0000010243

NEW APPLICATION

RECEIVED

BEFORE THE ARIZONA CORPORATION COMMISSION

2000 APR 28 P 4: 32

AZ CORP COMMISSION
DOCUMENT CONTROL

CARL J. KUNASEK
Chairman
JAMES M. IRVIN
Commissioner
WILLIAM MUNDELL
Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, AND BLACK MOUNTAIN GAS, A SUBSIDIARY OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, TO DETERMINE EARNINGS FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN FOR THE CAVE CREEK DIVISION.	Docket No. [redacted] G-03703A-00-0283 APPLICATION DOCKET NO. G-03703A-00-0283

Northern States Power Company ("NSP") and Black Mountain Gas Company ("BMG") hereby apply to the Arizona Corporation Commission ("Commission") to determine BMG's earnings for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return for BMG's Cave Creek Operations:

1. Applicants

1.1 NSP is a Minnesota corporation and a public utility that has traditionally provided electric service at retail and wholesale in the states of Minnesota, North Dakota and South Dakota; and natural gas service at retail in the states of

Minnesota and North Dakota.[1] At year-end 1999, NSP had combined assets of $9.8 billion, with annual revenues of $3.4 billion.

1.2 In July 1998, NSP merged with Black Mountain Gas Company of Arizona ("Old BMG") through a stock-for-stock transaction approved in Decision No. 61009, dated July 16, 1998. NSP thus became a public utility providing natural gas and propane service subject to the jurisdiction of the Commission, doing business as ("d/b/a") Black Mountain Gas Company. In 1998, the total natural gas revenues and net utility assets of NSP d/b/a BMG in Arizona were approximately $6.7 million and $10.8 million, respectively.

1.3 In January 1999, NSP filed an application to transfer or "spin down" its natural gas and propane operations in Arizona to a new wholly-owned subsidiary of NSP, i.e., BMG. Upon effectuation of the spin down, BMG would be a wholly owned subsidiary of NSP, with its own capital structure, rates and tariffs; and NSP would be the holding company parent of BMG. The Commission approved the spin down to BMG in Decision No. 61914, dated August 27, 1999 ("Spin Down Order").[2]

1.4 In September 1999, NSP and BMG filed a Notice of

---

[1] Northern States Power Company (Wisconsin) ("NSPW), a wholly-owned public utility subsidiary of NSP, provides electric service at wholesale and retail, and natural gas service at retail, in the states of Wisconsin and Michigan.

[2] In April 1999, the Minnesota Public Utilities Commission ("MPUC") and North Dakota Public Service Commission approved the NSP to BMG spin down transaction. However, the asset transfer is pending final Securities and Exchange ("SEC") action in SEC File No. 70-09337.

Restructure of Holding Company ("Merger Petition"), requesting Commission approval of the proposed merger of NSP and New Century Energies, Inc. ("NCE"), which would result in Xcel Energy Inc. ("Xcel") replacing NSP as the holding company parent of BMG. See Docket No. G-03703A-99-0535. The Merger Petition described in detail how the subsidiary status of BMG, and the regulatory authority of the Commission, would both protect BMG ratepayers in Arizona and preserve the jurisdiction of the Commission. See Merger Petition, Appendix 3, p. III-5 and Appendix 6, p. VI-4-1. The Commission approved the proposed restructuring in Decision No. 62341, dated March 6, 2000 ("Merger Order"). The Xcel merger is pending final regulatory approvals, including the SEC. NSP expects the merger with NCE to close in the second quarter of 2000.

1.5 BMG is a public service corporation subject to the jurisdiction of the Arizona Corporation Commission ("Commission") under Article XV of Arizona's Constitution and the applicable provisions of Title 40 of Arizona Revised Statutes ("A.R.S.").

1.6 BMG's certified service areas in Arizona are located in portions of the counties of Maricopa and Coconino. BMG is headquartered in Cave Creek, Arizona.

1.7 BMG provides natural gas service to approximately 5,850 customers located in Cave Creek for residential, commercial, and other miscellaneous uses (at the end of the test year). These services are rendered pursuant to a certificate of public convenience and necessity previously issued by the

Commission and in conformity with various municipal and county franchises.

2. <u>Principal Place of Business; Communications</u>

2.1 NSP's principal place of business and mailing address is 414 Nicollet Mall, Minneapolis, Minnesota, 55401, and its telephone number at this address is (612) 330-2500.

2.2 The local address and telephone number for BMG is 6021 East Cave Creek Road, Cave Creek, Arizona 85331 and (602) 488-3402.

2.3 Communications regarding this Application should be addressed to the attention of:

Black Mountain Gas Company
Attn: James H. Willson
General Manager and Chief Executive Officer
6021 East Cave Creek Road
Cave Creek, AZ 85331
(480) 488-3402

Timothy Berg, Esq.
Fennemore Craig
3003 N. Central Avenue
Suite 2600
Phoenix, AZ 85012
(602) 916-5000

Any discovery conducted in this matter should be addressed to the foregoing individuals and Daniel L. Neidlinger, Neidlinger & Associates, Ltd., 3020 North 17th Drive, Phoenix, Arizona, 85015, (602) 258-2343.

3. <u>Authority</u>

3.1 This Application is made pursuant to Sections 3 and 14 of Article XV, Arizona's Constitution, and A.R.S. Sections 40-250 and 40-251 and other applicable provisions of Title 40 of

A.R.S. and A.A.C. R14-2-103.

4. Nature of Relief Sought by Applicants

4.1 Applicants request authority to adjust the rates and charges for natural gas service in BMG's Cave Creek Operations to a just and reasonable level in order to provide BMG the opportunity to earn a fair and reasonable rate of return on the properties devoted to its Cave Creek Operations. Applicants are requesting an overall increase in annual revenues for the Cave Creek Operations of approximately $326,000 or 6.60% of test year revenues.

5. Circumstances and Conditions Justifying Rate Adjustments

5.1 This Application demonstrates that for the actual 12-month test year ended December 31, 1999, as adjusted, BMG's original cost less depreciation ("OCLD") and reconstruction cost new less depreciation ("RCND") are both $11,100,500 for the Cave Creek Operations. Applicants request permission to waive the requirement to prepare a separate RCND rate base analysis and, therefore, OCLD and RCND are equivalent in this case. Applying BMG's cost of capital to rate base produced an operating income requirement of $1,066,620, or $195,054 greater than adjusted test year results. Using a gross revenue conversion factor of 1.6722, the calculated increase in revenues required is $326,178.

5.2 In the best interests of the customers in BMG's certificated service areas in Arizona, Applicants request authority to implement an increase in rates for BMG's Cave Creek customers in a manner that: (1) ensures BMG's continued financial security; (2) promotes continued capital expenditures to maintain and improve its distribution system; and (3) enables BMG to secure reliable and alternative sources of gas supplies for use in its certificated service areas throughout Arizona.

6. <u>Exhibits</u>

BMG is a Class A utility pursuant to A.A.C. R14-2-103. Accordingly, the schedules required by that rule accompany this Application. Also appended are copies of the NSP 1999 Annual Report to Shareholders. Additionally, accompanying this Application is a prefiling of the direct testimony and exhibits that Applicants submit in support of this Application.

WHEREFORE, NSP and BMG respectfully request that the Commission issue an order pursuant to A.A.C. R14-3-101 to establish notice, prefiling, discovery and hearing procedures in this matter. NSP and BMG further request that upon conclusion of the hearing, the Commission issue its decision determining the fair value of BMG's Cave Creek properties, authorizing a just and reasonable rate of return thereon, and establishing rates and charges designed to realize the rate of return recommended by NSP and BMG.

RESPECTFULLY SUBMITTED this 28th day of April, 2000.

FENNEMORE CRAIG, P.C.

By ______________________
Timothy Berg
Theresa Dwyer

3003 North Central, Suite 2600
Phoenix, Arizona 85012
Attorneys for
Black Mountain Gas Company

ORIGINAL AND TEN COPIES of the foregoing hand-delivered for filing this 28th day of April, 2000, to:

ARIZONA CORPORATION COMMISSION
DOCKET CONTROL
1200 West Washington Street
Phoenix, AZ 85007

COPIES of the foregoing hand delivered this 28th day of April, 2000 to:

Lyn Farmer, Chief Counsel
Legal Division
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, Arizona 85007

Deborah R. Scott, Director
Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, Arizona 85007

Jerry Rudibaugh, Chief Hearing Officer
Hearing Division
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, Arizona 85007

Michelle Harding

DIRECT TESTIMONY OF DANIEL L. NEIDLINGER

BLACK MOUNTAIN GAS DIVISION OF NORTHERN STATES POWER COMPANY
CAVE CREEK OPERATION
DOCKET NO. G-03493-

Direct Testimony of Dan L. Neidlinger

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Dan L. Neidlinger. My business address is 3020 North 17th Drive, Phoenix, Arizona. I am President of Neidlinger & Associates, Ltd., a consulting firm specializing in utility rate economics.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. A summary of my professional qualifications and experience is included in the attached Statement of Qualifications. In addition to the Arizona Corporation Commission ("ACC" or the "Commission"), I have presented expert testimony before regulatory commissions and agencies in Alaska, California, Colorado, Guam, Idaho, New Mexico, Nevada, Texas, Utah, Wyoming and the Province of Alberta, Canada.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the applicant, Black Mountain Gas Company ("BMG" or the "Company"), a division of Northern States Power Company ("NSP"). This application is limited to the Cave Creek Operation of BMG and is the second rate filing mandated by the Commission pursuant to the acquisition of BMG by NSP in 1998. In its initial application, BMG filed for a reduction in the rates of its Page Operation in December of 1998 based on a calendar 1997 test year. The Commission approved a settlement agreement on this matter in December of 1999.

Q. WHAT IS THE TEST YEAR IN THIS CASE?

A. The test year in this case is the calendar year ended December 31, 1999.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses the following issues for BMG's Cave Creek Operation:

1. The development of original cost rate base at December 31, 1999;
2. Adjusted operating income for the test year;
3. The calculation of revenue requirements;
4. Preparation of a cost of service study; and
5. The design of revised gas rates for the Cave Creek Operation.

Q. WERE THE SCHEDULES FILED IN SUPPORT OF BMG'S RATE APPLICATION PREPARED BY YOU OR OTHERS UNDER YOUR SUPERVISION?

A. Yes. All of the schedules contained in the filing, as required by ACC R14-2-103, were prepared by me based on financial information obtained from the books and records of BMG together with statistical and accounting analyses that were prepared by BMG personnel at my request.

Q. PLEASE SUMMARIZE THE COMPANY'S OVERALL REQUEST IN THIS PROCEEDING.

A. The Company is requesting an increase in annual gas revenues for its Cave Creek Operation of approximately $326,000 or 6.6% of adjusted test year revenues of $4,944,000.

Q. PLEASE EXPLAIN THE REQUESTED INCREASE SHOWN ON SCHEDULE A-1, PAGE 1 OF THE FILING.

A. Schedule A-1 shows original cost less depreciation ("OCLD") and reconstruction cost new less depreciation ("RCND") rate bases both in the amount of $11,100,500 at December 31, 1999. OCLD AND RCND are the same in this case since BMG is seeking Staff permission to waive the requirement to prepare a separate and costly RCND rate base analysis. The current rate of return on OCLD rate base is 7.85%. Applying the Company's estimated cost of capital of 9.61% to rate base produces an operating income requirement of $1,066,620 or $195,054 greater than the adjusted test year operating income of $871,566. Using a gross revenue conversion factor of 1.6722, the calculated increase in revenues is $326,178.

Q. PLEASE EXPLAIN THE DEVELOPMENT OF THE OCLD RATE BASE SHOWN ON SCHEDULE B-1, PAGE 8 OF THE FILING.

A. Adjusted original cost net gas plant in service at the end of the test year was $12,726,290. Additions to this amount include materials and supplies inventories of $162,057, construction work in progress ("CWIP") of $282,035 and a new building estimated at $197,000. Deductions to rate base total $2,266,882 and are comprised of advances in aid of construction ("AIAC"), contributions in aid of construction ("CIAC"), customer deposits and deferred income taxes. Detail, by plant account classification, supporting the unadjusted gross utility plant amount of $15,745,435 shown on Schedule B-2 is provided on Schedule E-5, page 21 of the filing.

Q. WAS THE NEW BUILDING UNDER CONSTRUCTION AT THE END OF 1999?

A. No, but as discussed by Mr. Jim Willson, General Manager of BMG, in his testimony, the new building will be completed well before new rates in this matter are approved by the Commission. The new building will provide much needed space for the expanding operations of BMG. The building will be constructed on land adjacent to BMG's current offices. The land was purchased in 1999 for $502,000.

Q. PLEASE EXPLAIN THE ADJUSTMENTS TO OCLD SHOWN ON SCHEDULE B-2.

A. Two pro forma adjustments to OCLD are shown on Schedule B-2. The first increases gross utility plant in service by $91,046. This represents the annualized amount of increased salaries, wages and benefits that would be capitalized at current wage and benefit levels. The second increases accumulated depreciation by $83,038 to reflect the calculation of test year depreciation using year-end plant balances.

Q. PLEASE EXPLAIN SCHEDULE C-1 SHOWN ON PAGE 10.

A. Schedule C-1 is the adjusted operating income statement for the Cave Creek Operation. Cave Creek recorded an operating income for the test year of $918,981. As shown in the middle column of Schedule C-1, pro forma adjustments to actual test year numbers decrease operating income by $47,415 resulting in an adjusted operating income of $871,566. Detail supporting these pro forma adjustments is provided on Schedule C-2.

Q. WHAT ARE THE NATURE OF THE REVENUE AND EXPENSE PRO FORMA ADJUSTMENTS SHOWN ON SCHEDULE C-2?

A. The revenue and expense pro forma adjustments can be summarized as follows:

1. A $40,496 increase in gas sales and $19,579 reduction in the cost of gas to restore test year margins to base rates;
2. A $260,660 increase in residential gas sales due to year-end annualization; pro forma adjustments were also made to variable costs associated with these sales;
3. An adjustment of $6,602 to annualize the effect of increased billing costs;
4. An increase of $83,038 to reflect depreciation on year-end plant;
5. An increase of $35,918 in salaries and wages, including related employee taxes and benefits, to reflect incentive bonuses for 1999 that were not accrued during the test year;
6. A $60,766 increase in salaries and wages, including related employee taxes and benefits, to reflect salary and wage increases implemented in January, 2000;
7. A net decrease of $2,667 in salaries and wages, including related employee taxes and benefits, to reflect changes in current employment levels from test year levels;
8. A $86,089 increase in professional services to reflect the cost of on-going outside accounting services;
9. A $21,664 increase in other gas revenues to reflect a reclassification of late charges;
10. An increase in interest expense of $4,954 in recognition of the annual interest expense on customer deposits of $82,563 deducted from rate base;
11. A $30,000 adjustment to amortize over three years rate case expenses of $90,000; and
12. A net $757 adjustment to income tax expense to reflect the income tax effect of all of the pro forma adjustments. This net adjustment includes a $19,514 increase in income taxes for the Cave Creek Operation resulting from the reallocation of total company income taxes among regulated and non-regulated operations.

As previously mentioned, the net effect of all of these pro forma adjustments is a $47,415 reduction in test year operating income.

Q. HOW WAS THE GROSS REVENUE CONVERSION FACTOR OF 1.6722 SHOWN ON SCHEDULE C-3 DEVELOPED?

A. The gross revenue conversion factor was developed using NSP's incremental federal income tax rate, net of the effect of state taxes, of 32.2% and the Arizona corporate tax rate of 8%.

Q. WHAT ABOUT COST OF CAPITAL?

A. As shown on Schedule D-1, page 14 of the filing, the weighted cost of capital for the Company is estimated at 9.61% using the Company's actual capital structure at December 31, 1999. At that date, the capital structure was comprised of 23.15% in long-term debt and 76.85% in common equity. Test year interest expense on the Company's $3,000,000 IDA Bond debt was $174,549, net of sinking fund interest income, resulting in an embedded cost of debt of 5.82%. The requested return on common equity is 10.75% -- the same return on equity recommended by Staff rate of return witness, Ms Linda A. Jaress, in the recent rate proceeding for the Page Operation. In my judgment, 10.75% is a reasonable cost of equity for BMG at this time.

Q. DID YOU PREPARE A COST OF SERVICE STUDY FOR THE CAVE CREEK OPERATION?

A. Yes. A cost of service analysis of the Company's Cave Creek Operation is provided in the "G" series of schedules, pages 32 through 44 of the filing.

Q. WHY IS COST OF SERVICE IMPORTANT?

A. Cost of service is the single most important criterion in the development of revenues by customer class and the design of rates that will produce those revenues. If rates are not cost-based, the inevitable results are subsidies among classes of customers and customers within a class. This is not only perceived as inequitable, but may result in distorted customer decisions concerning the use of utility services. Although other factors, such as continuity, simplicity and stability, are valid considerations in the rate design process, the primary guideline should be cost of service.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR STUDY.

A. The results of my study are summarized on Schedules G-1 and G-2, pages 32 and 33. At present rates, Schedule G-1, the residential and commercial classes of customers are both producing positive returns on allocated rate base. However, the return index for the residential class is 0.92 whereas the index for the commercial class is 1.37.

Q. PLEASE EXPLAIN THE RATE OF RETURN INDEX CONCEPT.

A. The rate of return index is a relative measure of the class contribution to the system average rate of return. An index below 1.00 indicates that a class's revenues are not sufficient to recover its cost of service, while an index exceeding 1.00 indicates that a class is over-recovering its cost of service, thereby providing revenue subsidies to other classes. In this case, the commercial class is providing revenue subsidies to the residential class.

Q. DO THE PROPOSED RATES FOR THE CAVE CREEK OPERATION IMPROVE THE RELATIVE RETURN RELATIONSHIP BETWEEN THE RESIDENTIAL AND COMMERCIAL CLASSES OF CUSTOMERS?

A. Yes. As shown on Schedule G-2, the return index for the residential class, at proposed rates, increases to 0.94 and the corresponding index for the commercial class is 1.26. Although cross-subsidies still exist at proposed rates, the new rates move both classes closer to cost of service.

Q. PLEASE EXPLAIN THE PROPOSED CHANGES TO THE COMPANY'S RATE DESIGN.

A. A comparison of present and proposed rates is provided on Schedule H-3, pages 46 and 47 of the filing. The proposed monthly service charge of $6.00 for residential customers represents a $0.50 per month increase over the current $5.50 rate. The proposed residential commodity rate of $0.9294 per therm is $0.0592 per therm greater than the current rate of $0.8702 per therm. The proposed monthly service charge for standard commercial customers is $15.00 or $5.00 per month greater than the current rate of $10.00 per month. The monthly service charge for resort and co-generation customers has been increased to $30.00. The proposed commodity rate for standard commercial and resort customers is

$0.9008 per therm or $0.0306 per therm greater than the current rate. Much smaller increases in commodity rates are proposed for air conditioning and co-generation customers.

Q. ARE THE PROPOSED INCREASES IN MONTHLY SERVICE CHARGES COST JUSTIFIED?

A. Yes. As indicated by the unit cost calculations on page 34 of the filing, the customer cost per bill for residential customers, at proposed rates, is $14.97 per month – more than double the proposed rate of $6.00. The customer cost per bill for commercial customers at proposed rates is $37.52. This cost is likewise greater than the $15.00 and $30.00 monthly service charges proposed for standard commercial and large commercial customers, respectively.

Q. IS BMG PROPOSING ANY NEW RATES AT THIS TIME?

A. Yes. A Compressed Natural Gas (CNG) rate is being offered for those customers desiring to drive CNG-fueled vehicles. The proposed rate for this service is $6.00 per month plus a commodity rate of $0.40 per therm.

Q. WHAT IS THE EFFECT OF THE PROPOSED RATES ON THE AVERAGE MONTHLY BILL OF A RESIDENTIAL CUSTOMER?

A. As shown on Schedule H-4, page 48 of the filing, the average monthly bill of a residential customer will increase by $3.99 per month from $56.84 to $60.83 – an increase of 7.02%.

Q. HAS THE BASE COST OF PURCHASED GAS BEEN CHANGED IN THE PROPOSED RATES?

A. No. The base cost of purchased gas in the proposed rates remains at $0.27 per therm.

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES IN ITS GAS RATE SCHEDULES?

A. Yes. Proposed changes in other rates and charges, Schedule H-3, page 47, include proposed increases in regular-hours and after-hours re-connection of service and service calls from the current $25 charge to $30 for regular-hours and $45.00 for after-hours. The proposed establishment of service charge of $20 is $5 greater than the current $15 rate. Increases are also proposed for meter test fees and NSF check charges.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

DAN L. NEIDLINGER

SUMMARY STATEMENT OF QUALIFICATIONS

I. General:

Mr. Neidlinger is President of Neidlinger & Associates, Ltd., a Phoenix consulting firm specializing in utility rate economics and financial management. During his consulting career, he has managed and performed numerous assignments related to utility ratemaking and energy management.

II. Education:

Mr. Neidlinger was graduated from Purdue University with a Bachelor of Science degree in Electrical Engineering. He also holds a Master of Science degree in Industrial Management from Purdue's Krannert Graduate School of Management. He is a licensed Certified Public Accountant in Arizona and Ohio.

III. Consulting Experience:

Mr. Neidlinger has presented expert testimony on financial, accounting, cost of service and rate design issues in regulatory proceedings throughout the western United States involving companies from every segment of the utility industry. Testimony presented to these regulatory bodies has been on behalf of commission staffs, applicant utilities, industrial intervenors and consumer agencies. He has also testified in a number of civil litigation matters involving utility ratemaking and once served as a Special Master to a Nevada court in a lawsuit involving a Nevada public utility.

Mr. Neidlinger has performed feasibility studies related to energy management including cogeneration, self-generation, peak shaving and load-shifting analyses for clients with large electric loads. In addition, he has conducted electric and gas privatization studies for U.S. Army installations and assisted these and other consumer clients in contract negotiations with utility providers of electric, gas and wastewater service.

Mr. Neidlinger has extensive experience in the costing and pricing of utility services. During his consulting career, he has been responsible for the design and implementation of utility rates for over 30 electric, gas, water and wastewater utility clients ranging in size from 50 to 25,000 customers.

IV. Professional Affiliations:

Professional affiliations include the American Institute of Certified Public Accountants and the Association of Energy Engineers.

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JAMES M. IRVIN
Commissioner
WILLIAM MUNDELL
Commissioner

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, AND BLACK MOUNTAIN GAS, A SUBSIDIARY OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, TO DETERMINE EARNINGS FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN FOR THE CAVE CREEK DIVISION.	Docket No. G-03493A-00-_____ AFFIDAVIT OF DAN L. NEIDLINGER

STATE OF ARIZONA)
)
COUNTY OF MARICOPA)

Dan L. Neidlinger, of lawful age being first duly sworn, deposes and states:

1. My name is Dan L. Neidlinger. I am President of Neidlinger & Associates, Ltd., a consulting firm specializing in utility rate economics.

2. Attached hereto and made a part hereof for all purposes is my prefiled direct testimony consisting of pages 1 through 8.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct to the best of my knowledge and belief.

Dan L. Neidlinger

DAN L. NEIDLINGER

SUBSCRIBED AND SWORN to before me this 28th day of April, 2000.

OFFICIAL SEAL
STEPHANIE J. DEBUHR
NOTARY PUBLIC - ARIZONA
MARICOPA COUNTY
My Comm. Expires July

Stephanie DeBuhr
NOTARY PUBLIC

My Commission Expires:

July 15, 2000

SCHEDULES PURSUANT TO AACR14-2-103

NORTHERN STATES POWER COMPANY
BLACK MOUNTAIN GAS DIVISION
CAVE CREEK OPERATION

Before the Arizona Corporation Commission

Application for an Increase in Gas Rates
Test Year Ended December 31, 1999

May 1, 2000

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

INDEX OF SCHEDULES

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

INDEX OF SCHEDULES (Continued)

A

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS

DESCRIPTION	ORIGINAL COST	FAIR VALUE	RCND
Adjusted Rate Base (1)	$11,100,500		$11,100,500
Adjusted Operating Income (2)	871,566		871,566
Current Rate of Return	7.85%		7.85%
Fair Value Rate Base (50/50)		$11,100,500	
Required Rate of Return		9.61%	
Operating Income Requirement		$1,066,620	
Operating Income Deficiency		195,054	
Gross Revenue Conversion Factor (3)		1.6722	
Increase in Gross Revenue Requirements		$326,178	
Indicated Percentage Increase (4)		6.60%	

SUMMARY OF PROPOSED CHANGES IN CLASS REVENUES	PRESENT REVENUES	PROPOSED REVENUES	PERCENT INCREASE
Residential Gas Sales	$3,879,925	$4,152,518	7.03%
Commercial Gas Sales	1,007,444	1,052,859	4.51%
Total Gas Sales	4,887,369	5,205,377	6.51%
Other Gas Revenues	56,570	64,740	14.44%
Total Gas Revenues	$4,943,939	$5,270,117	6.60%

Supporting Schedules:
(1) Schedule B-1
(2) Schedule C-1
(3) Schedule C-3
(4) Schedule H-1

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

SUMMARY RESULTS OF OPERATIONS

	YEAR ENDED (1)				PROJECTED YEAR (3)	
DESCRIPTION	12-31-97	12-31-98	12-31-99	12-31-99 (2)	PRESENT RATES	ROPOSED RATES
Operating Revenues	$5,363,711	$5,983,479	$5,876,261	$6,199,081	$6,156,402	$6,489,715
Operating Expenses	4,133,800	4,818,304	4,931,633	5,301,868	5,242,189	5,401,080
Operating Income	1,229,911	1,165,175	944,628	897,213	914,213	1,088,635
Other Operating Income	145,347	148,469	27,426	27,426	29,072	29,072
Other Income	40,793	33,071	58,947	58,947	60,000	60,000
Interest Expense	(119,839)	(97,093)	(142,265)	(142,265)	(174,000)	(174,000)
Net Income	$1,296,212	$1,249,622	$888,736	$841,321	$829,284	$1,003,706
Return on Average Capital	13.21%	9.96%	7.55%	7.17%	6.84%	7.85%
Return on Y/E Capital	10.87%	9.65%	7.29%	6.92%	6.63%	7.80%
Return on Average Equity	18.62%	14.37%	9.34%	8.84%	7.99%	9.23%
Return on Y/E Equity	15.58%	13.78%	8.92%	8.45%	7.69%	9.16%

Supporting Schedules:
(1) Schedule E-2
(2) Adjusted Test Year - Schedule C-1
(3) Schedule F-1

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

SUMMARY OF CAPITAL STRUCTURE

				PROJECTED YEAR	
	YEAR ENDED (1)			PRESENT	PROPOSED
DESCRIPTION	12-31-97	12-31-98	12-31-99	RATES	RATES
Long Term Debt	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000
Common Equity	8,319,026	9,070,826	9,959,563	10,788,847	10,963,269
Total Capital	$11,319,026	$12,070,826	$12,959,563	$13,788,847	$13,963,269
Capitalization Ratios:					
Long Term Debt	26.50%	24.85%	23.15%	21.76%	21.48%
Common Equity	73.50%	75.15%	76.85%	78.24%	78.52%
Total Capital	100.00%	100.00%	100.00%	100.00%	100.00%

Note:
(1) Schedule E-2

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

CONSTRUCTION EXPENDITURES AND GROSS UTILITY PLANT IN SERVICE

YEAR	CONSTRUCTION EXPENDITURES (1)	NET PLANT PLACED IN SERVICE (2)	GROSS UTILITY PLANT IN SERVICE
1997	$1,628,815	$1,613,033	$14,725,578
1998	$1,402,917	$1,402,917	$16,128,495
1999	$3,476,803	$3,434,392	$19,562,887
2000	$2,150,975	$2,150,975	$21,713,862
2001	$2,621,340	$2,621,340	$24,335,202
2002	$2,674,742	$2,674,742	$27,009,944

Supporting Schedules:
(1) Schedule F-3
(2) Schedule E-5

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

CONSTRUCTION EXPENDITURES AND GROSS UTILITY PLANT IN SERVICE

YEAR	CONSTRUCTION EXPENDITURES (1)	NET PLANT PLACED IN SERVICE (2)	GROSS UTILITY PLANT IN SERVICE
1997	$1,429,135	$1,418,353	$11,685,892
1998	$892,780	$892,780	$12,578,672
1999	$3,210,864	$3,166,763	$15,745,435
2000	$2,047,991	$2,047,991	$17,793,426
2001	$2,458,847	$2,458,847	$20,252,273
2002	$2,509,718	$2,509,718	$22,761,991

Supporting Schedules:
(1) Schedule F-3
(2) Schedule E-5

BLACK MOUNTAIN GAS DIVISION OF NSP
PAGE OPERATION
Test Year Ended December 31, 1999

CONSTRUCTION EXPENDITURES AND GROSS UTILITY PLANT IN SERVICE

YEAR	CONSTRUCTION EXPENDITURES (1)	NET PLANT PLACED IN SERVICE (2)	GROSS UTILITY PLANT IN SERVICE
1997	$199,680	$194,680	$3,039,686
1998	$510,137	$510,137	$3,549,823
1999	$265,939	$267,629	$3,817,452
2000	$102,984	$102,984	$3,920,436
2001	$162,493	$162,493	$4,082,929
2002	$165,024	$165,024	$4,247,953

Supporting Schedules:
(1) Schedule F-3
(2) Schedule E-5

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

SUMMARY STATEMENT OF CASH FLOWS

	YEAR ENDED (1)			PROJECTED YEAR (2)	
DESCRIPTION	12-31-97	12-31-98	12-31-99	PRESENT RATES	PROPOSED RATES
Cash Flows From Operations:					
Net Income	$1,296,212	$102,158	$888,736	$829,284	$1,003,706
Non-Cash Adjustments	566,593	601,906	557,314	$570,000	$570,000
	1,862,805	704,064	1,446,050	$1,399,284	$1,573,706
Change in Current Assets and Liabilities	(486,205)	(228,044)	871,504	655,206	655,206
Cash Expenditures - Plant	(1,072,662)	(942,286)	(3,539,872)	(2,150,975)	(2,150,975)
Other Cash Items	0	759,025	686,510		
Financing Activities - Net	(202,007)	451,941	(191,157)	200,000	200,000
Net Increase in Cash	101,931	744,700	(726,965)	103,515	347,937
Beginning Cash	299,377	401,308	1,146,008	419,043	419,043
Ending Cash	$401,308	$1,146,008	$419,043	$522,558	$766,980

Notes:
(1) Schedule E-3
(2) Schedule F-2

B

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

ORIGINAL COST AND RCND RATE BASE ELEMENTS

DESCRIPTION	ORIGINAL COST RATE BASE (1)	RCND RATE BASE (2)
Gross Utility Plant In Service	$15,836,481	$15,836,481
Less: Accumulated Depreciation	3,110,191	3,110,191
Net Utility Plant In Service	12,726,290	12,726,290
Plus:		
Materials & Supplies Inventories	162,057	162,057
CWIP	282,035	282,035
New Building	197,000	197,000
	641,092	641,092
Less:		
Contributions In Aid of Construction	673,542	673,542
Advances in Aid of Construction	831,656	831,656
Customer Deposits	82,563	82,563
Deferred Income Taxes	679,121	679,121
	2,266,882	2,266,882
Total Rate Base	$11,100,500	$11,100,500

Supporting Schedules:
(1) Schedules B-2 and E-5
Note:
(2) Black Mountain Gas Company Requests a Waiver on the Development of RCND Rate Base

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

PRO FORMA ADJUSTMENTS TO ORIGINAL COST RATE BASE

DESCRIPTION	ACTUAL AT 12-31-99	PRO FORMA ADJUSTMENT (1)	ADJUSTED AMOUNT
Gross Utility Plant In Service	$15,745,435	$91,046	$15,836,481
Less: Accumulated Depreciation	3,027,153	83,038	3,110,191
Net Utility Plant In Service	$12,718,282	$8,008	12,726,290

Note:
(1) To Adjust Gross Plant for Capitalized Wages and Benefits and Adjust Accumulated Depreciation for . Depreciation of Year-End Plant.

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

OPERATING INCOME STATEMENT

DESCRIPTION	ACTUAL AT 12-31-99 (1)	PRO FORMA (2) ADJUSTMENTS	ADJUSTED AMOUNT
Revenues:			
Gas Sales	$4,635,685	$301,156	$4,936,841
Other Gas Revenues	34,906	21,664	56,570
Total Revenues	4,670,591	322,820	4,993,411
Operating Expenses:			
Purchased Gas Cost	1,406,683	53,515	1,460,198
Operating Wages & Expense	119,197	52,551	171,748
Maintenance Wages & Expense	103,161	0	103,161
Customer Accounting	116,456	32,368	148,824
Customer Service	33,232	0	33,232
Sales Promotion	53,750	47,660	101,410
Administrative & General	665,995	100,346	766,341
Depreciation	498,072	83,038	581,110
Property Taxes	212,052	0	212,052
Other Taxes	6,606	0	6,606
Corporate Expense Allocation	26,276	0	26,276
Income Taxes	510,130	757	510,887
Total Operating Expenses	3,751,610	370,235	4,121,845
Operating Income	$918,981	($47,415)	$871,566

Supporting Schedules:
(1) Schedule E-6
(2) Schedule C-2

C

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

PRO FORMA ADJUSTMENTS TO OPERATING INCOME STATEMENT

DESCRIPTION	AMOUNT
TEST YEAR MARGINS:	
Adjustments Required to Restore Test Year Margins to Base Rates:	
Pro Forma Adjustment - Gas Sales	$40,496
Pro Forma Adjustment - Purchased Gas Cost	(19,579)
YEAR-END CUSTOMERS:	
Adjustments to Annualize Residential Gas Sales:	
Pro Forma Adjustment - Gas Sales	$260,660
Pro Forma Adjustment - Purchased Gas Cost	73,094
Pro Forma Adjustment - Customer Accounting	11,263
CUSTOMER BILLING:	
Adjustment to Reflect Increased Billing Costs:	
Pro Forma Adjustment - Customer Accounting	$6,602
DEPRECIATION ON YEAR-END PLANT:	
Adjustment to Annualize Depreciation Expense on Year-End Plant:	
Pro Forma Adjustment - Depreciation	$83,038
INCENTIVE BONUSES:	
Adjustments to Record 1999 Bonuses Not Accured at 12-31-99:	
Pro Forma Adjustment - Operating Wages & Expense	$12,571
Pro Forma Adjustment - Customer Accounting Salaries & Wages	5,388
Pro Forma Adjustment - Sales Promotion Salaries & Wages	3,592
Pro Forma Adjustment - Admin. & Gen. Salaries & Wages	14,367

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

PRO FORMA ADJUSTMENTS TO OPERATING INCOME STATEMENT

DESCRIPTION	AMOUNT
SALARY & WAGE INCREASES:	
Adjustments to Reflect Increases in Salaries & Wages:	
Pro Forma Adjustment - Operating Wages & Expense	$21,268
Pro Forma Adjustment - Customer Accounting Salaries & Wages	9,115
Pro Forma Adjustment - Sales Promotion Salaries & Wages	6,077
Pro Forma Adjustment - Admin. & Gen. Salaries & Wages	24,306
EMPLOYMENT LEVELS:	
Adjustments to Reflect Changes in Employment Levels:	
Pro Forma Adjustment - Operating Wages & Expense	$18,712
Pro Forma Adjustment - Sales Promotion Salaries & Wages	37,991
Pro Forma Adjustment - Admin. & Gen. Salaries & Wages	(59,370)
OUTSIDE ACCOUNTING SERVICES:	
Adjustment to Annualize Contract Accounting Services:	
Pro Forma Adjustment - Professional Services	$86,089
LATE CHARGES:	
Adjustment to Reclassify Late Charges on Customer Bills:	
Pro Forma Adjustment - Other Gas Revenues	$21,664
INTEREST ON CUSTOMER DEPOSITS:	
Adjustment to Reclassify Interest on Customer Deposits:	
Pro Forma Adjustment - Admin. & Gen. Expense	$4,954
AMORTIZATION OF RATE CASE EXPENSES:	
Adjustment to Amortize Est. $90,000 Rate Case Expenses - 3 Years:	
Pro Forma Adjustment - Admin. & Gen. Expense	$30,000

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

PRO FORMA ADJUSTMENTS TO OPERATING INCOME STATEMENT

DESCRIPTION	AMOUNT
INCOME TAXES:	
Income Taxes on Pro Forma Adjustments:	
Revenues	$322,820
Expenses	369,478
Net Pro Forma Operating Income Adjustment Before Income Taxes	(46,658)
Income Taxes @ 40.2%	(18,757)
Reallocation of Federal Income Taxes Among Operations	19,514
Net Pro Forma Adjustment to Income Taxes	$757

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

COMPUTATION OF GROSS REVENUE CONVERSION FACTOR

DESCRIPTION	PERCENTAGE
Federal Income Taxes	32.2000%
State Income Taxes	8.0000%
Total Income Taxes	40.2000%
Gross Revenue Conversion Factor = 1/1-Income Taxe Percentage =	1.6722

D

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

SUMMARY COST OF CAPITAL

DESCRIPTION	AMOUNT	PERCENT	COST RATE	WEIGHTED COST RATE
Long Term Debt	$3,000,000	23.15%	5.820%	1.35%
Common Equity	9,959,563	76.85%	10.750%	8.26%
Total Capital	$12,959,563	100.00%		9.61%

E

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

COMPARATIVE BALANCE SHEETS
ASSETS

DESCRIPTION	BALANCE AT 12-31-99	12-31-98	12-31-97
Utility Plant:			
Plant In Service	$18,030,846	$14,722,536	$13,887,339
CWIP	287,050	224,817	103,151
Total Utility Plant	18,317,896	14,947,353	13,990,490
Less: Accumulated Depreciation	4,632,658	4,186,918	3,697,019
Net Utility Plant	13,685,238	10,760,435	10,293,471
Other Plant:			
Property Plant & Equipment	730,389	632,295	598,508
Less: Accumulated Depreciation	469,224	428,839	395,207
Net Other Plant	261,165	203,456	203,301
Current Assets:			
Cash and Cash Equivalents	419,043	1,146,007	401,308
Accounts Receivable	1,106,922	977,310	1,011,217
Inventories	301,939	451,251	225,100
Prepaids & Other Assets	110,462	38,487	44,100
Total Current Assets	1,938,366	2,613,055	1,681,725
Other Assets:			
Bond Sinking Fund	927,057	724,499	519,469
Unamortized Debt Issue Costs	70,433	81,834	89,166
Deferred Gas Costs	332,931	481,510	689,106
	1,330,421	1,287,843	1,297,741
Total Assets	$17,215,190	$14,864,789	$13,476,238

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

COMPARATIVE BALANCE SHEETS
CAPITAL AND LIABILITIES

DESCRIPTION	BALANCE AT 12-31-99	12-31-98	12-31-97
Capitalization:			
Common Stock	$3,634,193	$3,634,193	$2,984,555
Retained Earnings	6,327,116	5,438,379	5,336,217
Treasury Stock	(1,746)	(1,746)	(1,746)
Total Common Equity	9,959,563	9,070,826	8,319,026
Long Term Debt	3,000,000	3,000,000	3,000,000
Total Capitalization	12,959,563	12,070,826	11,319,026
Current Liabilities:			
Short-Term Debt	$250,000	0	0
Accounts Payable	380,742	428,943	673,109
Income Taxes Payable	221,482	89,532	96,099
Customer Deposits	286,337	259,883	200,908
Refund Liability - Page	696,100	158,169	0
Other Current Liabilities	962,412	498,276	121,802
Total Current Liabilities	2,797,073	1,434,803	1,091,918
Deferred Income Taxes and Other:			
Deferred Income Taxes	956,514	857,120	829,781
Regulatory Liability for Income Taxes	0	0	126,733
Post-Merger Liability	393,260	393,260	0
Deferred Investment Tax Credits - Net	108,780	108,780	108,780
Total Deferred Income Taxes	1,458,554	1,359,160	1,065,294
Total Capital and Liabilities	$17,215,190	$14,864,789	$13,476,238

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISON
Test Year Ended December 31, 1999

COMPARATIVE INCOME STATEMENTS

DESCRIPTION	YEAR ENDED (1) 12-31-99	12-31-98	12-31-97
Operating Revenues:			
Gas Sales	$5,839,533	$5,941,766	$5,312,481
Other Operating Revenues	36,728	41,713	51,230
Total Operating Revenues	5,876,261	5,983,479	5,363,711
Operating Expenses:			
Purchased Gas Cost	1,987,846	1,950,107	1,507,741
Operating Wages & Expense	149,009	166,935	98,610
Maintenance Wages & Expense	149,184	120,250	81,912
Customer Accounting	169,504	166,594	165,605
Customer Service	52,170	25,772	5,734
Sales Promotion	73,096	45,234	39,422
Administrative & General	930,924	574,410	389,569
Depreciation	625,206	523,218	501,201
Property Taxes	229,290	216,744	244,778
Other Taxes	7,608	13,950	6,934
Corporate Expenses	33,429	210,442	436,562
Income Taxes	524,367	804,648	655,732
Total Operating Expenses	4,931,633	4,818,304	4,133,800
Utility Operating Income	944,628	1,165,175	1,229,911
Other Operations:			
Revenues	738,042	693,372	814,134
Cost of Sales	(376,268)	(327,434)	(439,949)
Revenues, Less Cost of Sales	361,774	365,938	374,185
Other Expenses	(302,486)	(114,939)	(107,825)
Income Taxes	(31,862)	(102,530)	(121,013)
Total Other Operating Income	27,426	148,469	145,347
Other Income:			
AFUDC - Equity	92,280	55,909	66,754
Income Taxes	(33,333)	(22,838)	(25,961)
Total Other Income	58,947	33,071	40,793
Interest Income (Expense):			
Interest Income	71,166	102,291	71,140
Interest on Customer Deposits	(7,044)	(17,094)	(11,506)
Interest Expense	(206,387)	(182,290)	(179,473)
Total Interest Expense	(142,265)	(97,093)	(119,839)
Net Income Before Ex. Ord. Deduction	$888,736	$1,249,622	$1,296,212
Extra-Ordinary Deduction	$0	($1,147,464)	$0
Net Income	$888,736	$102,158	$1,296,212

(1) Schedule E-6

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISON
Test Year Ended December 31, 1999

COMPARATIVE STATEMENT OF CASH FLOWS

DESCRIPTION	YEAR ENDED 12-31-99	12-31-98	12-31-97
Cash Flows From Operating Activities:			
Net Income	$888,736	$102,158	$1,296,212
Non-Cash Adjustments:			
Depreciation	665,592	556,850	547,706
AFUDC	(108,278)	(81,677)	(84,093)
Deferred Income Taxes	0	126,733	109,346
Amortization of ITC	0	0	(6,366)
Total Non-Cash Adjustments	557,314	601,906	566,593
Change in Current Assets & Liabilities	871,504	(228,044)	(486,205)
Change in Post-Merger Liability	0	393,260	
Change in Rate Refund Provision	537,931	158,169	
Change in Deferred Gas Cost	148,579	207,596	
Cash Expenditures - Utility Plant	(3,539,872)	(942,286)	(1,072,662)
Financing Activities:			
Proceeds From Long Term Debt	0	0	0
Payment of Bond Issue Costs	11,401	7,332	(4,709)
Stock Revaluation	0	649,639	
Redemption of Fractional Shares	0		(907)
Treasury Stock	0		(775)
Sinking Fund Payment	(202,558)	(205,030)	(195,616)
Total Financing Activities	(191,157)	451,941	(202,007)
Increase (Decrease) in Cash & Cash Equivalents	(726,965)	744,700	101,931
Cash & Cash Equivalents - Beginning of Year	1,146,008	401,308	299,377
Cash & Cash Equivalents - End of Year	$419,043	$1,146,008	$401,308

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISON
Test Year Ended December 31, 1999

STATEMENTS OF STOCKHOLDERS' EQUITY

DESCRIPTION	COMMON STOCK	RETAINED EARNINGS	TREASURY STOCK
Balance, December 31, 1995	$2,040,009	$4,018,717	($5,045)
Net Income		967,806	
Treasury Stock Issued (Purchased) - Net			4,074
Redemption of Fractional Shares		(1,065)	
Payment of Stock Dividend	454,588	(454,588)	
Balance, December 31, 1996	$2,494,597	$4,530,870	($971)
Net Income		1,296,212	
Treasury Stock Issued (Purchased) - Net			(775)
Redemption of Fractional Shares		(907)	
Payment of Stock Dividend	489,958	(489,958)	
Balance, December 31, 1997	$2,984,555	$5,336,217	($1,746)
Net Income		102,162	
Restatement of Common Stock	649,638		
Balance, December 31, 1998	$3,634,193	$5,438,379	($1,746)
Net Income		888,737	
Balance, December 31, 1999	$3,634,193	$6,327,116	($1,746)

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

DETAIL OF UTILITY PLANT

DESCRIPTION	BALANCE AT 12-31-99	NET ADDITIONS	BALANCE 12-31-98
Intangible Plant - Organization	$628,562	$14,723	$613,839
AFUDC - Debt	21,932	14,853	7,079
AFUDC - Equity	554,217	86,076	468,141
Franchises & Consents	286,863	189,044	97,819
Misc. Intangible Plant	5,833	0	5,833
Storage Plant - Land	4,135	0	4,135
Distribution Land & Rights	1,768	0	1,768
Distribution Mains	8,660,801	1,475,488	7,185,313
Distribution Measuring & Reg.	189,903	14,869	175,034
Distribution Services	2,254,729	329,135	1,925,594
Meters	808,720	141,357	667,363
Meter Installations	363,128	0	363,128
House Regulators	19,154	0	19,154
House Regulators Installations	55,837	0	55,837
Industrial Meas. & Reg.	971	0	971
Dist. Property on Customer Premise	245	0	245
Other Distribution Equipment	3,874	0	3,874
Interest Capitalized	1,986	0	1,986
General Land & Rights	502,044	502,044	0
General Structures & Improvements	217,547	0	217,547
Office Furniture & Equipment	578,893	364,557	214,336
Transportation Equipment	314,030	10,925	303,105
Tools & Shop Equipment	128,483	15,658	112,825
Power Operating Equipment	23,116	0	23,116
Communication Equipment	40,578	8,034	32,544
Miscellaneous Equipment	10,026	0	10,026
Other Tangible Property	68,060	0	68,060
Total Gross Utility Plant	15,745,435	3,166,763	12,578,672
Accumulated Depreciation	3,027,153	318,605	2,708,548
Net Utility Plant	$12,718,282	$2,848,158	$9,870,124

BLACK MOUNTAIN GAS DIVISION OF NSP
PAGE OPERATION
Test Year Ended December 31, 1999

DETAIL OF UTILITY PLANT

DESCRIPTION	BALANCE AT 12-31-99	NET ADDITIONS	BALANCE 12-31-98
AFUDC - Debt	($2,569)	1,145	($3,714)
AFUDC - Equity	38,225	6,204	32,021
Franchises & Consents	13,395	0	13,395
Misc. Intangible Plant	9,473	0	9,473
Storage Plant - Land	7,135	0	7,135
Storage Plant - Structures & Imp.	76,157	0	76,157
Storage Plant - Gas Holders	94,736	0	94,736
Vaporizing Equipment	137,928	0	137,928
Storage Plant - Measuring & Reg.	35,503	0	35,503
Storage Plant - Other	1,651	0	1,651
Dist. Land & Land Rights	20,834	0	20,834
Dist. Structures & Improvements	4,808	0	4,808
Distribution Mains	1,900,280	66,790	1,833,490
Distribution Measuring & Reg.	21,781	0	21,781
Distribution Services	528,604	13,104	515,500
Meters	367,060	105,288	261,772
Meter Installations	117,436	0	117,436
House Regulators	16,597	0	16,597
Dist. Property on Customer Premise	409	0	409
Other Distribution Equipment	5,400	0	5,400
General Structures & Improvements	1,070	0	1,070
Office Furniture & Equipment	125,213	73,902	51,311
Transportation Equipment	132,248	0	132,248
Tools & Shop Equipment	43,517	1,206	42,311
Power Operating Equipment	88,915	0	88,915
Communication Equipment	17,744	0	17,744
Miscellaneous Equipment	5,220	0	5,220
Other Tangible Property	8,682	(10)	8,692
Total Gross Utility Plant	3,817,452	267,629	3,549,823
Accumulated Depreciation	1,605,505	127,135	1,478,370
Net Utility Plant	$2,211,947	$140,494	$2,071,453

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

COMPARATIVE OPERATING INCOME STATEMENTS

	YEAR ENDED		
DESCRIPTION	**12-31-99**	**12-31-98**	**12-31-97**
Operating Revenues:			
Gas Sales	$4,635,685	$4,408,940	$3,519,607
Other Operating Revenues	34,906	41,713	51,230
Total Operating Revenues	4,670,591	4,450,653	3,570,837
Operating Expenses:			
Purchased Gas Cost	1,406,683	1,465,237	897,362
Operating Wages & Expense	119,197	124,165	74,263
Maintenance Wages & Expense	103,161	78,333	46,064
Customer Accounting	116,456	102,035	90,899
Customer Service	33,232	21,722	4,275
Sales Promotion	53,750	26,348	22,719
Administrative & General	665,995	409,998	243,131
Depreciation	498,072	403,734	383,926
Property Taxes	212,052	198,712	220,298
Other Taxes	6,606	13,362	4,232
Corporate Expense Allocation	26,276	154,745	298,286
Income Taxes	510,130	593,231	446,991
Total Operating Expenses	3,751,610	3,591,622	2,732,446
Operating Income	$918,981	$859,031	$838,391

BLACK MOUNTAIN GAS DIVISION OF NSP
PAGE OPERATION
Test Year Ended December 31, 1999

COMPARATIVE OPERATING INCOME STATEMENTS

	YEAR ENDED		
DESCRIPTION	**12-31-99**	**12-31-98**	**12-31-97**
Operating Revenues:			
Gas Sales (1)	$1,203,848	$1,532,826	$1,792,874
Other Operating Revenues	1,822	0	0
Total Operating Revenues	1,205,670	1,532,826	1,792,874
Operating Expenses:			
Purchased Gas Cost	581,163	484,870	610,379
Operating Wages & Expense	29,812	42,770	24,347
Maintenance Wages & Expense	46,023	41,917	35,848
Customer Accounting	53,048	64,559	74,706
Customer Service	18,938	4,050	1,459
Sales Promotion	19,346	18,886	16,703
Administrative & General	264,929	164,412	146,438
Depreciation	127,134	119,484	117,275
Property Taxes	17,238	18,032	24,480
Other Taxes	1,002	588	2,702
Corporate Expense Allocation	7,153	55,697	138,276
Income Taxes	14,237	211,417	208,741
Total Operating Expenses	1,180,023	1,226,682	1,401,354
Operating Income	$25,647	$306,144	$391,520

Note:
(1) Includes Revenue Refund Accrual of $537,931

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

OPERATING STATISTICS

DESCRIPTION	YEAR ENDED 12-31-99	12-31-98	12-31-97
CAVE CREEK OPERATION:			
Year End Customers:			
Residential	5,653	4,951	4,586
Commercial	199	178	157
Average Customers:			
Residential	5,302	4,769	4,224
Commercial	199	168	150
Therms Sold:			
Residential	3,762,863	3,575,976	2,929,310
Commercial	1,197,326	1,257,549	1,155,775
Revenues: (1)			
Residential	$3,619,265	$3,419,645	$2,875,364
Commercial	$1,007,444	$989,295	$904,637
Revenues Per Avg. Customer:			
Residential	$683	$717	$681
Commercial	$5,063	$5,906	$6,031
PAGE OPERATION:			
Year End Customers:			
Residential	1,113	1,157	1,183
Commercial	193	178	171
Average Customers:			
Residential	1,135	1,170	1,158
Commercial	186	175	165
Therms Sold:			
Residential	422,977	460,595	448,082
Commercial	734,753	765,916	751,660
Revenues: (1)			
Residential	$571,658	$616,603	$599,338
Commercial	$1,033,399	$1,074,392	$1,054,171
Revenues Per Avg. Customer:			
Residential	$504	$527	$518
Commercial	$5,571	$6,157	$6,389

Note:
(1) Excluding Revenue Adjustments for PGA

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

TAXES CHARGED TO OPERATIONS

DESCRIPTION	YEAR ENDED 12-31-99	12-31-98	12-31-97
CAVE CREEK OPERATION:			
Property Taxes	$212,052	$198,712	$220,298
FICA Taxes	56,718	46,074	29,456
State & Federal Unemployment Taxes	1,878	2,192	1,355
Income Taxes	510,130	570,355	446,991
PAGE OPERATION:			
Property Taxes	$17,238	$18,031	$24,480
FICA Taxes	21,629	19,079	16,077
State & Federal Unemployment Taxes	701	1,649	1,355
Income Taxes	14,237	205,419	208,741

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

NOTES TO FINANCIAL STATEMENTS

A. AUDITS:
The financial statements of Black Mountain Gas are audited in conjunction with the audit of Northern State Power Company.

B. ACCOUNTING METHODS:
The accrual accounting method is used by Black Mountain Gas.

C. DEPRECIATION RATES:
Straight-line depreciation rates vary by plant account. The composite rate is approximately 3.4%

D. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC) :
AFUDC is capitalized pursuant to a 1994 order of the ACC.

F

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

PROJECTED INCOME STATEMENTS - PRESENT AND PROPOSED RATES

DESCRIPTION	TEST YEAR 12-31-99	PROJECTED YEAR AT PRESENT RATES 12-31-00	PROJECTED YEAR AT PROPOSED RATES 12-31-00
Operating Revenues:			
Gas Sales	$5,839,533	$6,117,674	$6,441,987
Other Operating Revenues	36,728	38,728	47,728
Total Operating Revenues	5,876,261	6,156,402	6,489,715
Operating Expenses:			
Purchased Gas Cost	1,987,846	2,072,247	2,072,247
Operating Wages & Expense	149,009	157,950	157,950
Maintenance Wages & Expense	149,184	158,135	158,135
Customer Accounting	169,504	179,674	179,674
Customer Service	52,170	55,300	55,300
Sales Promotion	73,096	77,482	77,482
Administrative & General	930,924	986,779	986,779
Depreciation	625,206	755,206	755,206
Property Taxes	229,290	254,290	279,290
Other Taxes	7,608	7,608	7,608
Corporate Expenses	33,429	33,429	33,429
Income Taxes	524,367	504,089	637,980
Total Operating Expenses	4,931,633	5,242,189	5,401,080
Utility Operating Income	944,628	914,213	1,088,635
Other Operations:			
Revenues	738,042	782,325	782,325
Cost of Sales	(376,268)	(398,844)	(398,844)
Revenues, Less Cost of Sales	361,774	383,480	383,480
Other Expenses	(302,486)	(320,635)	(320,635)
Income Taxes	(31,862)	(33,774)	(33,774)
Total Other Operating Income	27,426	29,072	29,072
Other Income:			
AFUDC - Equity	92,280	100,000	100,000
Income Taxes	(33,333)	(40,000)	(40,000)
Total Other Income	58,947	60,000	60,000
Interest Income (Expense):			
Interest Income	71,166	75,000	75,000
Interest on Customer Deposits	(7,044)	(9,000)	(9,000)
Interest Expense	(206,387)	(240,000)	(240,000)
Total Interest Expense	(142,265)	(174,000)	(174,000)
Net Income	$888,736	$829,284	$1,003,706

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

PROJECTED STATEMENTS OF CASH FLOWS - PRESENT AND PROPOSED RATES

		PROJECTED YEAR AT	
DESCRIPTION	TEST YEAR 12-31-99	PRESENT RATES 12-31-00	PROPOSED RATES 12-31-00
Cash Flows From Operations:			
Net Income	$888,736	$829,284	$1,003,706
Non-Cash Adjustments	557,314	570,000	570,000
	1,446,050	1,399,284	1,573,706
Change in Current Assets & Liabilities	871,504	655,206	655,206
Other Cash Changes	686,510	70,000	70,000
Cash Expenditures - Plant	(3,539,872)	($2,150,975)	($2,150,975)
Financing Activities - Net	(191,157)	200,000	200,000
Net Increase (Decrease) in Cash	(726,965)	173,515	347,937
Beginning Cash	1,146,008	419,043	419,043
Ending Cash	$419,043	$592,558	$766,980

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

PROJECTED CONSTRUCTION REQUIREMENTS

DESCRIPTION	ACTUAL 12-31-99	PROJECTED 2000	2001	2002
CAVE CREEK OPERATION:				
Distribution Mains	$1,475,488	$1,499,351	$1,830,847	$1,848,718
Distribution Services	329,135	48,000	55,000	59,000
Meters & Meter Installations	141,357	335,476	380,000	390,000
Structures & Improvements	0	102,764	120,000	128,000
Office Furniture & Equipment	364,557	12,000	18,000	24,000
Transportation Equipment	10,925	0	0	0
Tools & Shop Equipment	15,658	50,400	55,000	60,000
Other Plant Additions	873,744	0	0	0
Total	$3,210,864	$2,047,991	$2,458,847	$2,509,718
PAGE OPERATION:				
Storage	$0	0	$0	$0
Distribution Mains	66,790	$41,641	65,493	66,500
Distribution Services	13,104	15,742	25,000	25,500
Meters & Meter Installations	105,288	31,387	48,000	48,500
Structures & Improvements	0	0	0	0
Office Furniture & Equipment	73,902	5,175	9,000	9,024
Transportation Equipment	0	0	0	0
Tools & Shop Equipment	1,206	9,039	15,000	15,500
Other Plant Additions	5,649	0	0	0
Total	$265,939	$102,984	$162,493	$165,024
TOTAL DIVISION	$3,476,803	$2,150,975	$2,621,340	$2,674,742

BLACK MOUNTAIN GAS DIVISION OF NSP
TOTAL DIVISION
Test Year Ended December 31, 1999

KEY ASSUMPTIONS SUPPORTING THE DEVELOPMENT OF PROJECTIONS

DESCRIPTION

PROJECTED INCOME STATEMENTS & STATEMENTS OF CASH FLOWS - PRESENT RATES:

Projected income statements and statements of cash flows at present rates are based on the following key assumptions:

Increase in gas sales: Cave Creek - 6%; Page - 0%
Increase in purchased gas cost: Cave Creek - 6%; Page - 0%
Increase in other operating & maintenance expenses: 6% for total Division
Increase in depreciation: $130,000 for total Division
Increase in property taxes: $25,000 for total Division

PROJECTED INCOME STATEMENTS & STATEMENTS OF CASH FLOWS - PROPOSED RATES:

Projected income statements and statements of cash flows at proposed rates are based on projections at present rates adjusted for the proposed revenue increase for the Cave Creek Operation of 6.60%.

G

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
COST OF SERVICE SUMMARY - PRESENT RATES
TEST YEAR ENDED DECEMBER 31, 1999

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL
Operating Revenues	$4,993,411	$3,972,960	$1,020,451
Operating Expenses:			
Purchased Gas	$1,460,198	$1,127,260	$332,938
Distribution Expense - Operation	171,748	137,259	34,489
Distribution Expense - Maintenance	103,161	82,951	20,210
Customer Accounts Expense	148,824	144,280	4,544
Customer Service	33,232	32,217	1,015
Sales Promotion	101,410	78,288	23,122
Administrative & General	766,341	648,072	118,269
Depreciation	581,110	477,803	103,307
Property Taxes	212,052	174,354	37,698
Other Taxes	6,606	5,587	1,019
Corporate Expense Allocation	26,276	22,221	4,055
Income Taxes	510,887	385,319	125,568
Total Operating Expenses	$4,121,845	$3,315,611	$806,234
Operating Income	$871,566	$657,349	$214,217
Rate Base	$11,100,500	$9,111,219	$1,989,281
% Return - Present Rates	7.85%	7.21%	10.77%
Return Index	1.00	0.92	1.37

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
COST OF SERVICE SUMMARY - PROPOSED RATES
TEST YEAR ENDED DECEMBER 31, 1999

DESCRIPTION	TOTAL	RESIDENTIAL	COMMERCIAL
Operating Revenues	$5,319,589	$4,253,473	$1,066,116
Operating Expenses:			
Purchased Gas	$1,460,198	$1,127,260	$332,938
Distribution Expense - Operation	171,748	137,259	34,489
Distribution Expense - Maintenance	103,161	82,951	20,210
Customer Accounts Expense	148,824	144,280	4,544
Customer Service	33,232	32,217	1,015
Sales Promotion	101,410	78,288	23,122
Administrative & General	766,341	648,072	118,269
Depreciation	581,110	477,803	103,307
Property Taxes	212,052	174,354	37,698
Other Taxes	6,606	5,587	1,019
Corporate Expense Allocation	26,276	22,221	4,055
Income Taxes	642,011	498,085	143,925
Total Operating Expenses	$4,252,969	$3,428,377	$824,592
Operating Income	$1,066,620	$825,096	$241,525
Rate Base	$11,100,500	$9,111,219	$1,989,281
% Return - Proposed Rates	9.61%	9.06%	12.14%
Return Index	1.00	0.94	1.26

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

UNIT COSTS			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
UNIT COSTS - PRESENT RATES:				
DEMAND:				
Amount		$2,148,308	$1,716,906	$431,402
Bills		69,985	67,848	2,137
Therms		5,224,909	4,033,583	1,191,326
Per Bill		$30.70	$25.31	$201.87
Per Therm		$0.41	$0.43	$0.36
COMMODITY:				
Amount		$1,836,439	$1,417,715	$418,725
Per Therm		$0.35	$0.35	$0.35
CUSTOMER:				
Amount		$971,049	$899,419	$71,630
Per Bill		$13.88	$13.26	$33.52
UNIT COSTS - PROPOSED RATES:				
DEMAND:				
Amount		$2,389,374	$1,909,564	$479,810
Per Bill		$34.14	$28.14	$224.53
Per Therm		$0.46	$0.47	$0.40
COMMODITY:				
Amount		$1,836,439	$1,417,715	$418,725
Per Therm		$0.35	$0.35	$0.35
CUSTOMER:				
Amount		$1,047,744	$967,557	$80,187
Per Bill		$14.97	$14.26	$37.52

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOCATION OF RATE BASE			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
GROSS PLANT IN SERVICE:				
Demand	D-1	$11,861,343	9,479,467	2,381,877
Commodity	CM-1	0	0	0
Customer - Services	C-1	2,558,960	2,444,400	114,561
Customer - Meters	C-2	940,681	640,857	299,825
Customer - Meter Installations	C-3	475,496	456,427	19,069
Customer - Customer Accounts	C-4	0	0	0
Total		$15,836,481	$13,021,150	$2,815,331
ACCUMULATED DEPRECIATION:				
Demand	D-1	$2,329,498	1,861,711	467,786
Commodity	CM-1	0	0	0
Customer - Services	C-1	502,565	480,066	22,499
Customer - Meters	C-2	184,744	125,860	58,884
Customer - Meter Installations	C-3	93,385	89,640	3,745
Customer - Customer Accounts	C-4	0	0	0
Total		$3,110,191	$2,557,277	$552,914
NET PLANT IN SERVICE		12,726,290	10,463,873	2,262,417
M & S INVENTORIES:				
Demand	D-1	$162,057	129,514	32,543
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	0	0	0
Total		$162,057	$129,514	$32,543
CWIP:				
Demand	D-1	$211,241	168,822	42,419
Commodity	CM-1	0	0	0
Customer - Services	C-1	45,573	43,533	2,040
Customer - Meters	C-2	16,753	11,413	5,340
Customer - Meter Installations	C-3	8,468	8,129	340
Customer - Customer Accounts	C-4	0	0	0
Total		$282,035	$231,896	$50,139

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOCATION OF RATE BASE			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
NEW BUILDING:				
Demand	D-1	$147,551	117,921	29,630
Commodity	CM-1	0	0	0
Customer - Services	C-1	31,833	30,407	1,425
Customer - Meters	C-2	11,702	7,972	3,730
Customer - Meter Installations	C-3	5,915	5,678	237
Customer - Customer Accounts	C-4	0	0	0
Total		$197,000	$161,978	$35,022
CIAC & AIAC:				
Demand	D-1	($1,127,376)	(900,988)	(226,388)
Commodity	CM-1	0	0	0
Customer - Services	C-1	(243,220)	(232,331)	(10,889)
Customer - Meters	C-2	(89,408)	(60,911)	(28,497)
Customer - Meter Installations	C-3	(45,194)	(43,382)	(1,812)
Customer - Customer Accounts	C-4	0	0	0
Total		($1,505,198)	($1,237,611)	($267,587)
CUSTOMER DEPOSITS:				
Demand	D-1	$0	0	0
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	(82,563)	(80,042)	(2,521)
Total		($82,563)	($80,042)	($2,521)
DEFERRED INCOME TAXES:				
Demand	D-1	($508,654)	(406,511)	(102,143)
Commodity	CM-1	0	0	0
Customer - Services	C-1	(109,737)	(104,824)	(4,913)
Customer - Meters	C-2	(40,340)	(27,482)	(12,857)
Customer - Meter Installations	C-3	(20,391)	(19,573)	(818)
Customer - Customer Accounts	C-4	0	0	0
Total		($679,121)	($558,390)	($120,731)
TOTAL RATE BASE		$11,100,500	$9,111,219	$1,989,281

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOC. OF INCOME STATEMENT			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
REVENUES:				
Gas Sales - Base Rates		$4,887,369	$3,879,925	$1,007,444
PGA	CM-1	49,472	38,192	11,280
Service Charges & Other Revenues	C-4	56,570	54,843	1,727
Total Revenues		$4,993,411	$3,972,960	$1,020,451
OPERATING EXPENSES:				
Purchased Gas	CM-1	$1,460,198	$1,127,260	$332,938
Distribution Expense - Operation:				
Demand	D-1	$171,748	137,259	34,489
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	0	0	0
Total		$171,748	$137,259	$34,489
Distribution Expense - Maintenance:				
Demand	D-1	$99,917	79,853	20,064
Commodity	CM-1	0	0	0
Customer - Services	C-1	3,241	3,096	145
Customer - Meters	C-2	3	2	1
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	0	0	0
Total		$103,161	$82,951	$20,210
Customer Accounting:				
Demand	D-1	$0	0	0
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	148,824	144,280	4,544
Total		$148,824	$144,280	$4,544
Customer Service:				
Demand	D-1	$0	0	0
Commodity	CM-1	0	0	0
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	33,232	32,217	1,015
Total		$33,232	$32,217	$1,015

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOC. OF INCOME STATEMENT			CUSTOMER CLASS	
DESCRIPTION	FACTOR	TOTAL	RESIDENTIAL	COMMERCIAL
Sales Promotion:				
Demand	D-1	$0	0	0
Commodity	CM-1	101,410	78,288	23,122
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	0	0	0
Total		$101,410	$78,288	$23,122
Administrative & General:				
Demand	D-1	$251,530	201,020	50,510
Commodity	CM-1	263,524	203,438	60,086
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	251,287	243,614	7,673
Total		$766,341	$648,072	$118,269
Depreciation:				
Demand	D-1	$435,245	347,843	87,402
Commodity	CM-1	0	0	0
Customer - Services	C-1	93,899	89,696	4,204
Customer - Meters	C-2	34,518	23,516	11,002
Customer - Meter Installations	C-3	17,448	16,748	700
Customer - Customer Accounts	C-4	0	0	0
Total		$581,110	$477,803	$103,307
Property Taxes:				
Demand	D-1	$158,825	126,931	31,894
Commodity	CM-1	0	0	0
Customer - Services	C-1	34,265	32,731	1,534
Customer - Meters	C-2	12,596	8,581	4,015
Customer - Meter Installations	C-3	6,367	6,112	255
Customer - Customer Accounts	C-4	0	0	0
Total		$212,052	$174,354	$37,698

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

ALLOC. OF INCOME STATEMENT

DESCRIPTION	FACTOR	TOTAL	CUSTOMER CLASS RESIDENTIAL	COMMERCIAL
Other Taxes:				
Demand	D-1	$2,168	1,733	435
Commodity	CM-1	2,272	1,754	518
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	2,166	2,100	66
Total		$6,606	$5,587	$1,019
Corporate Allocation:				
Demand	D-1	$8,624	6,893	1,732
Commodity	CM-1	9,036	6,975	2,060
Customer - Services	C-1	0	0	0
Customer - Meters	C-2	0	0	0
Customer - Meter Installations	C-3	0	0	0
Customer - Customer Accounts	C-4	8,616	8,353	263
Total		$26,276	$22,221	$4,055
Total Operation Expenses Ex. Inc. Tx.		$3,610,958	$2,930,291	$680,667
Operating Income Ex. Inc. Tx.		1,382,453	1,042,668	339,785
Percent		100.00%	75.42%	24.58%
Income Taxes - Present Rates		510,887	385,319	125,568
Operating Income - Present Rates		871,566	657,349	214,217
Revenue Requirement		5,319,589	4,253,473	1,066,116
Revenue Increase		326,178	280,513	45,665
Percent Increase		6.67%	7.23%	4.53%
Increase in Income Taxes		131,124	112,766	18,357
Increase In Operating Income		195,054	167,747	27,308
Adjusted Operating Income		1,066,620	825,096	241,525
Return on Rate Base		9.61%	9.06%	12.14%
Return Index		1.00	0.94	1.26
Revenues - Proposed Rates		5,319,589	4,253,473	1,066,116
Income Taxes - Proposed Rates		642,011	498,085	143,925

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

FUNCT. OF RATE BASE COMPONENTS

DESCRIPTION	FACTOR	TOTAL	DEMAND	COMMOD.	SERVICES	METERS	MTR. INST.	CUST.
Gross Utility Plant In Service:								
Intangibles:								
Organization		$628,562						
AFUDC - Debt		21,932						
AFUDC Equity		554,217						
Franchises & Consents		286,863						
Misc. Intangible Plant		5,833						
Total Intangibles	F-1	$1,497,407	1,497,407					0
Distribution Plant:								
Distribution Land & Land Rights	F-3	$5,903	5,903					
Dist. Structures & Improvements	F-3	0	0					
Distribution Mains	F-3	8,660,801	8,660,801					
Distribution Measuring & Reg	F-3	189,903	189,903					
Distribution Services	F-4	2,254,729			2,254,729			
Meters	F-5	808,720				808,720		
Meter Installations	F-6	363,128					363,128	
House Regulators	F-5	19,154				19,154		
House Regulators Installations	F-6	55,837					55,837	
Industrial Meas. & Reg	F-5	971				971		
Dist. Property On Cust. Premises	F-3	245	245					0
Other Distribution Equipment	F-3	3,874	3,874					0
Interest Capitalized + Pro Forma	F-3	93,032	93,032					0
Total Distribution Plant		$12,456,297	$8,953,758	$0	$2,254,729	$828,845	$418,965	$0
Total Plant Excluding General		$13,953,704	$10,451,165	$0	$2,254,729	$828,845	$418,965	$0
Percent	F-8	100.00%	74.90%	0.00%	16.16%	5.94%	3.00%	0.00%

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

FUNCT. OF RATE BASE COMPONENTS

DESCRIPTION	FACTOR	TOTAL	DEMAND	COMMOD.	SERVICES	METERS	MTR. INST.	CUST.
General Plant:								
General Land & Land Rights		$502,044						
General Structures & Improvements		217,547						
Office Furniture & Equipment		578,893						
Transporation Equipment		314,030						
Tools & Shop Equipment		128,483						
Power Operating Equipment		23,116						
Communication Equipment		40,578						
Miscellaneous Equipment		10,026						
Other Tangible Property		68,060						
Total General Plant	F-8	$1,882,777	$1,410,178	$0	$304,231	$111,836	$56,531	$0
Total Utility Plant In Service		$15,836,481	$11,861,343	$0	$2,558,960	$940,681	$475,496	$0
Percent	F-8	100.00%	74.90%	0.00%	16.16%	5.94%	3.00%	0.00%
Accumulated Depreciation	F-8	3,110,191	2,329,498	0	502,565	184,744	93,385	0
Net Utility Plant In Service		$12,726,290	$9,531,846	$0	$2,056,396	$755,937	$382,111	$0
CWIP	F-8	$282,035	$211,241	$0	$45,573	$16,753	$8,468	$0
M & S Inventories	F-3	$162,057	$162,057					
CIAC & AIAC	F-8	$1,505,198	$1,127,376	$0	$243,220	$89,408	$45,194	$0
Customer Deposits	F-7	$82,563						$82,563
Deferred Income Taxes	F-8	$679,121	$508,654	$0	$109,737	$40,340	$20,391	$0
New Building	F-8	$197,000	$147,551	$0	$31,833	$11,702	$5,915	$0

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

FUNCT. OF OPERATING EXPENSES

DESCRIPTION	FACTOR	TOTAL	DEMAND	COMMOD.	SERVICES	METERS	MTR. INST.	CUST.
Purchased Gas Cost	F-2	1,460,198		1,460,198				
Operations:								
Operating Supervision & Labor	F-3	159,134	159,134					0
Vaporizer Expenses	F-1	0	0					
Mains & Services Expenses	F-3	11,060	11,060					0
Other Operating Expenses	F-3	1,554	1,554					0
Total Operations Expense		171,748	171,748	0	0	0	0	0
Maintenance:								
Maint. Supervision & Eng.	F-3	50,730	50,730					0
Maint. of Structures & Imp.	F-3	13,711	13,711					0
Maint. of Mains	F-3	7,405	7,405					0
Maint. of Vaporizer	F-1	44	44					
Maint. of Measuring Equip.	F-3	0	0					0
Maint. of Services	F-4	3,241			3,241			
Maint. of Meters & Regulators	F-5	3				3		
Maint. of Other Equip.	F-3	28,027	28,027					0
Total Maintenance Expense		103,161	99,917	0	3,241	3	0	0
Customer Accounting:								
Customer Accounting Payroll		130,171						
Customer Records Expense		5,449						
Uncollectible Accounts		(371)						
Misc. Cust. Acct. Expenses		13,575						
Total Customer Acct. Expense	F-7	148,824						148,824
Customer Service:								
Customer Service Expense	F-7	33,232						33,232
Sales Promotion Expense:								
Promotion Payroll		56,943						
Advertising Expenses		41,252						
Misc. Sales Expenses		3,215						
Total Sales Promotion Expense	F-2	101,410		101,410				

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

FUNCT. OF OPERATING EXPENSES

DESCRIPTION	FACTOR	TOTAL	DEMAND	COMMOD.	SERVICES	METERS	MTR. INST.	CUST.
Administrative & General Expenses:								
Admin. & General Salaries		207,453						
Office Supplies & Expense		17,761						
Professional Services		184,977						
Property & Liability Insurance		24,855						
Employee Benefits		123,582						
Other Administrative Supplies		4,292						
General Advertising		225						
Misc. Admin & General		79,044						
Rent Expense		29,811						
Maint. of General Plant		2						
Telephone Expense		29,362						
Other Utilities Expense		7,206						
Transportation Expense		21,266						
Travel & Entertainment		9,932						
Business Meals		5,903						
Taxes & Licenses		0						
Postage Expense		20,670						
Total Administrative & General Exp.	F-9	766,341	251,530	263,524	0	0	0	251,287
Depreciation	F-8	581,110	435,245	0	93,899	34,518	17,448	0
Property Taxes	F-8	212,052	158,825	0	34,265	12,596	6,367	0
Other Taxes	F-9	6,606	2,168	2,272	0	0	0	2,166
Corporate Exp. Allocation	F-9	26,276	8,624	9,036	0	0	0	8,616
Total Operating Exp. Ex. Inc.Txes		3,610,958	1,128,057	1,836,439	131,405	47,117	23,815	444,125
Functionalization of S & W:								
Operations	F-1/F-3	159,134	79,567	79,567				0
Maintenance	F-3	50,730	50,730					0
Customer Accounting	F-7	130,171						130,171
Sales Promotion	F-2	56,943		56,943				
Total		396,978	130,297	136,510	0	0	0	130,171
Percent	F-9	100.00%	32.82%	34.39%	0.00%	0.00%	0.00%	32.79%

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
TEST YEAR ENDED DECEMBER 31, 1999

FUNCT. FACTOR	DESCRIPTION	TOTAL	DEMAND	COMMOD.	WEIGHTED SERVICES	WEIGHTED METERS	WEIGHTED MTR. INSTA	CUST.
F-1	Demand	100.00%	100.00%					
F-2	Commodity	100.00%		100.00%				
F-3	Distribution Mains	100.00%	100.00%					
F-4	Services	100.00%			100.00%			
F-5	Meters & Regulators	100.00%				100.00%		
F-6	Meter Installations	100.00%					100.00%	
F-7	Customer Accounts	100.00%						100.00%
DERIVED UNCT. FCTRS	**DESCRIPTION**							
F-8	Gross Plant in Service	100.00%	74.90%	0.00%	16.16%	5.94%	3.00%	0.00%
F-9	Salaries & Wages	100.00%	32.82%	34.39%	0.00%	0.00%	0.00%	32.79%

CLASS ALLOC. FACTORS	DESCRIPTION	TOTAL	CUSTOMER CLASS RESID.	COMM.
D-1	Winter Peak Demand	100.000%	79.919%	20.081%
CM-1	Commodity	100.000%	77.199%	22.801%
C-1	Services	100.000%	95.523%	4.477%
C-2	Meters & Regulators	100.000%	68.127%	31.873%
C-3	Meter Installations	100.000%	95.990%	4.010%
C-4	Customer Accounts	100.000%	96.946%	3.054%

H

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

SUMMARY OF REVENUES AT PRESENT AND PROPOSED RATES

	REVENUES IN THE TEST YEAR		INCREASE	
DESCRIPTION	PRESENT (1)	PROPOSED	AMOUNT	PERCENT
Residential Gas Sales	$3,879,925	$4,152,518	$272,593	7.03%
Commercial Gas Sales	1,007,444	1,052,859	45,415	4.51%
Total Gas Sales	4,887,369	5,205,377	318,008	6.51%
Other Operating Revenues	56,570	64,740	8,170	14.44%
Total Gas Revenues	$4,943,939	$5,270,117	$326,178	6.60%

NOTE:
(1) Including Revenue Pro Forma Adjustments But Excluding PGA Revenues

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

PROPOSED CHANGES IN GAS RATES

DESCRIPTION	PRESENT RATE	PROPOSED RATE
RESIDENTIAL:		
Standard Rate:		
Monthly Service Charge	$5.50	$6.00
Commodity Rate Per Therm	$0.8702	$0.9294
Gas Air Conditioning:		
Monthly Service Charge	$5.50	$6.00
Commodity Rate Per Therm	$0.3500	$0.3605
CNG:		
Monthly Service Charge	No Current Rt.	$6.00
Commodity Rate Per Therm	No Current Rt.	$0.4000
COMMERCIAL:		
Standard Rate:		
Monthly Service Charge	$10.00	$15.00
Commodity Rate Per Therm	$0.8702	$0.9008
Resort:		
Monthly Service Charge	$22.95	$30.00
Commodity Rate Per Therm	$0.8702	$0.9008
Co-Gen:		
Monthly Service Charge	$10.00	$30.00
Commodity Rate Per Therm	$0.3260	$0.3300

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

PROPOSED CHANGES IN OTHER RATES & CHARGES

DESCRIPTION	PRESENT RATE	PROPOSED RATE
Establishment of Service	$15.00	$20.00
Re-Establishment of Service Within 12 Months:		
Monthly Minimum Times Months Disconnected		
(ACC R14-2-403)		No Change
Re-Connection of Service:		
Regular Hours	$25.00	$30.00
After Hours	$25.00	$45.00
Service Calls - Per Hour:		
Regular Hours	$25.00	$30.00
After Hours	$25.00	$45.00
Meter Re-read Charge (If Correct)	$25.00	No Change
Meter Test Fee - Per Hour (If Correct)	$12.50	$25.00
NSF Check Charge	$10.00	$15.00
Late Charge	1 1/2% Per Month	No Change

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

TYPICAL BILL ANALYSIS

DESCRIPTION	THERM USAGE	BILL AT: (1) PRESENT RATES	BILL AT: (1) PROPOSED RATES	PERCENT INCREASE
RESIDENTIAL:				
	5	$9.85	$10.65	8.08%
	10	14.20	15.29	7.69%
	15	18.55	19.94	7.48%
	20	22.90	24.59	7.35%
	30	31.61	33.88	7.20%
	40	40.31	43.18	7.12%
	50	49.01	52.47	7.06%
	60	57.71	61.76	7.02%
	70	66.41	71.06	6.99%
	80	75.12	80.35	6.97%
Average Bill	59	$56.84	$60.83	7.02%
GAS AIR COND.:				
	10	$9.00	$9.61	6.72%
	50	23.00	24.03	4.46%
	100	40.50	42.05	3.83%
	200	75.50	78.10	3.44%
	300	110.50	114.15	3.30%
	400	145.50	150.20	3.23%
	500	180.50	186.25	3.19%
	750	268.00	276.38	3.13%
	1,000	355.50	366.50	3.09%
	1,500	530.50	546.75	3.06%
Average Bill	523	$188.55	$194.54	3.18%

NOTES:
(1) Excluding Revenue Taxes & PGA

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

TYPICAL BILL ALL ANALYSIS

DESCRIPTION	THERM USAGE	BILL AT: (1) PRESENT RATES	BILL AT: (1) PROPOSED RATES	PERCENT INCREASE
COMMERCIAL:				
	10	$18.70	$24.01	28.37%
	50	53.51	60.04	12.20%
	100	97.02	105.08	8.31%
	200	184.04	195.16	6.04%
	300	271.06	285.24	5.23%
	400	358.08	375.32	4.81%
	500	445.10	465.40	4.56%
	750	662.65	690.60	4.22%
	1,000	880.20	915.80	4.04%
	1,500	1,315.30	1,366.20	3.87%
Average Bill	437	$390.28	$408.65	4.71%
RESORT:				
	10	$31.65	$39.01	23.24%
	50	66.46	75.04	12.91%
	100	109.97	120.08	9.19%
	200	196.99	210.16	6.69%
	300	284.01	300.24	5.71%
	400	371.03	390.32	5.20%
	500	458.05	480.40	4.88%
	750	675.60	705.60	4.44%
	1,000	893.15	930.80	4.22%
	1,500	1,328.25	1,381.20	3.99%
Average Bill	991	$885.32	$922.69	4.22%

NOTES:
(1) Excluding Revenue Taxes & PGA

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

TYPICAL BILL ANALYSIS

DESCRIPTION	THERM USAGE	BILL AT: (1) PRESENT RATES	BILL AT: (1) PROPOSED RATES	PERCENT INCREASE
CO-GEN:				
	100	$42.60	$63.00	47.89%
	500	173.00	195.00	12.72%
	1,000	336.00	360.00	7.14%
	2,000	662.00	690.00	4.23%
	3,000	988.00	1,020.00	3.24%
	4,000	1,314.00	1,350.00	2.74%
	5,000	1,640.00	1,680.00	2.44%
	6,000	1,966.00	2,010.00	2.24%
	7,000	2,292.00	2,340.00	2.09%
	8,000	2,618.00	2,670.00	1.99%
Average Bill	4,174	$1,370.72	$1,407.42	2.68%

NOTES:
(1) Excluding Revenue Taxes & PGA

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

BILL COUNT

	BLOCK				CUMULATIVE			
DESCRIPTION	BILLS	PERCENT	THERMS	PERCENT	BILLS	PERCENT	THERMS	PERCENT
RESIDENTIAL: (1)								
No Usage	3,296	5.21%	0	0.00%	3,296	5.21%	0	0.00%
0-5	4,459	7.05%	15,642	0.42%	7,755	12.26%	15,642	0.42%
5-10	9,677	15.29%	70,513	1.88%	17,432	27.55%	86,155	2.29%
10-20	11,961	18.90%	175,246	4.67%	29,393	46.45%	261,401	6.96%
20-30	6,106	9.65%	153,386	4.08%	35,499	56.10%	414,787	11.04%
30-40	4,270	6.75%	153,097	4.08%	39,769	62.85%	567,884	15.12%
40-50	3,514	5.55%	162,585	4.33%	43,283	68.40%	730,469	19.44%
50-75	6,269	9.91%	401,129	10.68%	49,552	78.31%	1,131,598	30.12%
75-100	4,428	7.00%	398,992	10.62%	53,980	85.31%	1,530,590	40.74%
100-200	6,389	10.10%	971,955	25.87%	60,369	95.41%	2,502,545	66.62%
200-300	1,499	2.37%	383,177	10.20%	61,868	97.77%	2,885,722	76.82%
300-400	574	0.91%	206,321	5.49%	62,442	98.68%	3,092,043	82.31%
400-500	301	0.48%	139,249	3.71%	62,743	99.16%	3,231,292	86.02%
Over 500	533	0.84%	525,299	13.98%	63,276	100.00%	3,756,591	100.00%
Total	*63,276*	*100.00%*	*3,756,591*	*100.00%*				
GAS AIR COND:								
No Usage	0	0.00%	0	0.00%	0	0.00%	0	0.00%
0-100	2	16.67%	3	0.05%	2	16.67%	3	0.05%
100-200	3	25.00%	496	7.91%	5	41.67%	499	7.96%
200-300	1	8.33%	273	4.35%	6	50.00%	772	12.31%
300-400	1	8.33%	378	6.03%	7	58.33%	1,150	18.34%
400-500	0	0.00%	522	8.32%	7	58.33%	1,672	26.66%
500-1,000	2	16.67%	736	11.73%	9	75.00%	2,408	38.39%
Over 1,000	3	25.00%	3,864	61.61%	12	100.00%	6,272	100.00%
Total	12	100.00%	6,272	100.00%				

NOTE:
(1) Excluding Year-End Customer Pro Forma Adjustment of 4,560 Bills

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

BILL COUNT

	BLOCK				CUMULATIVE			
DESCRIPTION	BILLS	PERCENT	THERMS	PERCENT	BILLS	PERCENT	THERMS	PERCENT
COMMERCIAL:								
No Usage	268	14.79%	0	0.00%	268	14.79%	0	0.00%
0-5	79	4.36%	248	0.03%	347	19.15%	248	0.03%
5-10	121	6.68%	867	0.11%	468	25.83%	1,115	0.14%
10-20	159	8.77%	2,212	0.28%	627	34.60%	3,327	0.42%
20-30	63	3.48%	1,538	0.19%	690	38.08%	4,865	0.61%
30-40	55	3.04%	1,932	0.24%	745	41.11%	6,797	0.86%
40-50	31	1.71%	1,393	0.18%	776	42.83%	8,190	1.03%
50-100	191	10.54%	14,136	1.78%	967	53.37%	22,326	2.82%
100-200	204	11.26%	29,790	3.76%	1,171	64.62%	52,116	6.57%
200-300	97	5.35%	24,367	3.07%	1,268	69.98%	76,483	9.65%
300-400	76	4.19%	26,492	3.34%	1,344	74.17%	102,975	12.99%
400-500	51	2.81%	23,030	2.91%	1,395	76.99%	126,005	15.89%
500-1,000	214	11.81%	150,920	19.04%	1,609	88.80%	276,925	34.93%
1,000-2,000	111	6.13%	156,820	19.78%	1,720	94.92%	433,745	54.71%
Over 2,000	92	5.08%	358,997	45.29%	1,812	100.00%	792,742	100.00%
Total	1,812	100.00%	792,742	100.00%				
CO-GEN:								
0-100	7	29.17%	35	0.03%	7	29.17%	35	0.03%
0-1,000	2	8.33%	900	0.90%	9	37.50%	935	0.93%
1,000 - 5,000	4	16.67%	16,501	16.47%	13	54.17%	17,436	17.41%
Over 5,000	11	45.83%	82,740	82.59%	24	100.00%	100,176	100.00%
Total	24	100.00%	100,176	100.00%				

BLACK MOUNTAIN GAS DIVISION OF NSP
CAVE CREEK OPERATION
Test Year Ended December 31, 1999

BILL COUNT

	BLOCK				CUMULATIVE			
DESCRIPTION	BILLS	PERCENT	THERMS	PERCENT	BILLS	PERCENT	THERMS	PERCENT
RESORT:								
No Usage	14	4.65%	0	0.00%	14	4.65%	0	0.00%
0-5	8	2.66%	18	0.01%	22	7.31%	18	0.01%
5-10	6	1.99%	48	0.02%	28	9.30%	66	0.02%
10-20	1	0.33%	15	0.01%	29	9.63%	81	0.03%
20-30	0	0.00%	0	0.00%	29	9.63%	81	0.03%
30-40	0	0.00%	0	0.00%	29	9.63%	81	0.03%
40-50	0	0.00%	0	0.00%	29	9.63%	81	0.03%
50-100	23	7.64%	1,859	0.62%	52	17.28%	1,940	0.65%
100-200	87	28.90%	12,887	4.32%	139	46.18%	14,827	4.97%
200-300	60	19.93%	14,495	4.86%	199	66.11%	29,322	9.83%
300-400	21	6.98%	7,284	2.44%	220	73.09%	36,606	12.27%
400-500	7	2.33%	3,196	1.07%	227	75.42%	39,802	13.34%
500-1,000	17	5.65%	11,478	3.85%	244	81.06%	51,280	17.18%
1,000-2,000	11	3.65%	16,743	5.61%	255	84.72%	68,023	22.80%
2,000-3,000	10	3.32%	25,328	8.49%	265	88.04%	93,351	31.28%
3,000-4,000	15	4.98%	52,170	17.48%	280	93.02%	145,521	48.77%
4,000-5,000	3	1.00%	13,324	4.47%	283	94.02%	158,845	53.23%
Over 5,000	18	5.98%	139,563	46.77%	301	100.00%	298,408	100.00%
Total	301	100.00%	298,408	100.00%				

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF BLACK MOUNTAIN GAS, A DIVISION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, TO DETERMINE ITS EARNINGS FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN FOR ITS CAVE CREEK DIVISION.	DOCKET NO. **AFFIDAVIT OF JAMES H. WILLSON**

STATE OF ARIZONA)

COUNTY OF MARICOPA)

James H. Willson, of lawful age being first duly sworn, deposes and states:

1. My name is James H. Willson. I am General Manager and Chief Executive Officer of Black Mountain Gas, located in Cave Creek, Arizona.

2. Attached hereto and made a part hereof for all purposes is my prefiled direct testimony consisting of pages 1 through 4 .

2. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct to the best of my knowledge and belief.

James H. Willson

James H. Willson

SUBSCRIBEED AND SWORN to before me this 27th day of April, 2000.

Noni Chettle

NOTARY PUBLIC

My Commission Expires:

12-30-2002

OFFICIAL SEAL
NONI CHETTLE
Notary Public - State of Arizona
MARICOPA COUNTY
My Comm. Expires Dec. 30, 2002

A

DIRECT TESTIMONY OF JAMES H. WILSON

JAMES H. WILLSON
General Manager & Chief Executive Officer

CURRENT RESPONSIBILITIES (1991 - Present)

1998 – PresentGeneral Manager and Chief Executive Officer, Black Mountain Gas

PREVIOUS EMPLOYMENT

1991 – 1998 Director Operations - Gas Utility, NSP (MN)
1990 - 1991 Director, Gas Supply & Marketing - NSP (MN)
1986 - 1990 General Manager, Gas Utility - NSP (WI)
1982 - 1986 Manager, Consumer Service - NSP (WI)
1981 - 1982 Asst. Manager, Consumer Service - NSP (WI)
1972 - 1981 Various Industrial Sales Positions - NSP (WI)
1969 - 1972 Engineering Estimator, Woodward Electric Contracting Co.
1964 - 1969 Sales Engineer - NSP (WI)

EDUCATION

Bachelor of Science, Industrial Electronics (1964)
University of South Dakota

PROFESSIONAL ACTIVITIES

American Gas Association, Distribution & Construction Committee

INDUSTRY ORGANIZATIONS

American Gas Association, Midwest Gas Association

1. Q. Please state your name, position at Black Mountain Gas, and business address.

   A. I am James H. Willson. My title is General Manager and Chief Executive Officer of Black Mountain Gas (BMG). I am responsible for the operation of Black Mountain Gas (BMG). Schedule 1 contains a resume of my professional and educational background. My office is located at 6021 East Cave Creek Road, Cave Creek Arizona, 85331.

2. Q. What is the purpose of your testimony?

   A. On July 16, 1998, the Arizona Corporation Commission (ACC) in Decision No. 61009 approved the sale of its assets and transfer of BMG's Certificate of Convenience and Necessity to Northern States Power Company (NSP). That Decision also required BMG to file a Rate Application and a Fuel Adjuster Application for BMG's Cave Creek Operation within 18 months of the effective date of the Decision. BMG has requested and received an extension on the 18 month filing requirement until May 1, 2000. The Decision also requested information on gas procurement activities. This filing is in compliance with those requirements.

3. Q. What other witnesses will present testimony for BMG?

   A. Mr. Dan L. Neidlinger, Neidlinger & Associates, Ltd., will support the Revenue Requirements and Rate Design for the rate application.

4. Q. Are you also filing an application to change the Fuel Adjuster for the Cave Creek Division?

   A. No. BMG filed on August 13, 1998 a request to change its Gas Fuel Adjuster. On October 30, 1998, in Decision No. 61224, the ACC approved BMG's request to recover $409,263 in its under-collected bank balance effective with billings after October 31, 1998 and over a three-year period.

5. Q. What is the overall result of the rate application to the customers of Cave Creek?

   A. BMG is proposing to increase rates to the Cave Creek Operation by approximately $326,000 or 6.60%. BMG is proposing to increase residential customer bills on average by approximately 7.0%, and commercial customers by approximately 4.5%. Mr. Neidlinger discusses the revenue requirements and rate design proposals in his testimony.

6. Q. Will any new customer classes be developed through this process?

   A. Yes. BMG is filing a new Compresses Natural Gas (CNG) rate.

7. Q. Will the proposed rate increase affect customer classes differently?

   A. Yes. BMG calculated its class cost allocations and proposed its rate design to fairly apportion costs to each customer class based on cost causation and to address their specific service demands. As discussed by Mr. Neidlinger, through this rate case BMG plans to modify class revenue responsibilities and related rate designs to bring them closer to cost of service, thereby reducing the cross-subsidies inherent in current rates.

8. Q. Please discuss how the merger between Northern States Power Company (NSP) and BMG has impacted gas procurement activities?

   A The merger between NSP and BMG has impacted gas procurement activities in that the gas procurement function is performed by NSP at the direction of BMG. BMG provides NSP volume requirements and NSP solicits bids from various suppliers. NSP provides BMG with supply alternatives and bid solicitation results, and recommends a competitive, least-cost option. NSP commits to the gas purchase at the expressed approval of BMG and administers the contract between BMG and the supplier.

9. Q. What savings has BMG realized as a result of the merger of BMG and NSP?

   A. Most of the savings realized to date are in the procurement of goods and services. Examples of these savings are as follows:

Insurance	40% reduction
Meters	39% to 43% reduction
Regulators	28% reduction
Plastic Pipe	10% to 12% reduction
Service Vehicles	6% to 8% reduction

10. Q. Are there any operational changes being planned for BMG?

   A. Yes. Because of the growth in the Cave Creek division, BMG purchased the building next door to the existing offices, to be made into the operational and warehouse complex. The building and property was purchased for $500,000. Remodeling costs are estimated to be $197,000. The bids are scheduled to be let May 1, 2000, with completion by September 1, 2000.

11 Q. With growth in the BMG service area of 12% to 15% per year, what do you see for future plant additions?

   A. The growth in the BMG service area appears to be accelerating at a rapid pace. In 1999, BMG added approximately 925 customers in Cave Creek. This year, BMG has received 18 requests from developers, who are scheduling new construction projects in 2000. These developments have a total of approximately 5000 residential lots. These units are scheduled to be fully developed over a 4-5 year period. The average embedded cost per residential lot for mains is $1,000 per lot.

   There is also a need to reinforce the existing infrastructure to accommodate increased load in the Cave Creek area. In 2000, BMG is spending approximately $700,000 to reinforce the east end of the service territory (north Scottsdale). Beginning in 2001, BMG will start replacing the feed from the El Paso Transmission system, starting at Carefree Highway and 99th Avenue to the main regulator located at Carefree Highway and 7th Street. The investment is estimated at $3,000,000.

12. Q. How does BMG propose to fund these plant additions?

A. BMG is currently researching the various alternatives for short term and long term financing to determine the best plan for the next five years. This plan will be filed with the ACC at a later date.

13. Q. Does this conclude your testimony?

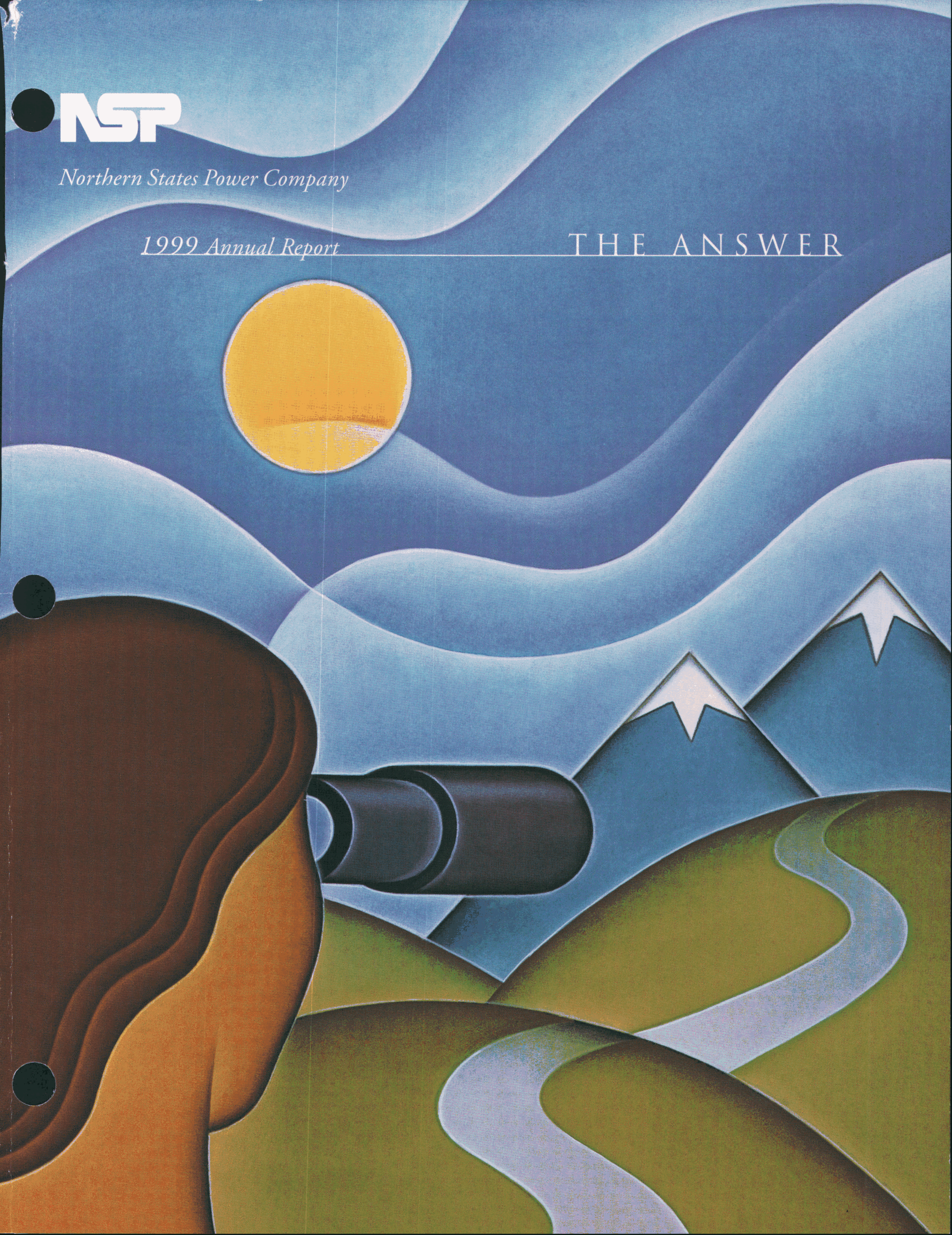
A. Yes, it does.

ANNUAL REPORT

Northern States Power Company

1999 Annual Report

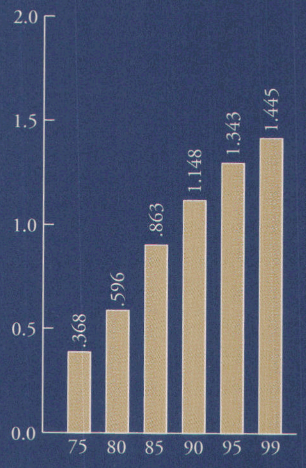
THE ANSWER



On the cover:

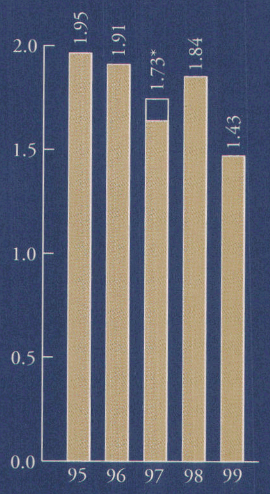
As NSP looks toward a bright future, we are in a strong position to answer the question: WHY INVEST IN NSP? *You'll find* THE ANSWER *in the pages that follow.*

25 YEARS OF
DIVIDEND GROWTH
Dollars per Share



Dividends reflect 2-for-1 stock splits effective June 5, 1986, and June 1, 1998

NSP EARNINGS
PER SHARE
Dollars per Share



Earnings reflect a 2-for-1 stock split effective June 1, 1998

** 1997 earnings per share were $1.73, excluding Primergy costs, and $1.61, including the Primergy cost write-off.*

CONTENTS

NSP AND ITS MAJOR SUBSIDIARIES

Northern States Power Company (NSP) | NSP is a major U.S. electric and natural gas utility with headquarters in Minneapolis, Minnesota. NSP and its wholly owned subsidiary NSP-Wisconsin operate generation, transmission and distribution facilities providing electricity to about 1.5 million customers in Minnesota, Wisconsin, North Dakota, South Dakota and Michigan. The two companies distribute natural gas to about 500,000 customers in Minnesota, Wisconsin, North Dakota, South Dakota, Michigan and Arizona.

FINANCIAL HIGHLIGHTS

	Year Ended December 31		
	1999	*1998*	*% Change*
Earnings per common share – diluted	$1.43	$1.84	(22.3)%
Dividends declared per share	$1.445	$1.425	1.4%
Stock price *(close)*	$19.50	$27.75	(29.7)%
Return on average common equity	8.7%	11.4%	
Assets *(millions)*	$9 768	$7 396	32.0%
Book value per common share	$16.42	$16.25	1.1%
Electric and gas customers *(thousands)*	1 979	1 934	2.3%
Retail energy sales:			
Electric *(millions of kilowatt hours)*	37 079	36 531	1.5%
Natural gas *(billions of cubic feet)*	91.1	85.2	6.9%

NRG Energy, Inc. (NRG) | NRG is a global leader in independent power production. The company specializes in the development, construction, operation, maintenance and ownership of power production and cogeneration facilities, thermal energy production and transmission facilities and resource recovery facilities. NRG has a high-quality portfolio of projects in the United States, Europe, Asia-Pacific and Latin America.

Seren Innovations, Inc. | Seren Innovations focuses on broadband, wireless and other communication technologies. Through its Astound℠ brand services, the company offers cable TV, high-speed Internet access and local and long distance telephone services over a new hybrid fiber-optic network.

Viking Gas Transmission Company | Viking Gas Transmission Company operates an interstate natural gas pipeline located in Minnesota, North Dakota and Wisconsin.

DEAR SHAREHOLDERS:

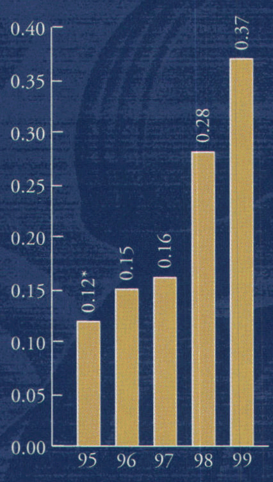
ALTHOUGH WE BEGAN 2000 WITH MANY FACTORS IN OUR FAVOR, we were tremendously disappointed in our 1999 financial results and in the performance of our stock. I'm sure you were too. Our 1999 earnings were $1.43 per share, compared with $1.84 per share in 1998. Our stock price declined 29.7 percent from the beginning of 1999 to year-end.

We describe the reasons for our poor earnings and stock performances in the Management's Discussion and Analysis section beginning on page 19. Several one-time events were responsible for the earnings decline, which in turn affected the stock performance. Also significant to the stock price, however, were higher interest rates, which contributed to a 23 percent overall decline among utility stocks in general.

Without going into more detail, I want to say that the reasons for those performances are for the most part behind us. We are in a strong position to get back on track in 2000.

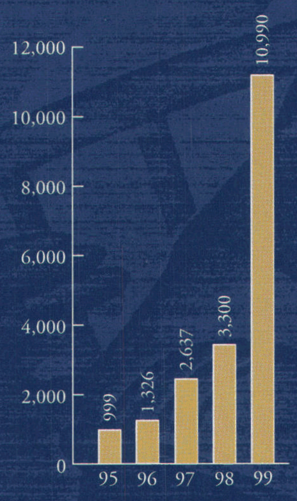
Our merger with New Century Energies (NCE) to form Xcel Energy Inc., for example, is ahead of schedule and could close during the second quarter. The merger will produce $1.1 billion in net cost savings synergies over 10 years, half of which we expect to retain for shareholders. We are eager to launch this new venture, to say the least. I will serve as Xcel Energy's chairman for a year and NCE's Wayne Brunetti will be Xcel Energy's president and CEO. We also have selected Xcel Energy's senior officers, a top-notch group of

NRG ENERGY
EARNINGS PER SHARE
Dollars per NSP Share



* *Excludes one-time, 11-cent gain*

NRG ENERGY
OWNED GENERATION
Megawatts



experienced and talented individuals. Our business plans are in place and we are ready to hit the ground running once all the regulatory approvals are secure.

When the merger is complete, we anticipate that Xcel Energy will adopt a dividend payment level equivalent to the current NCE dividend payment level adjusted for the exchange ratio. This would result in a dividend payment from Xcel Energy of $1.50 per share on an annual basis, a slight dividend increase for NSP shareholders.

From an operations perspective, NSP's utility system is strong, growing and enjoying the hard-earned support of our customers. Our electric and natural gas prices are low and will stay low in the coming competitive environment.

Our NRG Energy subsidiary has grown into the big league of independent power producers worldwide, with 11,000 megawatts of generating assets. Of those assets, 81 percent are in the U.S. Substantial shareholder value has been created in NRG that is not reflected in our stock price. Publicly traded IPPs like NRG enjoy price-earnings ratios of 25 times or more. We will explore ways to unlock that value for you this year. We expect NRG to continue its expansion and to provide a significant increase in earnings in 2000.

Seren Innovations, another NSP subsidiary, is a leader in the broadband communications industry with its proven strategy of selling significantly superior services, including cable television, high-speed Internet access and local and long distance telephone services. Video-on-demand will become a new service offering this year. While subject to some uncertainties, Seren's five-year plan is to obtain a customer base of approximately 500,000 customers, with an annual revenue stream of $400 million. The industry has valued companies with similar but inferior services and technology at about $5,000 per customer.

In other news of 1999, we accepted the resignation of NSP board member H. Lyman (Tad) Bretting, president and CEO of C.G. Bretting Manufacturing Company, Inc. Tad resigned in December after serving on the board since March 1990. He had a distinguished tenure on our board, and we thank him for his service.

I'm sorry to tell you that Ed Theisen, retired NSP president, died June 11 of cancer. In his 40 years at NSP, Ed made many lasting contributions to our company. We will remember his honesty, optimism and gentle nature. Along with his family and many friends, we will truly miss him.

As I look ahead, I'm encouraged by several facts. Our growth platforms, including utility operations, NRG and Seren, are strong and in many ways unique. We expect our merger with NCE and the creation of Xcel Energy to provide a strong boost to your value. In fact, the rest of this report provides more reasons why NSP is a good investment.

We are looking forward to an exciting new beginning, and appreciate your trust and continued support.

Sincerely,

James J. Howard

James J. Howard
Chairman of the Board
President and Chief Executive Officer
February 1, 2000

WHY INVEST IN NSP?

THAT'S THE QUESTION WE'RE ASKING IN THIS YEAR'S ANNUAL REPORT. And as our cover indicates, we have The Answer. In fact, we've chosen six reasons to invest in NSP. We provide more details in the pages that follow, but here they are at a glance.

1. *Excellence* | NSP is healthy and growing, with strong financial and operating fundamentals.

2. *Businesses* | NSP's nonregulated businesses, including NRG Energy and Seren Innovations, are thriving.

3. *Customers* | NSP has low rates and excellent customer service.

4. *Future* | NSP is ready for the future.

5. *Innovation* | NSP is innovative.

6. *Community* | NSP is committed to the community.

AN HONEST DEDICATION TO EXCELLENCE

DESPITE A SERIES OF ONE-TIME financial setbacks in 1999, NSP continues to grow, thanks to excellent financial and operating fundamentals. The company's service territory is thriving, its cost structure is competitive and its dividend increased for the 25th consecutive year.

NSP's core businesses are growing. In 1999, for example, NSP Gas purchased Natrogas, Inc., which includes 15,000 propane customers and 5,000 natural gas customers. NSP Energy Marketing also grew at a healthy pace, achieving wholesale sales of more than 6 million megawatt-hours of electricity.

Operating excellence is an NSP hallmark that is evident across the company. In 1999, NSP's combustion and hydroelectric plants generated more than 21.6 million megawatt-hours of electricity and held up under trying conditions. During a heat wave in July, for example, those plants operated with a forced outage rate of just 1.9 percent, better than the company's five-year average. NSP's Monticello and Prairie Island nuclear plants safely generated a record 13.3 million megawatt-hours of electricity, surpassing the previous record set in 1995.

The company continues to make careful investments in its generating plants to keep them reliable, efficient and competitive. In 1999, crews at NSP's coal-fired plants overhauled the unit 3 turbine at the Sherco plant and upgraded controls at the High Bridge, Black Dog and Riverside plants. Having benefited from a number of improvements over the years, the High Bridge plant marked its 75th anniversary in August.

In other measures of operating excellence, NSP Gas achieved the lowest costs for new gas service and new gas main in benchmarking comparisons. By working closely with excavators, NSP Gas continues to reduce the incidents of damage to NSP's underground gas lines by excavating crews. NSP Electric met or exceeded all of its reliability performance measures and kept the electric system running during the heat wave with relatively few heat-related outages.

NSP also achieved several notable safety milestones in 1999. In Grand Forks, N.D., employees worked 12 years without a lost work day accident. Viking Gas Transmission received a safety award from the state of Wisconsin recognizing Viking's Chippewa Falls and Osceola districts for working 39 and 32 years, respectively, without a lost work day accident.

THE STRENGTH TO GROW

BUSINESSES

NSP HAS BEEN ABLE TO LEVERAGE its excellent operating skills to its nonregulated businesses, which are thriving. The value of these businesses, which is not yet reflected in the company's stock price, is an added benefit for NSP shareholders.

NRG Energy, Inc., an NSP subsidiary that is now the seventh largest independent power producer (IPP) in the world, is the best example of the extra value shareholders receive by investing in NSP. In 1999, NRG purchased a number of power plants, tripling its ownership interests to approximately 11,000 megawatts of generating capacity.

In the Northeast region of the United States, NRG purchased 10 plants in New York, Massachusetts and Connecticut as well as four gas turbine plants. In 2000, NRG plans to purchase four plants and interests in two additional facilities from Conectiv of Wilmington, Del., for $800 million. These baseload facilities, which total 1,875 megawatts, add to NRG's existing Northeast holdings of more than 4,500 megawatts of generating capacity in the New York Power Pool and almost 2,500 megawatts in the New England Power Pool.

In Louisiana, NRG will purchase Cajun Electric Power Cooperative's 1,700 megawatts of fossil-fueled generation for $1.026 billion during 2000. In California, NRG is among the top four IPPs, with an interest in almost 2,800 megawatts. With solid footholds on both coasts, NRG is in a strong position to capture profits from emerging wholesale electric markets.

NRG also has a high-quality portfolio of projects in Europe, Australia and Latin America. In 2000, NRG plans to purchase the 665-megawatt, gas-fired Killingholme A power station in North Lincolnshire, England, for approximately $664 million.

Seren Innovations, Inc., a recognized telecommunications leader in the broadband market, provides high-speed Internet access, cable television and telephone services and soon will offer video-on-demand. The company's use of superior technology and its ability to deliver all services with one connection put it in the enviable position of having customers knocking on its door. In 1999, the company expanded operations from St. Cloud, Minn., to communities in the San Francisco East Bay area and Colorado.

Viking Gas Transmission Co., an NSP subsidiary that owns and operates an interstate natural gas pipeline, completed a 45-mile expansion that will increase capacity by 5 percent. Viking also initiated the Guardian Pipeline project in which the company and two partners plan to construct a gas pipeline to serve growing markets in northern Illinois and southeastern Wisconsin. In 1999, Viking increased its assets by 20 percent and received a favorable ruling from the Federal Energy Regulatory Commission, which allowed a 6 percent increase in revenues.

THE SATISFACTION OF OUR CUSTOMERS

COMPARED WITH OTHER LARGE utilities, NSP is a low-cost producer of electricity, and its natural gas rates are among the nation's lowest. Those rates complement the company's excellent customer service, which NSP recognizes as critical to its future success. If customers are satisfied today, they will be less likely to switch electricity providers when they are given a choice. By several measures, the company ranked high in customer satisfaction in 1999.

NSP was second in the nation for overall satisfaction among residential customers in a study by J.D. Power and Associates and Navigant Consulting, Inc. The study found that the key determinant of satisfaction in the electric utility industry is a provider's image, including such attributes as reputation, honesty, efforts to become more efficient and the ability to communicate changes. Other determinants of overall satisfaction are price and value, power quality and reliability, billing and the call center.

NSP's own customer satisfaction surveys also yielded strong results in 1999, with 94 percent of electric customers rating their overall satisfaction with NSP as excellent, very good or good. Employees working directly with customers turned in an outstanding performance in all categories, including meter reading, billing, calls answered and credit.

NSP continued several customer service enhancements in 1999, including expanding its automated meter reading system and consolidating its customer call centers into two locations. The company's investment in new technology to improve customer service and reliability proved especially worthwhile during the July heat storm, when NSP's energy management system helped system operators make critical decisions to keep the power flowing. After announcing in June that it was Y2K ready, NSP experienced a seamless transition to the year 2000, reporting no Y2K outages.

NSP Gas implemented new rates that provide customers more choices in how they purchase natural gas from NSP. Advantage Service, NSP's appliance repair service, began selling appliances in 1999 and offering competitive financing. In quarterly surveys, 87 percent of Advantage Service customers rated the company's service as excellent or very good.

Perhaps the most gratifying measure of customer satisfaction comes directly from customer letters, phone calls and e-mails. "I can't compliment them enough," wrote one St. Paul gas customer about the NSP crew who worked through the night in sub-zero temperatures to install a new meter. "They got the problem resolved quickly and without hassle," said a Minnesota electric customer. "They were friendly, courteous and caring."


XII
IX
VI

THE CONFIDENCE TO OWN OUR FUTURE

COMPETITION IN THE RETAIL electric market is increasing as states across the nation allow customers to choose their electricity providers. Although Michigan is the only state in NSP's service territory to mandate competition so far, NSP has taken significant steps to prepare for a full-fledged competitive market. One of the most important efforts is the proposed merger with New Century Energies (NCE), a gas and electric utility in Denver, Colo., to form Xcel Energy Inc.

Operating in 12 states and serving 3 million electric customers and 1.5 million natural gas customers, Xcel Energy will have the size and scope necessary to compete with large national energy companies, and the financial strength and flexibility it needs to grow its regulated and nonregulated businesses. Including its subsidiaries, the new company will do business in at least 40 states and 15 countries. As a result, Xcel Energy will be able to provide shareholders with stronger returns on their investment and long-lasting value.

Customers also will benefit. Today, NSP and NCE customers enjoy competitively priced electricity and natural gas. Xcel Energy will be in a strong position to keep prices competitive through the purchasing efficiencies and other economies of scale it will achieve.

To ensure a smooth transition and to make Xcel Energy a world-class energy company, NSP and NCE employees have reviewed the operating procedures of both companies to determine best practices, which Xcel Energy will implement. Xcel Energy will remain committed to environmental stewardship and to the social and economic well-being of the communities it serves.

With headquarters and an operational center in Minneapolis, Minn., Xcel Energy also will maintain operational centers in Eau Claire, Wis., Denver, Colo., and Amarillo, Texas. The company's international presence includes operations in the United Kingdom, central Europe, Australia and South America.

In other efforts to prepare for a competitive energy market, NSP in 1999 agreed to join the Midwest Independent System Operator (ISO), a broad, regional transmission group that will take operational responsibility for the company's transmission assets. NSP believes the Midwest ISO is the most effective means presently available to enhance the competitive market for wholesale electricity.

A LONG-TIME LEADER IN INNOVATION

AS FAR BACK AS 1923, WHEN NSP was part of an experiment to bring electricity to rural areas, the company has been blazing trails in the energy industry. In the 1950s, NSP began exploring the commercial use of nuclear power, which became a safe, efficient and economical source of generating electricity. In the 1970s, NSP was one of the first utilities to burn low-sulfur coal to reduce emissions. The company also installed pollution control equipment on its generating plants early on, putting it in compliance with the Clean Air Act regulations on sulfur dioxide well ahead of schedule. In the 1980s, NSP was experimenting with wind generation, long before the state of Minnesota required its use.

Today, NSP is implementing an innovative new model for operating its nuclear generating plants. With increasing regulation and its related costs, nuclear plants find it challenging to remain competitive in a restructured energy market. In response, some utilities are selling their nuclear plants. Others are shutting down units prematurely.

NSP, which considers its nuclear plants to be extremely valuable assets, is taking a far different approach by forming the Nuclear Management Company (NMC) with three regional utilities: Alliant Energy, Wisconsin Electric Co. and Wisconsin Public Service Corp. Together, the utilities own seven nuclear units at five sites, which are capable of producing 3,650 megawatts of electricity.

Formed in February 1999, the NMC is working to become a nuclear operating company responsible for operating all five plants. NSP's board of directors and the boards of the other utilities approved agreements to transfer the plants' operating licenses to the NMC. Pending approval from the Nuclear Regulatory Commission and state regulators, the NMC could be operating the plants by mid-2000.

Although the NMC will operate the facilities, NSP and the other parent companies will continue to own the plants and will retain the financial obligation for their safe operation, maintenance and decommissioning.

As the operator of seven nuclear units, the NMC will be able to share and employ best practices across the fleet of plants, achieve purchasing economies and capture many other benefits of scale. Best of all, the NMC concept ensures continued safe, reliable operations while enhancing the plants' value to shareholders.

A SINCERE COMMITMENT TO THE

COMMUNITY

CONTRIBUTING TO THE FINANCIAL and social well-being of communities in its service territory is a long-standing NSP commitment that will continue regardless of changes in the industry or the company. NSP's contributions include corporate funding, economic development and environmental efforts, as well as employee and retiree volunteerism.

In November, NSP celebrated its part in the restoration of the peregrine falcon, a bird that was taken off the endangered species list in 1999. Ten years ago, NSP began building nest boxes on the stacks of its power plants, where the peregrines could mate and raise their young. Almost 100 peregrines have hatched at NSP nest boxes.

On the economic development front, NSP encouraged Twin City Die Castings, a St. Paul-based foundry, to select Monticello, Minn., as the site for an expansion that eventually will result in 80 new jobs and an estimated $500,000 in annual electric revenues. In Wisconsin, the Nestlé Corporation plans to build a new manufacturing plant in Eau Claire that will employ 125–200 people and will generate almost $1 million in gas and electric sales for NSP. An expansion at Andersen Windows in Menomonie, Wis., will create 250 new jobs and generate approximately $360,000 in new gas and electric revenues. In Minot, N.D., ReliaStar opened a new service center, where 600 people now work, and Northwest Airlines announced plans to move its subsidiary MLT Vacations, Inc., to the city.

NSP's volunteerism was rewarded in 1999 when the company received the Judson Bemis Award for raising the most money during the Twin Cities UNCF walk-a-thon. The $28,000 that NSP walkers collected was the largest contribution by one company in the eight-year history of the walk-a-thon. NSP employees also raised more than $18,000 in Veterans' Day events that was given to veterans' homes. Other volunteer efforts include tutoring and mentoring students, delivering Meals on Wheels and serving as camp counselors at Camp Sunrise, a camp for urban teenagers that NSP helped establish in 1974.

To ensure the availability of affordable housing in the area, NSP's subsidiary Eloigne Company has an ownership interest in more than 50 housing developments, providing more than 3,300 rental units to eligible tenants. Eloigne is committed to investing in both family and senior housing that spans the social spectrum. In return, Eloigne's investments generate more than $9 million of tax credits annually, which are passed along to NSP.

SELECTED FINANCIAL DATA

(Millions of dollars, except per share data)	*1999*	*1998*	*1997*	*1996*	*1995*
Utility operating revenues	$2 869	$2 819	$2 734	$2 654	$2 569
Utility operating expenses	$2 526	$2 455	$2 372	$2 288	$2 223
Net income	$224	$282	$237	$275	$276
Earnings available for common stock	$219	$277	$226	$262	$263
Average number of common shares outstanding (000s)	153 366	150 502	140 594	137 121	134 646
Average number of common and potentially dilutive shares outstanding (000s)	153 443	150 743	140 870	137 358	134 832
Earnings per average common share:					
Basic	$1.43	$1.84	$1.61	$1.91	$1.96
Diluted	$1.43	$1.84	$1.61	$1.91	$1.95
Dividends declared per share	$1.445	$1.425	$1.403	$1.373	$1.343
Total assets	$9 768	$7 396	$7 144	$6 637	$6 229
Long-term debt	$3 453	$1 851	$1 879	$1 593	$1 542
Ratio of earnings to fixed charges	2.1	3.0	2.9	3.8	3.9

FINANCIAL STATISTICS

	1999	*1998*	*1997*	*1996*	*1995*
Return on average common equity *(a)*	8.7%	11.4%	10.2%	12.5%	13.4%
Dividends as percent of earnings	101.4%	77.7%	89.4%	71.5%	68.5%
Dividends as percent of book value	8.9%	9.0%	9.1%	9.3%	9.5%
Utility capital expenditures (millions)	$462	$411	$397	$387	$386
Internally generated utility funds *(b)*	80%	114%	109%	81%	94%
Cash dividend coverage	3.0	3.2	3.3	2.8	3.1
AFC as percent of earnings per share	2.8%	5.7%	7.3%	7.2%	6.5%
Effective tax rate	22.8%	27.1%	29.0%	34.8%	35.6%
Capitalization:					
Common equity	34.5%	47.3%	46.7%	46.5%	48.4%
Preferred equity and securities	4.1%	5.8%	7.9%	5.2%	5.7%
Debt *(c)*	61.4%	46.9%	45.4%	48.3%	45.9%
Total	100.0%	100.0%	100.0%	100.0%	100.0%
Accumulated depreciation as a percent of utility plant	50.3%	49.2%	47.6%	46.0%	44.2%
Depreciation expense as a percent of average depreciable utility plant	3.83%	3.77%	3.78%	3.68%	3.64%

(a) 13-month average

(b) Percent of utility capital expenditures that could be financed by internally generated utility funds, excluding allowance for funds used during construction (AFC) and after dividends

(c) Includes short-term debt, current portion of long-term debt and NRG project-secured debt of approximately $1 billion, as shown in the Statements of Capitalization

Northern States Power Company, a Minnesota corporation (NSP-Minnesota), has two significant subsidiaries: Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin), and NRG Energy, Inc., a Delaware corporation (NRG). NSP-Minnesota also has several other subsidiaries, including Viking Gas Transmission Company (Viking), Energy Masters International, Inc. (EMI), Eloigne Company (Eloigne), Seren Innovations, Inc. (Seren) and Ultra Power Technologies, Inc. (Ultra Power). NSP-Minnesota and its subsidiaries collectively are referred to as NSP.

FINANCIAL OBJECTIVES AND RESULTS

Because of several significant charges and adverse weather conditions (both are discussed later), 1999 earnings declined and NSP fell short of some of its financial objectives. This decline in earnings is not representative of NSP's continuing operational and financial strength.

Our earnings objective for 2000 is $1.95 per share, including build-out costs at Seren, which have reduced the projection by 15 cents per share. NRG is expected to contribute 80 cents per share, or about 40 percent of NSP's earnings. These projections assume NSP continues to own 100 percent of NRG and Seren.

In June 1999, NSP increased its dividend for the 25th consecutive year. The increase of 2 cents per share raised the dividend per share from $1.43 to $1.45 on an annual basis. At the time of the proposed merger to form Xcel Energy, the annual dividend is expected to be increased to $1.50 per share, equivalent to the current dividend of New Century Energies (NCE) adjusted for the 1.55 exchange ratio.

NSP's objective is to maintain continued financial strength with an AA rating for utility bonds. NSP-Minnesota's first mortgage bonds were rated:

- AA- by Fitch IBCA
- AA by Standard & Poors
- Aa3 by Moody's Investors Service

The three rating agencies placed NSP's bond ratings under review upon announcement of its merger with NCE. These ratings and the review reflect the views of rating agencies, which can provide an explanation of the significance. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by the rating agency. First mortgage bonds issued by NSP-Wisconsin carry comparable ratings.

BUSINESS STRATEGIES

NSP's mission is to be a recognized leader in the energy industry by increasing the value provided to our customers with energy-related products and services. We will utilize the skills and talents of our people to thrive in a dynamic and competitive energy environment that provides increased value for our customers and shareholders and significant growth opportunities for our company. NSP continues to move forward with its 10-Point Game Plan to achieve this mission.

Grow NRG | NRG's goal is to become a top independent power producer in each of its core markets: North America, Europe and Asia-Pacific. NRG expects to achieve this goal by profitably growing existing businesses and adding new businesses. NRG's asset acquisitions have enabled its earnings to grow from 16 cents per share in 1997 to 37 cents per share in 1999. NRG's long-term goal is to increase its earnings by an average of 25 percent per year. During 1999, NRG completed more than $1.6 billion of asset acquisitions, increasing its generation capability by more than 7,500 megawatts. During 2000, NRG expects to spend approximately $2.7 billion to acquire or develop more than 6,000 megawatts of generating facilities.

Position NSP's Generation Business for Long-Term Value | NSP's conventional plants include coal-fired, hydro, refuse-derived fuel, natural gas and oil-fired facilities. NSP will make strategic investments designed to enhance the value of these generating assets.

Create an Independent Nuclear Company | With increasing regulation and associated costs in the nuclear industry, NSP believes the best way to enhance NSP's nuclear assets is to combine our operations with other well-run nuclear plants and create a Nuclear Management Company. During 1999, NSP, Alliant Energy, Wisconsin Electric and Wisconsin Public Service Corporation formed a Nuclear Management Company (NMC) to provide services to member companies.

Expand Energy Marketing | To enhance NSP's position in the increasingly competitive electric market, NSP has expanded its wholesale energy marketing efforts by establishing an Energy Marketing function. Energy Marketing is responsible for meeting the requirements of NSP's retail and wholesale electric customers for low-cost energy, while optimizing margins from NSP's generation resources.

Provide for Independent Transmission Operations | To foster competition in the wholesale electricity market, the Federal Energy Regulatory Commission (FERC) requires the transmission portion of a utility's business to be functionally separate from the utility's generation facilities. The state of Wisconsin also calls for a separate transmission operating structure. During 1999, NSP joined the Midwest Independent System Operator (Midwest ISO) because it is the most effective means available to enhance the competitive market for wholesale electricity.

Expand NSP's Core Electric and Gas Distribution Business | To expand our core business, NSP will actively seek to acquire and merge with other energy companies. During 1999, NSP announced its plans to merge with NCE and form Xcel Energy. While NSP cannot guarantee the timing or receipt of the necessary regulatory approvals, NSP currently expects the merger to be completed by the middle of 2000.

Develop Seren | Seren provides broadband telecommunications services, including high-speed Internet access, telephone service and cable TV and soon will provide video-on-demand. Seren is expanding its broadband network in Minnesota, California and Colorado.

Grow Viking | NSP's goal is to continue the growth of Viking through pipeline expansion. During 1999, Viking completed a 5 percent capacity expansion. In addition, Viking, WICOR and CMS Energy announced plans to build a 147-mile natural gas pipeline to serve northern Illinois and southeastern Wisconsin.

Drive EMI to Profitability | EMI is narrowing its focus to concentrate on retrofitting and upgrading customer facilities for greater energy efficiency.

Manage NSP's Entire Business as a Portfolio | NSP will manage its collective businesses as a portfolio of assets with a focus on growth. NSP will acquire or divest businesses and assets if it will increase shareholder value. Pooling restrictions, associated with NSP's proposed merger with NCE, limit NSP's ability to divest assets for a period of time.

FINANCIAL REVIEW

The following discussion and analysis by management focuses on those factors that had a material effect on NSP's financial condition and results of operations during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying Financial Statements and Notes.

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "estimate," "expect," "objective," "outlook," "possible," "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to:

- general economic conditions, including their impact on capital expenditures
- business conditions in the energy industry
- competitive factors
- unusual weather
- changes in federal or state legislation
- regulation
- the higher risk associated with NSP's nonregulated businesses as compared with NSP's regulated business
- currency translation and transaction adjustments
- issues relating to Year 2000 remediation efforts
- regulatory delays or conditions imposed by regulatory agencies in approving the proposed merger with NCE
- the items described under "Factors Affecting Results of Operations"
- the other risk factors listed from time to time by NSP in reports filed with the Securities and Exchange Commission (SEC), including Exhibit 99.01 to NSP's 1999 report on Form 10-K

Proposed Business Combination | On March 24, 1999, NSP and NCE agreed to merge and form a new entity, Xcel Energy. The merger requires approval or regulatory review by certain state and federal regulators. The merger is expected to be a tax-free, stock-for-stock exchange for shareholders of both companies and to be accounted for as a pooling of interests. At the time of the merger, Xcel Energy will register as a holding company.

The Xcel Energy board of directors will determine the dividend payment level of Xcel Energy. However, NSP anticipates that Xcel Energy will adopt an initial dividend equivalent to the current dividend of NCE. Based on the conversion ratio of 1.55 shares of Xcel common stock for each share of NCE stock, the pro forma dividend for Xcel Energy would currently be $1.50 per share annually.

For more discussion of this merger, see Note 15 to the Financial Statements. The following discussion and analysis is based on the financial condition and operations of NSP and does not reflect the potential effects of the proposed merger between NSP and NCE.

RESULTS OF OPERATIONS

1999 Compared with 1998 and 1997 | NSP's earnings per share for the past three years were as follows:

(Earnings per Share – Diluted)	*1999*	*1998*	*1997*
Regulated utility operations (excluding Primergy costs)	$1.26	$1.58	$1.62
Nonregulated operations (see page 22)	0.22	0.26	0.11
CellNet investment write-down	(0.05)		
Subtotal excluding Primergy costs	$1.43	$1.84	$1.73
Write-off of Primergy merger costs			(0.12)
TOTAL	$1.43	$1.84	$1.61

The combination of four significant one-time items accounted for a decline in 1999 earnings per share of 40 cents compared with 1998.

Conservation Incentive Recovery 1998 | In 1999, the Minnesota Public Utilities Commission (MPUC) denied NSP recovery of 1998 lost margins, load management discounts and incentives associated with state-mandated programs for electric energy conservation. NSP recorded a $35 million charge based on this action, which reduced 1999 earnings by 14 cents per share. This charge represented a $32 million reduction in accrued revenue and a reduction of carrying charges. NSP may appeal the decision on 1998 conservation incentives.

Conservation Incentive Recovery 1999 | At the end of 1999, the MPUC had not approved a conservation plan for 1999 or subsequent years. Based on the change in MPUC policy on conservation incentives and regulatory uncertainty, management decided not to accrue any conservation incentives for 1999. On Jan. 27, 2000, the MPUC approved a conservation incentive plan under which utilities could earn incentives up to 30 percent of their annual conservation spending. For NSP, the maximum amount of conservation incentives that could be earned is approximately $10 million, with the actual incentive dependent on performance compared with conservation goals. The MPUC also decided that the conservation incentive program is not linked to earnings levels. NSP estimates it could potentially earn $2 million–$3 million in 2000 for 1999 performance. NSP will file its performance report with the MPUC in the spring of 2000 and request approval of the appropriate amount based on final conservation program results for 1999. In addition, the MPUC denied NSP's request to allow rate recovery of load management discounts provided to certain customers.

NSP's 1998 earnings included approximately 13 cents per share from accrued conservation incentives. Including carrying charges, the reversal of 1998 conservation incentives reduced 1999 earnings by 14 cents per share, a decrease of 27 cents per share compared with incentive recovery levels in 1998. The earnings impacts in 1999 are non-cash accrual adjustments. NSP will make a filing with the MPUC in 2000 to address the cash impacts of conservation incentives collected in rates, including any overcollections for 1998 and 1999.

EMI Goodwill | NSP recorded a pretax charge of approximately $17 million, or about 8 cents per share, to write off all goodwill that was recorded by its subsidiary EMI for its acquisitions of Energy Masters Corporation in 1995 and Energy Solutions International in 1997. This charge reflects a revised business outlook based on recent levels of contract signings by EMI.

Loss on Marketable Securities | During 1999, NSP recorded pretax charges of approximately $14 million, or 5 cents per share, for a valuation write-down on its investment in the publicly traded common stock of CellNet Data Systems, Inc. In October 1999, CellNet announced it was experiencing financial difficulties and was contemplating restructuring its capital financing. In February 2000, CellNet filed for Chapter 11 bankruptcy protection. At Dec. 31,1999, the remaining value of NSP's investment in CellNet stock was approximately $1 million and Seren had approximately $5 million of intangible assets related to CellNet. Recovery of these assets is uncertain, pending the resolution of CellNet's financial difficulties.

REGULATED UTILITY OPERATING RESULTS

Electric Revenues | The following table summarizes the principal reasons for the electric revenue changes during the past two years:

(Millions of dollars)	*1999 vs. 1998*	*1998 vs. 1997*
Retail sales growth (excluding weather impact)	$35	$ 63
Estimated impact of weather on retail sales volume	(2)	3
Sales for resale	25	47
Conservation incentive accrual adjustments	(78)	4
Fuel cost recovery	47	19
Rate changes	5	2
Transmission and other	3	6
TOTAL REVENUE INCREASE	$35	$144

Electric sales growth for 1999 and 1998 is listed in the following table on both an actual and weather-normalized basis. NSP's weather-normalization process removes the estimated impact on sales of temperature variations from historical averages.

(Sales growth)	*1999 vs. 1998*		*1998 vs. 1997*	
	Actual	*Weather-Normalized*	*Actual*	*Weather-Normalized*
Residential	2.4%	2.5%	3.4%	3.7%
Commercial and industrial	1.1%	1.2%	3.3%	3.1%
Total retail	1.5%	1.6%	3.3%	3.3%
Sales for resale	6.7%	na	35.3%	na
TOTAL ELECTRIC SALES	2.3%	na	7.1%	na

na = not applicable

Retail electric sales accounted for 93 percent of NSP's electric revenue in 1999 and 91 percent in 1998. Retail electric sales growth for 2000 is estimated to be 2.7 percent over 1999, or 2.1 percent on a weather-adjusted basis. Sales for resale volumes and revenues increased in 1999 and 1998 due to the expansion of NSP's wholesale energy marketing operations.

Electric Margin | As shown in the following table, electric margin equals electric revenue minus production expenses.

(Millions of dollars)	*1999*	*1998*	*1997*
Electric revenue	$2 397	$2 362	$2 218
Fuel for electric generation	(319)	(311)	(310)
Purchased and interchange power	(454)	(378)	(286)
ELECTRIC MARGIN	$1 624	$1 673	$1 622

Electric production expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Due to fuel clause cost recovery mechanisms for retail customers and the ability to vary wholesale prices with changing market conditions, most fluctuations in energy costs do not affect electric margin. However, during July 1999, NSP's service territory experienced extremely high temperatures, which drove customer usage to record levels. With NSP's power plants operating at maximum available capacity, market conditions forced NSP to purchase the power necessary to serve customer demand at very high costs. NSP's fuel clause billing adjustment process in Minnesota does not allow for the recovery of capacity charges above the levels reflected in base rates. In addition, NSP-Wisconsin does not have an automatic fuel clause to recover increased energy and capacity charges from customers. Without the ability to obtain full recovery, these unusually high energy and capacity costs reduced electric margin as shown below.

The following table summarizes the principal reasons for electric margin changes during the past two years:

(Millions of dollars)	*1999 vs. 1998*	*1998 vs. 1997*
Retail sales growth (excluding weather impact)	$ 29	$51
Estimated impact of weather on retail sales volume	(2)	3
Sales for resale	7	11
Conservation incentive accrual adjustments	(78)	4
Unrecovered demand, fuel and purchased power costs	(19)	(14)
Rate changes	5	2
Transmission and other	9	(6)
TOTAL ELECTRIC MARGIN INCREASE (DECREASE)	$(49)	$51

Gas Revenues | The following table summarizes the principal reasons for the gas revenue changes during the past two years:

(Millions of dollars)	*1999 vs. 1998*	*1998 vs. 1997*
Sales growth (excluding weather impact)	$ 7	$ 7
Estimated impact of weather on firm sales volume	20	(46)
Purchased gas adjustment clause recovery	(11)	(40)
Rate changes	1	9
Black Mountain Gas Company acquisition		6
Transportation and other	(2)	6
TOTAL REVENUE INCREASE (DECREASE)	$15	$(58)

Gas sales growth for 1999 and 1998 is listed in the following tables on both an actual and weather-normalized basis. The majority of NSP's retail gas sales are categorized as firm (primarily heating customers) and interruptible (commercial/industrial customers with an alternate energy supply).

(Sales growth)	*1999 vs. 1998*		*1998 vs. 1997*	
	Actual	*Weather-Normalized*	*Actual*	*Weather-Normalized*
Total firm	8.6%	1.4%	(13.1)%	2.9%
Interruptible	2.3%	na	(10.4)%	na
Total retail	6.9%	na	(12.4)%	na
Transportation and other	(11.8)%	na	33.4%	na
Viking (wholesale transportation)	(0.9)%	na	2.8%	na
TOTAL GAS SALES AND DELIVERY	1.1%	na	(1.5)%	na

na = not applicable

The 1999 firm sales increase was primarily due to slightly more favorable weather in 1999, compared with 1998, and sales growth. The 1998 firm sales decrease was due to more unfavorable weather in 1998, compared with 1997, partially offset by sales growth. Interruptible sales declined in 1998 because lower alternate fuel prices caused interruptible customers to purchase less natural gas and customers were able to switch to transportation-only service. Firm gas sales in 2000 are estimated to be 15.1 percent higher than 1999 sales, or 2.2 percent higher on a weather-adjusted basis.

Gas Margin | As shown in the following table, gas margin equals gas revenue less the cost of gas sold.

(Millions of dollars)	*1999*	*1998*	*1997*
Gas revenue	$472	$457	$515
Cost of gas purchased and transported	(278)	(267)	(331)
GAS MARGIN	$194	$190	$184

The cost of gas tends to vary with changing sales requirements and 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 gas margin. The following table summarizes the principal reasons for gas margin changes during the past two years:

(Millions of dollars)	*1999 vs. 1998*	*1998 vs. 1997*
Retail and transportation sales growth (excluding weather impact)	$ 4	$ 7
Estimated impact of weather on firm sales volume	6	(16)
Rate changes	1	9
Black Mountain Gas Company acquisition		4
Other	(7)	2
TOTAL GAS MARGIN INCREASE	$ 4	$ 6

Other Operation, Maintenance and Administrative and General | Expenses decreased in 1999 by $15.2 million, or 2.1 percent, compared with 1998. 1999 expenses decreased primarily due to cost control, including lower employee benefit costs, higher levels of insurance refunds and lower Year 2000 remediation costs. Expenses increased in 1998 by $48.3 million, or 7.2 percent, compared with 1997. The higher costs in 1998 are primarily due to increased expenses associated with plant outages, nuclear regulatory costs, storm damage, Year 2000 remediation, energy marketing activities, customer growth and an insurance refund in 1997.

Depreciation and Amortization | Costs increased $17.5 million in 1999 and $12.3 million in 1998, primarily due to higher levels of depreciable plant, including new information systems and equipment with relatively short depreciable lives.

NONOPERATING UTILITY ITEMS

Utility Financing Costs | Interest costs for NSP's utility businesses were $128.5 million in 1999, $115.8 million in 1998 and $120.3 million in 1997. The 1999 increase is largely due to higher average short-term debt levels to support financing needs. The 1998 decrease is largely due to lower average short-term debt levels, partially offset by increased long-term debt levels. For more information, see the Statements of Capitalization.

Allowance for Funds Used During Construction (AFC) | AFC declined primarily due to reductions in carrying charges and other adjustments related to conservation incentive adjustments, as discussed previously, and less construction activity presumed to be financed with equity capital.

Primergy Merger Costs | In May 1997, NSP and Wisconsin Energy Corp. mutually terminated their plans to merge. NSP's earnings for 1997 include a pretax charge to nonoperating expense of $29 million, or 12 cents per share, to write off its cumulative merger-related costs incurred.

NONREGULATED BUSINESS RESULTS

A description of NSP's primary nonregulated businesses and their earnings contribution is summarized below.

- NRG is involved in independent power production, commercial and industrial heating and cooling, and energy-related refuse-derived fuel production.
- EMI is an energy services company.
- Eloigne invests in affordable housing.
- Seren provides broadband communication services.

CONTRIBUTION TO NSP'S EARNINGS PER SHARE

	1999	*1998*	*1997*
NRG	$0.37	$0.28	$0.16
EMI	(0.13)	(0.05)	(0.08)
Eloigne	0.05	0.04	0.03
Seren	(0.06)	(0.02)	(0.01)
Other	(0.01)	0.01	0.01
Subtotal – nonregulated subsidiaries	$0.22	$0.26	$0.11
Write-down of investment in CellNet stock	(0.05)		
TOTAL	$0.17	$0.26	$0.11

NRG | NRG's earnings increased for 1999, compared with 1998, primarily due to acquisitions of generating facilities in the Northeast region of the United States. During 1999, NRG recognized a gain of approximately 3 cents per share due to the partial sale of its interest in Cogeneration Corporation of America. Results for 1999 also reflected increased earnings from MIBRAG. These increased earnings were partially offset by the effects of cooler-than-normal weather in

California, which reduced equity earnings at the El Segundo, Long Beach and Encina generating stations. In addition, earnings were decreased by costs related to project acquisitions and business development, and increased interest expenses. Also, equity earnings were affected by several other factors, including a currency transaction adjustment relating to the Kladno project and a decrease in earnings from NEO, NRG's landfill gas affiliate.

NRG's earnings increased in 1998, compared with 1997, primarily due to income from new projects. In addition, NEO generated higher levels of energy tax credits. Increased earnings were partially offset by higher interest costs. Also, NRG's earnings in 1998 were adversely affected by declines in the value of the Australian dollar and German deutsche mark in relation to the U.S. dollar. In 1997, NRG's investment in the Sunnyside project was written down by $9 million, or 4 cents per share.

In 1998, NRG sold one-half of its 50 percent interest in Enfield Energy Centre Ltd. for approximately $26 million, resulting in an after-tax gain of approximately $17 million. This gain increased 1998 earnings by approximately 11 cents per share. Also in 1998, NRG recorded a charge of approximately $22 million ($15 million after tax) to write down its investment in a 400-megawatt coal-fired power station in West Java, due to the political and economic instability in Indonesia. This write-down reduced 1998 earnings by approximately 10 cents per share.

Further information on NRG's financial results may be obtained from NRG's annual report on Form 10-K filed with the SEC.

EMI | EMI's losses for 1999 were greater than 1998, due to the write-off of goodwill associated with two acquisitions, as previously discussed. The write-off of goodwill reduced 1999 results by approximately 8 cents per share. EMI's losses for 1998 were lower than 1997, due to increased margins in 1998 and losses incurred by Enerval in 1997, a joint venture previously held by EMI. In 1998, EMI sold its interest in Enerval. EMI's investment in Enerval was written down in 1997.

Eloigne | Eloigne's earnings grew in 1999 and 1998 due to new investments in affordable housing projects.

Seren | Seren's build-out of its broadband communications network in St. Cloud, Minn., and initial construction in northern California resulted in losses for 1999 and 1998, consistent with Seren's business plan.

FACTORS AFFECTING RESULTS OF OPERATIONS

NSP's 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, NSP's nonregulated businesses are becoming a more significant factor in NSP's earnings. The historical and future trends of NSP's operating results have been and are expected to be affected by the following factors:

Regulation | NSP's utility rates are approved by the Federal Energy Regulatory Commission (FERC) and state regulatory commissions in Minnesota, North Dakota, South Dakota, Wisconsin, Arizona and Michigan. Rates are designed to recover plant investment, operating costs and an allowed return on investment. NSP requests changes in rates for utility services through filings with the governing commissions. The rates charged to retail customers in Wisconsin are reviewed and adjusted biennially. Because comprehensive rate changes are requested infrequently in Minnesota, NSP's primary jurisdiction, changes in operating costs can affect NSP's financial results. Except for Wisconsin electric operations, NSP's retail rate schedules provide for cost-of-energy and resource adjustments to billings and revenues for changes in the cost of fuel for electric generation, purchased energy, purchased gas and, in Minnesota, conservation and energy management program costs. In Minnesota, changes in electric capacity costs are not recovered through the fuel clause. For Wisconsin electric operations, where cost-of-energy adjustment clauses are not used, 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 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.

Regulated public utilities are allowed to record as assets certain costs that would be expensed by nonregulated enterprises and to record as liabilities certain gains that would be recognized as income by non-regulated enterprises. If restructuring or other changes in the regulatory environment occur, NSP 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 NSP's results of operations in the period the write-off is recorded. At Dec. 31, 1999, NSP reported on its balance sheet regulatory assets of approximately $136 million and regulatory liabilities of approximately $206 million that would need to be recognized in the income statement in the absence of regulation. In addition to a potential write-off of regulatory assets and liabilities, deregulation and competition may require recognition of certain "stranded costs" not recoverable under market pricing. NSP currently does 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 9 to the Financial Statements for further discussion of regulatory deferrals.

Merger Settlement Agreements | In December 1999, NSP signed separate agreements with the Minnesota Office of Attorney General and the Minnesota Energy Consumers related to stipulated terms under which those parties would support NSP's proposed merger with NCE. Under the agreements, which contained substantially the same financial terms, NSP agreed to reduce its Minnesota electric rates by $10 million per year, or approximately 0.6 percent less than current levels, for 2001–2005. The agreements are subject to the approval of the MPUC and can be terminated in the event the merger does not proceed. Under the agreements, NSP's electric rates may not otherwise be increased through 2005, except under limited circumstances.

In January 2000, NSP also signed a separate agreement with the Minnesota Dept. of Commerce (MDC), in which the MDC would support NSP's proposed merger with NCE. Under the agreement NSP agreed not to seek recovery of certain merger costs from customers, to meet various quality standards and to certain provisions affecting the regulatory oversight of Xcel Energy.

Competition | The Energy Policy Act of 1992 has been a catalyst for comprehensive and significant changes in the operation of electric utilities, including increased competition. The Act's reform of the Public Utility Holding Company Act of 1935 (PUHCA) promoted creation of wholesale nonutility power generators and authorized the FERC to require utilities to provide wholesale transmission services to third parties. The legislation allows utilities and nonregulated companies to build, own and operate power plants nationally and internationally without being subject to restrictions that previously applied to utilities under the PUHCA.

In 1996, the FERC issued Orders No. 888 and 889 to foster competition in the electric utility industry. These orders give competing wholesale suppliers the ability to transmit electricity through a utility's transmission system. Order No. 888 grants nondiscriminatory access to transmission service. Order No. 889 seeks to ensure a fair market by imposing standards of conduct on transmission system owners, by requiring separation of the wholesale power supply function from the transmission system operation function, and by mandating the posting of transmission availability and pricing information on an electronic bulletin board. NSP has made open access transmission tariff filings and compliance filings with the FERC and believes it is taking the proper steps to comply with these rules.

Some states have begun to allow retail customers to choose their electricity supplier, and many other states are considering retail access proposals. The Minnesota Legislature continues to study the issues, but has determined that further study is necessary before any action can be taken. The Public Service Commission of Wisconsin (PSCW) and Wisconsin Legislature have been focusing their efforts on improving electric reliability by requiring utility infrastructure improvements prior to addressing customer choice. The Michigan Public Service Commission has approved voluntary plans that began offering retail customers a choice of suppliers in selected markets in 1998. The Michigan Legislature is considering legislation to allow customer choice for all customers by 2002. The timing of regulatory and legislative actions regarding restructuring and their impact on NSP cannot be predicted at this time and may be significant.

Transmission Operations | During 1999, NSP joined the Midwest ISO, a FERC-approved Regional Transmission Organization (RTO). This action commits the NSP transmission system to control by the Midwest ISO and ensures transmission operations in compliance with FERC Order No. 888. Recent developments include:

- The Midwest ISO intends to commence operations in 2001. The Midwest ISO will administer transmission service for most of the area extending east from NSP's service area to Pennsylvania and south through Illinois and Kentucky. NSP remains a member of the Mid-Continent Area Power Pool (MAPP). MAPP recently signed an agreement with the Midwest ISO, which may further broaden the scope of the Midwest ISO and regional markets for transmission service.
- Wisconsin state law requires the PSCW to order a public utility that owns transmission facilities in Wisconsin to transfer control of its transmission facilities to an ISO or divest its interest in its transmission facilities to an Independent Transmission Company (ITC) by June 30, 2000. It is expected that during 2000 the PSCW will approve NSP-Wisconsin's request to join the Midwest ISO and certify that NSP-Wisconsin's joining of the Midwest ISO will satisfy the requirements of this Wisconsin law.

Nuclear Management Company (NMC) | As part of its game plan, NSP announced its intention to form an independent nuclear management company. Recent developments include:

- During 1999, NSP, Wisconsin Electric Power Co., Wisconsin Public Service Corp. and Alliant Energy established an NMC to improve plant performance and reliability, strengthen operational efficiency, maintain high safety levels and reduce costs. The four companies operate seven nuclear units at five sites, with a total generation capacity exceeding 3,650 megawatts.
- In late 1999, NMC member utilities filed with the Nuclear Regulatory Commission (NRC) to transfer plant operating licenses to the NMC. The four partners, including NSP, will retain ownership of their respective nuclear plant assets. License transfer would allow the NMC to become an operating company in 2000. During 1999, NSP's board of directors and the boards of the other utilities approved the transfer of the nuclear operating licenses for their respective companies to the NMC. The request to transfer operating licenses requires approval from federal regulators, including the NRC.

Used Nuclear Fuel Storage and Disposal | In 1994, NSP received legislative authorization from the state of Minnesota to use 17 casks for temporary spent-fuel storage at NSP's Prairie Island nuclear generating facility. NSP has determined that 17 casks will allow operation of the facility until 2007. NSP had loaded nine of the casks as of Dec. 31, 1999. As a condition of the authorization, the Minnesota Legislature established several resource commitments for NSP, including wind and biomass generation sources as well as other requirements. NSP is complying with these requirements, as discussed in Note 14 to the Financial Statements.

NSP and other utilities have an ongoing dispute with the U.S. Department of Energy (DOE) regarding the DOE's statutory and contractual obligations to provide permanent storage and disposal facilities for nuclear fuel by Jan. 31, 1998, as required by the Nuclear Waste Policy Act of 1982. See Note 13 to the Financial Statements for more information.

Year 2000 (Y2K) | NSP's Y2K program covered not only NSP's 2,000 computer applications, consisting of about 75,000 programs and totaling more than 30 million lines of code, but also the thousands of hardware and embedded system components in use throughout NSP. Although it appears that NSP successfully transitioned into the year 2000 with no Y2K disruptions to customers or to internal operations, there are no guarantees that a Y2K-related problem will not surface at a later date. NSP is not presently aware of any such situations; however, occurrences of this type could adversely affect NSP's business, operating results or financial condition.

NSP has spent approximately $22 million for Y2K efforts, from 1996–1999. This includes $9 million in 1999. These costs have been expensed as incurred, except for a small portion deferred for approved rate recovery.

Environmental Matters | NSP incurs several types of environmental costs, including 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 into the environment. Because of greater environmental awareness and increasingly stringent regulation, NSP has experienced increasing environmental costs. This trend has caused, and may continue to cause, slightly higher operating expenses and capital expenditures for environmental compliance. In addition, NRG's recent acquisition of generation facilities will tend to increase nonutility costs for environmental compliance.

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

- $32 million in 1999
- $32 million in 1998
- $31 million in 1997

NSP's utility operations expect to spend approximately $35 million per year for 2000–2004. 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 its utility facilities, which include the costs of constructing spent nuclear fuel storage casks, were approximately:

- $39 million in 1999
- $21 million in 1998
- $19 million in 1997

NSP expects to incur approximately $24 million in capital expenditures for compliance with environmental regulations in 2000 and approximately $74 million for 2000–2004. In addition, NRG expects to incur approximately $44 million in capital expenditures for environmental compliance for 2000–2004. See Notes 13 and 14 to the Financial Statements for further discussion of NSP's environmental contingencies.

Weather | NSP's earnings can be significantly affected by weather. Very hot summers and very cold winters increase electric and gas sales, but can also increase expenses, which may not be fully recoverable. Unseasonably mild weather reduces electric and gas sales. The following summarizes the estimated impact on NSP's earnings due to temperature variations from historical averages.

- Weather in 1999 decreased earnings by an estimated 8 cents per share.
- Weather in 1998 decreased earnings by an estimated 11 cents per share.
- Weather in 1997 decreased earnings by an estimated 6 cents per share.

Impact of Nonregulated Investments | A significant portion of NSP's earnings comes from nonregulated operations. NSP expects to continue investing in nonregulated projects, including domestic and international power production projects through NRG and broadband communications systems through Seren. NSP's nonregulated businesses may carry a higher level of risk than NSP's 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.

Some of NRG's project investments (as listed in Note 10 to the Financial Statements) consist of minority interests, which may limit NRG's financial risk, but also limit NRG's ability to control the development or operation of the projects. In addition, significant expenses may be incurred for projects pursued by NRG that do not materialize. The aggregate effect of these factors creates the potential for volatility in the nonregulated component of NSP's earnings. Accordingly, the historical operating results of NSP's nonregulated businesses may not necessarily be indicative of future operating results.

Use of Derivatives and Market Risk | NSP uses derivative financial instruments to mitigate the impact of changes in foreign currency exchange rates on NRG's international project cash flows, natural gas, electricity and fuel prices on margins and interest rates on the cost of borrowing. See Notes 1 and 11 to the Financial Statements for further discussion of NSP's financial instruments and derivatives.

The fair value of NRG's interest rate hedging contracts is sensitive to changes in interest rates. As of Dec. 31, 1999, a 10 percent decrease in interest rates from prevailing market rates would decrease the market value of NRG's interest rate hedging contracts by approximately $28 million. Conversely, a 10 percent increase in interest rates from the prevailing market rates would increase the market value by approximately $26 million.

NRG has an investment in the Kladno project in the Czech Republic. Statement of Financial Accounting Standard (SFAS) No. 52 requires foreign currency gains and losses to flow through the income statement if settlement of an obligation is in a currency other than the local currency of the entity. A portion of the Kladno project debt is in non-local currency (U.S. dollars and German deutsche marks). As of Dec. 31, 1999, if the value of the Czech koruna decreased by 10 percent in relation to the U.S. dollar and the German deutsche mark, NRG would have recorded a $5 million loss (after tax) on the currency transaction adjustment. If the value of the Czech koruna increased by 10 percent, NRG would have recorded a $5 million gain (after tax) on the currency transaction adjustment.

In February 1999, EMI transferred its natural gas supply and marketing function to NSP's Energy Marketing division. Sales commitments and natural gas futures and forward contracts that EMI entered into prior to the transfer remain the contractual responsibility of EMI. As of Dec. 31, 1999, EMI had natural gas forward and futures contracts in the notional amount of less than $1 million. These contracts will expire during 2000 and EMI will have no further derivative activity. EMI's market risk due to changes in market prices of natural gas forward and futures contracts is immaterial.

NSP's Energy Marketing division has exposure to the risk of changes in market prices of electricity and natural gas. As of Dec. 31, 1999, a 10 percent increase or decrease in electricity futures and forward prices would have an immaterial impact on NSP's financial results. Any changes in the values of these futures contracts would be offset by a change in the underlying commodities being hedged.

NRG's power marketing subsidiary is exposed to the risk of changes in market prices of fuel oil, natural gas and electricity. To manage exposure to this volatility, NRG uses a variety of energy contracts, including options, swaps and forward contracts. As of Dec. 31, 1999, a 10 percent increase in fuel oil, natural gas and electricity forward prices would result in a gain on these contracts of approximately $12 million. Conversely, a 10 percent decrease in fuel oil, natural gas and electricity forward prices would result in a loss on these contracts of approximately $12 million. These hypothetical gains and losses on energy forward contracts would be offset by the gains and losses on the underlying commodities being hedged.

Accounting Changes | The Financial Accounting Standards Board (FASB) has proposed new accounting standards that would require the full accrual of nuclear plant decommissioning and certain other site exit obligations. Material adjustments to NSP's balance sheet would occur upon implementation of the FASB's proposal, which would be no earlier than 2002. However, the effects of regulation are expected to minimize or eliminate any impact on operating expenses and earnings from this future accounting change. For further discussion of the expected impact of this change, see Note 13 to the Financial Statements.

In June 1998, the FASB issued SFAS No. 133 – Accounting for Derivative Instruments and Hedging Activities. This statement requires that all derivatives be recognized at fair value in the balance sheet and all changes in fair value be recognized currently in earnings or deferred as a component of other comprehensive income, depending on the intended use of the derivative, its resulting designation and its effectiveness. NSP plans to adopt this standard in 2001, as required. NSP has not yet determined the potential impact of implementing this statement.

Inflation | Inflation at its current level is not expected to materially affect NSP's prices or returns to shareholders.

LIQUIDITY AND CAPITAL RESOURCES

1999 Financing Requirements | NSP's need for capital funds primarily is related to the construction of plant and equipment to meet the needs of electric and gas utility customers and to fund equity commitments or other investments in nonregulated businesses. In 1999:

- Total utility capital expenditures were $462 million. Of that amount, $367 million related to replacements and improvements of NSP's electric system and nuclear fuel, and $67 million involved construction of natural gas facilities.
- NSP companies (mainly NRG) invested approximately $1.9 billion for equity interests in and loans to nonregulated projects for the acquisition of generating assets and for additions to nonregulated property.

1999 Financing Activity | During 1999, NSP's sources of capital included internally generated funds and external financings. The allocation of financing requirements between these capital resources is based on the relative cost of each resource, regulatory restrictions and NSP's long-range capital structure objectives. The following summarizes the financing sources used in 1999.

- Internal funds – Funds generated internally from operating cash flows in 1999 remained generally sufficient to meet working capital needs, debt service, dividend payout requirements and a significant portion of utility construction expenditures. NSP's goal for its pretax interest coverage ratio for utility operations is 3.5–5.0. The utility pretax interest coverage ratio, excluding AFC, was 3.2 in 1999, 3.8 in 1998 and 3.6 in 1997. Internally generated funds from utility operations could have provided financing for approximately 80 percent of NSP's utility capital expenditures for 1999 and approximately 95 percent of the $2.0 billion in utility capital expenditures incurred from 1995–1999. The pretax interest coverage ratio, excluding AFC, for all NSP operations was 2.1 in 1999, 2.9 in 1998 and 2.8 in 1997.
- External financing – NSP's short-term debt availability and usage is described in Note 2 to the Financial Statements. In general, short-term borrowings are used to provide temporary financing, mainly for NSP-Minnesota and NRG, utility capital expenditures, nonregulated projects and other short-term cash needs. NSP's long-term debt and capital stock activity are shown on the Statements of Capitalization and Stockholders' Equity. These sources are used to provide permanent financing for both regulated and nonregulated business activities.

The 1999 nonregulated asset acquisitions, property additions and equity investments by NSP's subsidiaries were primarily financed by the issuance of subsidiary debt and equity contributions from NSP. Project debt associated with some nonregulated investments is not reflected in NSP's balance sheet because the equity method of accounting is used for such investments as discussed in Note 10 to the Financial Statements.

Future Financing Requirements | NSP currently estimates that its utility capital expenditures will be $490 million in 2000 and $2.3 billion for 2000–2004. Of the 2000 amount, approximately $410 million is scheduled for electric utility facilities and approximately $50 million for natural gas facilities. In addition to utility capital expenditures, expected financing requirements for 2000–2004 include approximately $1 billion to retire long-term debt and fund principal maturities.

NSP subsidiaries expect to invest significant amounts 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.

- NRG expects to invest approximately $2.7 billion in 2000 and approximately $4.7 billion for 2000–2004 for nonregulated projects and property, which include acquisitions and project investments. NRG's capital requirements may vary significantly. NRG's capital requirements for 2000 reflect expected acquisitions of existing generation facilities, including Cajun, Killingholme A and the Conectiv fossil assets. A significant portion of NRG's capital requirements is expected to be financed by project-secured debt. In addition, NRG may issue a limited amount of equity financing to third parties for funding a portion of the capital requirements.

- Seren expects to spend approximately $180 million during 2000, which reflects the build-out of its broadband communications network in Northern California. Seren is evaluating its financing options, including equity financing to third parties and project-secured debt. Seren's capital requirements for 2001–2004 may vary significantly depending on the success of development efforts under way.

NSP and its subsidiaries continue to evaluate opportunities to enhance shareholder returns and achieve long-term financial objectives through investments in projects or acquisitions of existing businesses. 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.

NSP also will have future financing requirements for the portion of nuclear plant decommissioning costs not funded externally. Based on the most recent decommissioning study approved by regulators, these amounts are anticipated to be approximately $363 million and are expected to be paid during the years 2010–2022.

Future Sources of Financing | NSP expects to meet future financing requirements by periodically issuing long-term debt, short-term debt, common stock and preferred securities to maintain desired capitalization ratios. Over the long term, NSP's equity investments in and acquisitions of nonregulated projects are expected to be financed at the nonregulated subsidiary level from internally generated funds or the issuance of subsidiary debt. Financing requirements for the nonregulated projects, in excess of equity contributions from partners, are expected to be fulfilled through project or subsidiary debt. Decommissioning expenses not funded by an external trust will be financed through a combination of internally generated funds, long-term debt and common stock.

The following summarizes the financing sources expected to be available to NSP in the near future:

- Internal funds – Internally generated funds from utility operations are expected to equal approximately 85 percent of anticipated utility capital expenditures for 2000 and approximately 95 percent of the anticipated utility capital expenditures for 2000–2004. Because NRG has been reinvesting foreign cash flows in operations outside the United States, the equity income from foreign investments is not fully available to provide operating cash flows for domestic cash requirements such as payment of NSP dividends, domestic capital expenditures and domestic debt service.

- Short-term debt – NSP has received regulatory approval for up to approximately $1.5 billion in short-term borrowing levels. NSP credit lines (as discussed in Note 2 to the Financial Statements) make short-term financing available in the form of bank loans, letters of credit and support for commercial paper.

- Utility long-term debt – NSP-Minnesota's and NSP-Wisconsin's first mortgage indentures limit the amount of first mortgage bonds that may be issued. The MPUC and the PSCW have jurisdiction over securities issuance. At Dec. 31, 1999, with an assumed interest rate of 7.75 percent, NSP-Minnesota could have issued about $1.9 billion of additional first mortgage bonds under its indenture and NSP-Wisconsin could have issued about $320 million of additional first mortgage bonds under its indenture. NSP has $150 million of unissued bonds remaining from its $400 million universal shelf registration filed with the SEC in November 1998 and $50 million of unissued first mortgage bonds remaining from its shelf registration filed in October 1995. In addition, NSP-Minnesota is planning on filing a $400 million universal debt shelf registration during the first half of 2000. During 1999, NSP-Wisconsin filed a shelf registration with the SEC to issue up to $80 million of long-term debt. NSP-Wisconsin currently expects to issue between $50 million and $80 million of unsecured long-term debt during 2000, primarily to reduce short-term debt levels.

- NRG debt – In December 1999, NRG filed a shelf registration with the SEC to issue up to $500 million of unsecured debt. NRG expects to issue debt under this shelf during 2000 for general corporate purposes, which may include financing development and construction of new facilities, additions to working capital and financing capital expenditures and pending or potential acquisitions. In addition to NRG corporate debt, NRG Northeast Generating LLC (N.E. Generating), a wholly owned subsidiary of NRG, issued $750 million of bonds in February 2000 to pay down short-term borrowings and reduce NRG's corporate debt issued to fund N.E. Generating (see Note 2).

- Common stock – NSP's Articles of Incorporation authorize an additional 194.3 million shares of common stock in excess of shares issued at Dec. 31, 1999. In 1999, NSP filed registration statements with the SEC to allow for the sale of up to 1.9 million shares of newly issued common stock under NSP's Dividend Reinvestment and Stock Purchase Program (DRSPP) and Executive Long-Term Incentive Award Stock Plan. NSP plans to issue new shares for its DRSPP, Employee Stock Ownership Plan (ESOP) and Executive Long-Term Incentive Award Stock Plan in 2000. NSP filed its proposed 2000 Capital Structure and Financing Plan with the MPUC in November 1999. In its filing, NSP proposed that if the completion of its merger with NCE is timed as currently anticipated, NSP will be recapitalized as a subsidiary of Xcel Energy. If completion of the merger appears to be delayed, NSP may issue equity or an equity-related security in the first half of 2000.

- Preferred stock – NSP's Articles of Incorporation authorize the maximum amount of preferred stock that may be issued. Under these provisions, NSP could have issued all $595 million of its remaining authorized, but unissued, preferred stock at Dec. 31, 1999, and remained in compliance with all interest and dividend coverage requirements.

(Thousands of dollars, except per share data)	Year Ended December 31 1999	1998	1997
UTILITY OPERATING REVENUES			
Electric: Retail	$2 169 296	$2 152 221	$2 054 473
Sales for resale and other	227 800	210 130	164 077
Gas	471 915	456 823	515 196
Total	2 869 011	2 819 174	2 733 746
UTILITY OPERATING EXPENSES			
Fuel for electric generation	319 193	311 368	309 999
Purchased and interchange power	454 487	377 907	286 239
Cost of gas purchased and transported	278 240	267 050	331 296
Other operation	401 968	392 054	368 545
Maintenance	178 594	181 066	164 542
Administrative and general	127 427	150 078	141 802
Conservation and energy management	60 180	71 134	70 939
Depreciation and amortization	355 704	338 225	325 880
Property and general taxes	222 446	220 620	227 893
Income taxes	127 293	145 383	144 855
Total	2 525 532	2 454 885	2 371 990
Utility operating income	343 479	364 289	361 756
OTHER INCOME (EXPENSE)			
Income from nonregulated businesses – before interest and taxes	79 439	51 171	12 078
Allowance for funds used during construction – equity	162	8 509	6 401
Write-down of investment in CellNet stock	(14 063)		
Primergy merger costs			(29 005)
Other utility income (deductions) – net	(9 483)	(3 697)	(2 886)
Income taxes on nonregulated operations and nonoperating items – benefit	61 011	40 588	48 145
Total	117 066	96 571	34 733
Income before financing costs	460 545	460 860	396 489
FINANCING COSTS			
Interest on utility long-term debt	102 843	104 171	101 250
Other utility interest and amortization	25 677	11 612	19 063
Nonregulated interest and amortization	97 854	54 261	34 627
Allowance for funds used during construction – debt	(5 915)	(7 307)	(10 208)
Total interest charges	220 459	162 737	144 732
Distributions on redeemable preferred securities of subsidiary trust	15 750	15 750	14 437
Total financing costs	236 209	178 487	159 169
NET INCOME	224 336	282 373	237 320
Preferred stock dividends and redemption premiums	5 292	5 548	11 071
EARNINGS AVAILABLE FOR COMMON STOCK	$ 219 044	$ 276 825	$ 226 249
Average number of common shares outstanding (000s)	153 366	150 502	140 594
Average number of common and potentially dilutive shares outstanding (000s)	153 443	150 743	140 870
EARNINGS PER AVERAGE COMMON SHARE – BASIC	$ 1.43	$ 1.84	$ 1.61
EARNINGS PER AVERAGE COMMON SHARE – DILUTED	$ 1.43	$ 1.84	$ 1.61
Common dividends declared per share	$ 1.445	$ 1.425	$ 1.403

See Notes to Financial Statements

(Thousands of dollars)	Year Ended December 31 1999	1998	1997
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 224 336	$282 373	$237 320
Adjustments to reconcile net income to cash from operating activities:			
Depreciation and amortization	423 807	379 397	358 928
Nuclear fuel amortization	50 056	43 816	40 015
Deferred income taxes	(18 907)	(1 017)	(5 902)
Deferred investment tax credits recognized	(9 417)	(9 432)	(10 061)
Allowance for funds used during construction – equity	(162)	(8 509)	(6 401)
Undistributed equity in earnings of unconsolidated affiliates	(27 956)	(22 753)	(5 364)
Conservation incentive adjustments – noncash	71 348		
Write-downs of EMI goodwill and CellNet investment	31 346		
Write-off of prior year Primergy merger costs			25 289
Cash provided by (used for) changes in certain working capital items (see below)	(80 649)	(13 673)	36 117
Cash provided by changes in other assets and liabilities	17 348	51 863	19 844
NET CASH PROVIDED BY OPERATING ACTIVITIES	681 150	702 065	689 785
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures:			
Nonregulated property additions and asset acquisitions	(1 698 414)	(44 918)	(195 528)
Utility plant additions (including nuclear fuel)	(462 054)	(411 113)	(396 605)
Increase (decrease) in construction payables	(2 604)	5 270	2 563
Allowance for funds used during construction – equity	162	8 509	6 401
Investment in external decommissioning fund	(39 183)	(41 360)	(41 261)
Equity investments, loans and deposits for nonregulated projects	(176 207)	(234 214)	(395 495)
Collection of loans made to nonregulated projects	81 440	109 530	87 128
Other investments – net	(16 545)	1 307	(15 692)
NET CASH USED FOR INVESTING ACTIVITIES	(2 313 405)	(606 989)	(948 489)
CASH FLOWS FROM FINANCING ACTIVITIES			
Change in short-term debt – net issuances (repayments)	1 205 894	(20 522)	(108 023)
Proceeds from issuance of long-term debt – net	859 718	290 626	299 779
Repayment of long-term debt, including reacquisition premiums	(249 371)	(135 183)	(141 681)
Proceeds from issuance of preferred securities – net			193 315
Proceeds from issuance of common stock – net	55 127	72 348	267 965
Redemption of preferred stock, including reacquisition premiums		(95 000)	(41 278)
Dividends paid	(225 509)	(219 746)	(207 726)
NET CASH PROVIDED BY (USED FOR) FINANCING ACTIVITIES	1 645 859	(107 477)	262 351
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	13 604	(12 401)	3 647
Cash and cash equivalents at beginning of period	42 364	54 765	51 118
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 55 968	$ 42 364	$ 54 765
CASH PROVIDED BY (USED FOR) CHANGES IN CERTAIN WORKING CAPITAL ITEMS			
Customer accounts receivable and unbilled utility revenues	$ (106 692)	$ (1 583)	$ 47 745
Materials and supplies inventories	(22 228)	(5 385)	(8 547)
Payables and accrued liabilities (excluding construction payables)	73 136	7 845	(7 342)
Other	(24 865)	(14 550)	4 261
NET	$ (80 649)	$ (13 673)	$ 36 117
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
Cash paid during the year for:			
Interest (net of amount capitalized)	$ 201 276	$148 275	$144 062
Income taxes (net of refunds received)	$ 65 121	$ 74 005	$113 009

See Notes to Financial Statements

(Thousands of dollars)	December 31 1999	December 31 1998
ASSETS		
UTILITY PLANT		
Electric – including construction work in progress: 1999, $119,944; 1998, $120,095	$7 430 686	$7 199 843
Gas	952 131	884 182
Other	375 058	365 101
Total	8 757 875	8 449 126
Accumulated provision for depreciation	(4 409 151)	(4 155 641)
Nuclear fuel – including amounts in process: 1999, $13,708; 1998, $16,744	1 026 063	975 030
Accumulated provision for amortization	(923 336)	(873 281)
Net utility plant	4 451 451	4 395 234
CURRENT ASSETS		
Cash and cash equivalents	55 968	42 364
Customer accounts receivable – net of accumulated provisions for uncollectible accounts: 1999, $8,442; 1998, $5,176	370 270	253 559
Unbilled utility revenues	144 261	139 098
Other receivables	58 680	105 116
Materials and supplies inventories – at average cost:		
Fuel	59 600	58 806
Other	231 503	110 267
Prepayments and other	113 524	44 855
Total current assets	1 033 806	754 065
OTHER ASSETS		
Nonregulated property – net of accumulated depreciation: 1999, $203,767; 1998, $122,445	2 086 476	282 524
Equity investments in nonregulated projects	1 047 248	862 596
External decommissioning fund and other investments	561 682	479 402
Regulatory assets	248 127	331 940
Notes receivable from nonregulated projects	66 876	106 427
Long-term prepayments, deferred charges and receivables	158 096	88 194
Intangible assets – net of accumulated amortization	113 969	95 915
Total other assets	4 282 474	2 246 998
TOTAL	$9 767 731	$7 396 297
LIABILITIES AND EQUITY		
CAPITALIZATION (SEE CONSOLIDATED STATEMENTS OF CAPITALIZATION)		
Common stockholders' equity	$2 557 530	$2 481 246
Preferred stockholders' equity	105 340	105 340
Mandatorily redeemable preferred securities of subsidiary trust	200 000	200 000
Long-term debt	3 453 364	1 851 146
Total capitalization	6 316 234	4 637 732
CURRENT LIABILITIES		
Long-term debt due within one year	153 231	227 600
Other long-term debt potentially due within one year	141 600	141 600
Short-term debt – utility	420 443	114 273
Short-term debt – nonregulated	378 716	125 557
Accounts payable	321 382	271 799
Taxes accrued	172 059	170 274
Interest accrued	49 327	38 836
Dividends payable on common and preferred stocks	57 523	55 650
Accrued payroll, vacation and other	131 855	86 673
Total current liabilities	1 826 136	1 232 262
OTHER LIABILITIES		
Deferred income taxes	811 638	814 983
Deferred investment tax credits	118 582	128 444
Regulatory liabilities	461 569	372 239
Postretirement and other benefit obligations	143 905	129 514
Other long-term obligations and deferred income	89 667	81 123
Total other liabilities	1 625 361	1 526 303
COMMITMENTS AND CONTINGENT LIABILITIES (SEE NOTES 13 AND 14)		
TOTAL	$9 767 731	$7 396 297

See Notes to Financial Statements

(Thousands of dollars)	*Par Value*	*Premium*	*Retained Earnings*	*Shares Held by ESOP*	*Accumulated Other Comprehensive Income*	*Total Stockholders' Equity*
BALANCE AT DEC. 31, 1996	$345 318	$466 060	$1 340 799	$(19 091)	$ 2 794	$2 135 880
Net income			237 320			237 320
Currency translation adjustments					(65 681)	(65 681)
Comprehensive income for 1997						171 639
Dividends declared:						
Cumulative preferred stock			(9 923)			(9 923)
Common stock			(202 173)			(202 173)
Premium on redeemed preferred stock			(1 148)			(1 148)
Issuances of common stock – net	27 774	240 112				267 886
Tax benefit from stock options exercised		1 009				1 009
Repayment of ESOP loan *(a)*				8 558		8 558
BALANCE AT DEC. 31, 1997	$373 092	$707 181	$1 364 875	$(10 533)	$(62 887)	$2 371 728
Net income			282 373			282 373
Unrealized loss from marketable securities, net of tax of $4,417					(6 416)	(6 416)
Currency translation adjustments					(19 711)	(19 711)
Comprehensive income for 1998						256 246
Dividends declared:						
Cumulative preferred stock			(5 548)			(5 548)
Common stock			(215 069)			(215 069)
Issuances of common stock – net	8 650	66 294				74 944
Pooling of interests business combinations			6 065			6 065
Tax benefit from stock options exercised		850				850
Loan to ESOP to purchase shares *(a)*				(15 000)		(15 000)
Repayment of ESOP loan *(a)*				7 030		7 030
BALANCE AT DEC. 31, 1998	$381 742	$774 325	$1 432 696	$(18 503)	$(89 014)	$2 481 246
Net income			224 336			224 336
Recognition of unrealized loss from marketable securities, net of tax of $4,417					6 416	6 416
Currency translation adjustments					7 128	7 128
Comprehensive income for 1999						237 880
Dividends declared:						
Cumulative preferred stock			(5 292)			(5 292)
Common stock			(222 092)			(222 092)
Issuances of common stock – net	7 582	46 652				54 234
Pooling of interests business combination			4 599			4 599
Tax benefit from stock options exercised		58				58
Repayment of ESOP loan *(a)*				6 897		6 897
BALANCE AT DEC. 31, 1999	$389 324	$821 035	$1 434 247	$(11 606)	$(75 470)	$2 557 530

(a) Did not affect NSP cash flows
See Notes to Financial Statements

(Thousands of dollars)	December 31 1999	1998
COMMON STOCKHOLDERS' EQUITY		
Common stock – authorized 350,000,000 shares of $2.50 par value; issued shares: 1999, 155,729,663; 1998, 152,696,971	$ 389 324	$ 381 742
Premium on common stock	821 035	774 325
Retained earnings	1 434 247	1 432 696
Leveraged common stock held by Employee Stock Ownership Plan (ESOP) – shares at cost: 1999, 392,325; 1998, 641,884	(11 606)	(18 503)
Accumulated other comprehensive income	(75 470)	(89 014)
TOTAL COMMON STOCKHOLDERS' EQUITY	$2 557 530	$2 481 246
CUMULATIVE PREFERRED STOCK – authorized 7,000,000 shares of $100 par value; outstanding shares: 1999 and 1998, 1,050,000		
NSP-Minnesota		
$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, 100,000 shares	10 000	10 000
4.56 series, 150,000 shares	15 000	15 000
Total	105 000	105 000
Premium on preferred stock	340	340
TOTAL PREFERRED STOCKHOLDERS' EQUITY	$ 105 340	$ 105 340
MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST – holding as its sole asset junior subordinated deferrable debentures of NSP-Minnesota 7⅞% series, 8,000,000 shares due Jan. 31, 2037 (See Note 8)	$ 200 000	$ 200 000
LONG-TERM DEBT		
First Mortgage Bonds – NSP-Minnesota		
Series due:		
Feb. 1, 1999, 5½%		$ 200 000
Dec. 1, 2000, 5¾%	$ 100 000	100 000
Oct. 1, 2001, 7⅞%	150 000	150 000
April 1, 2003, 6⅜%	80 000	80 000
Dec. 1, 2005, 6⅛%	70 000	70 000
Dec. 1, 1999–2006, 6.00%–6.75%		16 900*
Dec. 1, 1999–2006, 3.50%–4.10%	15 170*	
March 1, 2011, Variable Rate	13 700**	13 700**
July 1, 2025, 7⅛%	250 000	250 000
April 1, 2007, 6.80%	60 000**	60 000**
March 1, 2019, Variable Rate	27 900**	27 900**
Sept. 1, 2019, Variable Rate	100 000**	100 000**
March 1, 2003, 5⅞%	100 000	100 000
March 1, 2028, 6½%	150 000	150 000
Total	1 116 770	1 318 500
Less redeemable bonds classified as current (See Note 3)	(141 600)	(141 600)
Less current maturities	(101 940)	(201 600)
Net	$ 873 230	$ 975 300

** Resource recovery financing*
*** Pollution control financing*
See Notes to Financial Statements

(Thousands of dollars)	December 31 1999	1998
LONG-TERM DEBT – CONTINUED		
First Mortgage Bonds – NSP-Wisconsin		
Series due:		
Oct. 1, 2003, 5¾%	$ 40 000	$ 40 000
March 1, 2023, 7¼%	110 000	110 000
Dec. 1, 2026, 7⅜%	65 000	65 000
Total	$ 215 000	$ 215 000
Guaranty Agreements – NSP-Minnesota		
Series due:		
Feb. 1, 1999–2003, 5.41%	$ 4 900**	$ 5 100**
May 1, 1999–2003, 5.70%	22 250**	22 750**
Feb. 1, 2003, 7.40%	3 500**	3 500**
Total	30 650	31 350
Less current maturities	(700)	(700)
Net	$ 29 950	$ 30 650
OTHER LONG-TERM DEBT		
NSP-Minnesota Senior Notes due Aug. 1, 2009, 6⅞%	$ 250 000	
City of Becker Pollution Control Revenue Bonds – Series due Dec. 1, 2005, 7.25%	9 000**	$ 9 000**
Anoka County Resource Recovery Bond – Series due Dec. 1, 1999–2008, 6.70%–7.15%		20 600*
Anoka County Resource Recovery Bond – Series due Dec. 1, 2000–2008, 3.95%– 4.60%	19 615*	
City of La Crosse Resource Recovery Bond – Series due Nov. 1, 2021, 6%	18 600*	18 600*
Viking Gas Transmission Company Senior Notes – Series due:		
Oct. 31, 2008, 6.65%	18 845	20 978
Nov. 30, 2011, 7.1%	4 290	4 650
Sept. 30, 2012, 7.31%	11 900	12 833
Sept. 30, 2014, 8.04%	19 667	
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	
Nov. 1, 2013, 8%	240 000	
NRG debt secured solely by project assets:		
NRG Northeast Generating debt reclassified from short-term (see Note 2)	646 564	
Crockett Corp. LLP debt due Dec. 31, 2014, 8.13%	255 000	
NRG Energy Center, Inc. (Minneapolis Energy Center) Senior Secured Notes – Series due June 15, 2013, 7.31%	68 881	71 783
Pacific Generation Company debt due 2000–2007, 4.7%–9.9%	26 216	28 586
Various NEO Corporation debt due Jan. 31, 2008, 9.35%	17 390	17 792
Pittsburgh Thermal LP Notes due 2002–2004, 10.61%–10.729%	6 800	
San Francisco Thermal LP Notes due Nov. 5, 2004, 10.6%	5 905	
COBEE debt due April 21, 2000, 0.0%	5 761	
United Power & Land Notes due March 31, 2000, 7.62%	5 208	6 041
Black Mountain Gas Industrial Development Bonds due June 1, 2004, May 1, 2005, 6%	3 000	3 000
Various Eloigne Company Affordable Housing Project Notes due 1999–2027, 1.0%–9.9%	47 116	46 024
Employee Stock Ownership Plan Bank Loans due 1999–2005, Variable Rate	11 606	18 504
Miscellaneous	27 665	9 122
Total	2 394 029	662 513
Less current maturities	(50 591)	(25 300)
Net	$2 343 438	$ 637 213
Unamortized discount on long-term debt – net	(8 254)	(7 017)
TOTAL LONG-TERM DEBT	$3 453 364	$1 851 146
TOTAL CAPITALIZATION	$6 316 234	$4 637 732

** Resource recovery financing*
*** Pollution control financing*
See Notes to Financial Statements

1. Summary of Significant Accounting Policies

Business and System of Accounts | NSP-Minnesota is primarily a public utility serving customers in Minnesota, North Dakota, South Dakota and Arizona. NSP-Wisconsin serves utility customers in Wisconsin and Michigan. Viking operates an interstate natural gas pipeline. All of the utility companies' accounting records conform to the Federal Energy Regulatory Commission (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 | The following wholly owned subsidiaries of NSP-Minnesota are included in the consolidated financial statements. In this report, we refer to these companies collectively as NSP.

- NSP-Wisconsin
- NRG Energy, Inc.
- Viking Gas Transmission Co.
- Energy Masters International, Inc.
- Eloigne Co.
- Seren Innovations, Inc.
- Ultra Power Technologies, Inc.

NSP uses the equity method of accounting for its investments in partnerships, joint ventures and certain projects, mainly at NRG and Eloigne. We record our portion of earnings from international investments after subtracting foreign income taxes. In the consolidation process, we eliminate all significant intercompany transactions and balances except for intercompany and intersegment profits for sales among the electric and gas utility businesses of NSP-Minnesota, NSP-Wisconsin and Viking, which are allowed in utility rates.

Revenues | NSP 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 estimate and record unbilled revenues from the monthly meter-reading dates to the month's end. NSP-Minnesota's rates include monthly adjustments for:

- changes in the average cost of fuel, including electricity and natural gas that NSP purchases, from base levels approved in the most recent rate case; and
- recovery of conservation and energy management program costs and incentives in Minnesota, which is reviewed annually.

NSP-Wisconsin's rates include a cost-of-energy adjustment clause for purchased gas, but not for purchased electricity or electric fuel. We can request recovery of those electric costs prospectively through the rate review process, which normally occurs every two years in Wisconsin, and an interim fuel cost hearing process.

Utility Plant and Retirements | Utility plant is stated at original cost. The cost of utility plant includes direct labor and materials, contracted work, overhead costs and applicable interest expense. The cost of utility plant retired, plus net removal cost, is charged to accumulated depreciation and amortization. Maintenance and replacement of items determined to be less than units of property are charged to operating expenses.

Allowance for Funds Used during Construction (AFC) | AFC, a noncash item, represents the cost of capital used to finance utility construction activity. AFC is computed by applying a composite pretax rate to qualified construction work in progress. The AFC rate was 5.25 percent in 1999, 8.0 percent in 1998 and 5.75 percent in 1997. The amount of AFC capitalized as a construction cost is credited to other income (for equity capital) and interest charges (for debt capital). AFC amounts capitalized are included in NSP's rate base for establishing utility service rates. In addition to construction-related amounts, AFC is also recorded to reflect returns on capital used to finance conservation programs.

Depreciation | NSP determines the depreciation of its plant by spreading the original cost equally over the plant's useful life. Every five years, NSP submits an average service life filing to the Minnesota Public Utilities Commission (MPUC) for electric and gas property. The most recent filing occurred in 1997. Depreciation expense as a percentage of the average utility plant in service was 3.83 percent in 1999, 3.77 percent in 1998 and 3.78 percent in 1997.

Decommissioning | NSP 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 will recover those costs through rates. (See Note 13 for more information on decommissioning.)

Nuclear Fuel Expense | Nuclear fuel expense, which is recorded as the plant uses fuel, includes the cost of:

- nuclear fuel used
- future spent nuclear fuel disposal, based on fees established by the U.S. Department of Energy (DOE)
- NSP's portion of the cost of decommissioning or shutting down the DOE's fuel enrichment facility

Environmental Costs | We record environmental costs when it is probable that NSP 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.

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 | Based on the liability method, NSP defers income taxes for all temporary differences between pretax financial and taxable income, and between the book and tax bases 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 9. We discuss our income tax policy for international operations in Note 7.

Foreign Currency Translation | NSP'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 Accumulated Other Comprehensive Income.

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 income from nonregulated businesses before interest and taxes. We do the same for foreign currency derivative arrangements that do not qualify for hedge accounting.

Derivative Financial Instruments | To preserve the U.S. dollar value of projected foreign currency cash flows, NRG hedges – or protects – those cash flows if appropriate foreign hedging instruments are available. The gains and losses on those agreements offset the effect of exchange rate fluctuations on NRG's known and anticipated cash flows. NRG defers gains on agreements that hedge firm commitments of cash flows, and accounts for them as part of the relevant foreign currency transaction when the transaction occurs. NRG defers losses on these agreements the same way, unless it appears that the deferral would result in recognizing a loss later.

While NRG is not currently hedging investments involving foreign currency, NRG will hedge such investments when it believes that preserving the U.S. dollar value of the investment is appropriate. NRG is not hedging currency translation adjustments related to future operating results. NRG does not speculate in foreign currencies.

From time to time, NRG also uses interest rate hedging instruments to protect it from an increase in the cost of borrowing. Gains and losses on interest rate hedging instruments are reported as part of the asset for Equity Investments in Nonregulated Projects when the hedging instrument relates to a project that has financial statements that are not consolidated into NRG's financial statements. Otherwise, they are reported as a part of debt.

In the past, EMI used natural gas futures and forward contracts to manage the risk of gas price fluctuations. In February 1999, EMI transferred its gas supply and marketing function to NSP's Energy Marketing division. EMI's remaining gas future and forward contracts will expire during 2000 and EMI will have no further derivative activity.

NSP's Energy Marketing division and NRG's Power Marketing subsidiary use future and forward contracts to manage the risk of natural gas and electricity price fluctuations. The cost or benefit of futures or forward contracts is recorded when related sales commitments are fulfilled as a component of operating expenses. NSP and NRG do not speculate in electricity or natural gas futures.

A final derivative instrument used by NSP and NRG is the interest rate swap. The cost or benefit of the interest rate swap agreements is recorded as a component of interest expense. None of these derivative financial instruments are reflected on NSP's balance sheet. For information on derivatives, see Note 11.

Use of Estimates | In recording transactions and balances resulting from business operations, NSP 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 Equivalents | NSP 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.

Regulatory Deferrals | As regulated entities, NSP-Minnesota, NSP-Wisconsin and Viking account for certain income and expense items using Statement of Financial Accounting Standards (SFAS) No. 71 – Accounting for the Effects 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 | NSP has several stock-based compensation plans, which are described in Note 4. NSP accounts 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 that NSP awards to certain employees, but holds until the restrictions lapse or the stock is forfeited. We do not use the optional accounting under SFAS No. 123 – Accounting for Stock-Based Compensation. If we had used the SFAS No. 123 method of accounting, the reduction in earnings for 1999, 1998 and 1997 would have been less than 1 cent per share per year.

Development Costs | As NRG develops projects, it expenses the development costs it incurs 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 year of the termination.

Intangible Assets | Goodwill results when NSP purchases an entity at a price higher than the underlying fair value of the net assets. We amortize the goodwill and other intangible assets over periods consistent with the economic useful life of the assets. Our intangible assets are currently amortized over a range of 15 to 40 years. We periodically evaluate the recovery of goodwill based on an analysis of estimated undiscounted future cash flows. At Dec. 31, 1999, NSP's intangible assets included $41 million of goodwill, net of accumulated amortization.

Intangible and other assets also included deferred financing costs, net of amortization, of approximately $37 million at Dec. 31, 1999. We are amortizing these financing costs over the remaining maturity period of the related debt.

Reclassifications | We reclassified certain items in the 1997 and 1998 income statements to conform to the 1999 presentation. These reclassifications had no effect on net income or earnings per share.

2. Short-Term Borrowings

Short-term debt outstanding at Dec. 31 consisted of:

(Millions of dollars)	*1999*	*1998*
Utility short-term debt	$ 420	$ 114
Weighted average interest rate – Dec. 31	5.9%	5.3%
Nonregulated short-term debt	$1 026	$ 126
Less amounts reclassified to long-term	(647)	
Net nonregulated short-term debt	379	126
Weighted average interest rate – Dec. 31	7.4%	5.9%

At the end of 1998 and 1999, NSP-Minnesota had a $300 million revolving credit facility under a commitment fee arrangement. This facility provides short-term financing in the form of bank loans, letters of credit and support for commercial paper sales. NSP did not borrow or issue any letters of credit against this facility in 1998 or 1999.

In addition, banks provided credit lines of $556 million to wholly owned subsidiaries of NSP at Dec. 31, 1999. At that time, a total of $343 million was borrowed against these lines, mainly by NRG.

On Feb. 22, 2000, NRG Northeast Generating issued $750 million of senior secured bonds to refinance short-term project borrowings. The bond offering included three tranches: $320 million with an interest rate of 8.065 percent due in 2004, $109 million with an interest rate of 8.842 percent due in 2010 and $321 million with an interest rate of 9.292 percent due in 2024. NRG used $647 million of the proceeds to repay short-term borrowings outstanding at Dec. 31, 1999. Accordingly, $647 million of short-term debt has been classified as long-term debt, based on this refinancing.

3. Long-Term Debt

Except for minor exclusions, all property of NSP-Minnesota and NSP-Wisconsin is subject to the liens of the first mortgage indentures, which are contracts between the companies and their bond holders. A lien on the related property secures other debt securities, as we indicate in the Consolidated Statements of Capitalization.

The annual sinking-fund requirements of NSP-Minnesota and NSP-Wisconsin's first mortgage indentures are the amounts necessary to redeem 1 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
- certain other series totaling $1 billion

NSP-Minnesota and NSP-Wisconsin may apply property additions in lieu of cash on all series, as permitted by their first mortgage indenture.

NSP-Minnesota's 2011 and 2019 series First Mortgage Bonds have variable interest rates, which currently change at various periods up to 270 days, based on prevailing rates for certain commercial paper securities or similar issues. The interest rates applicable to these issues averaged 5.75 percent and 3.7 percent, respectively, at Dec. 31, 1999. The 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. The principal amount of all of these variable rate bonds outstanding represents potential short-term obligations and, therefore, is reported under current liabilities on the Balance Sheets.

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

- $153 million in 2000
- $190 million in 2001
- $42 million in 2002
- $290 million in 2003
- $373 million in 2004

4. Common Stock and Incentive Stock Plans

NSP's Articles of Incorporation and first mortgage indenture include certain restrictions on paying cash dividends on common stock. Even with these restrictions, NSP could have paid more than $1.4 billion in additional cash dividends on common stock at Dec. 31, 1999.

NSP grants nonqualified stock options and restricted stock under our Executive Long-Term Incentive Award Stock Plan. The awards granted in any year cannot exceed 1 percent of the number of outstanding shares of NSP common stock at the end of the previous year. When options are exercised or when we grant restricted stock, we may either issue new shares or purchase market shares.

The weighted average number of common and potentially dilutive shares outstanding includes the dilutive effect of stock options and other stock awards based on the treasury stock method. Effective in January 1999, stock options granted to NSP officers vest at a rate of one-third each year for three years. Stock options for other employees vest one year from the date of grant. Once they have vested, options can be exercised up to 10 years after the date they were granted.

Employees forfeit stock options if their employment ends (for reasons other than retirement) before the vesting term. If employment ends after the vesting term, employees either forfeit their options or must exercise them within three to 36 months, depending on their circumstances. If an employee retires, all options granted in 1999 will vest immediately and can be exercised over their 10-year life. The exercise price of an option is the market price of NSP stock on the date of grant. The plan previously granted other types of performance awards, some of which remain outstanding. Most of these performance awards were valued in dollars, but paid in shares based on the market price at the time of payment. The following table includes transactions that have occurred under the various incentive stock programs, with the corresponding weighted average exercise price:

STOCK OPTION AND PERFORMANCE AWARDS

(Thousands of shares)	*1999* Shares	*1999* Average Price	*1998* Shares	*1998* Average Price	*1997* Shares	*1997* Average Price
Outstanding Jan. 1	2 389	$23.57	2 206	$22.57	2 235	$21.99
Options granted in January or February	993	$26.31	572	$26.88	573	$23.72
Options and awards exercised	(28)	$18.89	(346)	$22.39	(520)	$21.12
Options and awards forfeited	(8)	$26.45	(34)	$26.48	(60)	$23.60
Options and awards expired	(10)	$25.64	(9)	$23.24	(22)	$25.47
OUTSTANDING AT DEC. 31	3 336	$24.41	2 389	$23.57	2 206	$22.57
EXERCISABLE AT DEC. 31	2 349	$24.06	1 847	$23.34	1 685	$22.21

The following table summarizes information about stock options outstanding at Dec. 31, 1999:

	Range of Exercise Prices		
	$16.63–20.47	*$21.10–22.75*	*$23.72–26.88*
Options Outstanding: *(a)*			
Number outstanding at Dec. 31, 1999	271 624	715 216	2 336 859
Weighted average remaining contractual life (years)	1.2	4.2	7.9
Weighted average exercise price	$18.72	$21.96	$25.82
Options Exercisable: *(a)*			
Number exercisable at Dec. 31, 1999	271 624	715 216	1 349 786
Weighted average exercise price	$18.72	$21.96	$25.47

(a) There were also 12,197 other awards outstanding at Dec. 31, 1999.

In addition to granting stock options, NSP grants certain employees restricted stock based on a dollar value of the award. We use the market price of the stock on the date it was granted to determine the number of restricted shares to grant. NSP holds the stock until restrictions lapse; 50 percent of the stock vests one year from the date of the award and the other 50 percent vests two years from the date of the award. We reinvest dividends on the shares we hold while restrictions are in place. Restrictions also apply to the additional shares acquired through dividend reinvestment.

Over the last three years, NSP has granted the following restricted stock awards:

- 52,688 shares in 1997
- 49,651 shares in 1998
- 51,790 shares in 1999

Compensation expense related to these awards was immaterial.

5. Benefit Plans and Other Postretirement Benefits

NSP offers the following benefit plans to its benefit employees. Approximately 37 percent of benefit employees are represented by five local labor unions under a collective-bargaining agreement, which expires in 2004.

Pension Benefits | NSP has two 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.

NSP'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.

Postretirement Health Care | NSP has a contributory health and welfare benefit plan that provides health care and death benefits to almost all NSP retirees. The plan was terminated for nonbargaining employees retiring after 1998 and for bargaining employees after 1999. For covered retirees, the plan enables NSP and such retirees to share the costs of retiree health care. NSP nonbargaining retirees pay 40 percent of total health care costs. Cost-sharing for bargaining employees is governed by the terms of NSP's collective bargaining agreement.

In conjunction with the 1993 adoption of SFAS No. 106 – Employers' Accounting for Postretirement Benefits Other Than Pensions, NSP elected to amortize the unrecognized accumulated postretirement benefit obligation (APBO) on a straight-line basis over 20 years.

Regulators for almost all of NSP's retail and wholesale customers have allowed full rate recovery of increased benefit costs under SFAS No. 106. Minnesota and Wisconsin retail regulators require external funding to the extent it is tax advantaged. Such funding began for Wisconsin in 1993 and for Minnesota in 1998. For wholesale ratemaking, FERC requires external funding for all benefits paid and accrued under SFAS No. 106. Plan assets held in external funding trusts principally consist of investments in equity mutual funds and cash equivalents.

RECONCILIATION OF FUNDED STATUS (Thousands of dollars)	Pension Benefits 1999	Pension Benefits 1998	Other Postretirement Benefits 1999	Other Postretirement Benefits 1998
BENEFIT OBLIGATION AT JAN. 1	$1 143 464	$1 048 251	$ 219 762	$ 279 230
Service cost	36 421	31 643	196	3 247
Interest cost	86 429	78 839	9 184	15 896
Plan amendments	184 255	102 315	(80 840)	(51 456)
Actuarial (gain) loss	(105 634)	(41 635)	8 269	(9 732)
Benefit payments	(97 086)	(75 949)	(16 637)	(17 423)
BENEFIT OBLIGATION AT DEC. 31	$1 247 849	$1 143 464	$ 139 934	$ 219 762
Fair value of plan assets at Jan. 1	$2 221 819	$1 978 538	$ 34 514	$ 19 783
Actual return on plan assets	293 904	319 230	3 982	2 471
Employer contributions			13 339	29 683
Benefit payments	(97 086)	(75 949)	(16 637)	(17 423)
FAIR VALUE OF PLAN ASSETS AT DEC. 31	$2 418 637	$2 221 819	$ 35 198	$ 34 514
Funded status at Dec. 31 – net asset (obligation)	$1 170 788	$1 078 355	$(104 736)	$(185 248)
Unrecognized transition (asset) obligation	(311)	(387)	22 073	104 482
Unrecognized prior service cost	277 350	114 305	(2 926)	(2 399)
Unrecognized net (gain) loss	(1 381 889)	(1 167 340)	10 580	3 790
AMOUNT RECOGNIZED IN THE BALANCE SHEETS				
Prepaid benefit asset	$ 65 938	$ 24 933		
Accrued benefit liability			$ (75 009)	$ (79 375)

WEIGHTED AVERAGE ASSUMPTIONS USED IN BENEFIT CALCULATIONS	Pension Benefits 1999	Pension Benefits 1998	Other Postretirement Benefits 1999	Other Postretirement Benefits 1998
Discount rate at end of year	7.5%	6.5%	7.5%	6.5%
Expected return on plan assets for year – before tax	8.5%	8.5%	8.0%	8.0%
Rate of future compensation increase per year	4.5%	4.5%		
Rate of future health care cost increase per year:				
Next succeeding year – age 65 and older			6.1%	6.1%
Next succeeding year – under age 65			8.1%	8.1%
Final rate of increase in 2004			5.5%	5.0%
Effect of changes in the assumed health care cost trend rate for each year:				
1% increase in APBO components at Dec. 31, 1999			$12 188	
1% decrease in APBO components at Dec. 31, 1999			(10 565)	
1% increase in service and interest cost components of the net periodic cost			749	
1% decrease in service and interest cost components of the net periodic cost			(646)	

COMPONENTS OF NET PERIODIC BENEFIT COST (Thousands of dollars)	Pension Benefits 1999	Pension Benefits 1998	Pension Benefits 1997	Other Postretirement Benefits 1999	Other Postretirement Benefits 1998	Other Postretirement Benefits 1997
Service cost	$ 36 421	$ 31 643	$ 27 680	$ 196	$ 3 247	$ 5 095
Interest cost	86 429	78 839	72 651	9 184	15 896	18 872
Expected return on plan assets	(147 592)	(129 263)	(115 359)	(2 499)	(1 582)	(1 242)
Amortization of transition (asset) obligation	(76)	(76)	(76)	2 384	8 335	10 780
Amortization of prior service cost	21 210	6 673	1 071	(288)	(175)	
Recognized actuarial (gain) or loss	(37 397)	(27 727)	(20 762)	(5)	(4)	3
Net periodic benefit cost (credit) under SFAS 87 or 106	(41 005)	(39 911)	(34 795)	8 972	25 717	33 508
Credits not recognized due to effects of ratemaking	36 469	35 545	30 862			
NET PERIODIC BENEFIT COST (CREDIT) RECOGNIZED FOR FINANCIAL REPORTING	$ (4 536)	$ (4 366)	$ (3 933)	$ 8 972	$25 717	$33 508

401(k) | NSP has a contributory, defined contribution Retirement Savings Plan, which complies with section 401(k) of the Internal Revenue Code and covers substantially all utility employees. NSP matches specified amounts of employee contributions to the plan. NSP's matching contributions were approximately $6.5 million in 1999, $4.8 million in 1998 and $4.4 million in 1997.

ESOP | NSP has a leveraged Employee Stock Ownership Plan (ESOP) that covers substantially all utility employees. NSP makes contributions to this noncontributory, defined contribution plan to the extent we realize a tax savings from dividends paid on certain ESOP shares. Contributions to the ESOP, which represent compensation expense, were $4.2 million in 1999, $4.3 million in 1998 and $4.4 million in 1997.

ESOP contributions have no material effect on NSP earnings because the contributions are essentially offset by the tax savings provided by the dividends paid on ESOP shares. NSP allocates leveraged ESOP shares to participants when it repays ESOP loans with dividends on stock held by the ESOP.

NSP's ESOP held 11.3 million shares of NSP common stock at the end of 1999 and 1998, and 11.2 million shares of NSP common stock at the end of 1997.

NSP excluded the following uncommitted leveraged ESOP shares from earnings per share calculations: 0.5 million in 1999, 0.6 million in 1998 and 0.6 million in 1997.

6. Nonregulated Earnings Contribution

Income from nonregulated subsidiaries consists of the following:

(Thousands of dollars, except per share amounts)	*1999*	*1998*	*1997*
Operating revenues	$512 839	$182 230	$223 571
Equity in operating earnings of unconsolidated affiliates	67 859	79 884	18 600
Operating and development expenses, including project write-downs	(500 803)	(248 420)	(251 087)
Interest and other income (loss), including gains from project sales	(456)	37 477	20 994
Income from nonregulated businesses before interest and taxes	79 439	51 171	12 078
Interest expense	(97 854)	(54 261)	(34 627)
Income tax benefit	52 761	41 791	38 032
NET INCOME FROM NONREGULATED SUBSIDIARIES	$ 34 346	$ 38 701	$ 15 483
Earnings per share from nonregulated subsidiaries	$ 0.22	$ 0.26	$ 0.11
Loss per share from write-down of investment in CellNet stock	(0.05)		
TOTAL NONREGULATED EARNINGS PER SHARE CONTRIBUTION	$ 0.17	$ 0.26	$ 0.11

7. 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:

	1999	*1998*	*1997*
Federal statutory rate	35.0%	35.0%	35.0%
Increases (decreases) in tax from:			
State income taxes, net of federal income tax benefit	4.7%	4.7%	4.3%
Tax credits recognized	(13.6)%	(8.9)%	(7.9)%
Equity income from unconsolidated affiliates	(4.2)%	(3.8)%	(2.5)%
Regulatory differences – utility plant items	2.3%	0.7%	1.1%
Other – net	(1.4)%	(0.6)%	(1.0)%
EFFECTIVE INCOME TAX RATE	22.8%	27.1%	29.0%

(Thousands of dollars)			
Income taxes are comprised of the following expense (benefit) items:			
Included in utility operating expenses:			
Current federal tax expense	$111 280	$127 734	$125 202
Current state tax expense	29 113	32 750	28 812
Deferred federal tax expense	(3 878)	(6 625)	(88)
Deferred state tax expense	(115)	646	(23)
Deferred investment tax credits	(9 107)	(9 122)	(9 048)
Total	127 293	145 383	144 855
Included in income taxes on nonregulated operations and nonoperating items:			
Current federal tax expense	(15 740)	(15 732)	(19 470)
Current state tax expense	(3 949)	(6 744)	(5 804)
Current foreign tax expense	4 040	2 358	236
Current federal tax credits	(30 137)	(25 122)	(17 006)
Deferred federal tax expense	(4 066)	11 132	(2 237)
Deferred state tax expense	(4 097)	1 566	(662)
Deferred foreign tax expense	(6 868)	(7 736)	(2 892)
Deferred investment tax credits	(194)	(310)	(310)
Total	(61 011)	(40 588)	(48 145)
TOTAL INCOME TAX EXPENSE	$ 66 282	$104 795	$ 96 710

NRG intends to indefinitely reinvest earnings from foreign operations except 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 $195 million and $158 million at Dec. 31, 1999 and 1998. The additional U.S. income tax and foreign withholding tax on the unremitted foreign earnings, if repatriated, would be offset in whole or in part by foreign tax credits. Thus, it is not practicable to estimate the amount of tax that might be payable.

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

(Thousands of dollars)	*1999*	*1998*
Deferred tax liabilities:		
Differences between book and tax bases of property	$ 908 320	$ 886 099
Regulatory assets	70 546	103 640
Tax benefit transfer leases	23 431	27 170
Other	20 370	22 961
Total deferred tax liabilities	$1 022 667	$1 039 870
Deferred tax assets:		
Regulatory liabilities	$ 49 412	$ 75 774
Deferred compensation, vacation and other accrued liabilities not currently deductible	63 073	67 539
Deferred investment tax credits	46 969	51 003
Other	47 000	29 565
Total deferred tax assets	$ 206 454	$ 223 881
NET DEFERRED TAX LIABILITY	$ 816 213	$ 815 989

8. Preferred Securities

At Dec. 31, 1999, various preferred stock series were callable at prices per share ranging from $102.00 to $103.75, plus accrued dividends.

In 1997, a wholly owned special purpose subsidiary trust of NSP issued $200 million of 7.875 percent 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 NSP's consolidation. The preferred securities are redeemable at $25 per share beginning in 2002. Distributions and redemption payments are guaranteed by NSP. Distributions paid to preferred security holders are reflected as a financing cost in the Income Statement along with interest expense.

9. Regulatory Assets and Liabilities

The following summarizes the individual components of unamortized regulatory assets and liabilities shown on the Balance Sheets at Dec. 31:

(Thousands of dollars)	*Remaining Amortization Period*	*1999*	*1998*
AFC recorded in plant *(a)*	Plant Lives	$112 291	$121 551
Conservation programs *(a)*	3 Years	5 254	72 995
Losses on reacquired debt	Term of Related Debt	52 698	56 242
Environmental costs	Primarily 10 Years	48 708	50 158
Unrecovered gas costs	1–2 Years	15 266	16 259
State commission accounting adjustments *(a)*	Plant Lives	7 641	7 370
Other	Various	6 269	7 365
TOTAL REGULATORY ASSETS		$248 127	$331 940
Deferred income tax adjustments		$ 77 433	$ 75 066
Investment tax credit deferrals		78 281	84 865
Unrealized gains from decommissioning investments		177 578	138 613
Pension costs – regulatory differences		84 198	53 012
Conservation incentives		25 284	
Fuel costs, refunds and other		18 795	20 683
TOTAL REGULATORY LIABILITIES		$461 569	$372 239

(a) Earns a return on investment in the ratemaking process

10. Investments Accounted for by the Equity Method

NSP'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. That's because the ownership structure prevents NSP from exercising a controlling influence over the projects' operating and financial policies. Under this method, NSP records its portion of the earnings or losses of unconsolidated affiliates as equity earnings. A summary of NSP's significant equity method investments follows.

Name	*Geographic Area*	*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	49.10%
MIBRAG mbH	Europe	33.33%
Cogeneration Corp. of America	USA	20.00%
Schkopau Power Station	Europe	20.95%
Long Beach Generating	USA	50.00%
El Segundo Generating	USA	50.00%
Encina	USA	50.00%
San Diego Combustion Turbines	USA	50.00%
Energy Developments Limited	Australia	29.14%
Scudder Latin American Power	Latin America	6.63%
Various independent power production facilities	USA	45%–50%
Various affordable housing limited partnerships	USA	20%–99.9%

Summarized Financial Information of Unconsolidated Affiliates | Summarized financial information for these projects, including interests owned by NSP and other parties, is as follows for the years ended Dec. 31:

RESULTS OF OPERATIONS

(Millions of dollars)	*1999*	*1998*	*1997*
Operating revenues	$1 752	$1 509	$1 698
Operating income	$ 215	$ 205	$ 93
Net income	$ 200	$ 143	$ 84
NSP's equity in earnings of unconsolidated affiliates	$ 68	$ 80	$ 19

FINANCIAL POSITION

(Millions of dollars)	*1999*	*1998*
Current assets	$ 748	$ 714
Other assets	7 461	8 071
TOTAL ASSETS	$8 209	$8 785
Current liabilities	$ 716	$ 537
Other liabilities	5 246	5 931
Equity	2 247	2 317
TOTAL LIABILITIES AND EQUITY	$8 209	$8 785
NSP's equity investment in unconsolidated affiliates	$1 047	$ 863

11. Financial Instruments

Fair Values | The estimated Dec. 31 fair values of NSP's recorded financial instruments are as follows:

(Thousands of dollars)	*1999*		*1998*	
	Carrying Amount	*Fair Value*	*Carrying Amount*	*Fair Value*
Cash, cash equivalents and short-term investments	$ 55 968	$ 55 968	$ 42 364	$ 42 364
Long-term investments	$ 517 129	$ 517 129	$ 438 981	$ 438 981
Long-term debt, including current portion	$3 748 195	$3 626 638	$2 220 346	$2 313 468

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 NSP'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 NSP's long-term debt is 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.

Derivatives | As of Dec. 31, 1999, NRG had no contracts to hedge – or protect – foreign currency denominated future cash flows. One contract that was outstanding during 1999 had no material effect on earnings.

During the third quarter of 1999, NRG Northeast Generating LLC (N.E. Generating), a wholly owned subsidiary of NRG, entered into $600 million of "treasury locks," at various interest rates, which expired in February 2000. These treasury locks were an interest rate hedge for an N.E. Generating bond offering issued in February 2000 (see Note 2).

At Dec. 31, 1999, NRG had three interest rate swap agreements with notional amounts totaling approximately $393 million. The contracts are used to manage NRG's exposure to changes in interest rates. If the swaps had been discontinued on Dec. 31, 1999, NRG would have owed the counterparties approximately $3 million. Management believes that NRG's exposure to credit risk due to nonperformance by the counterparties to its hedging contracts is insignificant, based on the investment grade rating of the counterparties.

- In September 1999, NRG entered into a $200 million swap agreement effectively converting the 7.5 percent fixed rate on its senior notes to a variable rate. It expires on June 1, 2009.
- A second swap effectively converts a $16 million issue of variable rate debt into fixed rate debt. The swap expires on Sept. 30, 2002.
- A third swap converts $177 million of floating rate debt into fixed rate debt. The swap expires on Dec. 17, 2014.

As of Dec. 31, 1999, EMI had natural gas forward and futures contracts in the notional amount of less than $1 million. These contracts will expire during 2000 and EMI will have no further derivative activity.

NSP's Energy Marketing division uses energy futures contracts, along with physical supply, to hedge market risk in the energy market. At Dec. 31, 1999, the notional amount of energy futures contracts was approximately $2 million. Management believes that the risk of counterparty nonperformance with regard to any of Energy Marketing's hedge transactions is not significant.

NRG's Power Marketing subsidiary uses energy forward contracts, along with physical supply, to hedge market risk in the energy market. At Dec. 31, 1999, the notional amount of energy forward contracts was approximately $207 million. If the contracts had been terminated at Dec. 31, 1999, NRG would have received approximately $12 million based on price fluctuations to date. Management believes the risk of counterparty nonperformance with regards to any of NRG's hedging transactions is not significant.

Letters of Credit | NSP and its subsidiaries use letters of credit, generally with terms of one year, 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, 1999, there were $140 million in letters of credit outstanding, including $116 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.

12. Joint Plant Ownership

NSP is part owner of an 860-megawatt coal-fired electric generating unit called Sherco 3. NSP owns and has financed 59 percent and Southern Minnesota Municipal Power Agency owns and has financed 41 percent of Sherco 3. NSP is the operating agent under the joint ownership agreement. NSP's share of related expenses for Sherco 3 is included in Utility Operating Expenses. NSP's share of the gross cost recorded in Utility Plant was approximately $607 million at year-end 1999 and $604 million at year-end 1998. The accumulated provisions for depreciation were $233 million in 1999 and $215 million in 1998.

13. Nuclear Obligations

Fuel Disposal | NSP is responsible for temporarily storing used – or spent – nuclear fuel from its nuclear plants. The U.S. Department of Energy (DOE) is responsible for permanently storing spent fuel from NSP's nuclear plants as well as from other U.S. nuclear plants. NSP has been funding 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 $12 million in 1999, $11 million in 1998 and $10 million in 1997.

In total, NSP had paid approximately $272 million to the DOE through Dec. 31, 1999. 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 requires 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 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.

Without a DOE facility, NSP has been providing, with regulatory and legislative approval, its own temporary on-site storage facilities at its Monticello and Prairie Island nuclear plants. With the dry cask storage facilities approved in 1994, NSP 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. NSP is investigating all of its 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, NSP 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 recorded the DOE's initial assessment of $46 million, which is payable in annual installments from 1993–2008. NSP is amortizing each installment to expense on a monthly basis. The most recent installment paid in 1999 was $4 million; future installments are subject to inflation adjustments under DOE rules. NSP 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 $32 million at Dec. 31, 1999, as a regulatory asset.

Plant Decommissioning | Decommissioning of NSP's nuclear facilities is planned for the years 2010–2022, using the prompt dismantlement method. NSP currently is following industry practice by ratably accruing the costs for decommissioning over the approved cost recovery period and including the accruals in Utility Plant – Accumulated Depreciation. Consequently, the total decommissioning cost obligation and corresponding assets currently are not recorded in NSP's financial statements.

The Financial Accounting Standards Board (FASB) has proposed new accounting standards, which, if approved, would require the full accrual of nuclear plant decommissioning and other site exit obligations no sooner than 2002. Using Dec. 31, 1999, estimates, NSP's adoption of the proposed accounting would result in the recording of the total discounted decommissioning obligation of $705 million as a liability, with the corresponding costs capitalized as plant and other assets and depreciated over the operating life of the plant. NSP has not yet determined the potential impact of the FASB's proposed changes in the accounting for site exit obligations, such as costs of removal, other than nuclear decommissioning. However, the ultimate decommissioning and site exit costs to be accrued are expected to be similar to the current methodology. The effects of regulation are expected to minimize or eliminate any impact on operating expenses and results of operations from this future accounting change.

Consistent with cost recovery in utility customer rates, NSP records 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. Since the costs are expected to be paid in 2010–2022, funding presumes that current costs will escalate in the future at a rate of 4.5 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 6 percent, net of tax, for external funding and approximately 8 percent, net of tax, for internal funding.

The MPUC last approved NSP's nuclear decommissioning study and related nuclear plant depreciation capital recovery request in April 1997, using 1993 cost data. Although NSP expects 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 2008. This is about six years earlier than each unit's licensed life. The approved recovery period for Prairie Island has been reduced because of the uncertainty regarding used fuel storage. NSP believes future decommissioning cost accruals will continue to be recovered in customer rates.

The total obligation for decommissioning currently is expected to be funded approximately 82 percent by external funds and 18 percent by internal funds, as approved by the MPUC. Contributions to the external fund started in 1990 and are expected to continue until plant decommissioning begins. Costs not funded by external trust assets, including accumulated earnings, will be funded through internally generated funds and issuance of NSP debt or stock. The assets held in trusts as of Dec. 31, 1999, primarily consisted of investments in fixed income securities, such as tax-exempt municipal bonds and U.S. government securities that mature in two to 30 years, and common stock of public companies. NSP plans to reinvest matured securities until decommissioning begins.

At Dec. 31, 1999, NSP had recorded and recovered in rates cumulative decommissioning accruals of $549 million. The following table summarizes the funded status of NSP's decommissioning obligation at Dec. 31, 1999:

(Thousands of dollars)	1999
Estimated decommissioning cost obligation from most recent approved study (1993 dollars)	$ 750 824
Effect of escalating costs to 1999 dollars (at 4.5% per year)	226 944
Estimated decommissioning cost obligation in current dollars	977 768
Effect of escalating costs to payment date (at 4.5% per year)	867 017
Estimated future decommissioning costs (undiscounted)	1 844 785
Effect of discounting obligation (using risk-free interest rate)	(1 140 003)
Discounted decommissioning cost obligation	704 782
Assets held in external decommissioning trust	517 129
DISCOUNTED DECOMMISSIONING OBLIGATION IN EXCESS OF ASSETS CURRENTLY HELD IN EXTERNAL TRUST	$ 187 653

Decommissioning expenses recognized include the following components:

(Thousands of dollars)	1999	1998	1997
Annual decommissioning cost accrual reported as depreciation expense:			
Externally funded	$33 178	$33 178	$33 178
Internally funded (including interest costs)	1 595	1 477	1 368
Interest cost on externally funded decommissioning obligation	4 191	6 960	7 690
Earnings from external trust funds	(4 191)	(6 960)	(7 690)
NET DECOMMISSIONING ACCRUALS RECORDED	$34 773	$34 655	$34 546

Decommissioning and interest accruals are included with the accumulated provision for depreciation on the balance sheet. Interest costs and trust earnings associated with externally funded obligations are reported in Other Utility Income and Deductions on the income statement.

A triennial nuclear plant decommissioning filing was made with the MPUC in October 1999. Approval by the MPUC is expected in the first quarter of 2000 and will be effective for cost accruals Jan. 1, 2000.

14. Commitments and Contingent Liabilities

Capital Commitments | NSP estimates utility capital expenditures, including purchases of nuclear fuel, will be $490 million in 2000 and $2.3 billion for 2000–2004. There also are contractual commitments for the disposal of spent nuclear fuel. (See Note 13.)

NRG expects to invest approximately $2.7 billion in 2000 and approximately $4.7 billion for 2000–2004 for nonregulated projects and property, which include acquisitions and project investments. NRG's capital requirements may vary significantly. NRG's capital requirements for 2000 reflect expected acquisitions of existing generation facilities, including Cajun, Killingholme A and the Conectiv fossil assets. A significant portion of NRG's capital requirements is expected to be financed by project-secured debt. In addition, NRG may issue a limited amount of equity financing to third parties for funding a portion of the capital requirements.

Seren expects to spend approximately $180 million during 2000, which reflects the build-out of its broadband communications network in Northern California. Seren is evaluating its financing options, including equity financing to third parties and project-secured debt. Seren's capital requirements for 2001–2004 may vary significantly depending on the success of development efforts under way.

Legislative Resource Commitments | In 1994, NSP received Minnesota legislative approval for additional on-site temporary spent fuel storage facilities at NSP's Prairie Island plant, provided NSP satisfies certain requirements. Seventeen dry cask containers were approved. As of Dec. 31, 1999, NSP had loaded nine casks. The Minnesota Legislature established several energy resource and other commitments for NSP 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.

The 1994 legislation requires NSP to have 425 megawatts of wind resources contracted by Dec. 31, 2002. Of this commitment, approximately 130 megawatts remain to be contracted. During 1999, the MPUC ordered an additional 400 megawatts to be contracted by 2012, subject to least-cost determinations.

During 1997 and 1998, NSP executed three separate power purchase agreements (PPA) for a total of 125 megawatts of biomass-fueled generation resources. These contracts would meet the statutory requirements to contract for 125 megawatts of biomass energy by Dec. 31, 1998. However, in December 1999, NSP terminated one of the contracts due to the nonperformance of the vendor. NSP is currently working to replace this contract. At a hearing in December 1999, the MPUC approved two 25-megawatt PPAs and required further reporting by NSP in relation to its efforts to meet the mandate, including whether NSP intends to exercise an option to increase the megawatt size of one of the contracts. Although the agreements met the requirements for biomass scheduled to be operational by Dec. 31, 2001, and Dec. 31, 2002, due to various delays the actual operational dates of the biomass facilities may be later than scheduled.

Other commitments established by the Legislature include a discount for low-income electric customers, required conservation improvement expenditures and various study and reporting requirements to a legislative electric energy task force. NSP has implemented programs to meet the legislative commitments. NSP'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.

Guarantees | NSP has sold a portion of its other 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. Under the sales agreements, NSP is required to guarantee repayment to the third party of the remaining loan balances. At Dec. 31, 1999, the outstanding balance of the loans was approximately $25 million. Based on prior collection experience of these loans, NSP believes that losses under the loan guarantees, if any, would have an immaterial impact on the results of operations.

Leases | Rentals under operating leases were approximately $43 million, $33 million and $32 million for 1999, 1998 and 1997, respectively. Future commitments under these leases generally decline from current levels.

Fuel Contracts | NSP 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 2000 and 2013. In total, NSP is committed to the minimum purchase of approximately $399 million of coal, $21 million of nuclear fuel and $235 million of natural gas and related transportation, or to make payments in lieu thereof, under these contracts. In addition, NSP is required to pay additional amounts depending on actual quantities shipped under these agreements.

NSP has developed a mix of natural gas supply, transportation and storage contracts designed to meet its needs for retail gas sales. The contracts are with several suppliers and for various periods of time. Because NSP has other sources of fuel available and suppliers are expected to continue to provide reliable fuel supplies, risk of loss from nonperformance under all fuel contracts is not considered significant. In addition, NSP'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 nearly all fuel costs.

Power Agreements | NSP has several agreements to purchase electricity from the Manitoba Hydro-Electric Board (MH). A summary of the agreements is as follows:

POWER AGREEMENTS

	Years	Megawatts
Participation power purchase	2000–2005	500
Seasonal diversity exchanges:		
Summer exchanges from MH	2000–2014	150
	2000–2016	200
Winter exchanges to MH	2000–2014	150
	2000–2015	200
	2015–2017	400
	2018	200

The cost of the 500-megawatt participation power purchase commitment is based on 80 percent of the costs of owning and operating NSP's Sherco 3 generating plant, adjusted to 1993 dollars. The future annual capacity costs for the 500-megawatt MH agreement are estimated to be approximately $58 million. There are no capacity payments for the diversity exchanges. These commitments represent about 17 percent of MH's system capacity and account for approximately 10 percent of NSP's 2000 electric system capability. The risk of loss from nonperformance by MH is not considered significant, and the risk of loss from market price changes is mitigated through cost-of-energy rate adjustments.

NSP has an agreement with Minnkota Power Cooperative for the purchase of summer season capacity and energy. NSP will buy 150 megawatts of summer season capacity for approximately $12 million annually in 2000 and 2001. From 2002–2015, NSP will purchase 100 megawatts of capacity for $10 million annually. NSP also has a summer purchase power agreement with Minnesota Power for the purchase of 173 megawatts, including reserves, for 2000. The annual cost of this capacity will be approximately $2 million.

NSP has agreements with several nonregulated power producers to purchase electric capacity and associated energy. The cost of these commitments is approximately $45 million annually for 379 megawatts of summer capacity for 2000–2003. These commitments are expected to range between $52 million and $84 million annually for 2004–2024. These commitments are expected to decline to approximately $27 million annually for 2025–2027, due to the expiration of existing agreements.

Wholesale Sales Agreement | In 1999, NRG entered into a Standard Offer Service Wholesale Sales Agreement with Connecticut Light & Power Co. (CL&P). NRG will supply CL&P with 35 percent of its standard offer service load during 2000, 40 percent during 2001 and 2002 and 45 percent during 2003. The four-year contract is valued at $1.7 billion. NRG will serve the load with a combination of existing generation and power purchases. Also in 1999, NRG acquired generating stations with a combined capacity of 2,235 megawatts from CL&P.

Nuclear Insurance | NSP'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 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 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 purchases insurance for property damage and site decontamination cleanup costs from Nuclear Electric Insurance Limited (NEIL). The coverage limits are $1.5 billion for each of NSP'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 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 could be subject to maximum assessments of approximately $4 million for business interruption insurance and $15 million for property damage insurance if losses exceed accumulated reserve funds.

Environmental Contingencies | Other long-term liabilities include an accrual of $35 million, and other current liabilities include an accrual of $6 million, at Dec. 31, 1999, for estimated costs associated with environmental remediation. Approximately $24 million of the long-term liability and $4 million of the current liability relate to a DOE assessment for decommissioning a federal uranium enrichment facility, as discussed in Note 13. Other estimates have been recorded for expected environmental costs associated with manufactured gas plant sites formerly used by NSP, and other waste disposal sites, as discussed later. 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's nuclear generating plants. See Note 13 for further discussion of nuclear items.

The Environmental Protection Agency (EPA) or state environmental agencies have designated NSP-Minnesota as a potentially responsible party (PRP) for 14 waste disposal sites to which NSP-Minnesota allegedly sent hazardous materials.

- Eleven of these 14 sites have been remediated and, consistent with settlements reached with the EPA and other PRPs, NSP-Minnesota has paid $2.4 million for its share of the remediation costs. One site that was previously remediated was reactivated due to a change in the use of the land. While these remediated sites will continue to be monitored, NSP-Minnesota expects that future remediation costs, if any, will be immaterial. Under applicable law, NSP-Minnesota, along with each PRP, could be held jointly and severally liable for the total remediation costs of PRP sites.
- Neither the total remediation cost nor the final method of cost allocation among all PRPs of the three unremediated sites has been determined. However, NSP-Minnesota has recorded an estimate of approximately $0.1 million for its share of future costs for these sites. NSP-Minnesota is not aware of the other parties' inability to pay, nor does it know if responsibility for any of the sites is in dispute.

While it is not feasible to determine the ultimate impact of PRP site remediation at this time, the amounts accrued represent the best current estimate of NSP-Minnesota's future liability. It is NSP-Minnesota's practice to vigorously pursue and, if necessary, litigate with insurers to recover incurred remediation costs whenever possible. Through litigation, NSP-Minnesota has recovered a portion of the remediation costs paid to date. Management believes remediation costs incurred, but not recovered, from insurance carriers or other parties should be allowed recovery in future ratemaking. Until NSP-Minnesota is identified as a PRP, it is not possible to predict the timing or amount of any costs associated with sites, other than those discussed previously.

NSP-Wisconsin may be involved in the cleanup and remediation at three sites, including one that NSP-Minnesota is also investigating. One site is a former transformer disposal facility in New Lisbon, Wis., and the remaining two are locations where fuel tanks were installed. The ultimate cleanup and remediation costs of these sites and the extent of NSP-Wisconsin's responsibility, if any, for sharing such costs are not known at this time, but are expected to be immaterial.

NSP-Minnesota is also investigating other properties that were formerly sites of gas manufacturing, gas storage plants or gas pipelines to determine if waste materials are present and if they are an environmental or health risk. NSP-Minnesota also determines if it has any responsibility for remedial action and if recovery under NSP-Minnesota's insurance policies can contribute to remediation costs.

- NSP-Minnesota has remediated four sites, which continue to be monitored. NSP-Minnesota has paid $7.3 million to remediate these sites and expects to incur only immaterial monitoring costs related to these sites.
- Another 11 gas sites remain under investigation. NSP-Minnesota is taking remedial action at four of these sites.
- As of Dec. 31, 1999, NSP-Minnesota had paid $4.3 million for the four active sites and had recorded an estimated liability of approximately $2.6 million for future costs at these sites, with payment expected over the next five years. This estimate is based on prior experience and includes investigation, remediation and litigation costs.
- No liability has been recorded for remediation or investigation of the remaining seven sites under investigation because the present land use at each of these sites does not warrant a response action.

While it is not feasible to determine at this time the ultimate cost of gas site remediation, the amounts accrued represent the best current estimate of NSP-Minnesota's future liability for any required cleanup or remedial actions at these former gas operating sites. Environmental remediation costs may be recovered from insurance carriers, third parties or in future rates. The MPUC allowed NSP-Minnesota to defer certain remediation costs of four active sites in 1994. In September 1998, the MPUC allowed the recovery of these gas site remediation costs in gas rates, with a portion assigned to NSP's electric operations for two sites formerly used by NSP generating facilities. Accordingly, NSP-Minnesota has recorded an environmental regulatory asset for these costs. NSP-Minnesota may request recovery of costs to remediate other activated sites following the completion of preliminary investigations.

NSP-Wisconsin will be involved in the cleanup and remediation at locations of former manufactured gas plants at Ashland, La Crosse, Eau Claire and Chippewa Falls, Wis. The ultimate cleanup and remediation costs of sites other than Ashland (discussed below) and the extent of NSP-Wisconsin's responsibility, if any, for sharing such costs are not known at this time, but are expected to be immaterial.

The Wisconsin Department of Natural Resources (WDNR) named NSP-Wisconsin as one of three PRPs for creosote and coal tar contamination at the Ashland site. The Ashland site includes property owned by NSP-Wisconsin and two other properties, which include an adjacent city lakeshore park area and a small area of Lake Superior's Chequemegon Bay adjoining the park.

The EPA has accepted a petition from a local environmental group to conduct a preliminary assessment of the Ashland site under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA). A preliminary assessment (PA) is a limited scope investigation to evaluate the potential for hazardous substance releases from a site and also to determine if the site is likely to score at a high enough level to be considered for inclusion on the National Priorities List (NPL). The PA was performed in the second half of 1999 and the results indicated a score sufficiently high to proceed to the next formal step of the EPA scoring under the Hazardous Ranking System (HRS) under CERCLA. The HRS scoring process being performed by the EPA is now under way. NSP-Wisconsin anticipates the WDNR will still act as lead agency on the site. The PA and HRS scoring process will result in a delay in selection of a remedial strategy for the site until later in 2000. NSP-Wisconsin has proposed and WDNR has conceptually approved an interim action (groundwater treatment system) for one operable unit at the site for which NSP-Wisconsin has accepted responsibility. This interim action is expected to be operational by the spring of 2000 and is designed to be a first step in remediating one portion of the site.

The 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, based on different assumptions for methods of remediation and expected results.

However, NSP-Wisconsin believes that the estimated costs of the most reasonable and effective solutions are between $24 million and $51 million. During 2000, the WDNR is expected to select the method of remediation for use at the site, after which a more accurate estimate of the cost can be developed. NSP-Wisconsin has already recorded a liability for remediation costs for its portion of the Ashland site, estimated using reasonably effective remedial methods. NSP-Wisconsin has deferred as a regulatory asset the remediation costs accrued for the Ashland site because management expects that the 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 utilities.

In 1998, the EPA published nitrogen oxide (NO_X) emission regulations affecting 22 states, including Wisconsin. The goal of the new regulations is to reduce NO_X emissions by 85 percent by May 1, 2003. Two of NSP-Wisconsin's boilers and eight of its combustion turbines may be affected by this action. If the existing boilers and combustion turbines are made compliant using retrofit technology to control NO_X emissions, it could cost NSP-Wisconsin up to $62 million for capital improvements and add $14 million each year for operation and maintenance expenses. This is the estimated cost of the most expensive alternative to achieve compliance, which is not necessarily the compliance alternative of choice. If the rules are finalized in their most stringent form, other alternatives for these older units may be deemed more cost effective than retrofitting. How the WDNR will implement the new EPA NO_X regulations and their applicability to NSP-Wisconsin are still uncertain.

NSP-Wisconsin has joined with two other Wisconsin-based utilities as well as the Wisconsin Paper Council and Wisconsin Manufacturers and Commerce industrial organizations to request a judicial review of the EPA's final NO_X rules. NSP-Wisconsin believes that the EPA improperly included Wisconsin in the scope of the regulatory action and it improperly calculated potential emissions of NO_X, reducing the allowable emission limits for the state.

In 1999, the EPA was ordered by a federal appeals panel to suspend implementation of the NO_X rules pending further action on a lawsuit brought by another trade group. It is possible that the state of Wisconsin will either not be required to meet the more stringent NO_X requirements or that their implementation will be delayed substantially.

The Clean Air Act calls for phased-in reductions in emissions of sulfur dioxide and nitrogen oxides from electric generating plants. NSP has invested significantly over the years to reduce sulfur dioxide emissions at its plants. No additional capital expenditures are anticipated to comply with the sulfur dioxide emission limits of the Clean Air Act. NSP-Minnesota is completing installation of over-fire air at the King plant to meet the NO_X emission limitations. NSP-Minnesota's capital expenditures include some costs for ensuring compliance with the Clean Air Act; other expenditures may be necessary upon EPA finalization of remaining rules. Because NSP is still in the process of implementing some provisions of the Clean Air Act, its total financial impact is unknown at this time. Capital expenditures for opacity compliance are included in the capital expenditure commitments disclosed previously. The depreciation of these capital costs will be subject to regulatory recovery in future rate proceedings.

In addition to NSP's utility plants, NRG has several plants throughout the United States, some of which were acquired during 1999. These plants are subject to federal and state emission standards and other environmental regulations. Although NRG continues to study and investigate the methods and costs of complying with these standards and regulations, the future financial effect is not known at this time and may be material.

Several of NSP's facilities contain asbestos, which can be a health hazard to people who come in contact with it. Under governmental requirements, asbestos not readily accessible to the environment need not be removed until the facilities containing the material are demolished. Although the ultimate cost and timing of asbestos removal is not yet known, it is estimated that removal under current regulations would cost $45 million in 1999 dollars. Asbestos removal costs would be recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Environmental liabilities are subject to considerable uncertainties that affect NSP's ability to estimate its share of the ultimate costs of remediation and pollution control efforts. Uncertainties include the nature and extent of site contamination, the extent of required cleanup efforts, varying costs of alternative cleanup methods and pollution control technologies, changes in environmental remediation and pollution control requirements, the potential effect of technological improvements, the number and financial strength of other potentially responsible parties at multi-party sites and the identification of new environmental cleanup sites. NSP has recorded and/or disclosed its best estimate of expected future environmental costs and obligations.

Legal Claims | In the normal course of business, NSP is a party to routine claims and litigation arising from prior and current operations. NSP is actively defending these matters and has recorded an estimate of the probable cost of settlement or other disposition.

On Dec. 11, 1998, a gas explosion in St. Cloud, Minn., killed four people, including two NSP 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 10 lawsuits relating to the explosion. NSP is a defendant in eight of the lawsuits. NSP and Seren deny any liability for this accident. NSP 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 NSP and Seren, if any, is presently unknown.

In April 1997, a fire damaged several buildings in downtown Grand Forks, N.D., during a flood in the city. On July 23, 1998, the St. Paul Mercury Insurance Co. commenced a lawsuit against NSP for damages in excess of $15 million. The suit was filed in the District Court in Grand Forks County in North Dakota. The insurance company alleges the fire was electrical in origin and that NSP was legally responsible for the fire because it failed to shut off electrical power to downtown Grand Forks during the flood and prior to the fire. Seven additional lawsuits have been filed against NSP by insurance companies that insured businesses damaged by the fire. It is NSP's position that it is not legally responsible for this unforeseeable event. NSP has a self-insured retention deductible of $2 million, with general liability insurance coverage limits of $150 million. The ultimate cost to NSP, if any, is unknown at this time.

On or about July 12, 1999, Fortistar Capital, Inc. commenced an action against NRG in Hennepin County (Minnesota) District Court, seeking damages in excess of $100 million and an order restraining NRG from consummating the acquisition of Niagara Mohawk Power Corp.'s Oswego generating station. Fortistar's motion for a temporary restraining order was denied and a temporary injunction hearing was held on Sept. 27, 1999. The acquisition of the Oswego generating station was closed on Oct. 22, 1999, following notification to the court of the closing date. NRG intends to continue to vigorously defend the suit and believes Fortistar's claims to be without merit. NRG has asserted numerous counterclaims against Fortistar.

15. Proposed Business Combination

As previously reported in NSP's Report on Form 8-K, dated March 24, 1999, which was filed on March 25, 1999, NSP and NCE agreed to merge and form Xcel Energy. At the time of the merger, each share of NCE common stock will be exchanged for 1.55 shares of Xcel Energy common stock. NSP shares need not be exchanged and will become Xcel Energy shares on a one-for-one basis. Cash will be paid in lieu of any fractional shares of Xcel Energy common stock.

The merger requires approval or regulatory review by certain state utilities regulators, the SEC, the FERC, the Nuclear Regulatory Commission and the Federal Communications Commission, and expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act. During June 1999, shareholders of both NSP and NCE approved the merger. The FERC approved the merger in January 2000. The states of Kansas and Colorado have approved the merger. Merger approval is not required in Michigan, Oklahoma, South Dakota or Wisconsin. NSP and NCE have filed merger applications with regulators in Arizona, Minnesota, New Mexico, North Dakota, Wyoming and Texas, and at the SEC. While NSP cannot guarantee the timing or receipt of the necessary regulatory approvals, NSP currently expects the merger to be completed by the middle of 2000.

The merger is expected to be a tax-free, stock-for-stock exchange for shareholders of both companies (except for fractional shares), and to be accounted for as a pooling of interests. NSP and NCE have agreed to certain undertakings and limitations regarding the conduct of their businesses prior to the closing of the transaction. At the time of the merger, Xcel Energy will register as a holding company under the Public Utility Holding Company Act of 1935.

At Dec. 31, 1999, NSP had deferred approximately $25 million of merger costs, pending the consummation of the business combination and consistent with NSP's filed request for regulatory amortization over future periods.

Xcel Energy Summarized Pro Forma Information | The following summary of unaudited pro forma financial information for Xcel Energy gives effect to the merger using the pooling of interests method of accounting. Under this accounting method, NSP's and NCE's balance sheets and income statements are treated as if they have always been combined for financial reporting purposes. This unaudited pro forma summarized financial information should be read in conjunction with the historical financial statements and related notes of NSP and NCE, which are included in the 1999 Annual Reports on Form 10-K of the respective companies.

The unaudited pro forma balance sheet information at Dec. 31, 1999, assumes the merger had been completed on Dec. 31, 1999. The unaudited pro forma income statement information assumes the merger had been completed on Jan.1, 1999, the beginning of the earliest period presented.

These summarized pro forma amounts do not include any of the estimated cost savings expected to result from the merger of NCE and NSP. Such cost savings, net of the costs incurred to achieve such savings and to complete the merger transaction, are subject to regulatory review and approval. However, the pro forma amounts for NSP and NCE include approximately $25 million and $20 million, respectively, of deferred nonrecurring merger costs as of Dec. 31, 1999, mainly those directly attributable to the merger transaction. Assuming the business combination is accounted for as a pooling of interests, these costs will be expensed upon the consummation of the NCE/NSP merger. The pro forma income statement information amounts do not reflect any of these costs. The pro forma balance sheet information has been adjusted to reflect a write-off of the deferred costs and a related reduction of retained earnings.

In addition to the pro forma balance sheet adjustment discussed above, adjustments have also been made to the historical amounts for NCE and NSP to conform their presentation for pro forma combined reporting, mainly to group nonregulated property with utility plant, and to report nonregulated revenue and operating income with utility amounts.

The unaudited summarized pro forma financial information does not necessarily indicate what the combined company's financial position or operating results would have been if the merger had been completed on the assumed completion dates and does not necessarily indicate future operating results of the combined company.

As of Dec. 31, 1999:

XCEL ENERGY

(Millions of dollars)	*NSP*	*NCE*	*Adjustments*	*Pro Forma*
Plant – Net	$4 451	$6 261	$ 2 087	$12 799
Current Assets	1 034	1 027		2 061
Other Assets	4 283	1 034	(2 132)	3 185
TOTAL ASSETS	$9 768	$8 322	$ (45)	$18 045
Common Equity	$2 558	$2 733	$ (45)	$ 5 246
Preferred Securities	305	294		599
Long-Term Debt	3 454	2 374		5 828
Total Capitalization	6 317	5 401	(45)	11 673
Current Liabilities	1 826	1 657		3 483
Other Liabilities	1 625	1 264		2 889
TOTAL EQUITY AND LIABILITIES	$9 768	$8 322	$ (45)	$18 045

For the year ended Dec. 31, 1999:

XCEL ENERGY

(Millions of dollars, except for earnings per share)	*NSP*	*NCE*	*Adjustments*	*Pro Forma*
Revenue	$2 869	$3 375	$625	$6 869
Operating Income	343	642	237	1 222
Net Income	224	347		571
Available for Common	$ 219	$ 347		$ 566
EARNINGS PER SHARE – DILUTED	$ 1.43	$ 3.01		$ 1.70

New NSP Utility Sub Summarized Pro Forma Information | The following summary of unaudited pro forma financial information for New NSP Utility Sub adjusts the historical financial statements of NSP after the transfer of ownership. Upon completion of the merger, all NSP-Minnesota utility assets (other than investments in and assets of subsidiaries) and liabilities associated with the assets will be transferred to New NSP Utility Sub.

The unaudited pro forma balance sheet information at Dec. 31, 1999, assumes the merger had been completed on Dec. 31, 1999. The unaudited pro forma income statement information assumes the merger had been completed on Jan.1, 1999, the beginning of the earliest period presented.

The unaudited summarized pro forma financial information does not necessarily indicate what New NSP Utility Sub's financial position or operating results would have been if the merger had been completed on the assumed completion dates and does not necessarily indicate future operating results of New NSP Utility Sub.

As of Dec. 31, 1999:

NEW NSP UTILITY SUB

(Millions of dollars)	*NSP*	*Adjustments*	*Pro Forma*
Utility Plant – Net	$4 451	$ (856)	$3 595
Current Assets	1 034	(434)	600
Other Assets	4 283	(3 416)	867
TOTAL ASSETS	$9 768	$(4 706)	$5 062
Common Equity	$2 558	$(1 374)	$1 184
Preferred Securities	305	(305)	
Long-Term Debt	3 454	(2 077)	1 377
Total Capitalization	6 317	(3 756)	2 561
Current Liabilities	1 826	(686)	1 140
Other Liabilities	1 625	(264)	1 361
TOTAL EQUITY AND LIABILITIES	$9 768	$(4 706)	$5 062

For the year ended Dec. 31, 1999:

NEW NSP UTILITY SUB

(Millions of dollars)	*NSP*	*Adjustments*	*Pro Forma*
Revenue	$2 869	$ (236)	$2 633
Operating Income	343	(64)	279
Net Income	224	(74)	150
AVAILABLE FOR COMMON	$ 219	$ (69)	$ 150

16. Segment and Related Information

NSP has four reportable segments: Electric Utility, Gas Utility and two of its nonregulated energy businesses, its wholly owned subsidiaries NRG and EMI.

- NSP's Electric Utility generates, transmits and distributes electricity primarily in Minnesota, Wisconsin, Michigan, North Dakota and South Dakota. It also makes sales for resale and provides wholesale transmission service to various entities in the United States.
- NSP's Gas Utility transmits, transports, stores and distributes natural gas and propane primarily in Minnesota, Wisconsin, North Dakota, Michigan and Arizona.
- NRG develops, builds, 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.
- EMI is an energy service company, primarily retrofitting and upgrading facilities for greater energy efficiency, in the United States.

In general, NSP has segmented its operations as either regulated or nonregulated businesses. Further, the regulated businesses are separated between electric and gas; and nonregulated businesses are separated by company (primarily based on product and services). The electric and gas businesses are part of NSP-Minnesota, NSP-Wisconsin and Viking companies and are reviewed at various jurisdiction and/or company levels. They have been aggregated as reportable segments as they are aggregated for reporting to NSP's board of directors. Assets by segment are not reported to management and are not included in the disclosures that follow.

The measure of profit or loss for electric and gas segments reported in the various management reports varies, but the largest component, NSP-Minnesota, reports net income and earnings per share on a basis consistent with consolidated net income and earnings per share, except that allocations are needed for some items, as described later. Intercompany and intersegment sales are priced at approved tariff rates and are immaterial. In addition, since NRG and EMI are separate companies, their net income and earnings per share are the measure of profit or loss for both internal management reporting and consolidated external NSP reporting.

To report net income for electric and gas utility segments, NSP-Minnesota and NSP-Wisconsin 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
- allocated based on a general allocator for all other costs not assigned by the above two methods

The "all other" category includes segments that measure below the quantitative threshold for separate disclosure and consists primarily of nonregulated companies, including Eloigne, an affordable housing investment company; Seren, a broadband telecommunications company; Ultra Power, a power-cable testing company; and several other small companies and businesses.

BUSINESS SEGMENTS

1999 *(Thousands of dollars)*	*Electric Utility*	*Gas Utility*	*NRG*	*EMI*	*All Other*	*Reconciling Eliminations*	*Consolidated Total (a)*
Operating revenues							
from external customers *(b)*	$2 396 263	$471 780	$427 567	$ 48 017	$ 37 255		$3 380 882
Intersegment revenues	833	4 369	963			$ (5 197)	968
TOTAL REVENUES	$2 397 096	$476 149	$428 530	$ 48 017	$ 37 255	$ (5 197)	$3 381 850
Depreciation and amortization	322 858	34 857	37 026	2 223	6 098		403 062
Interest income	2 189	658	10 038	52	885	(165)	13 657
Financing costs	121 465	17 055	92 570	318	4 966	(165)	236 209
Income tax expense (credit)	116 601	8 177	(26 416)	(8 061)	(24 019)		66 282
Equity in earnings (losses)							
of unconsolidated affiliates			68 947		(1 088)		67 859
Segment net income (loss)	$ 178 908	$ 19 458	$ 57 195	$ (19 221)	$ (12 004)		$ 224 336

1998 *(Thousands of dollars)*	*Electric Utility*	*Gas Utility*	*NRG*	*EMI*	*All Other*	*Reconciling Eliminations*	*Consolidated Total (a)*
Operating revenues from							
external customers *(b)*	$2 361 536	$456 710	$ 98 688	$ 54 254	$ 29 288		$3 000 476
Intersegment revenues	815	9 292	1 737			$(10 916)	928
TOTAL REVENUES	$2 362 351	$466 002	$100 425	$ 54 254	$ 29 288	$(10 916)	$3 001 404
Depreciation and amortization	308 415	31 864	16 320	2 129	3 779		362 507
Interest income	9 103	1 403	8 052	184	776	(608)	18 910
Financing costs	109 192	15 485	50 313	108	3 997	(608)	178 487
Income tax expense (credit)	135 914	10 672	(25 654)	(4 214)	(11 923)		104 795
Equity in earnings (losses)							
of unconsolidated affiliates			81 706	300	(2 122)		79 884
Segment net income (loss)	$ 226 351	$ 17 321	$ 41 732	$ (7 659)	$ 4 628		$ 282 373

1997 *(Thousands of dollars)*	*Electric Utility*	*Gas Utility*	*NRG*	*EMI*	*All Other*	*Reconciling Eliminations*	*Consolidated Total (a)*
Operating revenues from							
external customers *(b)*	$2 217 542	$515 162	$102 791	$ 94 375	$ 26 405		$2 956 275
Intersegment revenues	1 008	6 113	926			$ (7 005)	1 042
TOTAL REVENUES	$2 218 550	$521 275	$103 717	$ 94 375	$ 26 405	$ (7 005)	$2 957 317
Depreciation and amortization	299 325	28 609	10 310	1 768	3 069		343 081
Interest income	1 696	331	10 806	604	774	(482)	13 729
Financing costs	111 595	13 429	30 729	272	3 626	(482)	159 169
Primergy cost write-off	29 005						29 005
Income tax expense (credit)	122 655	12 087	(23 680)	(5 921)	(8 431)		96 710
Equity in earnings (losses)							
of unconsolidated affiliates			26 003	(5 144)	(2 259)		18 600
Segment net income (loss)	$ 199 553	$ 22 284	$ 21 982	$ (10 841)	$ 4 342		$ 237 320

(a) The Consolidated Total amounts for income and expense items represent the sum of utility amounts (including some nonoperating items) from the Statements of Income and the nonregulated amounts from Note 6. The depreciation and amortization amounts in the Statements of Cash Flows are different than reported in the Consolidated Total column due to classification of certain depreciation and amortization amounts as other expense items in the Income Statement.

(b) All operating revenues are from external customers located in the United States. However, NRG has significant equity investments for nonregulated projects outside of the United States. Equity in earnings of unconsolidated affiliates, primarily independent power projects, includes $38.6 million in 1999, $29.3 million in 1998 and $27.1 million in 1997 from nonregulated projects located outside of the United States. NRG's equity investments in projects outside of the United States were $606 million in 1999, $557 million in 1998 and $517 million in 1997.

17. Summarized Quarterly Financial Data (Unaudited)

(Thousands of dollars, except per share amounts)	*Quarter Ended* *March 31, 1999*	*June 30, 1999 (a)*	*Sept. 30, 1999*	*Dec. 31, 1999 (a)*
Utility operating revenues	$743 183	$627 157	$813 482	$685 189
Utility operating income	87 654	47 944	122 566	85 315
Net income	52 321	11 490	111 337	49 188
Earnings available for common stock	51 261	9 380	110 277	48 126
Earnings per average common share:				
Basic	$0.34	$0.06	$0.72	$0.31
Diluted	$0.34	$0.06	$0.72	$0.31
Dividends declared per common share	$0.3575	$0.3625	$0.3625	$0.3625
Stock prices – high	$27 15/16	$26 3/4	$24 11/16	$22 11/16
– low	$23 1/16	$22 9/16	$20 15/16	$19 5/16

(Thousands of dollars, except per share amounts)	*Quarter Ended* *March 31, 1998*	*June 30, 1998*	*Sept. 30, 1998 (b)*	*Dec. 31, 1998 (c)*
Utility operating revenues	$701 402	$638 601	$766 448	$712 723
Utility operating income	79 050	65 054	134 985	85 200
Net income	57 117	35 034	101 694	88 528
Earnings available for common stock	54 750	33 974	100 634	87 467
Earnings per average common share:				
Basic	$0.37	$0.23	$0.67	$0.58
Diluted	$0.37	$0.23	$0.67	$0.58
Dividends declared per common share	$0.3525	$0.3575	$0.3575	$0.3575
Stock prices – high	$29 25/32	$30 7/32	$29 3/16	$30 13/16
– low	$26 1/2	$27 11/32	$25 11/16	$26 3/16

(a) 1999 results include two adjustments related to regulatory recovery of conservation program incentives. Second quarter results were reduced by $35 million before taxes, or 14 cents per share, due to the disallowance of 1998 incentives. Fourth quarter results were reduced by $22 million before taxes, or 8 cents per share, due to the reversal of all income recorded through the third quarter for 1999 electric conservation program incentives.
In addition, 1999 fourth quarter results include a pretax charge of $17 million, or 8 cents per share, to write off goodwill related to EMI acquisitions. Also, a pretax charge of $11 million, or 4 cents per share, was recorded in the fourth quarter of 1999 to write down an investment in CellNet common stock. In addition, NRG recorded a gain of approximately 3 cents per share on the partial sale of its interest in Cogeneration Corp. of America during the fourth quarter of 1999.

(b) 1998 results include a $22 million pretax charge, which reduced third quarter earnings by 10 cents per share, for the write-down of NRG projects.

(c) 1998 results include a $26 million pretax gain, which increased fourth quarter earnings by 11 cents per share, for a partial sale of an NRG project.

REPORT OF MANAGEMENT

Management is responsible for the preparation and integrity of NSP's financial statements. The financial statements have been prepared in accordance with generally accepted accounting principles and necessarily include some amounts that are based on management's estimates and judgment.

To fulfill its responsibility, management maintains a strong internal control structure, supported by formal policies and procedures that are communicated throughout NSP. Management also maintains a staff of internal auditors who evaluate the adequacy of and investigate the adherence to these controls, policies and procedures.

Our independent public accountants have audited the financial statements and have rendered an opinion as to the statements' fairness of presentation, in all material respects, in conformity with generally accepted accounting principles. During the audit, they obtained an understanding of NSP's internal control structure, and performed tests and other procedures to the extent required by generally accepted auditing standards.

The board of directors pursues its oversight role with respect to NSP's financial statements through the Audit Committee, which is comprised solely of nonmanagement directors. The Committee meets periodically with the independent public accountants, internal auditors and management to ensure that all are properly discharging their responsibilities. The Committee approves the scope of the annual audit and reviews the recommendations the independent public accountants have for improving the internal control structure. The board of directors, on the recommendation of the Audit Committee, engages the independent public accountants, subject to shareholder approval.

Both the independent public accountants and the internal auditors have unrestricted access to the Audit Committee.

James J. Howard

James J. Howard
Chairman of the Board, President
and Chief Executive Officer

E J McIntyre

Edward J. McIntyre
Vice President and Chief
Financial Officer

NORTHERN STATES POWER COMPANY
Minneapolis, Minnesota
January 31, 2000

REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareholders of Northern States Power Company:

In our opinion, the accompanying consolidated balance sheets and statements of capitalization and the related consolidated statements of income, of common stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Northern States Power Company (NSP), a Minnesota corporation, and its subsidiaries at Dec. 31, 1999 and 1998, and the results of their operations and their cash flows for each of the three years in the period ended Dec. 31, 1999, in conformity with accounting principles generally accepted in the United States. These financial statements are the responsibility of NSP's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for the opinion expressed above.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP
Minneapolis, Minnesota
January 31, 2000, except as to Note 2,
which is as of February 22, 2000

REGULATED ELECTRIC OPERATIONS

RETAIL REVENUES *(Thousands of dollars)*	1999	1998	1997	1996	1995
Residential	$ 809 528	$ 774 803	$ 739 684	$ 727 145	$ 735 743
Small commercial and industrial	405 620	389 744	379 848	376 797	362 521
Medium commercial and industrial	489 633	466 352	433 526	401 137	399 259
Large commercial and industrial	504 195	483 595	468 404	450 811	448 226
Streetlighting and other	31 668	31 054	30 826	30 033	29 162
Conservation accrual adjustments *(a)*	(71 348)	6 673	2 185	4 577	(666)
Total retail	2 169 296	2 152 221	2 054 473	1 990 500	1 974 245
Sales for resale	168 581	149 707	107 464	98 961	133 961
Transmission and other	59 219	60 423	56 613	37 952	34 564
TOTAL	$2 397 096	$2 362 351	$2 218 550	$2 127 413	$2 142 770
RETAIL SALES *(millions of kilowatt-hours)*					
Residential	10 373	10 127	9 791	9 847	9 956
Small commercial and industrial	6 117	5 999	5 907	6 091	5 763
Medium commercial and industrial	8 981	8 801	8 263	7 470	7 511
Large commercial and industrial	11 283	11 277	11 059	11 089	10 941
Streetlighting and other	325	327	335	336	329
Total retail	37 079	36 531	35 355	34 833	34 500
Sales for resale	6 724	6 304	4 658	4 929	6 500
TOTAL	43 803	42 835	40 013	39 762	41 000
CUSTOMER ACCOUNTS *(at Dec. 31) (b)*					
Residential	1 306 900	1 287 080	1 273 161	1 252 476	1 238 576
Small commercial and industrial	160 880	155 536	150 103	149 134	144 774
Medium commercial and industrial	9 731	9 510	9 142	7 962	7 906
Large commercial and industrial	762	727	695	669	652
Streetlighting and other	6 365	6 243	6 276	5 030	4 883
Total retail	1 484 638	1 459 096	1 439 377	1 415 271	1 396 791
Sales for resale	82	78	59	54	67
TOTAL	1 484 720	1 459 174	1 439 436	1 415 325	1 396 858
AVERAGE REVENUE PER KILOWATT-HOUR					
Residential	7.80¢	7.65¢	7.55¢	7.38¢	7.39¢
Small commercial and industrial	6.63	6.50	6.43	6.19	6.29
Medium commercial and industrial	5.45	5.30	5.25	5.37	5.32
Large commercial and industrial	4.47	4.29	4.24	4.07	4.10
TOTAL RETAIL	5.85¢	5.89¢	5.81¢	5.71¢	5.72¢
KILOWATT-HOUR OUTPUT *(millions)*					
Thermal	34 091	32 902	31 896	32 657	33 802
Hydro	845	696	1 015	1 194	1 049
Purchased and interchange	12 397	12 529	10 661	9 065	9 189
TOTAL	47 333	46 127	43 572	42 916	44 040
CAPABILITY AT TIME OF MAXIMUM DEMAND *(megawatts)*					
Company owned	7 176	7 149	7 117	7 109	7 100
Purchased and sales – net (with reserve)	2 024	1 871	1 706	1 698	1 910
TOTAL	9 200	9 020	8 823	8 807	9 010
Maximum demand *(megawatts)*	7 990	7 660	7 353	7 487	7 519
Date of maximum demand	July 29	July 14	July 16	Aug. 6	July 13

(a) Represents excess (deficiency) of conservation incentives recognized as revenue in comparison to levels billed to retail customers under rates in effect.

(b) Customer accounts for 1996–2000 may not be fully comparable to prior years due to differences in meter accumulation in a new billing system implemented in 1996.

REGULATED GAS OPERATIONS

RETAIL REVENUES *(Thousands of dollars)*	*1999*	*1998*	*1997*	*1996*	*1995*
Residential	$237 976	$226 936	$253 065	$267 130	$215 543
Commercial and industrial					
Firm	130 066	124 099	144 539	146 145	119 863
Interruptible	63 376	61 050	79 135	63 585	48 646
Other	151	114	34	153	1 686
Total retail	431 569	412 199	476 773	477 013	385 738
Interstate transmission (Viking)	25 172	23 375	19 809	17 553	16 328
Agency, transportation and off-system sales	18 372	23 792	21 287	34 662	26 122
Elimination of Viking sales to NSP	(3 198)	(2 543)	(2 673)	(2 435)	(2 374)
TOTAL	$471 915	$456 823	$515 196	$526 793	$425 814
RETAIL SALES *(thousands of mmBtu)*					
Residential	40 658	37 522	42 428	48 149	42 294
Commercial and industrial					
Firm	26 584	24 410	28 880	31 748	28 275
Interruptible	23 732	23 201	25 898	23 210	22 408
Other	97	48	33	394	772
TOTAL RETAIL	91 071	85 181	97 239	103 501	93 749
OTHER GAS DELIVERED *(thousands of mmBtu)*					
Interstate transmission (Viking)	167 360	168 187	166 588	161 972	152 952
Agency, transportation and off-system sales	13 773	15 609	11 701	17 535	19 679
Elimination of Viking sales to NSP	(15 114)	(14 563)	(17 145)	(19 311)	(20 440)
TOTAL OTHER GAS DELIVERED	166 019	169 233	161 144	160 196	152 191
CUSTOMER ACCOUNTS *(at Dec. 31) (a)*					
Residential	443 692	430 240	410 773	398 723	386 007
Commercial and industrial	50 886	44 523	41 905	40 244	38 575
Total retail	494 578	474 763	452 678	438 967	424 582
Other gas delivered	63	58	36	30	62
TOTAL	494 641	474 821	452 714	438 997	424 644
AVERAGE REVENUE PER MMBTU					
Residential	$5.85	$6.05	$5.96	$5.55	$5.10
Firm commercial and industrial	4.89	5.08	5.00	4.60	4.24
Interruptible commercial and industrial	2.67	2.63	3.06	2.74	2.17
TOTAL RETAIL	$4.74	$4.84	$4.90	$4.61	$4.11
GAS PURCHASED FOR RESALE TO UTILITY CUSTOMERS					
Total cost *(thousands) (b)*	$267 859	$250 661	$317 646	$312 943	$236 714
Cost recognized per mmBtu sold *(b)*	$2.85	$2.78	$3.20	$3.00	$2.49
Maximum sendout *(mmBtu)*	782 702	710 831	662 025	737 258	659 800
Date of maximum sendout	Jan. 4	Jan. 10	Jan. 27	Feb. 1	Jan. 3

(a) Customer accounts for 1996–1999 may not be fully comparable to prior years due to differences in meter accumulation in a new billing system implemented in 1996.
(b) Excludes cost and volumes for other gas delivered.

NONREGULATED BUSINESS INFORMATION

(Thousands of dollars)	*December 31* 1999	1998
EQUITY INVESTMENT BY NONREGULATED BUSINESSES IN UNCONSOLIDATED PROJECTS		
(Including undistributed earnings and capitalized development costs)		
Australian projects	$ 349 893	$ 327 841
European projects	138 760	134 197
South American and Latin American projects	117 106	95 173
Affordable housing projects (U.S.)	53 338	45 411
U.S. power and energy projects	386 951	259 974
Other	1 200	
Total equity investment in unconsolidated nonregulated projects	$1 047 248	$ 862 596
Nonregulated property of consolidated subsidiaries (net of accumulated depreciation) – primarily U.S. projects	2 086 476	282 524
Notes receivable from unconsolidated projects, including current portion	67 163	110 886
Current assets	375 275	107 541
Other assets	207 306	126 110
TOTAL ASSETS OF NONREGULATED BUSINESSES	$3 783 468	$1 489 657
Long-term debt, including current maturities	$2 048 842	$ 578 233
Short-term debt (including intercompany)	379 438	126 236
Other current liabilities	159 679	39 183
Other liabilities	137 150	69 072
Total liabilities of nonregulated businesses	2 725 109	812 724
NSP's equity investment in nonregulated businesses	1 133 829	759 530
Cumulative currency translation adjustments	(75 470)	(82 597)
Total equity of nonregulated businesses	1 058 359	676 933
TOTAL LIABILITIES AND EQUITY OF NONREGULATED BUSINESSES	$3 783 468	$1 489 657

SIGNIFICANT NONREGULATED GENERATION PROJECTS OPERATING AT DEC. 31, 1999

Generation Projects Operating	*Location*	*Total Mw*	*NRG Ownership*	*Mw-Equity*	*Operator*
Gladstone Power Station	Australia	1 680	37.50%	630	NRG
Loy Yang Power A	Australia	2 000	25.37%	507	NRG/CMS Generation
Crockett Cogeneration	USA	240	57.67%	138	NRG
Schkopau Power Station *(a)*	Germany	960	20.95%	200	PreussenElektra Kraftwerke A.G.
Cogeneration Corp. of America *(b)*	USA	575	20.00%	99	Calpine
COBEE (Bolivian Power Co. Ltd.)	Bolivia	219	49.10%	108	COBEE
MIBRAG mbH	Germany	233	33.33%	78	MIBRAG
Energy Developments Limited	Australia	274	29.14%	79	Energy Developments Limited
Scudder Latin American Power Projects *(c)*	Latin America	772	6.63%	51	Stewart & Stevenson/Wartsila
Long Beach Generating	USA	530	50.00%	265	Southern California Edison
El Segundo Generating	USA	1 020	50.00%	510	Southern California Edison
Enfield Energy Centre	UK	396	25.00%	99	NRG/Indeck
Encina	USA	965	50.00%	483	San Diego Gas & Electric
San Diego Combustion Turbines	USA	253	50.00%	127	NRG
NRG Northeast Generating LLC	USA	6 980	100.00%	6 980	NRG

(a) Through a lease agreement, NRG has ownership of 200 megawatts.
(b) Cogeneration Corp. of America owns various percentages of projects, making NRG's share of ownership 99 megawatts.
(c) Scudder owns various percentages of projects, making NRG's share of ownership 51 megawatts.

SHAREHOLDER INFORMATION

	1999	*1998*	*1997*	*1996*	*1995*
Common stock shareholders at year-end	81 569	81 990	83 232	86 337	83 902
Book value at year-end	$16.42	$16.25	$15.89	$15.47	$14.87
Market prices					
High	$27 15/16	$30 13/16	$29 7/16	$26 11/16	$24 3/4
Low	$19 5/16	$25 11/16	$22 1/4	$22 1/4	$21 1/4
Year-end closing	$19 1/2	$27 3/4	$29 1/8	$22 15/16	$24 9/16
Dividends declared per share	$1.445	$1.425	$1.403	$1.373	$1.343

Headquarters | 414 Nicollet Mall, Minneapolis, MN 55401

Internet Address | http://www.nspco.com

Shareholders Information | Contact the NSP Shareholders Department at NSP headquarters toll-free at (800) 527-4677, or e-mail at shareholders@nspco.com; from the Minneapolis-St. Paul area, call (612) 330-5560.

Street-Name Shareholders and Beneficial Owners | To receive NSP's quarterly report, contact the Shareholders Department at the number listed previously.

Duplicate Mailings | If there are two or more shareholders at your address, you may have received duplicate shareholder mailings. To eliminate duplicate mailings, write or call the Shareholders Department at the number listed previously.

Direct Dividend Deposit | NSP offers direct deposit of dividends to shareholders' checking or savings accounts. To sign up for this free service, contact the Shareholders Department for information and an authorization form.

Dividend Reinvestment and Stock Purchase Plan | NSP's Dividend Reinvestment and Stock Purchase Plan offered by Prospectus is a convenient way to purchase shares of NSP's common stock without payment of any brokerage commission or service charge. Contact the Shareholders Department for a Prospectus and authorization form. Those eligible to participate in the plan are:

- Shareholders of record of NSP
- Shareholders who hold stock in "street name" through investment firms, provided the firm has established procedures permitting participation
- Employees of NSP and its subsidiaries
- Non-shareholders of legal age who live in Minnesota, North Dakota, South Dakota, Wisconsin and Michigan. (Non-shareholders must make an initial investment of at least $100.)

Once enrolled in the plan, participants may:

- Automatically reinvest all or a portion of their quarterly dividends
- Make additional cash investments. The minimum single payment is $25 and the maximum quarterly payment is $10,000.

Stock Exchange Listings and Ticker Symbol | Common stock is traded on the New York, Chicago and Pacific Exchanges. Ticker symbol: NSP. Newspaper stock tables list NSP as NoStPw, NoStPwr or NSPw. NYSE lists some of NSP's preferred stock and its preferred securities.

Form 10-K (The Annual Report to the Securities and Exchange Commission) | Available online at: http://www.nspco.com/ir.htm or contact the Shareholders Department at the number listed previously. A statistical supplement to the annual report is also available.

Investor Relations | Internet address: http://www.nspco.com/ir.htm; Richard J. Kolkmann, Investor Relations, at NSP headquarters (612) 330-6622.

Schedule of Anticipated Dividend Record Dates and Payment Dates for 2000:

Preferred Stock		Common Stock	
Record Dates	Payment Dates	Record Dates (a)	Payment Dates (a)
Dec. 31, 1999	Jan. 15, 2000	Jan. 4, 2000	Jan. 20, 2000
March 31, 2000	April 15, 2000	April 13, 2000	April 20, 2000
June 30, 2000	July 15, 2000	July 13, 2000	July 20, 2000
Sept. 29, 2000	Oct. 15, 2000	Oct. 2, 2000	Oct. 20, 2000
Dec. 29, 2000	Jan. 15, 2001		

(a) Dates for common dividends may change pending the Xcel Energy merger.

FISCAL AGENTS

NSP-MINNESOTA

Transfer Agent, Common and Preferred Stocks
Northern States Power Company

Registrar, Common and Preferred Stocks
Norwest Bank Minnesota, N.A.
Sixth St. and Marquette Ave.
Minneapolis, MN 55479-0059

Dividend Distribution
Northern States Power Company

Forwarding Agent
Norwest Bank International
3 New York Plaza, New York, NY 10004

Trustee-Bonds
Harris Trust and Savings Bank *(a)*
111 West Monroe St., Chicago, IL 60690

U.S. Bank Trust, N.A.
180 East 5th St., St. Paul, MN 55101

Norwest Bank Minnesota, N.A., Minneapolis

Firstar Trust Company
1555 North River Center Drive, Suite 301
Milwaukee, WI 53212

Coupon Paying Agents-Bonds
Harris Trust and Savings Bank, Chicago *(a)*

Firstar Trust Company, Milwaukee

U.S. Bank Trust, N.A., St. Paul

Norwest Bank Minnesota, N.A., Minneapolis

Tender, Registrar and Paying Agent
Chase Manhattan Bank
450 West 33rd St., New York, NY 10001

Trustee-Trust Originated Preferred Securities (b)
Wilmington Trust Company
1100 North Market St.
Wilmington, DE 19807

(a) Harris Corporate Trust Services is being sold to Bank of New York in March 2000

(b) Securities of NSP Financing I, a wholly owned special purpose subsidiary trust of Northern States Power Company (Minnesota)

NSP-WISCONSIN

Trustee-Bonds
U.S. Bank Trust, N.A., St. Paul

Firstar Trust Company, Milwaukee

NRG ENERGY, INC.

Trustee-Senior Notes
Norwest Bank Minnesota, N.A., Minneapolis

VIKING GAS

Trustee-Bonds
Norwest Bank Minnesota, N.A., Minneapolis

DIRECTORS OF THE MINNESOTA COMPANY

David A. Christensen (64) 2, 4
President and CEO
Raven Industries, Inc.
(elected December 1976)

W. John Driscoll (70) 2, 4
Retired Chairman and President
Rock Island Company
(elected November 1974)

Giannantonio Ferrari (60) 1, 3
Chief Operating Officer and Executive Vice President
Honeywell International, Inc.
(elected October 1997)

James J. Howard (64) *(a)*
Chairman, President and CEO
Northern States Power Company
(elected January 1987)

Douglas W. Leatherdale (63) 2, 3
Chairman and CEO
The St. Paul Companies Inc.
(elected April 1991)

Dr. Margaret R. Preska (62) 2, 4
Distinguished Service Professor
Minnesota State Universities
(elected January 1980)

A. Patricia Sampson (51) 1, 4
President and CEO
The Sampson Group, Inc.
(elected January 1985)

Allan L. Schuman (65) 1, 3
Chairman, President and CEO
Ecolab Inc.
(elected January 1999)

Board Committees
1. Audit
2. Corporate Management
3. Finance
4. Power Supply

(a) James J. Howard is an ex officio member of all committees.

PRINCIPAL OFFICERS OF THE MINNESOTA COMPANY

Paul E. Anders Jr. (56)
Vice President and CIO

Grady P. Butts (53)
Vice President – Human Resources

James J. Howard (64)
Chairman, President and CEO

Gary R. Johnson (53)
Vice President and General Counsel

Cynthia L. Lesher (51)
President – NSP Gas

Edward J. McIntyre (49)
Vice President and CFO

John P. Moore Jr. (53)
Vice President and Corporate Secretary

Paul E. Pender (45)
Vice President – Finance and Treasurer

Roger D. Sandeen (54)
Vice President and Controller

David M. Sparby (45)
Vice President – Regulatory Services

Loren L. Taylor (53)
President – NSP Electric

Michael D. Wadley (43)
President – Nuclear Generation

DIRECTORS OF THE WISCONSIN COMPANY

Philip M. Gelatt (49) *(b)*
President
Northern Engraving Corporation
(elected May 1990)

Jerome L. Larsen (51)
President and CEO
NSP-Wisconsin
(elected June 1998)

Ray A. Larson Jr. (70) *(b)*
President
Wissota Sand and Gravel Company
(elected November 1979)

Larry G. Schnack (62) *(b)*
Chancellor
University of Wisconsin – Eau Claire
(elected May 1988)

Loren L. Taylor (53)
President – NSP Electric
(elected May 1992)

(b) Audit committee members

PRINCIPAL OFFICERS OF THE WISCONSIN COMPANY

Michael N. Gregerson (52)
Vice President – Marketing and Business Development

Jerome L. Larsen (51)
President and CEO

John P. Moore Jr. (53)
Vice President and Corporate Secretary

Roger D. Sandeen (54)
Vice President, Treasurer and Controller

Anthony G. Schuster (55)
Vice President – Transmission Systems

John D. Wilson (40)
Vice President – Regulatory Affairs and General Counsel

Directors of the Minnesota Company in 1999 included (front row, left to right): Douglas W. Leatherdale, James J. Howard, A. Patricia Sampson and Giannantonio Ferrari. In the back are (left to right): Dr. Margaret R. Preska, H. Lyman (Tad) Bretting, who resigned in December, Allan L. Schuman, David A. Christensen and W. John Driscoll.

Northern States Power Company
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

Printed in U.S.A.