue insurance claims and believes it will recover some portion of these costs through such claims. Additionally, where applicable, Xcel Energy is pursuing, or intends to pursue, recovery from other potentially responsible parties and through the rate regulatory process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense for such unrecoverable amounts.

Note 7 to the Financial Statements describes the current status of credit contingencies related to NRG and related financial impacts. The circumstances set forth in Notes 15 and 16 to Xcel Energy s financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2001, appropriately represent, in all material respects, the current status of other commitments and contingent liabilities, including those regarding public liability for claims resulting from any nuclear incident, and are incorporated herein by reference. The following are unresolved contingencies discussed in the 2001 Annual Report on Form 10-K that are material to Xcel Energy s financial position as of Sept. 30, 2002:

California Power Market Collectibility of NRG receivables;

Tax Matters Tax deductibility of corporate-owned life insurance loan interest and

Commitments

Capital Commitments Xcel Energy has received and revised its capital expenditure forecast. The utility capital expenditure forecast is detailed in the following table.

	2002	2003	2004
	(Millions of dollars)		
Total utility	$960	$925	$1,030

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)   (Continued)

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 affect 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 circumstances to provide up to $300 million to NRG. Xcel Energy has not to date provided funds to NRG under this agreement. Xcel Energy currently is evaluating the circumstances under which it would make any further investment in NRG.

In September 2002 and in connection with NRG s collateral extension agreement, Xcel Energy provided NRG with an acknowledgement letter pursuant to which Xcel Energy acknowledged and agreed that demand for a drawing of the $300 million had been made by NRG and its lenders, pursuant to the Support and Capital Subscription Agreement; and funds provided by Xcel Energy will be contributed as equity or as subordinated loans. As a part of the agreement, NRG and its lenders agreed not to enforce the terms of the Support and Capital Subscription Agreement, in exchange for which Xcel Energy agreed not to make any dividends or repurchase shares of its capital stock during the term of the collateral extension agreement, expiring on Nov. 15, 2002, if it would negatively affect its ability to perform under the Support and Capital Subscription Agreement. See further discussion at Note 6.

Environmental Contingencies

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 United States 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. Xcel Energy disagrees with the assertions contained in the NOV and intends to vigorously defend its 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 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.

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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 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 EPA s initial information requests related to NSP-Minnesota plants in Minnesota. On May 22, 2002, EPA issued a follow-up information request to Xcel Energy seeking additional information regarding NSR compliance at its plants in Minnesota. Xcel Energy is in the process of responding to the follow-up request.

NRG Opacity Consent Order NRG became part of an opacity consent order as a result of acquiring its Huntley, Dunkirk and Oswego plants from Niagara Mohawk. At the time of financial close on these assets, a consent order was being negotiated between Niagara Mohawk and the New York Department of Environmental Conservation (NYDEC). The order required Niagara Mohawk to pay a stipulated penalty for each opacity event at these facilities. On Jan. 14, 2002, the NYDEC issued NRG NOVs for opacity events, which had occurred since the time NRG assumed ownership of Huntley, Dunkirk and Oswego generating stations. The NOVs allege that a total of 7,231 events had occurred where the average opacity during a six-minute block of time had exceeded 20 percent. The NYDEC proposed a penalty associated with the NOVs at $900,000. NRG is in negotiations with the NYDEC to settle the dispute.

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, 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.

Estimates of the ultimate cost to remediate the Ashland site vary from $4 million to $93 million, depending on the final remediation option chosen by the EPA and the Wisconsin Department of Natural Resources (WDNR). The EPA and WDNR have not yet selected the final method of remediation to use at the site. In the interim, NSP-Wisconsin has recorded a liability 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, reasonably effective remedial methods and considering the results of ongoing negotiations with governmental authorities overseeing the remediation.

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 2003 or 2004.

Legal Contingencies

California Litigation Public Utility District No. 1 of Snohomish County, Washington, has filed a suit against Xcel Energy in United States District Court for the Central District of California 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. A hearing on the motion to dismiss is scheduled for Dec. 19, 2002.

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.

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Fortistar Litigation In July 1999, Fortistar Capital Inc. filed a complaint in District Court 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 entered into a binding, conditional settlement of the litigation, pending certain approvals and final agreement on the terms of the settlement. Because the conditions for settlement have not been satisfied, the parties have renewed negotiations to explore alternative terms for reaching a settlement.

During the second quarter of 2002, NRG expensed a pre-tax charge of $36 million related to its NEO Corporation landfill gas generation operations, as discussed in Note 2. The charge related largely to asset impairments based on a revised project outlook developed in 2002. It also reflects the accrued impact of the 2002 dispute settlement with Fortistar, a partner with NEO in the Minnesota Methane LLC landfill gas generation operations.

Shareholder/ ERISA Litigation On July 31, 2002, a lawsuit purporting to be a class action on behalf of purchasers of Xcel Energy common stock between Jan. 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 alleges 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, the existence of cross-default provisions in Xcel Energy s and its subsidiary NRG Energy s credit agreements with lenders, NRG s liquidity and credit status, the supposed risks to Xcel Energy s credit rating and the status of Xcel Energy s internal controls to monitor trading of its power. Since the filing of the lawsuit, 13 additional, similar lawsuits have been filed on behalf of a similar class of common stock purchasers, seeking similar remedies, one of which has subsequently been voluntarily dismissed. The complaint seeks an unspecified amount of damages, interest, attorneys fees and other costs. On Sept. 30, 2002, a further lawsuit making essentially identical allegations, identifying the same class period and seeking the same type of relief was filed in the same court on behalf of a purported class of purchasers of two series of NRG Senior Notes.

On Sept. 23, 2002, an action was filed in the United States District Court in Colorado, on behalf of a purported class of employee participants in certain Xcel Energy employee benefit plans, identifying a class period of Sept. 23, 1999, through the date of filing, and naming Xcel Energy and certain present and former directors and officers as defendants. A second similar action, identifying a class period of Oct. 8, 1999, through the date of filing, followed in the same court. Both actions assert violations of the Employee Retirement Income Security Act of 1974 (ERISA), predicated on essentially the same financial circumstances underlying the class actions and the derivative actions, and asserting breach of fiduciary duty and disclosure violations regarding Xcel Energy stock in the benefit plans. The complaints seek a declaration that defendants violated ERISA, unspecified injunctive relief, restitution, disgorgement and other unspecified relief, interest, attorneys fees and other costs.

The defendants in all these actions deny any liability and maintain that their disclosures and other conduct have been fully compliant with applicable laws and reporting requirements.

On Aug. 15, 2002, a shareholder derivative action was filed in the same court as the class actions described above purportedly on Xcel Energy s behalf, against certain present and former directors and officers of Xcel Energy, citing essentially the same circumstances as the class actions and asserting breach of fiduciary duty. Subsequently, two additional derivative actions were filed in the District Court for Hennepin County, Minnesota against essentially the same defendants, focusing on supposed wrongful energy trading

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

activities and asserting breach of fiduciary duty for failure to establish and maintain adequate accounting controls, abuse of control and gross mismanagement. Collectively, the derivative complaints seek judgment in favor of Xcel Energy for an unspecified amount of damages, return of salaries and other compensation, attorney s fees and other costs. Xcel Energy and its board of directors will consider the proper manner in which to address the derivative actions, which are ostensibly brought for Xcel Energy s benefit.

Potential NRG Bankruptcy As discussed in Notes 6 and 7, NRG continues to work 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. Following an agreement on the restructuring with NRG s Creditors and as described in Note 6 above, 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 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; 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. 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 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 resolve the issue. One of the creditors of an NRG project (Pike, as discussed in Note 4) 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 financial statements do not reflect any conditions or matters that would arise if NRG was in bankruptcy.

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) to Shaw. Pike is 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. See Note 4 for additional discussion regarding Pike.

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. Due to the uncertainty of the final adjustment, an estimate of the final amount has not been recorded in the results for the quarter ended Sept. 30, 2002.

Conectiv Agreement Termination On Nov. 8, 2002 Conectiv provided NRG with a Notice of Termination of Transaction under the Master Power Purchase and Sale Agreement (Master PPA) dated June 21, 2001. Under the Master PPA, which was assumed by NRG in its acquisition of various assets from Conectiv, NRG had been required to deliver 500 MW of electrical energy around the clock at a specified price through 2005. In connection with the Conectiv acquisition, NRG recorded an out-of-market contract

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

obligation for this agreement. As a result of the cancellation, NRG will lose approximately $402 million in future contracted revenues. Also, in conjunction with the terms of the Master PPA, NRG will receive from Conectiv a termination payment in the amount of $955,000. At Sept. 30, 2002, the balance of the contract obligation was approximately $54 million.

10. Short-Term Borrowings and Financing Instruments

Xcel Energy Short-Term Borrowings At Sept. 30, 2002, Xcel Energy and its subsidiaries had approximately $2.0 billion of short-term debt outstanding at a weighted average interest rate of approximately 4.383 percent. See Managements Discussion and Analysis Financing Activities for discussion of debt issuance in 2002.

On Nov. 8, 2002, Xcel Energy entered into a Securities Purchase Agreement (the Purchase Agreement) with Citadel Equity Fund Ltd., Citadel Credit Trading Ltd. and Jackson Investment Fund Ltd. (together, the Purchasers). Pursuant to the Purchase Agreement, Xcel Energy may issue and sell, in one or more private placements, up to $350 million principal amount of 8 percent senior convertible notes (the Notes). In all cases, the notes shall be issued for a gross amount equal to their principal amount. The Notes are convertible into Xcel Energy s common stock at any time and from time to time after their issuance date by the holder at the conversion prices described below (subject in each instance to adjustment for stock splits, stock dividends, stock combinations and similar transactions as well as certain issuances by Xcel Energy of common stock or common stock derivative securities). Each of the Notes has an initial maturity of 364 days that can be extended by the holder for additional 364-day periods up to a maximum maturity of 5 years.

The following summary highlights certain material terms of the private placement transactions between Xcel Energy and the Purchasers. Because this is a summary, it does not contain all of the information that is included in the transaction documents and, consequently, is qualified in its entirety by the Purchase Agreement, the Registration Rights Agreement, and the form of Notes, which are attached, or incorporated by reference as exhibits to the this Form 10-Q (the forms of Notes are being refiled with this 10-Q to reflect certain technical corrections) (collectively, the Transaction Documents).

On Nov. 8, 2002, Xcel Energy issued $100 million principal amount of Notes (the First Notes). The conversion price for the First Notes will be 110 percent of the arithmetic average of the weighted average price of Xcel Energy s common stock for the 20 consecutive trading days commencing on the 5th trading day immediately following the date of issuance (the First Notes Pricing Period) provided (i) that the conversion price shall not exceed $11.59 and (ii) until the end of the First Notes Pricing Period the conversion price shall equal 110 percent of the arithmetic average of the weighted average price of Xcel Energy s common stock for the each of the trading days during the First Call Pricing Period through the date of receipt of a Company Call Notice (as hereinafter defined); and provided further that the conversion price shall be equal to 110 percent of the closing bid price of Xcel Energy s common stock on the 35th business day following the date of issuance date of the First Notes if Xcel Energy has not delivered a Company Call Notice and such price is less than the conversion price then in effect.

Unless the First Notes have previously been redeemed by Xcel Energy, the sale of $50 million principal amount of Notes (the Second Notes) is expected to occur on Nov. 22, 2002, subject to satisfaction of certain conditions precedent. The conversion price for the Second Notes will be 110 percent of the arithmetic average of the weighted average price of Xcel Energy s common stock for the 10 consecutive trading days following the First Notes Pricing Period (the Second Notes Pricing Period, and together with the First Notes Pricing Period, the Pricing Periods); provided that (i) the conversion price shall not exceed 110 percent of the weighted average price of Xcel Energy s common stock on the date of issuance of the Second Notes and (ii) during the Second Notes Pricing Period the conversion price shall equal the lesser of (x) 110 percent of the arithmetic average of the weighted average price of Xcel Energy s common stock for each of the trading days in the Second Notes Pricing Period through the date of receipt of a Company Call Notice and (y) the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

weighted average price of the common stock on the date of issuance of the Second Notes; and provided further that the conversion price shall be equal to 110 percent of the closing bid price of Xcel Energy s common stock on the 35th business day following the issuance date of the First Notes if Xcel Energy has not delivered a Company Call Notice and such price is less than the conversion price then if effect.

The First Notes and the Second Notes are redeemable at the option of Xcel Energy during the period of 35 business days following the issuance of the First Notes upon delivery by Xcel Energy of a notice to the holder of such Notes (the Company Call Notice); provided that Xcel Energy cannot deliver a Company Call Notice unless it has first consummated an offering of convertible debt securities in an underwritten offering resulting in gross proceeds to Xcel Energy of not less than $150 million (a Qualified Offering). Xcel Energy is under no obligation to consummate a Qualified Offering nor is there any obligation on Xcel Energy to redeem the Notes in the event of Xcel Energy s consummation of Qualified Offering. The closing of any redemption effected by Xcel Energy shall be on the date that is five business days after the 35th business day following the issuance of the First Notes (the Redemption Closing Date). Except as provided above, Xcel Energy may not retire, redeem or otherwise accelerate the final maturity of the Notes.

If Xcel Energy has elected to optionally redeem the Notes, Xcel Energy shall pay to the holders of the Notes in cash the greater of (1) 102 percent of the principal amount, plus accrued interest, on such Notes (the Conversion Amount) and (ii) the sum of (x) the product of the Conversion Amount and the quotient determined by dividing the closing bid price of Xcel Energy s common stock on the date of the Company Call Notice and the applicable Redemption Conversion Price (as hereinafter defined) and (y) 12 percent of the Conversion Amount of the Note. In addition, Xcel Energy shall deliver to the holders of the Note a written agreement granting the holders the right for a one-year period following the redemption of the Notes to purchase securities identical (other than the issuance date) to the securities issued in the Qualified Offering in an aggregate principal amount of up to 25 percent of the aggregate principal amount of securities issued in the Qualified Offering. The Redemption Conversion Price equals, in the case of the First Notes and the Second Notes, 110 percent of the volume weighted average price of the common stock on the respective dates of issuance of such Notes; provided that if the Company Call Notice is delivered after the initiation of a Pricing Period, then the Redemption Conversion Price shall equal 110 percent of the arithmetic average of the volume weighted average price of the common stock during such period if such price is lower. Under certain circumstance described in the Transaction Documents, the holders of Notes may elect to receive all or a portion of the cash amount described above in shares of Xcel Energy s common stock by providing notice thereof to Xcel Energy prior to the Redemption Closing Day.

In the event that the Company Call Notice is not delivered within the first 35 business days following the issuance date of the First Notes, from and after such 35th day through and including the one year anniversary date of the issuance of the First Notes, the holders of the Notes shall have the right, at any time and from time to time to purchase up to an additional (i) $50 million of Notes identical (other than the issuance date) to the First Notes (the First Call Notes) and (ii) $25 million of Notes identical (other than the issuance date) to the Second Notes (the Second Call Notes). The holders of the Notes are under no obligation to elect to purchase First Call Notes or Second Call Notes.

In the event that the Company Call Notice is not delivered within the first 35 business days following the issuance date of the First Notes, Xcel Energy may elect to issue and sell to the Purchasers, on a date which is 120 calendar days after the issuance date of the First Notes, up to $100 million principal amount of the Notes (the Third Notes). Xcel Energy s election to effect such issue and sale (the Company Put) must be made within the 90 calendar days following the issuance date of the First Notes. The conversion price of the Third Notes shall be 110 percent of the arithmetic average of the weighted average price of Xcel Energy s common stock during the 20 day trading period beginning 90 days after the date of issuance of the First Notes, not to exceed the arithmetic average of the weighted average price of Xcel Energy s common stock during the 20 day trading period ending on the trading day that is immediately prior to the 90th calendar day after the

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date of issuance of the First Notes. Xcel Energy s right to elect the Company Put is subject to certain terms and conditions described in the Transaction Documents. Xcel Energy is under no obligation to elect the Company Put.

At any time and from time to time during the period from the date of issuance of the Third Notes until the date which is 365 days after the date of issuance of the Third Notes, the holders may purchase additional Notes identical to the Third Notes (other than the issuance date) in an aggregate principal amount up to 25 percent of the aggregate principal amount of the Third Notes issued (the Third Call Notes). A holder of Third Notes is under no obligation to elect to purchase Third Call Notes.

Upon the occurrence of a Change of Control (as defined in the Notes), the holders of the Notes may elect to require Xcel Energy to redeem all or any portion of the Notes. The redemption price payable by Xcel Energy in such circumstance is a price equal to the Conversion Amount of such Notes multiplied by the greater of 115 percent and a fraction, the numerator of which is equal to the closing sale price immediately following the public announcement of such proposed Change of Control and a denominator equal to the conversion price applicable to such Notes.

The Notes are also subject to acceleration upon the occurrence of an Event of Default (as defined in the Notes). The coupon rate is subject to increase by 2 percent upon the occurrence of an Event of Default and upon the occurrence of other events described in the Transaction Documents.

Credit Facilities As of Sept. 30, 2002, Xcel Energy had the following credit facilities available to meet its liquidity needs:

Company	Total Facility	Drawn	Credit Available	Cash	Total Liquidity	Facility Maturity
			(Millions of dollars)			
NSP-Minnesota	$ 300	$ 100	$200	$408	$609	Aug-2003
NSP-Wisconsin	0	0	0	15	15	
PSCo	530	88	442	111	553	June-2003
SPS	250	0	250	78	328	Feb-2003
Xcel Energy -	400*	400	0			Nov-2002
Holding Company	400	400	0	238	238	Nov-2005
NRG	1,000	1,000	0	347	347	Mar-2003

* This facility matured in November 2002 and was not renewed.

NSP-Minnesota Credit Facility In August 2002, in connection with its 364-day, $300-million credit agreement renewal, NSP-Minnesota also issued $308 million of first mortgage bonds, due Aug. 15, 2003 to Wells Fargo Bank, N.A. pursuant to the credit agreement. The obligations under the credit agreement will be secured by this series of bonds.

PSCo Credit Facility In September 2002, PSCo issued and delivered $530 million of first collateral trust bonds to a certain bank to secure its payment obligations under its $530-million, 364-day credit facility.

NRG Short-Term Borrowings In March 2002, NRG s $500-million recourse revolving credit facility matured and was replaced with a $1.0-billion, 364-day revolving line of credit, which terminates on March 7, 2003. The facility is unsecured. The credit agreement for this facility was amended in April 2002 to revise the interest coverage ratio covenant. As amended, the covenant requires NRG to maintain a minimum interest coverage ratio that varies throughout the year from 1.75 to 1.00 as determined at the end of each fiscal quarter. The facility contains additional covenants that, among other things, restrict the incurrence of liens and require NRG to maintain a net worth of at least $1.5 billion plus 25 percent of NRG s consolidated net income from Jan. 1, 2002, through the determination date. In addition, NRG must maintain a debt to

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capitalization ratio, as defined in the credit agreement, of not more than 0.68 to 1.00. The failure to comply with any of these covenants would be an Event of Default under the terms of the credit agreement At Sept. 30, 2002, NRG had a $1-billion outstanding balance under this credit facility. As of Sept. 30, 2002, the weighted average interest rate of such outstanding advances was 7.7 percent per year. NRG missed the $7.6 million interest payment due on Sept. 30, 2002, and as of Sept. 30, 2002, NRG violated both the minimum net worth covenant and the minimum interest coverage ratio. 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 $1.0-billion, 364-day revolving line of credit. During the second quarter of 2002, the letter of credit facility agreement was amended to incorporate the same covenant revisions and other amendments that had previously been made to the terms and conditions of NRG s $1-billion revolving credit facility, including the addition of an interest coverage ratio covenant. As of Sept. 30, 2002, NRG violated both the minimum net worth covenant and the minimum interest coverage ratio. Accordingly, the facility is in default.

As of Dec. 31, 2001, NRG, through its wholly owned subsidiary NRG South Central Generating LLC, had outstanding approximately $40 million under a project level, non-recourse revolving credit agreement. In June 2002, this facility was paid off and was not renewed.

NRG Revolving Credit In May 2001, NRG s wholly-owned subsidiary, NRG Finance Company I LLC, entered into a $2-billion revolving credit facility. The facility was to be 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 provides for borrowings of base rate loans and Eurocurrency loans and is secured by mortgages and security agreements in respect of the assets of the projects financed under the facility, pledges of the equity interests in the subsidiaries or affiliates of the borrower that own such projects and by guaranties from each such subsidiary or affiliate. Provided that certain conditions are met that assure the lenders that sufficient security remains for the remaining outstanding loans, the borrower may repay loans relating to one project and have the liens relating to that project released. Loans that have been repaid may be re-borrowed, as permitted by the terms of the facility. The facility terminates on May 8, 2006. The facility is non-recourse to NRG other than its obligation to contribute equity at certain times in respect of projects and turbines financed under the facility. As of Sept. 30, 2002, the aggregate amount outstanding under this facility was $1.1 billion, and NRG estimates the obligation to contribute equity to be approximately $819 million. At Sept. 30, 2002, the weighted average interest rate of such outstanding advances was 7.6 percent. Interest and fees due on Sept. 30, 2002 were not paid, and NRG has suspended equity contributions to the project in order to support construction activities. Thus, NRG is currently in default under this facility. See Note 7 for a discussion of the acceleration of debt under this credit facility and for further discussion of NRG s credit and liquidity contingencies.

Financing Instruments As of Sept. 30, 2002, Xcel Energy, excluding NRG, had several interest rate swaps with a notional amount of approximately $101 million. If the swaps were terminated at Sept. 30, 2002, Xcel Energy or its subsidiaries would have had to pay the counterparties approximately $18 million. In addition, as of Sept. 30, 2002, NRG had several interest rate swaps with a notional amount of approximately $2.9 billion. If the NRG swaps were terminated at Sept. 30, 2002, NRG would have had to pay the counterparties approximately $112 million.

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. The majority of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in

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XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

the guarantees. As of Sept. 30, 2002, Xcel Energy had the following amount of guarantee and exposure under these guarantees:

Subsidiary	Total Guarantee	Exposure under Guarantee
	(Millions of dollars)	
NRG	$234	$104
e prime	$294	$ 78
Viking	$ 60	$ 60
Other Subsidiaries	$276	$ 81
Total	$864	$323

Xcel Energy guarantees certain obligations for NRG s power marketing subsidiary, relating to power marketing obligations, fuel purchasing transactions and hedging activities; e prime, relating to trading and hedging activities; and Viking Gas, relating to the Guardian pipeline project. The Viking Gas guarantee terminates no earlier than 90 days after the in-service date of the project. Viking expects the guarantee to terminate in April 2003.

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 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 Sept. 30, 2002, NRG s obligations pursuant to its guarantees of the performance, equity and indebtedness obligations of its subsidiaries totaled approximately $687.9 million.

In addition, Xcel Energy provides indemnity protection for bonds issued by subsidiaries. The total amount of bonds with this indemnity outstanding as of Sept. 30, 2002, was approximately $351 million, of which $6.7 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.

11. Derivative Valuation and Financial Impacts

Xcel Energy analyzes derivative financial instruments in accordance with SFAS No. 133. This statement requires that all derivative financial instruments 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 income statement, 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.

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XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

The components of SFAS No. 133 impacts on Xcel Energy s Other Comprehensive Income, included in stockholders equity, are detailed in the following table:

	9 Months ended Sept. 30	
	2002	2001
	(Millions of dollars)	
Balance at Jan. 1	$ 34.2	$
Net unrealized transition loss at adoption, Jan. 1, 2001		(28.8)
After-tax net unrealized gains related to derivatives accounted for as hedges	69.2	7.2
After-tax net realized (gains) losses on derivative transactions reclassified into earnings	(11.9)	32.2
Acquisition of NRG minority interest	27.4	
Accumulated other comprehensive income related to SFAS No. 133	$118.9	$ 10.6

The components of the gain for SFAS No. 133 impacts on Xcel Energy s income statement for the three and nine months ended Sept. 30, 2002 and 2001, excluding gains and losses from trading activities, are detailed in the following table:

	3 Months ended Sept. 30		9 Months ended Sept. 30	
	2002	2001	2002	2001
	(Millions of dollars, except per share data)			
Increase (decrease) in income:				
Nonregulated and other revenues	$(33.8)	$(10.2)	$ 2.5	$(21.6)
Equity earnings from investment in affiliates	1.8	(1.7)	(0.9)	(0.9)
Electric fuel and purchased power utility	(0.6)	(1.2)	0.4	(1.0)
Cost of goods sold nonregulated and other	(21.3)	(7.6)	(21.1)	(12.8)
Other income (deductions)	(2.9)	(2.2)	(3.1)	
Total decrease before minority interest and income tax	$(56.8)	$(22.9)	$(22.2)	$(36.3)
Net-of-tax decrease in net income	$(33.6)	$(11.5)	$(15.1)	$(13.9)
Increase (decrease) in EPS-diluted	$(0.08)	$(0.03)	$(0.04)	$(0.04)

Xcel Energy records the fair value of its derivative instruments in its Consolidated Balance Sheet as separate line items noted as Derivative Instruments Valuation for assets and liabilities as well as current and noncurrent.

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 their 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 INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

Xcel Energy evaluates all of its contracts within the regulated and nonregulated operations when such contracts are entered into 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 operations are considered normal under the provisions of SFAS No. 133.

Normal purchases and normal sales contracts are accounted for as executory contracts as required under other generally accepted accounting principles.

Cash Flow Hedges Xcel Energy and its subsidiaries enter into derivative instruments to manage their 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 Sept. 30, 2002, Xcel Energy had various commodity related contracts extending through 2018. Earnings on these cash flow hedges are recorded as the hedged purchase or sales transaction is completed. This could include the physical sale of electric energy or the usage of natural gas to generate electric energy. Xcel Energy expects to reclassify into earnings through September 2003 net gains from Other Comprehensive Income of approximately $86.4 million.

As required by SFAS No. 133, Xcel Energy recorded losses of $0.6 million and losses of $15.9 million related to ineffectiveness on commodity cash flow hedges during the three months ended Sept. 30, 2002, and 2001, respectively; and gains of $0.4 million and losses of $2.0 million related to ineffectiveness on commodity cash flow hedges during the nine months ended Sept. 30, 2002, and 2001, respectively.

Xcel Energy recorded unrealized losses of $53.1 million and unrealized losses of $1.2 million associated with changes in the fair value of non-hedge, energy-related derivative instruments for the three months ended Sept. 30, 2002 and Sept. 30, 2001, respectively. Xcel Energy recorded unrealized losses of $19.5 million associated with changes in the fair value of non-hedge, energy-related derivative instruments for the nine months ended Sept. 30, 2002. There was no impact for the nine months ended Sept. 30, 2001.

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 through September 2003 net gains from Other Comprehensive Income of approximately $30.6 million.

As a result of various defaults under certain loan agreements, NRG s counterparties have terminated interest rate swaps with NRG, Brazos Valley LP and NRG Finance Company I LLC. As a result of the interest rate swap agreement terminations, the amounts recorded for them as cash flow hedges in Other Comprehensive Income are expected to be relieved from the Other Comprehensive Income account over the remaining period of the debt. Until NRG successfully restructures outstanding debt and returns to credit quality, the company will not seek to manage interest rate risk through the use of financial derivatives.

Xcel Energy records hedge effectiveness 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 are recorded as a component of interest expense.

Fair Value Hedges and 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. Xcel Energy does not expect to reclassify any significant amounts into earnings through September 2003 from Other Comprehensive Income on foreign currency swaps accounted for as hedges.

XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

Xcel Energy recorded unrealized losses of $1.0 million and unrealized losses of $2.1 million associated with changes in the fair value of non-hedge, foreign currency derivative instruments for the three months ended Sept. 30, 2002, and Sept. 30, 2001, respectively. Unrealized losses of $0.8 million and unrealized gains of $3,000 associated with changes in the fair value of non-hedge, foreign currency derivative instruments were recorded for the nine months ended Sept. 30, 2002, and Sept. 30, 2001, respectively.

In addition, Xcel Energy recorded losses of $2.3 million related to the discontinuance of hedge accounting for the three and nine months ended Sept. 30, 2002.

Derivatives Not Qualifying for Hedge Accounting Xcel Energy and its subsidiaries have various trading operations that enter into derivative instruments. These derivative instruments are accounted for on a mark-to-market basis in our Consolidated Statements of Income. All derivative financial instruments are recorded at the amount of the gain or loss from the transaction within Operating Revenues on the Consolidated Statements of Income.

In order to preserve the U.S. dollar value of projected foreign currency cash flows from European trading operations, Xcel Energy and its subsidiaries enter into various foreign currency exchange contracts that are not designated as accounting hedges but are considered economic hedges. Accordingly, the changes in fair value of these derivatives are reported in Other Nonoperating Income in the Consolidated Statements of Income.

12. Segment Information

Xcel Energy has the following reportable segments: Electric Utility, Gas Utility and two of its nonregulated energy businesses, NRG and e prime. Trading operations performed by regulated operating companies are not a reportable segment; electric trading results (net of trading costs) are included in the Electric Utility segment and gas trading results are presented as e prime. In 2002, all other includes $676 million of tax benefits as discussed in Note 14.

	Electric Utility	Gas Utility	NRG	e prime	All Other	Reconciling Eliminations	Consolidated Total
	(Thousands of dollars)						
3 months ended Sept. 30, 2002							
Operating revenues from external customers	$1,553,800	$138,961	$ 728,653	$5,113	$ 82,129		$ 2,508,656
Intersegment revenues	281	(93)			24,956	(25,681)	(537)
Equity in earnings of unconsolidated affiliates			26,718	559	693		27,970
Total revenues	$1,554,081	$138,868	$ 755,371	$5,672	$107,778	$(25,681)	$ 2,536,089
Segment net income (loss)	$ 175,427	$ 3,127	$(2,925,314)	$2,451	$684,776	$(14,427)	$(2,073,960)

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XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

	Electric Utility	Gas Utility	NRG	e prime	All Other	Reconciling Eliminations	Consolidated Total
	(Thousands of dollars)						
3 months ended Sept. 30, 2001							
Operating revenues from external customers	$1,824,458	$216,030	$749,448	$3,442	$ 76,428		$2,869,806
Intersegment revenues	253	1,082	165		21,271	(21,959)	812
Equity in earnings of unconsolidated affiliates			111,132	323	(434)		111,021
Total revenues	$1,824,711	$217,112	$860,745	$3,765	$ 97,265	$(21,959)	$2,981,639
Segment net income (loss)	$ 183,442	$ (5,295)	$141,580	$1,293	$(40,103)	$ (8,014)	$ 272,903

	Electric Utility	Gas Utility	NRG	e prime	All Other	Reconciling Eliminations	Consolidated Total
	(Thousands of dollars)						
9 months ended Sept. 30, 2002							
Operating revenues from external customers	$4,114,715	$937,751	$ 1,859,123	$6,597	$248,726		$ 7,166,912
Intersegment revenues	782	663			67,903	(68,628)	720
Equity in earnings of unconsolidated affiliates			68,916	1,266	2,957		73,139
Total revenues	$4,115,497	$938,414	$ 1,928,039	$7,863	$319,586	$(68,628)	$ 7,240,771
Segment net income (loss)	$ 384,875	$ 51,965	$(2,993,129)	$1,750	$701,563	$(30,178)	$(1,883,154)

	Electric Utility	Gas Utility	NRG	e prime	All Other	Reconciling Eliminations	Consolidated Total
	(Thousands of dollars)						
9 months ended Sept. 30, 2001							
Operating revenues from external customers	$5,085,433	$1,576,732	$1,852,280	$15,385	$249,838		$8,779,668

Intersegment revenues	716	3,241	1,859		48,711	(53,384)	1,143
Equity in earnings of unconsolidated affiliates			193,875	1,022	3,629		198,526
Total revenues	$5,086,149	$1,579,973	$2,048,014	$16,407	$302,178	$(53,384)	$8,979,337
Segment net income (loss)	$ 449,926	$ 48,464	$ 225,872	$ 7,131	$ (62,637)	$(18,686)	$ 650,070

XCEL ENERGY INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) (Continued)

13. Pension Plan Funding and Costs

As disclosed in the 2001 Annual Report on Form 10-K, all of the Xcel Energy pension plans were fully funded and had no cash funding requirements as of Dec. 31, 2001. Investment performance on plan assets during 2002 has resulted in a deterioration of the funded status of the plans compared to 2001. Xcel Energy s pension plans, in the aggregate, were still fully funded as of Sept. 30, 2002 and, with minimal investment volatility for the rest of 2002, are expected to remain fully funded at year-end. Depending on final 2002 investment performance, some smaller plans within the group may be underfunded at Dec. 31, 2002.

However, no cash funding to any of Xcel Energy s pension plans was required for 2002 or is expected for 2003 under ERISA regulations. The level of discretionary funding allowed for 2003 and 2004, if made, would not have a material impact on pension costs. Plan investment performance in the past several years has increased Xcel Energy pension costs due to the difference between assumed asset returns reflected in actuarially determined costs, and actual return levels. Xcel Energy s aggregate annual 2002 pension costs recognized will be approximately $6 million more than comparable 2001 levels. Xcel Energy currently expect that costs to be recognized in 2003 may increase by approximately $40 million in relation to 2002 levels due to the impacts of lower-than-expected asset returns over the past few years.

Depending on final 2002 pension plan investment performance, some of the smaller Xcel Energy plans may have to record a minimum pension liability at Dec. 31, 2002. Based on year-to-date 2002 investment performance, Xcel Energy is estimating that a minimum liability may occur (mainly at PSCo) and be in the range of $100 million to $150 million, with a corresponding reduction in shareholders equity (other comprehensive income) for the unrealized loss on pension assets. Recording a minimum pension liability, if necessary, would have no impact on PSCo or Xcel Energy earnings.

14. Income Taxes

As discussed in Note 6, prior to reporting third quarter results for 2002, the likely tax filing status of NRG for 2002 has changed from being included as part of Xcel Energy s consolidated federal income tax group to filing on a stand-alone basis. On a stand-alone basis, NRG does not have the ability to recognize all tax benefits that may ultimately accrue from losses occurring in 2002. Consequently, current income taxes have been recorded only for refunds actually expected from filing amended returns to carry back 2002 losses to earlier periods, and deferred tax benefits have been recorded only to the extent a tax valuation allowance was not considered necessary.

NRG s current income tax benefit recognized for the third quarter and nine months ended Sept. 30, 2002 does not include the impact of net pretax operating loss carryforwards of $1.094 billion. In addition, NRG s deferred tax benefit recognized for the third quarter and nine months ended Sept. 30, 2002 is net of a valuation allowance of $383 million.

The commencement of a loss carryforward position for NRG in the third quarter of 2002 limits the availability of energy tax credits to NRG in 2002, and such credits cannot be carried forward. Accordingly, in third quarter NRG reversed $23 million of 2002 energy tax credits that had previously been recorded through June 30, 2002.

Effective in third quarter 2002, Xcel Energy no longer considers it likely that NRG will be included in Xcel Energy s consolidated federal income tax group for 2002 tax return purposes. 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 Sept. 30, 2002. This benefit (estimated at $676 million) is reported as deferred income taxes at one of Xcel Energy s nonregulated intermediate holding companies, and as a reduction of deferred income tax liabilities on the balance sheet. This benefit is based on the difference between the book and tax bases of Xcel Energy s investment in NRG.

SCHEDULE II

XCEL ENERGY INC.

AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

Years ended Dec. 31, 2001, 2000 and 1999

		Additions			
	Balance at Beginning of Period	Charged to Cost and Expenses	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:					
2001	$41,350	$38,220	$6,487	$28,242	$57,815
2000	$13,043	$51,052	$3,953	$26,698	$41,350
1999	$10,018	$17,841	$5,324	$20,140	$13,043

(1) Uncollectible accounts written off or transferred to other parties.

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PART II

INFORMATION NOT REQUIRED IN PROSPECTUS

Item 13. ***Other Expenses Of Issuance And Distribution.***

Set forth below is an estimate of the approximate amount of our fees and expenses in connection with the issuance and sale of the notes and the shares of common stock issuable upon conversion of the notes and the associated rights to purchase common stock pursuant to the Stockholder Protection Rights Agreement dated as of December 13, 2000, by and between our company and Wells Fargo Bank Minnesota, N.A.:

Registration fee under the Securities Act of 1933, as amended	$ 25,630.48
State qualification fees and expenses	$ 1,000.00
Printing	$ 100,000.00
Accounting services	$ 20,000.00
Company counsel fees	$ 50,000.00
Miscellaneous, including telephone, stationery, postage and other out-of-pocket expenses	$ 10,000.00
Total	$ 206,630.48

* All items are estimated except the first.

Item 14. ***Indemnification Of Directors And Officers.***

Section 302A.521 of the Minnesota Statutes permits indemnification of officers and directors of domestic or foreign corporations under certain circumstances and subject to certain limitations. Pursuant to authorization contained in the Restated Articles of Incorporation, as amended, Article 4 of our Bylaws contains provisions for indemnification of our directors and officers consistent with the provisions of Section 302A.521 of the Minnesota Statutes. Our Restated Articles of Incorporation also contain provisions limiting the liability of our company s directors in certain instances.

We have obtained insurance policies indemnifying our company and our company s directors and officers against certain civil liabilities and related expenses.

Item 15. ***Recent Sales of Unregistered Securities***

During the last three years, Xcel Energy has issued the following securities without registration under the Securities Act:

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). We relied on an exemption form registration under Rule 144A of the Securities Act. For additional information regarding the terms of the Securities Purchase Agreement and the terms of the 8% senior convertible notes, see Note 10 to our interim consolidated financial statements for the quarter ended September 30, 2002.

On November 21, 2002, we issued $230 million principal amount of 7 1/2% convertible senior notes, the notes covered by this registration statement, 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. 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.

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.

Item 16. ***Exhibits and Financial Statement Schedules.***

(a) *Exhibits*

Xcel Energy

2.01*	Agreement and Plan of Merger, dated as of March 24, 1999, by and between Northern States Power Company and New Century Energies, Inc. (Incorporated by reference to Exhibit 2.1 to the Report on Form 8-K (File No. 1-12927) of New Century Energies, Inc. dated March 24, 1999).
3.01*	Restated Articles of Incorporation of the Company (Filed as Exhibit 4.01 to the Company s Form 8-K (File no. 1-3034) filed on August 21, 2000).
3.02*	By-Laws of the Company (Filed as Exhibit 4.3 to the Company s Registration Statement on Form S-8 (File no. 333-48590) filed on October 25, 2000).
4.01*	Trust Indenture dated Dec. 1, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee. (Filed as Exhibit 4.01 to the Company s Form 8-K Report (File No. 1-3034) dated Dec. 14, 2000).
4.02*	Supplemental Trust Indenture dated Dec. 15, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee, creating $600,000,000 principal amount of 7% Senior Notes, Series due 2010. (Filed as Exhibit 4.02 to the Company s Form 8-K Report (File No. 1-3034) dated Dec. 18, 2000).
4.03*	Stockholder Protection Rights Agreement dated Dec. 13, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, N.A., as Rights Agent. (Filed as Exhibit 1 to the Company s Form 8-K Report (File No. 1-3034) dated Jan. 4, 2001).
4.04*	Subordinated Convertible Note, dated Feb. 28, 2002, between NRG Energy, Inc. and Xcel Energy Inc. (Filed as Exhibit 4.112 to the Company s Registration Statement on Form S-4 (File No. 333-84264) filed on March 13, 2002).
4.05*	Indenture between Xcel Energy, Inc. and Wells Fargo Bank Minnesota, National Association dated as of November 21, 2002 (Filed as Exhibit 99.01 to the Company s Form 8-K Report (File No. 1-3034) dated November 21, 2002)
4.06*	Form of Convertible Senior Note due 2007 (included in Exhibit 4.05 above and incorporated herein by reference)
4.07*	Registration Rights Agreement among the Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Lazard Freres & Co. LLC dated November 21, 2002 (Filed as Exhibit 99.02 to the Company s Form 8-K Report (File No. 1-3034) dated November 21, 2002)

NSP-Minnesota

4.08*	Trust Indenture, dated Feb. 1, 1937, from NSP to Harris Trust and Savings Bank, as Trustee. (Exhibit B-7 to File No. 2-5290).
4.09*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP to Harris Trust and Savings Bank, as Trustee. (Exhibit 4.02 to Form 10-K of NSP for the year 1988, File No. 1-3034).
	Supplemental Indenture between NSP and said Trustee, supplemental to Exhibit 4.03, dated as follows:
4.10*	June 1, 1942 (Exhibit B-8 to File No. 2-97667).
4.11*	Feb. 1, 1944 (Exhibit B-9 to File No. 2-5290).
4.12*	Oct. 1, 1945 (Exhibit 7.09 to File No. 2-5924).
4.13*	July 1, 1948 (Exhibit 7.05 to File No. 2-7549).
4.14*	Aug. 1, 1949 (Exhibit 7.06 to File No. 2-8047).
4.15*	June 1, 1952 (Exhibit 4.08 to File No. 2-9631).
4.16*	Oct. 1, 1954 (Exhibit 4.10 to File No. 2-12216).

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4.17*	Sept. 1, 1956 (Exhibit 2.09 to File No. 2-13463).
4.18*	Aug. 1, 1957 (Exhibit 2.10 to File No. 2-14156).
4.19*	July 1, 1958 (Exhibit 4.12 to File No. 2-15220).
4.20*	Dec. 1, 1960 (Exhibit 2.12 to File No. 2-18355).
4.21*	Aug. 1, 1961 (Exhibit 2.13 to File No. 2-20282).
4.22*	June 1, 1962 (Exhibit 2.14 to File No. 2-21601).
4.23*	Sept. 1, 1963 (Exhibit 4.16 to File No. 2-22476).
4.24*	Aug. 1, 1966 (Exhibit 2.16 to File No. 2-26338).
4.25*	June 1, 1967 (Exhibit 2.17 to File No. 2-27117).
4.26*	Oct. 1, 1967 (Exhibit 2.01R to File No. 2-28447).
4.27*	May 1, 1968 (Exhibit 2.01S to File No. 2-34250).
4.28*	Oct. 1, 1969 (Exhibit 2.01T to File No. 2-36693).
4.29*	Feb. 1, 1971 (Exhibit 2.01U to File No. 2-39144).
4.30*	May 1, 1971 (Exhibit 2.01V to File No. 2-39815).
4.31*	Feb. 1, 1972 (Exhibit 2.01W to File No. 2-42598).
4.32*	Jan. 1, 1973 (Exhibit 2.01X to File No. 2-46434).
4.33*	Jan. 1, 1974 (Exhibit 2.01Y to File No. 2-53235).
4.34*	Sept. 1, 1974 (Exhibit 2.01Z to File No. 2-53235).
4.35*	April 1, 1975 (Exhibit 4.01AA to File No. 2-71259).
4.36*	May 1, 1975 (Exhibit 4.01BB to File No. 2-71259).
4.37*	March 1, 1976 (Exhibit 4.01CC to File No. 2-71259).
4.38*	June 1, 1981 (Exhibit 4.01DD to File No. 2-71259).
4.39*	Dec. 1, 1981 (Exhibit 4.01EE to File No. 2-83364).
4.40*	May 1, 1983 (Exhibit 4.01FF to File No. 2-97667).
4.41*	Dec. 1, 1983 (Exhibit 4.01GG to File No. 2-97667).
4.42*	Sept. 1, 1984 (Exhibit 4.01HH to File No. 2-97667).
4.43*	Dec. 1, 1984 (Exhibit 4.01II to File No. 2-97667).
4.44*	May 1, 1985 (Exhibit 4.36 to Form 10-K for the year 1985, File No. 1-3034).
4.45*	Sept. 1, 1985 (Exhibit 4.37 to Form 10-K for the year 1985, File No. 1-3034).
4.46*	July 1, 1989 (Exhibit 4.01 to Form 8-K dated July 7, 1989, File No. 1-3034).
4.47*	June 1, 1990 (Exhibit 4.01 to Form 8-K dated June 1, 1990, File No. 1-3034).
4.48*	Oct. 1, 1992 (Exhibit 4.01 to Form 8-K dated Oct. 13, 1992, File No. 1-3034).
4.49*	April 1, 1993 (Exhibit 4.01 to Form 8-K dated March 30, 1993, File No. 1-3034).
4.50*	Dec. 1, 1993 (Exhibit 4.01 to Form 8-K dated Dec. 7, 1993, File No. 1-3034).
4.51*	Feb. 1, 1994 (Exhibit 4.01 to Form 8-K dated Feb. 10, 1994, File No. 1-3034).
4.52*	Oct. 1, 1994 (Exhibit 4.01 to Form 8-K dated Oct. 5, 1994, File No. 1-3034).
4.53*	June 1, 1995 (Exhibit 4.01 to Form 8-K dated June 28, 1995, File No. 1-3034).
4.54*	April 1, 1997 (Exhibit 4.47 to Form 10-K for the year 1997, File No. 1-3034).
4.55*	March 1, 1998 (Exhibit 4.01 to Form 8-K dated March 11, 1998, File No. 1-3034).
4.56*	May 1, 1999 (Exhibit 4.49 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.57*	June 1, 2000 (Exhibit 4.50 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.58*	Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.59*	June 1, 2002 (Exhibit 4.05 to Form 10-Q of NSP-Minnesota, File No. 1-03034).
4.60*	July 1, 2002 (Exhibit 4.06 to Form 10-Q of NSP-Minnesota, File No. 1-03034).

4.61*	Aug. 1, 2002 (Exhibit 4.01 to Form 8-K dated Aug. 22, 2002, File No. 1-31387).
4.62*	Subordinated Debt Securities Indenture, dated as of Jan. 30, 1997, between Xcel Energy and Norwest Bank Minnesota, National Association, as trustee. (Exhibit 4.02 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.63*	Preferred Securities Guarantee Agreement, dated as of Jan. 31, 1997, between Xcel Energy and Wilmington Trust Company, as Trustee. (Exhibit 4.05 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.64*	Preferred Securities Guarantee Agreement, dated as of Aug. 18, 2000, between Northern States Power Company and Wilmington Trust Company, as Trustee. (Exhibit 4.54 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.65*	Amended and Restated Declaration of Trust of NSP Financing I, dated as of Jan. 31. 1997, including form of Preferred Security. (Exhibit 4.10 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.66*	Supplemental Indenture, dated as of Jan. 31, 1997, between Xcel Energy and Norwest Bank Minnesota, National Association, as trustee, including form of Junior Subordinated Debenture. (Exhibit 4.12 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.67*	Supplemental Trust Indenture dated Aug. 18, 2000 between Xcel Energy, Northern States Power Company and Wells Fargo Bank Minnesota, National Association, as Trustee (Exhibit 4.57 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.68*	Common Securities Guarantee Agreement dated as of Jan. 31, 1997, between Xcel Energy and Wilmington Trust Company, as Trustee. (Exhibit 4.13 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.69*	Common Securities Guarantee Agreement dated as of Aug. 18, 2000, between NSP and Wilmington Trust Company, as Trustee. (Exhibit 4.59 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.70*	Subscription Agreement, dated as of Jan. 28, 1997, between NSP Financing I and NSP. (Exhibit 4.14 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.71*	Trust Indenture, dated July 1, 1999, between NSP and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to Form 8-K dated July 21, 1999, File No. 1-03034).
4.72*	Supplemental Trust Indenture, dated July 15, 1999, between NSP and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.02 to Form 8-K dated July 21, 1999, File No. 1-03034).
4.73*	Supplemental Trust Indenture, dated Aug. 18, 2000, among Xcel Energy, Northern States Power Company and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.63 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.74*	Supplemental Trust Indenture, dated July 1, 2002, between NSP and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to Form 8-K dated July 8, 2002, File No. 000-31709).
4.75*	Supplemental Indenture dated as of June 1, 2002, between NSP-Minnesota and BNY Midwest Trust Company, as successor trustee, creating $308,000,000 principal amount of First Mortgage Bonds, Series due 2003. (Exhibit 4.05 to Form 10-Q filed on November 18, 2002, File No. 001-3034.)
4.76*	Supplemental Indenture dated as of July 1, 2002, between NSP-Minnesota and BNY Midwest Trust Company, as successor trustee, creating $69,000,000 principal amount of First Mortgage Bonds, Pollution Control Series S. (Exhibit 4.06 to Form 10-Q filed on November 18, 2002, File No. 001-3034.)
4.77*	Supplemental Indenture dated Aug. 1, 2002, between NSP-Minnesota and BNY Midwest Trust Company, as successor trustee, creating $450,000,000 principal amount of 8 percent First Mortgage Bonds, Series A due Aug. 28, 2012. (Exhibit 4.09 to Form 10-Q dated November 18, 2002, File No. 001-3034.)

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NSP-Wisconsin

4.78*	Copy of Trust Indenture, dated April 1, 1947, From NSP-Wisconsin to Firstar Trust Company (formerly First Wisconsin Trust Company). (Filed as Exhibit 7.01 to Registration Statement 2-6982).
4.79*	Copy of Supplemental Trust Indenture, dated March 1, 1949. (Filed as Exhibit 7.02 to Registration Statement 2-7825).
4.80*	Copy of Supplemental Trust Indenture, dated June 1, 1957. (Filed as Exhibit 2.13 to Registration Statement 2-13463).
4.81*	Copy of Supplemental Trust Indenture, dated Aug. 1, 1964. (Filed as Exhibit 4.20 to Registration Statement 2-23726).
4.82*	Copy of Supplemental Trust Indenture, dated Dec. 1, 1969. (Filed as Exhibit 2.03E to Registration Statement 2-36693).
4.83*	Copy of Supplemental Trust Indenture, dated Sept. 1, 1973. (Filed as Exhibit 2.03F to Registration Statement 2-49757).
4.84*	Copy of Supplemental Trust Indenture, dated Feb. 1, 1982. (Filed as Exhibit 4.01G to Registration Statement 2-76146).
4.85*	Copy of Supplemental Trust Indenture, dated March 1, 1982. (Filed as Exhibit 4.08 to Form 10-K Report 10-3140 for the year 1982).
4.86*	Copy of Supplemental Trust Indenture, dated June 1, 1986. (Filed as Exhibit 4.09 to Form 10-K Report 10-3140 for the year 1986).
4.87*	Copy of Supplemental Trust Indenture, dated March 1, 1988. (Filed as Exhibit 4.10 to Form 10-K Report 10-3140 for the year 1988).
4.88*	Copy of Supplemental and Restated Trust Indenture, dated March 1, 1991. (Filed as Exhibit 4.01K to Registration Statement 33-39831).
4.89*	Copy of Supplemental Trust Indenture, dated April 1, 1991. (Filed as Exhibit 4.01 to Form 10-Q Report 10-3140 for the quarter ended March 31, 1991).
4.90*	Copy of Supplemental Trust Indenture, dated March 1, 1993. (Filed as Exhibit to Form 8-K Report 10-3140 dated March 3, 1993).
4.91*	Copy of Supplemental Trust Indenture, dated Oct. 1, 1993. (Filed as Exhibit 4.01 to Form 8-K Report 10-3140 dated Sept. 21, 1993).
4.92*	Copy of Supplemental Trust Indenture, dated Dec. 1, 1996. (Filed as Exhibit 4.01 to Form 8-K Report 10-3140 dated Dec. 12, 1996).
4.93*	Trust Indenture dated September 1, 2000, between Northern States Power Company and Firstar Bank, N.A. as Trustee. (Filed as Exhibit 4.01 to Form 8-K 10-3140 dated Sept. 25, 2000).
4.94*	Supplemental Trust Indenture dated September 15, 2000, between Northern States Power Company and Firstar Bank, N.A. as Trustee, creating $80,000,000 principal amount of 7.64% Senior Notes, Series due 2008. (Filed as Exhibit 4.02 to Form 8-K 10-3140 dated Sept. 25, 2000).

PSCo

4.95*	Indenture, dated as of Dec. 1, 1939, providing for the issuance of First Mortgage Bonds (Form 10 for 1946-Exhibit (B-1)).
4.96*	Indentures supplemental to Indenture dated as of Dec. 1, 1939:

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Mar. 14, 1941	10, 1946	B-2
May 14, 1941	10, 1946	B-3
Apr. 28, 1942	10, 1946	B-4
Apr. 14, 1943	10, 1946	B-5
Apr. 27, 1944	10, 1946	B-6
Apr. 18, 1945	10, 1946	B-7

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Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Apr. 23, 1946	10-K, 1946	B-8
Apr. 9, 1947	10-K, 1946	B-9
June 1, 1947	S-1, (2-7075)	7(b)
Apr. 1, 1948	S-1, (2-7671)	7(b)(1)
May 20, 1948	S-1, (2-7671)	7(b)(2)
Oct. 1, 1948	10-K, 1948	4
Apr. 20, 1949	10-K, 1949	1
Apr. 24, 1950	8-K, Apr. 1950	1
Apr. 18, 1951	8-K, Apr. 1951	1
Oct. 1, 1951	8-K, Nov. 1951	1
Apr. 21, 1952	8-K, Apr. 1952	1
Dec. 1, 1952	S-9, (2-11120)	2(b)(9)
Apr. 15, 1953	8-K, Apr. 1953	2
Apr. 19, 1954	8-K, Apr. 1954	1
Oct. 1, 1954	8-K, Oct. 1954	1
Apr. 18, 1955	8-K, Apr. 1955	1
Apr. 24, 1956	10-K, 1956	1
May 1, 1957	S-9, (2-13260)	2(b)(15)
Apr. 10, 1958	8-K, Apr. 1958	1
May 1, 1959	8-K, May 1959	2
Apr. 18, 1960	8-K, Apr. 1960	1
Apr. 19, 1961	8-K, Apr. 1961	1
Oct. 1, 1961	8-K, Oct. 1961	2
Mar. 1, 1962	8-K, Mar. 1962	3(a)
June 1, 1964	8-K, June 1964	1
May 1, 1966	8-K, May 1966	2
July 1, 1967	8-K, July 1967	2
July 1, 1968	8-K, July 1968	2
Apr. 25, 1969	8-K, Apr. 1969	1
Apr. 21, 1970	8-K, Apr. 1970	1
Sept. 1, 1970	8-K, Sept. 1970	2
Feb. 1, 1971	8-K, Feb. 1971	2
Aug. 1, 1972	8-K, Aug. 1972	2
June 1, 1973	8-K, June 1973	1
Mar. 1, 1974	8-K, Apr. 1974	2
Dec. 1, 1974	8-K, Dec. 1974	1
Oct. 1, 1975	S-7, (2-60082)	2(b)(3)
Apr. 28, 1976	S-7, (2-60082)	2(b)(4)
Apr. 28, 1977	S-7, (2-60082)	2(b)(5)
Nov. 1, 1977	S-7, (2-62415)	2(b)(3)
Apr. 28, 1978	S-7, (2-62415)	2(b)(4)
Oct. 1, 1978	10-K, 1978	D(1)
Oct. 1, 1979	S-7, (2-66484)	2(b)(3)
Mar. 1, 1980	10-K, 1980	4(c)

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Apr. 28, 1981	S-16, (2-74923)	4(c)
Nov. 1, 1981	S-16, (2-74923)	4(d)
Dec. 1, 1981	10-K, 1981	4(c)
Apr. 29, 1982	10-K, 1982	4(c)
May 1, 1983	10-K, 1983	4(c)
Apr. 30, 1984	S-3, (2-95814)	4(c)
Mar. 1, 1985	10-K, 1985	4(c)
Nov. 1, 1986	10-K, 1986	4(c)
May 1, 1987	10-K, 1987	4(c)
July 1, 1990	S-3, (33-37431)	4(c)
Dec. 1, 1990	10-K, 1990	4(c)
Mar. 1, 1992	10-K, 1992	4(d)
Apr. 1, 1993	10-Q, June 30, 1993	4(a)
June 1, 1993	10-Q, June 30, 1993	4(b)
Nov. 1, 1993	S-3, (33-51167)	4(a)(3)
Jan. 1, 1994	10-K, 1993	4(a)(3)
Sept. 2, 1994	8-K, Sept. 1994	4(a)
May 1, 1996	10Q, June 30, 1996	4(a)
Nov. 1, 1996	10-K, 1996	4(a)(3)
Feb. 1, 1997	10-Q, Mar. 31, 1997	4(a)
April 1, 1998	10-Q, Mar. 31, 1998	4(a)
August 15, 2002	10-Q, Sept. 30, 2002	4.01
September 15, 2002	10-Q, Sept. 30, 2002	4.02

4.97* Indenture, dated as of Oct. 1, 1993, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993 Exhibit 4(a)).

4.98* Indentures supplemental to Indenture dated as of Oct. 1, 1993:

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Nov. 1, 1993	S-3, (33-51167)	4(b)(2)
Jan. 1, 1994	10-K, 1993	4(b)(3)
Sept. 2, 1994	8-K, Sept. 1994	4(b)
May 1, 1996	10-Q, June 30, 1996	4(b)
Nov. 1, 1996	10-K, 1996	4(b)(3)
Feb. 1, 1997	10-Q, Mar. 31, 1997	4(b)
April 1, 1998	10-Q, Mar. 31, 1998	4(b)
Aug. 15, 2002	10-Q, Sept. 30, 2002	4.03
Sept. 15, 2002	10-Q, Sept. 30, 2002	4.04

4.99* Indenture dated May 1, 1998, between PSCo and The Bank of New York, providing for the issuance of Subordinated Debt Securities (Form 8-K, May 6, 1998 Exhibit 4.2).

4.100* Supplemental Indenture dated May 11, 1996, between PSCo and The Bank of New York, (Form 8-K, May 6, 1998 Exhibit 4.3).

4.101* Preferred Securities Guarantee Agreement dated May 11, 1998, between PSCo and The Bank of New York, (Form 8-K, May 6, 1998 Exhibit 4.4).

4.102* Amended and Restated Declaration of Trust of PSCo Capital and Trust I dated May 11, 1998, (Form 8-K, May 6, 1998 Exhibit 4.1).

4.103*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities (Form 8-K, July 13, 1999, Exhibit 4.1) and Supplemental Indenture dated July 15, 1999, between PSCO and The Bank of New York (Form 8-K, July 13, 1999, Exhibit 4.2).
4.104*	Supplemental Indenture dated Aug. 15, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $48,750,000 principal amount of First Mortgage Bonds Collateral, Series G, due 2019. (Exhibit 4.01 to Form 10-Q dated November 18, 2002, File No. 001-3034.)
4.105*	Supplemental Indenture dated as of Sept. 15, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $530,000,000 principal amount of First Mortgage Bonds Collateral, Series I, due 2003. (Exhibit 4.02 to Form 10-Q dated November 18, 2002, File No. 001-3034.)
4.106*	Supplemental Indenture dated Aug. 15, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $48,750,000 principal amount of First Collateral Trust Bonds Collateral, Series No. 7, due 2019. (Exhibit 4.03 to Form 10-Q dated November 18, 2002, File No. 001-3034.)
4.107*	Supplemental Indenture dated as of Sept. 15, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $530,000,000 principal amount of First Collateral; Trust Bonds, Series No. 9, due 2003. (Exhibit 4.04 to Form 10-Q dated November 18, 2002, File No. 001-3034.)
4.108*	Supplemental Indenture dated as of Sept. 1, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $600 million principal amount of 7.875 percent First Collateral Trust Bonds, Series No. 8 due 2012. (Incorporated by reference to Exhibit 4.01 to PSCO s Current Report on Form 8-K, dated Sept. 18, 2002)
4.109*	Supplemental Indenture dated as of Sept. 18, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $600 million principal amount of 7.875 percent First Mortgage Bonds, Series H due 2012. (Incorporated by reference to Exhibit 4.02 to PSCO s Current Report on Form 8-K, dated Sept. 18, 2002)

SPS

4.110*	Indenture, dated as of Aug. 1, 1946, providing for the issuance of First Mortgage Bonds (Registration No. 2-6910, Exhibit 7-A).
4.111*	Indentures supplemental to Indenture dated as of Aug. 1, 1946:

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Feb. 1, 1967	2-25983	2-S
Oct. 1, 1970	2-38566	2-T
Feb. 9, 1977	2-58209	2-Y
March 1, 1979	2-64022	b(28)
April 1, 1983 (two)	10-Q, May 1983	4(a)
Feb. 1, 1985	10-K, Aug. 1985	4(c)
July 15, 1992 (two)	10-K, Aug. 1992	4(a)
Dec. 1, 1992 (two)	10-Q, Feb. 1993	4
Feb. 15, 1995	10-Q, May 1995	4
March 1, 1996	333-05199	4(c)

4.112*	Indenture dated Feb. 1, 1999 between SPS and The Chase Manhattan Bank (Form 8-K, Feb. 25, 1999, Exhibit 99.2).
4.113*	Supplemental Indenture dated March 1, 1999, between SPS and The Chase Manhattan Bank (Form 8-K, Feb. 25, 1999, Exhibit 99.3).
4.114*	Supplemental Indenture dated October 1, 2001, between SPS and The Chase Manhattan Bank (Form 8-K, Oct. 23, 2001, Exhibit 4.01).

4.115*	Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 Exhibit 4(b)).
4.116*	Indenture dated Oct. 21, 1996, between SPS and Wilmington Trust Company, (Form 10-Q, Nov. 30, 1996 Exhibit 4(a)).
4.117*	Supplemental Indenture dated Oct. 21, 1996, between SPS and Wilmington Trust Company, (Form 10-Q, Nov. 30, 1996 Exhibit 4(b)).
4.118*	Guarantee Agreement dated Oct. 21, 1996, between SPS and Wilmington Trust Company, (Form 10-Q, Nov. 30, 1996 Exhibit 4(c)).
4.119*	Amended and Restated Trust Agreement dated Oct. 21, 1996, among SPS, David M. Wilks, as initial depositor, Wilmington Trust Company and the administrative trustees named therein (Form 10-Q, Nov. 30, 1996 Exhibit 4(d)).
4.120*	Agreement as to Expenses dated Oct. 21, 1996, between SPS and Southwestern Public Service Capital I, (Form 10-K, Dec. 31, 1996 Exhibit F).
NRG	
4.121*	Indenture, dated as of June 1, 1997, between NRG and Norwest Bank Minnesota, National Association. (Incorporated herein by reference to Exhibit 4.1 to NRG s Form S-1 (File no. 333-33397)).
4.122*	Form of Exchange Notes. (Incorporated herein by reference to Exhibit 4.2 to NRG s Form S-1 (File no. 333-33397).
4.123*	Loan Agreement, dated June 4, 1999 between NRG Northeast Generating LLC, Chase Manhattan Bank and Citibank, N.A. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
4.124*	Indenture between NRG and Norwest Bank Minnesota, National Association, as Trustee dated as of May 25, 1999 (incorporated herein by reference to Exhibit 4.1 to NRG s current report on Form 8-K (File no. 000-25569) dated May 25, 1999 and filed on May 27, 1999).
4.125*	Indenture between NRG and NRG Northeast Generating LLC and The Chase Manhattan Bank, as Trustee dated as of February 22, 2000. (Incorporated by reference to NRG s Form 10-K (File no. 000-15891) for the year ended December 31, 1999).
4.126*	NRG Energy Pass-Through Trust 2000-1, $250,000,000 8.70% Remarketable or Redeemable Securities (ROARS) due March 15, 2005. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
4.127*	Trust Agreement between NRG Energy, Inc. and The Bank of New York, as Trustee, dated March 20, 2000. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
4.128*	Indenture between NRG Energy, Inc. and the Bank of New York, as Trustee dated March 20, 2000, 160,000,000 pounds sterling Reset Senior Notes due March 15, 2020. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
4.129*	Indenture, dated March 13, 2001, between NRG Energy, Inc. and The Bank of New York, a New York banking corporation, as Trustee. (Incorporated by reference to NRG s current report on Form 8-K (File no. 001-15891) dated March 15, 2001).
4.130*	First Supplement Indenture, dated March 13, 2001, between NRG Energy, Inc. and The Bank of New York, a New York banking corporation, as Trustee. (Incorporated by reference to NRG s current report on Form 8-K (File no. 001-15891) dated March 15, 2001).
4.131*	364-Day Revolving Credit Agreement dated as of March 8, 2002, among NRG Energy, Inc., The Financial Institutions Party hereto and ABN AMRO Bank N.V., as agent. (Incorporated by reference to NRG s quarterly report on Form 10-Q (File no. 001-15891) for the quarter ended March 31, 2001).
4.132*	$2.0 billion credit agreement dated May 8, 2001 among NRG Finance Company LLC and certain financial institutions named therein. (Incorporated by reference to NRG s quarterly report on Form 10-Q (File no. 001-15891) for the quarter ended June 30, 2001).

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Xcel Energy

5.1**	Opinion of Gary R. Johnson as to certain legal matters
5.2**	Opinion of Jones Day as to certain legal matters
8.1**	Opinion of Jones Day as to certain U.S. federal income tax considerations

NSP-Minnesota

10.01*	Facilities Agreement, dated July 21, 1976, between NSP and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kilovolt (kv) line. (Exhibit 5.06I to File No. 2-54310).
10.02*	Transactions Agreement, dated July 21, 1976, between NSP and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kv line. (Exhibit 5.06J to File No. 2-54310).
10.03*	Coordinating Agreement, dated July 21, 1976, between NSP and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kv line. (Exhibit 5.06K to File No. 2-54310).
10.04*	Ownership and Operating Agreement, dated March 11, 1982, among NSP, Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3. (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994, File No. 1-3034).
10.05*	Transmission Agreement, dated April 27, 1982, and Supplement No. 1, dated July 20, 1982, between NSP and Southern Minnesota Municipal Power Agency. (Exhibit 10.02 to Form 10-Q for the quarter ended Sept. 30, 1994, File No. 1-3034).
10.06*	Power Agreement, dated June 14, 1984, between NSP and the Manitoba Hydro-Electric Board, extending the agreement scheduled to terminate on April 30, 1993, to April 30, 2005. (Exhibit 10.03 to Form 10-Q for the quarter ended Sept. 30, 1994, File No. 1-3034).
10.07*	Power Agreement, dated August 1988, between NSP and Minnkota Power Company. (Exhibit 10.08 to Form 10-K for the year 1988, File No. 1-3034).
10.08*	Assignment and Assumption Agreement, dated Aug. 18, 2000 between Northern States Power Company and Xcel Energy Inc. (Exhibit 10.08 to Form 10 of NSP-Minnesota, File No. 000-31709)
10.09*	Copy of Interchange Agreement dated Sept. 17, 1984, and Settlement Agreement dated May 31, 1985, between NSP-Wisconsin, the NSP-Minnesota Company and LSDP. (Filed as Exhibit 10.10 to Form 10-K Report 10-3140 for the year 1985).

PSCo

10.10*	Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between PSCo and Amax Inc. on behalf of its division, Amax Coal Company (Form 10-K, (File no. 001-03280) Dec. 31, 1984 Exhibit 10(c)(1)).
10.11*	First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between PSCo and Amax Coal Company (Form 10-K, (File no. 001-03280) Dec. 31, 1988 Exhibit 10(c)(2).

SPS

10.12*	Coal Supply Agreement (Harrington Station) between SPS and TUCO, dated May 1, 1979 (Form 8-K (File no. 001-3789), May 14, 1979 Exhibit 3).
10.13*	Master Coal Service Agreement between Swindell-Dressler Energy Supply Company and TUCO, dated July 1, 1978 (Form 8-K, (File no. 001-3789) May 14, 1979 Exhibit 5(A)).
10.14*	Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Company and TUCO (Form 8-K, (File no. 3789) May 14, 1979 Exhibit 5(B)).
10.15*	Coal Supply Agreement (Tolk Station) between SPS and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (File no. 3789) Feb. 28, 1982 Exhibit 10(b)).
10.16*	Master Coal Service Agreement between Wheelabrator Coal Services Co. and TUCO dated Dec. 30, 1981, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (File no. 3789) Feb. 28, 1982 Exhibit 10(c)).

Xcel Energy

10.17*	Xcel Energy Omnibus Incentive Plan (Exhibit A to Xcel s Proxy Statement (File no. 1-3034) filed Aug. 29, 2000).
10.18*	Xcel Energy Executive Annual Incentive Award (Exhibit B to Xcel s Proxy Statement (File no. 1-3034) filed Aug. 29, 2000).
10.19*	Xcel Energy Senior Executive Severance (Exhibit 10.19 to Form 10-K for the year 2000, File No. 1-3034).
10.20*	Employment Agreement of James J. Howard dated March 24, 1999. (Exhibit 10.14 to Form 10-K for the year 1998. File No. 1-3034).
10.21*	Employment Agreement, effective December 15, 1997, between company and Mr. Paul J. Bonavia (Form 10-Q, (File no. 001-12927) September 30, 1998 Exhibit 10(a)).
10.22*	The employment agreement, dated March 24, 1999, among Northern States Power Company, New Century Energies, Inc. and Wayne H. Brunetti (Form 10-Q, (File no. 001-12927) March 31, 1999, Exhibit 10(b)).
10.23*	Summary of Terms and Conditions of Employment of James J. Howard, Chairman, President and Chief Executive Officer, effective Feb. 1, 1987, as amended and restated effective as of Jan. 28, 1998. (Agreement filed as Exhibit 10.03 to Form 10-Q for the quarter ended March 31, 1998, File No. 1-3034).
10.24*	NSP Severance Plan. (Exhibit 10.12 to Form for the year 1994, File No. 1-3034).
10.25*	NSP Deferred Compensation Plan amended effective Jan. 1, 1993. (Exhibit 10.16 to Form 10-K for the year 1993, File No. 1-3034).
10.26*	Amended and Restated Executive Long-Term Incentive Award Stock Plan. (Exhibit 10.02 to Form 10-Q for the quarter ended March 31, 1998, File No. 1-3034).
10.27*	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy As Amended and Restated Effective Oct. 1, 1997. (Exhibit 10.15 to Form 10-K for the year 1997. File No. 1-3034).
10.28*	Form of Key Executive Change in Control Agreement (Form 10-K, (File no. 001-12927) December 31, 1998, Exhibit 10(a)(1)).
10.29*	Senior Executive Severance Policy, effective March 24, 1999, between New Century Energies, Inc. and Senior Executives (Form 10-Q, (File no. 001-12927) March 31, 1999, Exhibit 10(a)(2)).
10.30*	Employment Agreement, effective August 1, 1997, between the Company and Mr. Wayne H. Brunetti (Form S-4, Annex I, File No. 33-64951).
10.31*	New Century Energies Omnibus Incentive Plan, effective August 1, 1997 (Form Def 14A, (File no. 001-12927) December 31, 1997 Exhibit A).
10.32*	Directors Voluntary Deferral Plan (Form 10-K, (File no. 001-12927) December 31, 1998, Exhibit 10(d)(1)).
10.33*	Supplemental Executive Retirement Plan (Form 10-K, (File no. 001-12927) December 31, 1998. Exhibit 10(e)(1)).
10.34*	Salary Deferral and Supplemental Savings Plan for Executive Officers (Form 10-K, (File no. 001-12927) December 31, 1998, Exhibit 10(f)(1)).
10.35*	Salary Deferral and Supplemental Savings Plan for Key Managers (Form 10-K, (File no. 001-12927) December 31, 1998, Exhibit 10(g)(1)).
10.36*	Supplemental Executive Retirement Plan for Key Management Employees, as amended and restated March 26, 1991 (Form 10-K, (File no. 001-3280) Dec. 31, 1991 Exhibit 10(e)(2)).
10.37*	Form of Key Executive Severance Agreement, as amended on Aug. 22, and Nov. 27, 1995. (Form 10-K, (File no. 001-3280) Dec. 31, 1995 Exhibit 10(3)(4)).
10.38*	SPS 1989 Stock Incentive Plan as amended April 23, 1996 (Form 10-K, (File no. 001-3789) Aug. 31, 1996 Exhibit 10(b)).

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	10.39*	Director s Deferred Compensation Plan as amended Jan. 10, 1990 (Form 10-K, (File no. 001-3789) Aug. 31, 1996 Exhibit 10(c)).
	10.40*	Supplemental Retirement Income Plan as amended July 23, 1991 (Form 10-K, (File no. 001-3789) Aug. 31, 1996 Exhibit 10(e)).
	10.41*	EPS Performance Unit Plan dated Oct. 27, 1992 (Form 10-K, (File no. 001-3789) Aug. 31, 1996 Exhibit 10(a)).
NRG		
	10.42*	Employment Contract, dated as of June 28, 1995, between NRG and David H. Peterson. (Incorporated herein by reference to Exhibit 10.1 to NRG s Form S-1, File no. 333-33397).
	10.43*	Note Agreement, dated August 20, 1993, among NRG Energy Center, Inc. and each of the purchasers named therein. (Incorporated herein by reference to Exhibit 10.5 to NRG s Form S-1 (File no. 333-33397).
	10.44*	Master Shelf and Revolving Credit Agreement dated August 20, 1993 among NRG Energy Center, Inc., The Prudential Insurance Registrants of America and each Prudential Affiliate, which becomes party thereto. (Incorporated herein by reference to Exhibit 10.4 to NRG s Form S-1 (File no. 333-33397).
	10.45*	Energy Agreement dated February 12, 1988 between NRG (formerly known as Norenco Corporation) and Waldorf Corporation (the Energy Agreement). (Incorporated herein by reference to Exhibit 10.6 to NRG s Form S-1, File no. 333-33397).
	10.46*	First Amendment to the Energy Agreement dated August 27, 1993. (Incorporated herein by reference to Exhibit 10.7 to NRG s Form S-1, File no. 333-33397).
	10.47*	Second Amendment to the Energy Agreement, dated August 27, 1993. (Incorporated herein by reference to Exhibit 10.8 to NRG s Form S-1, File no. 333-33397).
	10.48*	Third Amendment to the Energy Agreement dated August 27, 1993. (Incorporated herein by reference to Exhibit 10.9 to NRG s Form S-1, File no. 333-33397).
	10.49*	Construction, Acquisition, and Term Loan Agreement, dated September 2, 1997 by and among NEO Landfill Gas, Inc., as Borrower, the lenders named on the signature pages, Credit Lyonnais New York Branch, as Construction/ Acquisition Agent and Lyon Credit Corporation as Term Agent. (Incorporated herein by reference to Exhibit 10.10 to NRG s Form S-1, File no. 333-33397).
	10.50*	Guaranty, dated September 12, 1997 by NRG in favor of Credit Lyonnais New York Branch as agent for the Construction/ Acquisition Lenders. (Incorporated herein by reference to Exhibit 10.11 to NRG s Form S-1, File no. 333-33397).
	10.51*	Construction, Acquisition, and Term Loan Agreement, dated September 2, 1997 by and among Minnesota Methane LLC, as Borrower, the lenders named on the signature pages, Credit Lyonnais New York Branch, as Construction/ Acquisition Agent and Lyon Credit Corporation as Term Agent. (Incorporated herein by reference to Exhibit 10.12 to NRG s Form S-1, File no. 333-33397).
	10.52*	Guaranty, dated September 12, 1997 by NRG in favor of Credit Lyonnais New York Branch as agent for the Construction/ Acquisition Lenders. (Incorporated herein by reference to Exhibit 10.13 to NRG s Form S-1, File no. 333-33397).
	10.53*	Non Operating Interest Acquisition Agreement dated as of September 12, 1997, by and among NRG and NEO Corporation. (Incorporated herein by reference to Exhibit 10.14 to NRG s Form S-1, File no. 333-33397).
	10.54*	Employment Agreements between NRG and certain officers dated as of April 15, 1998. (Incorporated herein by reference to Exhibit 10.17 of NRG s Form 10-Q (File no. 001-15891) for the quarter ended March 31, 1998).
	10.55*	Wholesale Standard Offer Service Agreement between Blackstone Valley Electric Company, Eastern Edison Company, Newport Electric Corporation and NRG Power Marketing, Inc., dated October 13, 1998. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).

10.56*	Asset Sales Agreement by and between Niagara Mohawk Power Corporation and NRG Energy, Inc., dated December 23, 1998. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.57*	First Amendment to Wholesale Standard Offer Service Agreement between Blackstone Valley Electric Company, Eastern Edison Company, Newport Electric Corporation and NRG Power Marketing, Inc., dated January 15, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.58*	Generating Plant and Gas Turbine Asset Purchase and Sale Agreement for the Arthur Kill generating plants and Astoria gas turbines by and between Consolidated Edison Company of New York, Inc., and NRG Energy, Inc., dated January 27, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.59*	Transition Energy Sales Agreement between Arthur Kill Power LLC and Consolidated Edison Company of New York, Inc., dated June 1, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.60*	Transition Power Purchase Agreement between Astoria Gas Turbine Power LLC and Consolidated Edison Company of New York, Inc., dated June 1, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.61*	Transition Power Purchase Agreement between Niagara Mohawk Power Corporation and Huntley Power LLC, dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.62*	Transition Power Purchase Agreement between Niagara Mohawk Power Corporation and Dunkirk Power LLC, dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.63*	Power Purchase Agreement between Niagara Mohawk Power Corporation and Dunkirk Power LLC, dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.64*	Power Purchase Agreement between Niagara Mohawk Power Corporation and Huntley Power LLC, dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.65*	Amendment to the Asset Sales Agreement by and between Niagara Mohawk Power Corporation and NRG Energy, Inc., dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.66*	Transition Capacity Agreement between Astoria Gas Turbine Power LLC and Consolidated Edison Company of New York, Inc., dated June 25, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.67*	Transition Capacity Agreement between Arthur Kill Power LLC and Consolidated Edison Company of New York, Inc., dated June 25, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.68*	First Amendment to the Employment Agreement of David H. Peterson, dated June 27, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.69*	Second Amendment to the Employment Agreement of David H. Peterson, dated August 26, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.70*	Third Amendment to the Employment Agreement of David H. Peterson, dated October 20, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.71*	Swap Master Agreement between Niagara Mohawk Power Corporation and NRG Power Marketing, Inc., dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).

10.72*	Standard Offer Service Wholesale Sales Agreement between the Connecticut Light And Power Company and NRG Power Marketing, Inc., dated October 29, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.73*	364-day Revolving Credit Agreement among NRG and The Financial Institutions party thereto, and ABN-AMRO Bank, N.V., as Agent, dated as of March 10, 2000. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
Xcel Energy	
12.1	Computation of Ratio of Earnings to Fixed Charges
21.01*	Subsidiaries of Xcel Energy Inc.
23.01**	Independent Accountants Consent of Deloitte & Touche LLP.
23.02**	Independent Accountants Consent of PricewaterhouseCoopers LLP.
23.05	Consent of Gary R. Johnson (included in Exhibit 5.1)
23.04	Consent of Jones Day (included in Exhibit 5.2)
24.1	Power of Attorney (included on signature page of this Registration Statement).
25.1	Form of T-1 Statement of Eligibility of the Trustee under the Indenture.
99.01*	Description of Business of NRG Energy, Inc. (Item 1 of NRG Energy, Inc. s Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2001, File No. 001-15891).

* Indicates incorporation by reference

** Indicates to be filed by amendment.

Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors

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(b) *Financial Statement Schedules*

* Reports by PricewaterhouseCoopers LLP to be filed by amendment.

2000 and 2001 superseded by unaudited financial statements

** To be filed by amendment

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Item 17. ***Undertakings.***

The undersigned registrant hereby undertakes:

(1) To file, during any period in which offers or sales are being made, a post-effective amendment to this registration statement: (i) to include any prospectus required by section 10(a)(3) of the Securities Act of 1933; (ii) to reflect in the prospectus any facts or events arising after the effective date of the registration statement (or the most recent post-effective amendment thereof) which, individually or in the aggregate, represent a fundamental change in the information set forth in the registration statement. Notwithstanding the foregoing, any increase or decrease in volume of securities offered (if the total dollar value of securities offered would not exceed that which was registered) and any deviation from the low or high end of the estimated maximum offering range may be reflected in the form of prospectus filed with the Commission pursuant to Rule 424(b) if, in the aggregate, the changes in volume and price represented no more than a 20% change in the maximum aggregate offering price set forth in the Calculation of Registration Fee table in the effective registration statement; and (iii) to include any material information with respect to the plan of distribution not previously disclosed in the registration statement or any material change to such information in the registration statement; provided, however, that clauses (i) and (ii) above do not apply if the registration statement is on Form S-3 or Form S-8, and the information required to be included in a post-effective amendment by those clauses is contained in periodic reports filed by the registrant pursuant to section 13 or section 15(d) of the Securities Exchange Act of 1934.

(2) That, for the purpose of determining any liability under the Securities Act of 1933, each such post-effective amendment shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

(3) To remove from registration by means of a post-effective amendment any of the securities being registered which remain unsold at the termination of the offering.

Insofar as indemnification for liabilities arising under the Securities Act of 1933 may be permitted to directors, officers and controlling persons of the Registrant pursuant to the provisions described under Item 15, or otherwise, the registrant has been advised that in the opinion of the Securities and Exchange Commission such indemnification is against public policy as expressed in the Securities Act of 1933 and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the Registrant of expenses incurred or paid by a director, officer or controlling person of the registrant in the successful defense of any action, suit or proceeding) is asserted by such director, officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act of 1933 and will be governed by the final adjudication of such issue.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, as amended, the registrant certifies that it has reasonable grounds to believe that it meets all the requirements of filing on Form S-1 and has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Minneapolis, and State of Minnesota, on the 14th day of February, 2003.

XCEL ENERGY INC.

By: /s/ RICHARD C. KELLY

Richard C. Kelly
Vice President and Chief Financial Officer

KNOW ALL MEN BY THESE PRESENT, that each person whose signature appears below constitutes and appoints Richard C. Kelly and Benjamin G.S. Fowke, III, his or her true and lawful attorney-in-fact and agent, with full and several power of substitution and resubstitution, for him or her and his or her name, place and stead, in any and all capacities, to sign any or all amendments, to this registration statement, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as they, he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or their substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, as amended, this registration statement has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ WAYNE H. BRUNETTI Wayne H. Brunetti	Chairman of the Board, President, Chief Executive Officer and Director	February 14, 2003
/s/ DAVID E. RIPKA David E. Ripka	Controller (Chief Accounting Officer)	February 14, 2003
/s/ RICHARD C. KELLY Richard C. Kelly	Chief Financial Officer	February 14, 2003
/s/ C. CONEY BURGESS C. Coney Burgess	Director	February 14, 2003
/s/ DAVID A. CHRISTENSEN David A. Christensen	Director	February 14, 2003
/s/ ROGER R. HEMMINGHAUS Roger R. Hemminghaus	Director	February 14, 2003
/s/ A. BARRY HIRSCHFELD	Director	February 14, 2003

A. Barry Hirschfeld

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Signature	Title	Date
/s/ DOUGLAS W. LEATHERDALE Douglas W. Leatherdale	Director	February 14, 2003
/s/ ALBERT F. MORENO Albert F. Moreno	Director	February 14, 2003
/s/ MARGARET R. PRESKA Margaret R. Preska	Director	February 14, 2003
/s/ A. PATRICIA SAMPSON A. Patricia Sampson	Director	February 14, 2003
/s/ ALLAN L. SCHUMAN Allan L. Schuman	Director	February 14, 2003
/s/ RODNEY E. SLIFER Rodney E. Slifer	Director	February 14, 2003
/s/ W. THOMAS STEPHENS W. Thomas Stephens	Director	February 14, 2003

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INDEX TO EXHIBITS

Xcel Energy	
2.01*	Agreement and Plan of Merger, dated as of March 24, 1999, by and between Northern States Power Company and New Century Energies, Inc. (Incorporated by reference to Exhibit 2.1 to the Report on Form 8-K (File No. 1-12927) of New Century Energies, Inc. dated March 24, 1999).
3.01*	Restated Articles of Incorporation of the Company (Filed as Exhibit 4.01 to the Company s Form 8-K (File no. 1-3034) filed on August 21, 2000).
3.02*	By-Laws of the Company (Filed as Exhibit 4.3 to the Company s Registration Statement on Form S-8 (File no. 333-48590) filed on October 25, 2000).
4.01*	Trust Indenture dated Dec. 1, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee. (Filed as Exhibit 4.01 to the Company s Form 8-K Report (File No. 1-3034) dated Dec. 14, 2000).
4.02*	Supplemental Trust Indenture dated Dec. 15, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, National Association, as Trustee, creating $600,000,000 principal amount of 7% Senior Notes, Series due 2010. (Filed as Exhibit 4.02 to the Company s Form 8-K Report (File No. 1-3034) dated Dec. 18, 2000).
4.03*	Stockholder Protection Rights Agreement dated Dec. 13, 2000, between Xcel Energy Inc. and Wells Fargo Bank Minnesota, N.A., as Rights Agent. (Filed as Exhibit 1 to the Company s Form 8-K Report (File No. 1-3034) dated Jan. 4, 2001).
4.04*	Subordinated Convertible Note, dated Feb. 28, 2002, between NRG Energy, Inc. and Xcel Energy Inc. (Filed as Exhibit 4.112 to the Company s Registration Statement on Form S-4 (File No. 333-84264) filed on March 13, 2002).
4.05*	Indenture between Xcel Energy, Inc. and Wells Fargo Bank Minnesota, National Association dated as of November 21, 2002 (Filed as Exhibit 99.01 to the Company s Form 8-K Report (File No. 1-3034) dated November 21, 2002)
4.06*	Form of Convertible Senior Note due 2007 (included in Exhibit 4.05 above and incorporated herein by reference)
4.07*	Registration Rights Agreement among the Company and Merrill Lynch, Pierce, Fenner & Smith Incorporated and Lazard Freres & Co. LLC dated November 21, 2002 (Filed as Exhibit 99.02 to the Company s Form 8-K Report (File No. 1-3034) dated November 21, 2002)
NSP-Minnesota	
4.08*	Trust Indenture, dated Feb. 1, 1937, from NSP to Harris Trust and Savings Bank, as Trustee. (Exhibit B-7 to File No. 2-5290).
4.09*	Supplemental and Restated Trust Indenture, dated May 1, 1988, from NSP to Harris Trust and Savings Bank, as Trustee. (Exhibit 4.02 to Form 10-K of NSP for the year 1988, File No. 1-3034).
	Supplemental Indenture between NSP and said Trustee, supplemental to Exhibit 4.03, dated as follows:
4.10*	June 1, 1942 (Exhibit B-8 to File No. 2-97667).
4.11*	Feb. 1, 1944 (Exhibit B-9 to File No. 2-5290).
4.12*	Oct. 1, 1945 (Exhibit 7.09 to File No. 2-5924).
4.13*	July 1, 1948 (Exhibit 7.05 to File No. 2-7549).
4.14*	Aug. 1, 1949 (Exhibit 7.06 to File No. 2-8047).
4.15*	June 1, 1952 (Exhibit 4.08 to File No. 2-9631).
4.16*	Oct. 1, 1954 (Exhibit 4.10 to File No. 2-12216).
4.17*	Sept. 1, 1956 (Exhibit 2.09 to File No. 2-13463).
4.18*	Aug. 1, 1957 (Exhibit 2.10 to File No. 2-14156).
4.19*	July 1, 1958 (Exhibit 4.12 to File No. 2-15220).
4.20*	Dec. 1, 1960 (Exhibit 2.12 to File No. 2-18355).
4.21*	Aug. 1, 1961 (Exhibit 2.13 to File No. 2-20282).

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4.22*	June 1, 1962 (Exhibit 2.14 to File No. 2-21601).
4.23*	Sept. 1, 1963 (Exhibit 4.16 to File No. 2-22476).
4.24*	Aug. 1, 1966 (Exhibit 2.16 to File No. 2-26338).
4.25*	June 1, 1967 (Exhibit 2.17 to File No. 2-27117).
4.26*	Oct. 1, 1967 (Exhibit 2.01R to File No. 2-28447).
4.27*	May 1, 1968 (Exhibit 2.01S to File No. 2-34250).
4.28*	Oct. 1, 1969 (Exhibit 2.01T to File No. 2-36693).
4.29*	Feb. 1, 1971 (Exhibit 2.01U to File No. 2-39144).
4.30*	May 1, 1971 (Exhibit 2.01V to File No. 2-39815).
4.31*	Feb. 1, 1972 (Exhibit 2.01W to File No. 2-42598).
4.32*	Jan. 1, 1973 (Exhibit 2.01X to File No. 2-46434).
4.33*	Jan. 1, 1974 (Exhibit 2.01Y to File No. 2-53235).
4.34*	Sept. 1, 1974 (Exhibit 2.01Z to File No. 2-53235).
4.35*	April 1, 1975 (Exhibit 4.01AA to File No. 2-71259).
4.36*	May 1, 1975 (Exhibit 4.01BB to File No. 2-71259).
4.37*	March 1, 1976 (Exhibit 4.01CC to File No. 2-71259).
4.38*	June 1, 1981 (Exhibit 4.01DD to File No. 2-71259).
4.39*	Dec. 1, 1981 (Exhibit 4.01EE to File No. 2-83364).
4.40*	May 1, 1983 (Exhibit 4.01FF to File No. 2-97667).
4.41*	Dec. 1, 1983 (Exhibit 4.01GG to File No. 2-97667).
4.42*	Sept. 1, 1984 (Exhibit 4.01HH to File No. 2-97667).
4.43*	Dec. 1, 1984 (Exhibit 4.01II to File No. 2-97667).
4.44*	May 1, 1985 (Exhibit 4.36 to Form 10-K for the year 1985, File No. 1-3034).
4.45*	Sept. 1, 1985 (Exhibit 4.37 to Form 10-K for the year 1985, File No. 1-3034).
4.46*	July 1, 1989 (Exhibit 4.01 to Form 8-K dated July 7, 1989, File No. 1-3034).
4.47*	June 1, 1990 (Exhibit 4.01 to Form 8-K dated June 1, 1990, File No. 1-3034).
4.48*	Oct. 1, 1992 (Exhibit 4.01 to Form 8-K dated Oct. 13, 1992, File No. 1-3034).
4.49*	April 1, 1993 (Exhibit 4.01 to Form 8-K dated March 30, 1993, File No. 1-3034).
4.50*	Dec. 1, 1993 (Exhibit 4.01 to Form 8-K dated Dec. 7, 1993, File No. 1-3034).
4.51*	Feb. 1, 1994 (Exhibit 4.01 to Form 8-K dated Feb. 10, 1994, File No. 1-3034).
4.52*	Oct. 1, 1994 (Exhibit 4.01 to Form 8-K dated Oct. 5, 1994, File No. 1-3034).
4.53*	June 1, 1995 (Exhibit 4.01 to Form 8-K dated June 28, 1995, File No. 1-3034).
4.54*	April 1, 1997 (Exhibit 4.47 to Form 10-K for the year 1997, File No. 1-3034).
4.55*	March 1, 1998 (Exhibit 4.01 to Form 8-K dated March 11, 1998, File No. 1-3034).
4.56*	May 1, 1999 (Exhibit 4.49 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.57*	June 1, 2000 (Exhibit 4.50 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.58*	Aug. 1, 2000 (Assignment and Assumption of Trust Indenture) (Exhibit 4.51 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.59*	June 1, 2002 (Exhibit 4.05 to Form 10-Q of NSP-Minnesota, File No. 1-03034).
4.60*	July 1, 2002 (Exhibit 4.06 to Form 10-Q of NSP-Minnesota, File No. 1-03034).
4.61*	Aug. 1, 2002 (Exhibit 4.01 to Form 8-K dated Aug. 22, 2002, File No. 1-31387).
4.62*	Subordinated Debt Securities Indenture, dated as of Jan. 30, 1997, between Xcel Energy and Norwest Bank Minnesota, National Association, as trustee. (Exhibit 4.02 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).

4.63*	Preferred Securities Guarantee Agreement, dated as of Jan. 31, 1997, between Xcel Energy and Wilmington Trust Company, as Trustee. (Exhibit 4.05 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.64*	Preferred Securities Guarantee Agreement, dated as of Aug. 18, 2000, between Northern States Power Company and Wilmington Trust Company, as Trustee. (Exhibit 4.54 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.65*	Amended and Restated Declaration of Trust of NSP Financing I, dated as of Jan. 31. 1997, including form of Preferred Security. (Exhibit 4.10 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.66*	Supplemental Indenture, dated as of Jan. 31, 1997, between Xcel Energy and Norwest Bank Minnesota, National Association, as trustee, including form of Junior Subordinated Debenture. (Exhibit 4.12 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.67*	Supplemental Trust Indenture dated Aug. 18, 2000 between Xcel Energy, Northern States Power Company and Wells Fargo Bank Minnesota, National Association, as Trustee (Exhibit 4.57 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.68*	Common Securities Guarantee Agreement dated as of Jan. 31, 1997, between Xcel Energy and Wilmington Trust Company, as Trustee. (Exhibit 4.13 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.69*	Common Securities Guarantee Agreement dated as of Aug. 18, 2000, between NSP and Wilmington Trust Company, as Trustee. (Exhibit 4.59 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.70*	Subscription Agreement, dated as of Jan. 28, 1997, between NSP Financing I and NSP. (Exhibit 4.14 to Form 8-K dated Jan. 28, 1997, File No. 001-03034).
4.71*	Trust Indenture, dated July 1, 1999, between NSP and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to Form 8-K dated July 21, 1999, File No. 1-03034).
4.72*	Supplemental Trust Indenture, dated July 15, 1999, between NSP and Norwest Bank Minnesota, National Association, as Trustee. (Exhibit 4.02 to Form 8-K dated July 21, 1999, File No. 1-03034).
4.73*	Supplemental Trust Indenture, dated Aug. 18, 2000, among Xcel Energy, Northern States Power Company and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.63 to Form 10 of NSP-Minnesota, File No. 000-31709).
4.74*	Supplemental Trust Indenture, dated July 1, 2002, between NSP and Wells Fargo Bank Minnesota, National Association, as Trustee. (Exhibit 4.01 to Form 8-K dated July 8, 2002, File No. 000-31709).
4.75*	Supplemental Indenture dated as of June 1, 2002, between NSP-Minnesota and BNY Midwest Trust Company, as successor trustee, creating $308,000,000 principal amount of First Mortgage Bonds, Series due 2003. (Exhibit 4.05 to Form 10-Q filed on November 18, 2002, File No. 001-3034.)
4.76*	Supplemental Indenture dated as of July 1, 2002, between NSP-Minnesota and BNY Midwest Trust Company, as successor trustee, creating $69,000,000 principal amount of First Mortgage Bonds, Pollution Control Series S. (Exhibit 4.06 to Form 10-Q filed on November 18, 2002, File No. 001-3034.)
4.77*	Supplemental Indenture dated Aug. 1, 2002, between NSP-Minnesota and BNY Midwest Trust Company, as successor trustee, creating $450,000,000 principal amount of 8 percent First Mortgage Bonds, Series A due Aug. 28, 2012. (Exhibit 4.09 to Form 10-Q dated November 18, 2002, File No. 001-3034.)
NSP-Wisconsin	
4.78*	Copy of Trust Indenture, dated April 1, 1947, From NSP-Wisconsin to Firstar Trust Company (formerly First Wisconsin Trust Company). (Filed as Exhibit 7.01 to Registration Statement 2-6982).
4.79*	Copy of Supplemental Trust Indenture, dated March 1, 1949. (Filed as Exhibit 7.02 to Registration Statement 2-7825).

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4.80*	Copy of Supplemental Trust Indenture, dated June 1, 1957. (Filed as Exhibit 2.13 to Registration Statement 2-13463).
4.81*	Copy of Supplemental Trust Indenture, dated Aug. 1, 1964. (Filed as Exhibit 4.20 to Registration Statement 2-23726).
4.82*	Copy of Supplemental Trust Indenture, dated Dec. 1, 1969. (Filed as Exhibit 2.03E to Registration Statement 2-36693).
4.83*	Copy of Supplemental Trust Indenture, dated Sept. 1, 1973. (Filed as Exhibit 2.03F to Registration Statement 2-49757).
4.84*	Copy of Supplemental Trust Indenture, dated Feb. 1, 1982. (Filed as Exhibit 4.01G to Registration Statement 2-76146).
4.85*	Copy of Supplemental Trust Indenture, dated March 1, 1982. (Filed as Exhibit 4.08 to Form 10-K Report 10-3140 for the year 1982).
4.86*	Copy of Supplemental Trust Indenture, dated June 1, 1986. (Filed as Exhibit 4.09 to Form 10-K Report 10-3140 for the year 1986).
4.87*	Copy of Supplemental Trust Indenture, dated March 1, 1988. (Filed as Exhibit 4.10 to Form 10-K Report 10-3140 for the year 1988).
4.88*	Copy of Supplemental and Restated Trust Indenture, dated March 1, 1991. (Filed as Exhibit 4.01K to Registration Statement 33-39831).
4.89*	Copy of Supplemental Trust Indenture, dated April 1, 1991. (Filed as Exhibit 4.01 to Form 10-Q Report 10-3140 for the quarter ended March 31, 1991).
4.90*	Copy of Supplemental Trust Indenture, dated March 1, 1993. (Filed as Exhibit to Form 8-K Report 10-3140 dated March 3, 1993).
4.91*	Copy of Supplemental Trust Indenture, dated Oct. 1, 1993. (Filed as Exhibit 4.01 to Form 8-K Report 10-3140 dated Sept. 21, 1993).
4.92*	Copy of Supplemental Trust Indenture, dated Dec. 1, 1996. (Filed as Exhibit 4.01 to Form 8-K Report 10-3140 dated Dec. 12, 1996).
4.93*	Trust Indenture dated September 1, 2000, between Northern States Power Company and Firstar Bank, N.A. as Trustee. (Filed as Exhibit 4.01 to Form 8-K 10-3140 dated Sept. 25, 2000).
4.94*	Supplemental Trust Indenture dated September 15, 2000, between Northern States Power Company and Firstar Bank, N.A. as Trustee, creating $80,000,000 principal amount of 7.64% Senior Notes, Series due 2008. (Filed as Exhibit 4.02 to Form 8-K 10-3140 dated Sept. 25, 2000).

PSCo

4.95*	Indenture, dated as of Dec. 1, 1939, providing for the issuance of First Mortgage Bonds (Form 10 for 1946-Exhibit (B-1)).
4.96*	Indentures supplemental to Indenture dated as of Dec. 1, 1939:

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Mar. 14, 1941	10, 1946	B-2
May 14, 1941	10, 1946	B-3
Apr. 28, 1942	10, 1946	B-4
Apr. 14, 1943	10, 1946	B-5
Apr. 27, 1944	10, 1946	B-6
Apr. 18, 1945	10, 1946	B-7
Apr. 23, 1946	10-K, 1946	B-8
Apr. 9, 1947	10-K, 1946	B-9
June 1, 1947	S-1, (2-7075)	7(b)
Apr. 1, 1948	S-1, (2-7671)	7(b)(1)
May 20, 1948	S-1, (2-7671)	7(b)(2)
Oct. 1, 1948	10-K, 1948	4

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Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Apr. 20, 1949	10-K, 1949	1
Apr. 24, 1950	8-K, Apr. 1950	1
Apr. 18, 1951	8-K, Apr. 1951	1
Oct. 1, 1951	8-K, Nov. 1951	1
Apr. 21, 1952	8-K, Apr. 1952	1
Dec. 1, 1952	S-9, (2-11120)	2(b)(9)
Apr. 15, 1953	8-K, Apr. 1953	2
Apr. 19, 1954	8-K, Apr. 1954	1
Oct. 1, 1954	8-K, Oct. 1954	1
Apr. 18, 1955	8-K, Apr. 1955	1
Apr. 24, 1956	10-K, 1956	1
May 1, 1957	S-9, (2-13260)	2(b)(15)
Apr. 10, 1958	8-K, Apr. 1958	1
May 1, 1959	8-K, May 1959	2
Apr. 18, 1960	8-K, Apr. 1960	1
Apr. 19, 1961	8-K, Apr. 1961	1
Oct. 1, 1961	8-K, Oct. 1961	2
Mar. 1, 1962	8-K, Mar. 1962	3(a)
June 1, 1964	8-K, June 1964	1
May 1, 1966	8-K, May 1966	2
July 1, 1967	8-K, July 1967	2
July 1, 1968	8-K, July 1968	2
Apr. 25, 1969	8-K, Apr. 1969	1
Apr. 21, 1970	8-K, Apr. 1970	1
Sept. 1, 1970	8-K, Sept. 1970	2
Feb. 1, 1971	8-K, Feb. 1971	2
Aug. 1, 1972	8-K, Aug. 1972	2
June 1, 1973	8-K, June 1973	1
Mar. 1, 1974	8-K, Apr. 1974	2
Dec. 1, 1974	8-K, Dec. 1974	1
Oct. 1, 1975	S-7, (2-60082)	2(b)(3)
Apr. 28, 1976	S-7, (2-60082)	2(b)(4)
Apr. 28, 1977	S-7, (2-60082)	2(b)(5)
Nov. 1, 1977	S-7, (2-62415)	2(b)(3)
Apr. 28, 1978	S-7, (2-62415)	2(b)(4)
Oct. 1, 1978	10-K, 1978	D(1)
Oct. 1, 1979	S-7, (2-66484)	2(b)(3)
Mar. 1, 1980	10-K, 1980	4(c)
Apr. 28, 1981	S-16, (2-74923)	4(c)
Nov. 1, 1981	S-16, (2-74923)	4(d)
Dec. 1, 1981	10-K, 1981	4(c)
Apr. 29, 1982	10-K, 1982	4(c)
May 1, 1983	10-K, 1983	4(c)
Apr. 30, 1984	S-3, (2-95814)	4(c)

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Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Mar. 1, 1985	10-K, 1985	4(c)
Nov. 1, 1986	10-K, 1986	4(c)
May 1, 1987	10-K, 1987	4(c)
July 1, 1990	S-3, (33-37431)	4(c)
Dec. 1, 1990	10-K, 1990	4(c)
Mar. 1, 1992	10-K, 1992	4(d)
Apr. 1, 1993	10-Q, June 30, 1993	4(a)
June 1, 1993	10-Q, June 30, 1993	4(b)
Nov. 1, 1993	S-3, (33-51167)	4(a)(3)
Jan. 1, 1994	10-K, 1993	4(a)(3)
Sept. 2, 1994	8-K, Sept. 1994	4(a)
May 1, 1996	10Q, June 30, 1996	4(a)
Nov. 1, 1996	10-K, 1996	4(a)(3)
Feb. 1, 1997	10-Q, Mar. 31, 1997	4(a)
April 1, 1998	10-Q, Mar. 31, 1998	4(a)
August 15, 2002	10-Q, Sept. 30, 2002	4.01
September 15, 2002	10-Q, Sept. 30, 2002	4.02

4.97*	Indenture, dated as of Oct. 1, 1993, providing for the issuance of First Collateral Trust Bonds (Form 10-Q, Sept. 30, 1993 Exhibit 4(a)).
4.98*	Indentures supplemental to Indenture dated as of Oct. 1, 1993:

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Nov. 1, 1993	S-3, (33-51167)	4(b)(2)
Jan. 1, 1994	10-K, 1993	4(b)(3)
Sept. 2, 1994	8-K, Sept. 1994	4(b)
May 1, 1996	10-Q, June 30, 1996	4(b)
Nov. 1, 1996	10-K, 1996	4(b)(3)
Feb. 1, 1997	10-Q, Mar. 31, 1997	4(b)
April 1, 1998	10-Q, Mar. 31, 1998	4(b)
Aug. 15, 2002	10-Q, Sept. 30, 2002	4.03
Sept. 15, 2002	10-Q, Sept. 30, 2002	4.04

4.99*	Indenture dated May 1, 1998, between PSCo and The Bank of New York, providing for the issuance of Subordinated Debt Securities (Form 8-K, May 6, 1998 Exhibit 4.2).
4.100*	Supplemental Indenture dated May 11, 1996, between PSCo and The Bank of New York, (Form 8-K, May 6, 1998 Exhibit 4.3).
4.101*	Preferred Securities Guarantee Agreement dated May 11, 1998, between PSCo and The Bank of New York, (Form 8-K, May 6, 1998 Exhibit 4.4).
4.102*	Amended and Restated Declaration of Trust of PSCo Capital and Trust I dated May 11, 1998, (Form 8-K, May 6, 1998 Exhibit 4.1).
4.103*	Indenture dated July 1, 1999, between PSCo and The Bank of New York, providing for the issuance of Senior Debt Securities (Form 8-K, July 13, 1999, Exhibit 4.1) and Supplemental Indenture dated July 15, 1999, between PSCO and The Bank of New York (Form 8-K, July 13, 1999, Exhibit 4.2).
4.104*	Supplemental Indenture dated Aug. 15, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $48,750,000 principal amount of First Mortgage Bonds Collateral, Series G, due 2019. (Exhibit 4.01 to Form 10-Q dated November 18, 2002, File No. 001-3034.)

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4.105*	Supplemental Indenture dated as of Sept. 15, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $530,000,000 principal amount of First Mortgage Bonds Collateral, Series I, due 2003. (Exhibit 4.02 to Form 10-Q dated November 18, 2002, File No. 001-3034.)
4.106*	Supplemental Indenture dated Aug. 15, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $48,750,000 principal amount of First Collateral Trust Bonds Collateral, Series No. 7, due 2019. (Exhibit 4.03 to Form 10-Q dated November 18, 2002, File No. 001-3034.)
4.107*	Supplemental Indenture dated as of Sept. 15, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $530,000,000 principal amount of First Collateral; Trust Bonds, Series No. 9, due 2003. (Exhibit 4.04 to Form 10-Q dated November 18, 2002, File No. 001-3034.)
4.108*	Supplemental Indenture dated as of Sept. 1, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $600 million principal amount of 7.875 percent First Collateral Trust Bonds, Series No. 8 due 2012. (Incorporated by reference to Exhibit 4.01 to PSCO s Current Report on Form 8-K, dated Sept. 18, 2002)
4.109*	Supplemental Indenture dated as of Sept. 18, 2002, between PSCo and U.S. Bank Trust National Association, as trustee, creating $600 million principal amount of 7.875 percent First Mortgage Bonds, Series H due 2012. (Incorporated by reference to Exhibit 4.02 to PSCO s Current Report on Form 8-K, dated Sept. 18, 2002)

SPS

4.110*	Indenture, dated as of Aug. 1, 1946, providing for the issuance of First Mortgage Bonds (Registration No. 2-6910, Exhibit 7-A).
4.111*	Indentures supplemental to Indenture dated as of Aug. 1, 1946:

Dated as of	Previous Filing: Form; Date or File No.	Exhibit No.
Feb. 1, 1967	2-25983	2-S
Oct. 1, 1970	2-38566	2-T
Feb. 9, 1977	2-58209	2-Y
March 1, 1979	2-64022	b(28)
April 1, 1983 (two)	10-Q, May 1983	4(a)
Feb. 1, 1985	10-K, Aug. 1985	4(c)
July 15, 1992 (two)	10-K, Aug. 1992	4(a)
Dec. 1, 1992 (two)	10-Q, Feb. 1993	4
Feb. 15, 1995	10-Q, May 1995	4
March 1, 1996	333-05199	4(c)

4.112*	Indenture dated Feb. 1, 1999 between SPS and The Chase Manhattan Bank (Form 8-K, Feb. 25, 1999, Exhibit 99.2).
4.113*	Supplemental Indenture dated March 1, 1999, between SPS and The Chase Manhattan Bank (Form 8-K, Feb. 25, 1999, Exhibit 99.3).
4.114*	Supplemental Indenture dated October 1, 2001, between SPS and The Chase Manhattan Bank (Form 8-K, Oct. 23, 2001, Exhibit 4.01).
4.115*	Red River Authority for Texas Indenture of Trust dated July 1, 1991 (Form 10-K, Aug. 31, 1991 Exhibit 4(b)).
4.116*	Indenture dated Oct. 21, 1996, between SPS and Wilmington Trust Company, (Form 10-Q, Nov. 30, 1996 Exhibit 4(a)).
4.117*	Supplemental Indenture dated Oct. 21, 1996, between SPS and Wilmington Trust Company, (Form 10-Q, Nov. 30, 1996 Exhibit 4(b)).
4.118*	Guarantee Agreement dated Oct. 21, 1996, between SPS and Wilmington Trust Company, (Form 10-Q, Nov. 30, 1996 Exhibit 4(c)).

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	4.119*	Amended and Restated Trust Agreement dated Oct. 21, 1996, among SPS, David M. Wilks, as initial depositor, Wilmington Trust Company and the administrative trustees named therein (Form 10-Q, Nov. 30, 1996 Exhibit 4(d)).
	4.120*	Agreement as to Expenses dated Oct. 21, 1996, between SPS and Southwestern Public Service Capital I, (Form 10-K, Dec. 31, 1996 Exhibit F).
NRG		
	4.121*	Indenture, dated as of June 1, 1997, between NRG and Norwest Bank Minnesota, National Association. (Incorporated herein by reference to Exhibit 4.1 to NRG s Form S-1 (File no. 333-33397)).
	4.122*	Form of Exchange Notes. (Incorporated herein by reference to Exhibit 4.2 to NRG s Form S-1 (File no. 333-33397).
	4.123*	Loan Agreement, dated June 4, 1999 between NRG Northeast Generating LLC, Chase Manhattan Bank and Citibank, N.A. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
	4.124*	Indenture between NRG and Norwest Bank Minnesota, National Association, as Trustee dated as of May 25, 1999 (incorporated herein by reference to Exhibit 4.1 to NRG s current report on Form 8-K (File no. 000-25569) dated May 25, 1999 and filed on May 27, 1999).
	4.125*	Indenture between NRG and NRG Northeast Generating LLC and The Chase Manhattan Bank, as Trustee dated as of February 22, 2000. (Incorporated by reference to NRG s Form 10-K (File no. 000-15891) for the year ended December 31, 1999).
	4.126*	NRG Energy Pass-Through Trust 2000-1, $250,000,000 8.70% Remarketable or Redeemable Securities (ROARS) due March 15, 2005. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
	4.127*	Trust Agreement between NRG Energy, Inc. and The Bank of New York, as Trustee, dated March 20, 2000. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
	4.128*	Indenture between NRG Energy, Inc. and the Bank of New York, as Trustee dated March 20, 2000, 160,000,000 pounds sterling Reset Senior Notes due March 15, 2020. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
	4.129*	Indenture, dated March 13, 2001, between NRG Energy, Inc. and The Bank of New York, a New York banking corporation, as Trustee. (Incorporated by reference to NRG s current report on Form 8-K (File no. 001-15891) dated March 15, 2001).
	4.130*	First Supplement Indenture, dated March 13, 2001, between NRG Energy, Inc. and The Bank of New York, a New York banking corporation, as Trustee. (Incorporated by reference to NRG s current report on Form 8-K (File no. 001-15891) dated March 15, 2001).
	4.131*	364-Day Revolving Credit Agreement dated as of March 8, 2002, among NRG Energy, Inc., The Financial Institutions Party hereto and ABN AMRO Bank N.V., as agent. (Incorporated by reference to NRG s quarterly report on Form 10-Q (File no. 001-15891) for the quarter ended March 31, 2001).
	4.132*	$2.0 billion credit agreement dated May 8, 2001 among NRG Finance Company LLC and certain financial institutions named therein. (Incorporated by reference to NRG s quarterly report on Form 10-Q (File no. 001-15891) for the quarter ended June 30, 2001).
Xcel Energy		
	5.1**	Opinion of Gary R. Johnson as to certain legal matters
	5.2**	Opinion of Jones Day as to certain legal matters
	8.1**	Opinion of Jones Day as to certain U.S. federal income tax considerations

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NSP-Minnesota

10.01*	Facilities Agreement, dated July 21, 1976, between NSP and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kilovolt (kv) line. (Exhibit 5.06I to File No. 2-54310).
10.02*	Transactions Agreement, dated July 21, 1976, between NSP and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kv line. (Exhibit 5.06J to File No. 2-54310).
10.03*	Coordinating Agreement, dated July 21, 1976, between NSP and the Manitoba Hydro-Electric Board relating to the interconnection of the 500 kv line. (Exhibit 5.06K to File No. 2-54310).
10.04*	Ownership and Operating Agreement, dated March 11, 1982, among NSP, Southern Minnesota Municipal Power Agency and United Minnesota Municipal Power Agency concerning Sherburne County Generating Unit No. 3. (Exhibit 10.01 to Form 10-Q for the quarter ended Sept. 30, 1994, File No. 1-3034).
10.05*	Transmission Agreement, dated April 27, 1982, and Supplement No. 1, dated July 20, 1982, between NSP and Southern Minnesota Municipal Power Agency. (Exhibit 10.02 to Form 10-Q for the quarter ended Sept. 30, 1994, File No. 1-3034).
10.06*	Power Agreement, dated June 14, 1984, between NSP and the Manitoba Hydro-Electric Board, extending the agreement scheduled to terminate on April 30, 1993, to April 30, 2005. (Exhibit 10.03 to Form 10-Q for the quarter ended Sept. 30, 1994, File No. 1-3034).
10.07*	Power Agreement, dated August 1988, between NSP and Minnkota Power Company. (Exhibit 10.08 to Form 10-K for the year 1988, File No. 1-3034).
10.08*	Assignment and Assumption Agreement, dated Aug. 18, 2000 between Northern States Power Company and Xcel Energy Inc. (Exhibit 10.08 to Form 10 of NSP-Minnesota, File No. 000-31709)
10.09*	Copy of Interchange Agreement dated Sept. 17, 1984, and Settlement Agreement dated May 31, 1985, between NSP-Wisconsin, the NSP-Minnesota Company and LSDP. (Filed as Exhibit 10.10 to Form 10-K Report 10-3140 for the year 1985).

PSCo

10.10*	Amended and Restated Coal Supply Agreement entered into Oct. 1, 1984 but made effective as of Jan. 1, 1976 between PSCo and Amax Inc. on behalf of its division, Amax Coal Company (Form 10-K, (File no. 001-03280) Dec. 31, 1984 Exhibit 10(c)(1)).
10.11*	First Amendment to Amended and Restated Coal Supply Agreement entered into May 27, 1988 but made effective Jan. 1, 1988 between PSCo and Amax Coal Company (Form 10-K, (File no. 001-03280) Dec. 31, 1988 Exhibit 10(c)(2).

SPS

10.12*	Coal Supply Agreement (Harrington Station) between SPS and TUCO, dated May 1, 1979 (Form 8-K (File no. 001-3789), May 14, 1979 Exhibit 3).
10.13*	Master Coal Service Agreement between Swindell-Dressler Energy Supply Company and TUCO, dated July 1, 1978 (Form 8-K, (File no. 001-3789) May 14, 1979 Exhibit 5(A)).
10.14*	Guaranty of Master Coal Service Agreement between Swindell-Dressler Energy Supply Company and TUCO (Form 8-K, (File no. 3789) May 14, 1979 Exhibit 5(B)).

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10.15*	Coal Supply Agreement (Tolk Station) between SPS and TUCO dated April 30, 1979, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (File no. 3789) Feb. 28, 1982 Exhibit 10(b)).
10.16*	Master Coal Service Agreement between Wheelabrator Coal Services Co. and TUCO dated Dec. 30, 1981, as amended Nov. 1, 1979 and Dec. 30, 1981 (Form 10-Q, (File no. 3789) Feb. 28, 1982 Exhibit 10(c)).
Xcel Energy	
10.17*	Xcel Energy Omnibus Incentive Plan (Exhibit A to Xcel s Proxy Statement (File no. 1-3034) filed Aug. 29, 2000).
10.18*	Xcel Energy Executive Annual Incentive Award (Exhibit B to Xcel s Proxy Statement (File no. 1-3034) filed Aug. 29, 2000).
10.19*	Xcel Energy Senior Executive Severance (Exhibit 10.19 to Form 10-K for the year 2000, File No. 1-3034).
10.20*	Employment Agreement of James J. Howard dated March 24, 1999. (Exhibit 10.14 to Form 10-K for the year 1998. File No. 1-3034).
10.21*	Employment Agreement, effective December 15, 1997, between company and Mr. Paul J. Bonavia (Form 10-Q, (File no. 001-12927) September 30, 1998 Exhibit 10(a)).
10.22*	The employment agreement, dated March 24, 1999, among Northern States Power Company, New Century Energies, Inc. and Wayne H. Brunetti (Form 10-Q, (File no. 001-12927) March 31, 1999, Exhibit 10(b)).
10.23*	Summary of Terms and Conditions of Employment of James J. Howard, Chairman, President and Chief Executive Officer, effective Feb. 1, 1987, as amended and restated effective as of Jan. 28, 1998. (Agreement filed as Exhibit 10.03 to Form 10-Q for the quarter ended March 31, 1998, File No. 1-3034).
10.24*	NSP Severance Plan. (Exhibit 10.12 to Form for the year 1994, File No. 1-3034).
10.25*	NSP Deferred Compensation Plan amended effective Jan. 1, 1993. (Exhibit 10.16 to Form 10-K for the year 1993, File No. 1-3034).
10.26*	Amended and Restated Executive Long-Term Incentive Award Stock Plan. (Exhibit 10.02 to Form 10-Q for the quarter ended March 31, 1998, File No. 1-3034).
10.27*	Stock Equivalent Plan for Non-Employee Directors of Xcel Energy As Amended and Restated Effective Oct. 1, 1997. (Exhibit 10.15 to Form 10-K for the year 1997. File No. 1-3034).
10.28*	Form of Key Executive Change in Control Agreement (Form 10-K, (File no. 001-12927) December 31, 1998, Exhibit 10(a)(1)).
10.29*	Senior Executive Severance Policy, effective March 24, 1999, between New Century Energies, Inc. and Senior Executives (Form 10-Q, (File no. 001-12927) March 31, 1999, Exhibit 10(a)(2)).
10.30*	Employment Agreement, effective August 1, 1997, between the Company and Mr. Wayne H. Brunetti (Form S-4, Annex I, File No. 33-64951).
10.31*	New Century Energies Omnibus Incentive Plan, effective August 1, 1997 (Form Def 14A, (File no. 001-12927) December 31, 1997 Exhibit A).
10.32*	Directors Voluntary Deferral Plan (Form 10-K, (File no. 001-12927) December 31, 1998, Exhibit 10(d)(1)).
10.33*	Supplemental Executive Retirement Plan (Form 10-K, (File no. 001-12927) December 31, 1998. Exhibit 10(e)(1)).
10.34*	Salary Deferral and Supplemental Savings Plan for Executive Officers (Form 10-K, (File no. 001-12927) December 31, 1998, Exhibit 10(f)(1)).
10.35*	Salary Deferral and Supplemental Savings Plan for Key Managers (Form 10-K, (File no. 001-12927) December 31, 1998, Exhibit 10(g)(1)).

10.36*	Supplemental Executive Retirement Plan for Key Management Employees, as amended and restated March 26, 1991 (Form 10-K, (File no. 001-3280) Dec. 31, 1991 Exhibit 10(e)(2)).
10.37*	Form of Key Executive Severance Agreement, as amended on Aug. 22, and Nov. 27, 1995. (Form 10-K, (File no. 001-3280) Dec. 31, 1995 Exhibit 10(3)(4)).
10.38*	SPS 1989 Stock Incentive Plan as amended April 23, 1996 (Form 10-K, (File no. 001-3789) Aug. 31, 1996 Exhibit 10(b)).
10.39*	Director s Deferred Compensation Plan as amended Jan. 10, 1990 (Form 10-K, (File no. 001-3789) Aug. 31, 1996 Exhibit 10(c)).
10.40*	Supplemental Retirement Income Plan as amended July 23, 1991 (Form 10-K, (File no. 001-3789) Aug. 31, 1996 Exhibit 10(e)).
10.41*	EPS Performance Unit Plan dated Oct. 27, 1992 (Form 10-K, (File no. 001-3789) Aug. 31, 1996 Exhibit 10(a)).
NRG	
10.42*	Employment Contract, dated as of June 28, 1995, between NRG and David H. Peterson. (Incorporated herein by reference to Exhibit 10.1 to NRG s Form S-1, File no. 333-33397).
10.43*	Note Agreement, dated August 20, 1993, among NRG Energy Center, Inc. and each of the purchasers named therein. (Incorporated herein by reference to Exhibit 10.5 to NRG s Form S-1 (File no. 333-33397).
10.44*	Master Shelf and Revolving Credit Agreement dated August 20, 1993 among NRG Energy Center, Inc., The Prudential Insurance Registrants of America and each Prudential Affiliate, which becomes party thereto. (Incorporated herein by reference to Exhibit 10.4 to NRG s Form S-1 (File no. 333-33397).
10.45*	Energy Agreement dated February 12, 1988 between NRG (formerly known as Norenco Corporation) and Waldorf Corporation (the Energy Agreement). (Incorporated herein by reference to Exhibit 10.6 to NRG s Form S-1, File no. 333-33397).
10.46*	First Amendment to the Energy Agreement dated August 27, 1993. (Incorporated herein by reference to Exhibit 10.7 to NRG s Form S-1, File no. 333-33397).
10.47*	Second Amendment to the Energy Agreement, dated August 27, 1993. (Incorporated herein by reference to Exhibit 10.8 to NRG s Form S-1, File no. 333-33397).
10.48*	Third Amendment to the Energy Agreement dated August 27, 1993. (Incorporated herein by reference to Exhibit 10.9 to NRG s Form S-1, File no. 333-33397).
10.49*	Construction, Acquisition, and Term Loan Agreement, dated September 2, 1997 by and among NEO Landfill Gas, Inc., as Borrower, the lenders named on the signature pages, Credit Lyonnais New York Branch, as Construction/ Acquisition Agent and Lyon Credit Corporation as Term Agent. (Incorporated herein by reference to Exhibit 10.10 to NRG s Form S-1, File no. 333-33397).
10.50*	Guaranty, dated September 12, 1997 by NRG in favor of Credit Lyonnais New York Branch as agent for the Construction/ Acquisition Lenders. (Incorporated herein by reference to Exhibit 10.11 to NRG s Form S-1, File no. 333-33397).
10.51*	Construction, Acquisition, and Term Loan Agreement, dated September 2, 1997 by and among Minnesota Methane LLC, as Borrower, the lenders named on the signature pages, Credit Lyonnais New York Branch, as Construction/ Acquisition Agent and Lyon Credit Corporation as Term Agent. (Incorporated herein by reference to Exhibit 10.12 to NRG s Form S-1, File no. 333-33397).
10.52*	Guaranty, dated September 12, 1997 by NRG in favor of Credit Lyonnais New York Branch as agent for the Construction/ Acquisition Lenders. (Incorporated herein by reference to Exhibit 10.13 to NRG s Form S-1, File no. 333-33397).

10.53*	Non Operating Interest Acquisition Agreement dated as of September 12, 1997, by and among NRG and NEO Corporation. (Incorporated herein by reference to Exhibit 10.14 to NRG s Form S-1, File no. 333-33397).
10.54*	Employment Agreements between NRG and certain officers dated as of April 15, 1998. (Incorporated herein by reference to Exhibit 10.17 of NRG s Form 10-Q (File no. 001-15891) for the quarter ended March 31, 1998).
10.55*	Wholesale Standard Offer Service Agreement between Blackstone Valley Electric Company, Eastern Edison Company, Newport Electric Corporation and NRG Power Marketing, Inc., dated October 13, 1998. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.56*	Asset Sales Agreement by and between Niagara Mohawk Power Corporation and NRG Energy, Inc., dated December 23, 1998. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.57*	First Amendment to Wholesale Standard Offer Service Agreement between Blackstone Valley Electric Company, Eastern Edison Company, Newport Electric Corporation and NRG Power Marketing, Inc., dated January 15, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.58*	Generating Plant and Gas Turbine Asset Purchase and Sale Agreement for the Arthur Kill generating plants and Astoria gas turbines by and between Consolidated Edison Company of New York, Inc., and NRG Energy, Inc., dated January 27, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.59*	Transition Energy Sales Agreement between Arthur Kill Power LLC and Consolidated Edison Company of New York, Inc., dated June 1, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.60*	Transition Power Purchase Agreement between Astoria Gas Turbine Power LLC and Consolidated Edison Company of New York, Inc., dated June 1, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.61*	Transition Power Purchase Agreement between Niagara Mohawk Power Corporation and Huntley Power LLC, dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.62*	Transition Power Purchase Agreement between Niagara Mohawk Power Corporation and Dunkirk Power LLC, dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.63*	Power Purchase Agreement between Niagara Mohawk Power Corporation and Dunkirk Power LLC, dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.64*	Power Purchase Agreement between Niagara Mohawk Power Corporation and Huntley Power LLC, dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.65*	Amendment to the Asset Sales Agreement by and between Niagara Mohawk Power Corporation and NRG Energy, Inc., dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.66*	Transition Capacity Agreement between Astoria Gas Turbine Power LLC and Consolidated Edison Company of New York, Inc., dated June 25, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).

10.67*	Transition Capacity Agreement between Arthur Kill Power LLC and Consolidated Edison Company of New York, Inc., dated June 25, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).

10.68*	First Amendment to the Employment Agreement of David H. Peterson, dated June 27, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.69*	Second Amendment to the Employment Agreement of David H. Peterson, dated August 26, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.70*	Third Amendment to the Employment Agreement of David H. Peterson, dated October 20, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.71*	Swap Master Agreement between Niagara Mohawk Power Corporation and NRG Power Marketing, Inc., dated June 11, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.72*	Standard Offer Service Wholesale Sales Agreement between the Connecticut Light And Power Company and NRG Power Marketing, Inc., dated October 29, 1999. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
10.73*	364-day Revolving Credit Agreement among NRG and The Financial Institutions party thereto, and ABN-AMRO Bank, N.V., as Agent, dated as of March 10, 2000. (Incorporated by reference to NRG s Form 10-K (File no. 000-25569) for the year ended December 31, 1999).
Xcel Energy	
12.1	Computation of Ratio of Earnings to Fixed Charges
21.01	Subsidiaries of Xcel Energy Inc.
23.01**	Independent Accountants Consent of Deloitte & Touche LLP.
23.02**	Independent Accountants Consent of PricewaterhouseCoopers LLP.
23.05	Consent of Gary R. Johnson (included in Exhibit 5.1)
23.04	Consent of Jones Day (included in Exhibit 5.2)
24.1	Power of Attorney (included on signature page of this Registration Statement).
25.1	Form of T-1 Statement of Eligibility of the Trustee under the Indenture.
99.01*	Description of Business of NRG Energy, Inc. (Item 1 of NRG Energy, Inc. s Annual Report on Form 10-K for the fiscal year ended Dec. 31, 2001, File No. 001-15891).

* Indicates incorporation by reference

** Indicates to be filed by amendment.

Executive Compensation Arrangements and Benefit Plans Covering Executive Officers and Directors