Sierra Pacific™
RESOURCES

2002 ANNUAL REPORT

SIERRA PACIFIC RESOURCES IN BRIEF

Headquartered in Nevada, Sierra Pacific Resources is an investor-owned corporation with operating subsidiaries engaged in utility and energy services businesses. The company's stock is traded on the New York Stock Exchange under the symbol SRP.

The company's chief operating subsidiaries are Nevada Power Company and Sierra Pacific Power Company, which serve approximately 987,000 electric customers. Their combined 54,500 square mile service area covers most of Nevada, including Las Vegas and Reno, plus the Lake Tahoe area of northern California. Sierra Pacific Power also provides natural gas service to approximately 123,500 customers in the Reno-Sparks metropolitan area.

Other operating subsidiaries include the Tuscarora Gas Pipeline Company, which owns a 50 percent interest in an interstate natural gas pipeline.

The number of registered holders of common stock was 23,206 as of December 31, 2002.

SELECTED FINANCIAL DATA—SIERRA PACIFIC RESOURCES

See Management's Discussion and Analysis of Financial Condition and Results of Operations for a discussion of factors that may affect the future financial condition and results of operations of Sierra Pacific Resources (SPR), Nevada Power Company (NPC), and Sierra Pacific Power Company (SPPC).

The July 28, 1999, merger between SPR and NPC was treated for accounting purposes as a reverse acquisition and deemed to have occurred on August 1, 1999. As a result, for financial reporting and accounting purposes, NPC was considered the acquiring entity under Accounting Principles Board Opinion No. 16, "Business Combinations," even though SPR became the legal parent of NPC. Because of this accounting treatment, for the year ended December 31, 1999, the table below reflects twelve months of information for NPC and five months of information for SPR and its pre-merger subsidiaries, and for the year ended December 31, 1998, reflects information for NPC only.

Year ended December 31,	**2002**	2001	2000	1999	1998
(dollars in thousands, except per share amounts)					
Operating Revenues	**$2,991,703**	$4,591,374	$2,336,113	$1,284,792	$ 873,682
Operating Income (Loss)	**$ (33,056)**	$ 222,869	$ 126,385	$ 162,861	$ 147,277
Net Income (Loss) from Continuing Operations	**$ (302,055)**	$ 33,566	$ (45,915)	$ 50,410	$ 83,673
Earnings (Deficit) from Continuing Operations Per Average Common Share—Basic	**$ (3.00)**	$ 0.34	$ (0.63)	$ 0.77	$ 1.64
Earnings (Deficit) from Continuing Operations Per Average Common Share—Diluted	**$ (3.00)**	$ 0.34	$ (0.63)	$ 0.77	$ 1.64
Total Assets	**$6,896,244**	$7,992,076	$5,677,908	$5,235,917	$2,541,840
Long-Term Debt and NPC Obligated Mandatorily Redeemable Preferred Trust Securities	**$3,251,755**	$3,564,977	$2,371,051	$1,793,999	$1,089,099
Dividends Declared Per Common Share	**$ 0.20**	$ 0.40	$ 1.00	$ 1.17	$ 1.45

SELECTED FINANCIAL DATA—NEVADA POWER COMPANY

Year ended December 31,	**2002**	2001	2000	1999	1998
(dollars in thousands)					
Operating Revenues	**$1,901,034**	$3,025,103	$1,326,192	$ 977,262	$ 873,682
Operating Income (Loss)	**$ (104,003)**	$ 144,364	$ 74,182	$ 116,983	$ 147,277
Net Income (Loss)	**$ (235,070)**	$ 63,405	$ (7,928)	$ 38,787	$ 83,673
Total Assets	**$4,068,522**	$4,704,606	$2,903,983	$2,724,329	$2,541,840
Long-Term Debt and Obligated Mandatorily Redeemable Preferred Trust Securities	**$1,677,469**	$1,796,839	$1,116,656	$1,119,876	$1,089,099
Dividends Declared—Common Stock	**$ 10,000**	$ 33,000	$ 64,267	$ 72,000	$ 73,715

SELECTED FINANCIAL DATA—SIERRA PACIFIC POWER COMPANY

The table below, for the year ended December 31, 1998, includes information for SPPC's water business disposed of in 2001.

Year ended December 31,	**2002**	2001	2000	1999	1998
(dollars in thousands)					
Operating Revenues	**$1,081,034**	$1,547,430	$ 995,722	$ 709,374	$ 685,189
Operating Income	**$ 55,292**	$ 78,968	$ 45,409	$ 112,703	$ 114,263
Net Income (Loss) from Continuing Operations	**$ (13,968)**	$ 22,743	$ (4,077)	$ 64,615	$ 84,475
Total Assets	**$2,398,490**	$2,706,976	$2,208,389	$2,084,707	$2,011,820
Long-Term Debt	**$ 914,788**	$ 923,070	$ 654,316	$ 673,930	$ 654,950
Dividends Declared—Common Stock	**$ 44,900**	$ 63,000	$ 85,000	$ 76,000	$ 76,000

TO OUR SHAREHOLDERS:

The past year was the most difficult in the history of Sierra Pacific Resources and its subsidiaries, Nevada Power and Sierra Pacific Power. While we have taken important steps forward to restore the company's financial health, significant challenges lie ahead.

As of this writing, we await regulatory decisions in our utility subsidiaries' latest deferred energy cases, filed in late 2002, as well as legal and regulatory rulings related to disputes with Enron and others resulting from the dysfunctional power and fuel markets that caused the energy crisis that gripped the Western United States in 2000 and 2001.

Sierra Pacific is only one of many companies that have experienced severe difficulties because of the energy markets in recent years. Credit ratings have been downgraded and the energy industry as a whole has lost billions of dollars in market capitalization.

Our Board and management team remain intently focused on developing and implementing business strategies that will enable us to continue restoring the company's financial health.

Importantly, we have successfully refinanced maturing debt despite a credit rating below investment grade. And, from an operational standpoint, we are well positioned for the always challenging peak demand summer months in southern Nevada after negotiating new purchased power contracts for this year and beyond. Protecting our customers from future volatility in energy markets and ensuring price stability remain at the top of our list of priorities.

Despite the company's extraordinary financial challenges, we experienced some notable operating successes in 2002. Thanks to the dedication and hard work of our employees, we continued to provide electric and natural gas customers with reliable, safe service.

While scorching temperatures resulted in record peak demand at both ends of the state, we kept the bright lights of Nevada shining through the summer. Efforts by Sierra Pacific Power and Nevada Power field crews were simply outstanding in restoring electric service to thousands of northern Nevada customers following a destructive storm in December, with all-time record winds and very heavy snow. In addition, the employees who operate and maintain our generating plants performed admirably, ensuring generation was available when needed.

Financial Results for 2002

Financial results for Sierra Pacific during the past year were the poorest we have ever experienced because of a $523 million pre-tax write-off necessitated by Public Utilities Commission of Nevada (PUCN) decisions in March and May 2002 to disallow a large portion of our actual power costs from the summer of 2001. Including the write-off, we reported a net loss of $307.5 million for the year. (For a detailed discussion of financial results, see the Management's Discussion and Analysis of Financial Condition and Results of Operations section and Financial Tables included in this report.)

Following the purchased power disallowances, Sierra Pacific's stock price fell sharply. In addition, credit rating services Moody's and Standard and Poor's downgraded our ratings.

Several actions were, and are continuing to be, taken in a concerted effort to repair the company's financial situation:

- To preserve cash, we immediately reduced costs and delayed construction on major electric transmission line projects for Nevada Power and Sierra Pacific Power without sacrificing system reliability. We are moving forward with portions of the Centennial Project in southern Nevada and the Falcon-to-Gonder transmission line in the north because they are critical to system reliability and in satisfying Nevada's growing demand for energy.

- We petitioned the Nevada state court to require the PUCN to reconsider its 2002 deferred energy decision and to allow full recovery of the dollars we spent to secure power supplies for our customers.

- We have forcefully refuted claims by Enron in federal bankruptcy court that we owe them approximately $300 million for energy that was never delivered to us. The bankruptcy judge presiding over the lawsuit filed against us by Enron has ordered the parties to the lawsuit to attempt to resolve their differences through mediation. This mediation is non-binding and will not necessarily affect the motions already filed with the bankruptcy court.
- We asked the Federal Energy Regulatory Commission (FERC) to modify purchased power contracts with energy providers from whom we had to buy power to meet our needs in a market now clearly proven to have been manipulated and dysfunctional, making it unjust and unreasonable during the California energy crisis.

New deferred energy rate cases for Nevada Power and Sierra Pacific Power are pending before the PUCN to recover actual power costs expended during 2002. Because purchased power costs have been and are expected to be significantly lower than they were during the 2000–2001 energy crisis, Nevada Power is seeking an overall rate decrease of 5.3 percent. Sierra Pacific Power's deferred energy recovery case is essentially flat with a slight charge requested for conservation program cost recovery. The Commission is expected to decide the Nevada Power case by mid May and we expect an order in the Sierra Pacific Power case by mid July.

Recent financing activities have provided much needed liquidity, and we continue to work on further improvements in our credit rating to strengthen our balance sheet and to rebuild shareholder value.

Our most pressing concern is to successfully resolve the legal and regulatory issues that could have an immediate impact on the company's balance sheet.

We are emphasizing a back-to-basics, cost-efficient approach throughout our organization and developing long-term business strategies appropriate for a traditional regulated utility. And we have implemented new energy procurement and risk-management policies and procedures designed to stabilize Sierra Pacific's risk in energy markets and address criticism from the PUCN, which was levied at the time of the March 2002 disallowances.

We are fully and painfully aware of how the events of the past two years have affected your investment in Sierra Pacific Resources, and we are working hard to make the changes needed to begin moving shareholder value in the right direction. On behalf of your Board of Directors, your company's management team, and the dedicated and skilled employees of Sierra Pacific, I would like to thank you for your patience and support.

Walter M. Higgins
Chairman, President and
Chief Executive Officer

March 28, 2003

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

The information in this report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements relate to anticipated financial performance, management's plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions, and other matters. Words such as "anticipate," "believe," "estimate," "expect," "intend," "plan," and "objective" and other similar expressions identify those statements that are forward-looking. These statements are based on management's beliefs and assumptions and on information currently available to management. Actual results could differ materially from those contemplated by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such statements, factors that could cause the actual results of SPR, NPC, or SPPC to differ materially from those contemplated in any forward-looking statement include, among others, the following:

(1) unfavorable rulings in rate cases previously filed, currently pending and to be filed by NPC and SPPC (the Utilities) with the Public Utilities Commission of Nevada (PUCN), including the periodic applications to recover costs for fuel and purchased power that have been recorded by the Utilities in their deferred energy accounts, and deferred natural gas recorded by SPPC for its gas distribution business;

(2) the ability of SPR, NPC, and SPPC to access the capital markets to support their requirements for working capital, including amounts necessary to finance deferred energy costs, construction costs, and the repayment of maturing debt, particularly in the event of additional unfavorable rulings by the PUCN, a further downgrade of the current debt ratings of SPR, NPC, or SPPC, and/or adverse developments with respect to NPC's or SPPC's power and fuel suppliers;

(3) whether NPC's ability to pay SPR dividends will be restored in the near future, and whether SPPC will be able to continue to pay SPR dividends under the terms of SPPC's financing agreements and/or restated articles of incorporation;

(4) whether the PUCN will issue favorable orders in a timely manner to permit the Utilities to borrow money and issue additional securities to finance the Utilities' operations and to purchase power and fuel necessary to serve their respective customers;

(5) whether suppliers, such as Enron, which have terminated their power supply contracts with NPC and/or SPPC will be successful in pursuing their claims against the Utilities for liquidated damages under their power supply contracts, and whether Enron will be successful in its lawsuit against NPC and SPPC;

(6) whether SPR, NPC, and SPPC will be able to maintain sufficient stability with respect to their liquidity and relationships with suppliers;

(7) whether current suppliers of purchased power, natural gas, or fuel to NPC or SPPC will continue to do business with NPC or SPPC or will terminate their contracts and seek liquidated damages from the respective Utility;

(8) whether the Utilities will need to purchase additional power on the spot market to meet unanticipated power demands (for example, due to unseasonably hot weather) and whether suppliers will be willing to sell such power to the Utilities in light of their weakened financial condition;

(9) whether SPPC will be able to make the gasifier facility at the Piñon Pine Power Project operational and, in any event, whether SPPC will be successful in obtaining PUCN approval to recover the costs of the gasifier in a future general rate case;

(10) whether NPC and SPPC will be successful in obtaining PUCN approval to recover goodwill and other merger costs recorded in connection with the 1999 merger between SPR and NPC in a future general rate case;

(11) wholesale market conditions, including availability of power on the spot market, which affect the prices the Utilities have to pay for power as well as the prices at which the Utilities can sell any excess power;

(12) the outcome of the Utilities' pending lawsuits in Nevada state court seeking to reverse portions of the PUCN's orders denying the recovery of deferred energy costs, including the outcome of petitions filed by the Bureau of Consumer Protection of the Nevada Attorney General's Office seeking additional disallowances;

(13) whether the Utilities will be able, either through Federal Energy Regulatory Commission (FERC) proceedings or negotiation, to obtain lower prices on their longer-term purchased power contracts entered into during 2000 and 2001 that are priced above current market prices for electricity;

(14) the effect that any future terrorist attacks, wars, or threats of war may have on the tourism and gaming industries in Nevada, particularly in Las Vegas, as well as on the economy in general;

(15) unseasonable weather and other natural phenomena, which can have potentially serious impacts on the Utilities' ability to procure adequate supplies of fuel or purchased power to serve their respective customers and on the cost of procuring such supplies;

(16) industrial, commercial, and residential growth in the service territories of the Utilities;

(17) the loss of any significant customers;

(18) the effect of existing or future Nevada, California, or federal legislation or regulations affecting electric industry restructuring, including laws or regulations which could allow additional customers to choose new electricity suppliers or change the conditions under which they may do so;

(19) changes in the business of major customers, including those engaged in gold mining or gaming, which may result in changes in the demand for services of the Utilities, including the effect on the Nevada gaming industry of the opening of additional Indian gaming establishments in California and other states;

(20) changes in environmental regulations, tax, or accounting matters or other laws and regulations to which the Utilities are subject;

(21) future economic conditions, including inflation or deflation rates and monetary policy;

(22) financial market conditions, including changes in availability of capital or interest rate fluctuations;

(23) unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs; and

(24) employee workforce factors, including changes in collective bargaining unit agreements, strikes, or work stoppages.

Other factors and assumptions not identified above may also have been involved in deriving these forward-looking statements, and the failure of those other assumptions to be realized, as well as other factors, may also cause actual results to differ materially from those projected. SPR, NPC, and SPPC assume no obligation to update forward-looking statements to reflect actual results, changes in assumptions, or changes in other factors affecting forward-looking statements.

CRITICAL ACCOUNTING POLICIES

The following items represent critical accounting policies that under different conditions or using different assumptions could have a material effect on the financial condition, liquidity, and capital resources of SPR and the Utilities:

Regulatory Accounting

The Utilities' rates are currently subject to the approval of the PUCN and, in the case of SPPC, they are also subject to the California Public Utility Commission (CPUC) and are designed to recover the cost of providing generation, transmission, and distribution services. As a result, the Utilities qualify for the application of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," issued by the Financial Accounting Standards Board (FASB). This statement recognizes that the rate actions of a regulator can provide reasonable assurance of the existence of an asset and requires the capitalization of incurred costs that would otherwise be charged to expense where it is probable that future revenue will be provided to recover these costs. SFAS No. 71 prescribes the method to be used to record the financial transactions of a regulated entity. The criteria for applying SFAS No. 71 include the following: (i) rates are set by an independent third-party regulator, (ii) approved rates are intended to recover the specific costs of the regulated products or services, and (iii) rates that are set at levels that will recover costs can be charged to and collected from customers.

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management regularly assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and the status of any pending or potential deregulation legislation. Although current rates do not include the recovery of all existing regulatory assets as discussed further below and in Note 1 in Notes to Financial Statements, management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the write-off of regulatory assets would be required to be recognized as a charge or expensed in current period earnings.

Regulatory Accounting affects other Critical Accounting Policies, including Deferred Energy Accounting, Accounting for Goodwill and Merger Costs, Accounting for Generation Divestiture Costs, Impairment of Long-Lived Assets, and Accounting for Derivatives and Hedging Activities, all of which are discussed immediately below.

Deferred Energy Accounting

On April 18, 2001, the Governor of Nevada signed into law Assembly Bill 369 (AB 369). The provisions of AB 369, which are described in greater detail in Regulation and Rate Proceedings, later, include, among others, a reinstatement of deferred energy accounting for fuel and purchased power costs incurred by electric utilities. In accordance with the provisions of SFAS No. 71, the Utilities implemented deferred energy accounting on March 1, 2001, for their respective electric operations. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates, that excess is not recorded as a current expense on the statement of operations but rather is deferred and recorded as an asset on the balance sheet. Conversely, a liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to PUCN review. AB 369 provides that the PUCN may not allow the recovery of any costs for purchased fuel or purchased power "that were the result of any practice or transaction that was undertaken, managed or performed imprudently by the electric utility." In reference to deferred energy accounting, AB 369 specifies that fuel and purchased power costs include all costs incurred to purchase fuel, to purchase capacity, and to purchase energy. The Utilities also record, and are eligible under the statute to recover, a carrying charge on such deferred balances.

The Utilities are exposed to commodity price risk primarily related to changes in the market price of electricity as well as changes in fuel costs incurred to generate electricity. See Energy Supply, later, for a discussion of the Utilities' purchased power procurement strategies, and Commodity Price Risk in Item 7A, Quantitative and Qualitative Disclosures About Market Risk, for a discussion of the Utilities' commodity risk management program. As discussed above, deferred energy accounting facilitates the recovery of costs incurred to procure fuel and purchased power for SPPC and NPC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

As described in more detail under Regulation and Rate Proceedings, Nevada Matters, Nevada Power Company 2001 Deferred Energy Case, on November 30, 2001, NPC filed an application with the PUCN seeking to establish a Deferred Energy Accounting Adjustment (DEAA) rate to clear deferred balances for purchased fuel and power costs accumulated between March 1, 2001 and September 30, 2001. The application sought to establish a rate to clear accumulated purchased fuel and power costs of $922 million and spread the cost recovery over a period of not more than three years. On March 29, 2002, the PUCN issued its decision on the deferred energy application, disallowing $434 million of deferred purchased fuel and power costs, and allowing NPC to collect the remaining $478 million over three years beginning April 1, 2002. As a result of this disallowance, NPC wrote off $465 million of deferred energy costs and related carrying charges, the two major national rating agencies immediately downgraded the credit rating on SPR's, NPC's, and SPPC's debt securities (followed by further downgrades late in April), and the market price of SPR's common stock fell substantially.

As described in more detail under Regulation and Rate Proceedings, Nevada Matters, Sierra Pacific Power Company 2002 Deferred Energy Case, SPPC filed an application with the PUCN seeking to establish a DEAA rate to clear its deferred balances for purchased fuel and power costs accumulated between March 1, 2001 and November 30, 2001. The application sought to establish a rate to clear accumulated purchased fuel and power costs of $205 million and spread the cost recovery over a period of not more than three years. On May 28, 2002, the PUCN issued its decision on SPPC's deferred energy application, disallowing $53 million of deferred purchased fuel and power costs, and allowing SPPC to collect the remaining $150 million over three years beginning June 1, 2002. As a result of this decision, SPPC wrote off $58 million of disallowed deferred energy costs and related carrying charges.

Both Utilities have continued to be entitled under AB 369 to utilize deferred energy accounting for their electric operations. Because of contracts entered into during the Western energy crisis in 2001 to assure adequate supplies of electricity for their customers, the Utilities incurred fuel and purchased power costs in excess of amounts they were permitted to recover in current rates. As a result, during 2002 both Utilities continued to record additional amounts in their deferral of energy costs accounts.

On November 14, 2002, NPC filed an application with the PUCN seeking to clear deferred balances of $195.7 million for purchased fuel and power costs accumulated between October 1, 2001, and September 30, 2002, and to spread the recovery of the deferred costs, together with a carrying charge, over a period of not more than three years.

Intervenors filed their direct testimony on March 7, 2003 calling for disallowances between approximately $83 and $300 million of the total fuel and purchased power costs. The largest of the proposed disallowances are based on the same alleged imprudence as found in the PUCN order for NPC's 2001 Deferred Energy Case relating to NPC's failure to enter into power contracts in 1999. Some Intervenors' testimony, in the current case, argue in favor of this disallowance based on the last Deferred order but did not quantify their proposals and in some cases would be additive to the ranges stated above. The PUCN Staff does not support this disallowance but calculated a range of $116 to $347 million in the event that the PUCN disallows deferred energy costs based upon the same alleged imprudence cited by the PUCN in its 2001 decision relative to this issue.

While all Intervenors call for the PUCN to reduce NPC's requested energy rates for recovery of past energy costs, some also propose to increase customers' energy rates for purchases that will occur during the upcoming deferred accounting period.

On January 14, 2003, SPPC filed an application with the PUCN seeking to clear deferred balances of $15.4 million for purchased fuel and power costs accumulated between December 1, 2001, and November 30, 2002, and to spread the recovery of the deferred costs, together with a carrying charge over a period of not more than three years.

A significant disallowance in either or both of these deferred energy rate cases or in future cases to be filed by either Utility would have a material adverse affect on the future financial position, results of operations, and liquidity of SPR, NPC, and SPPC and could make it difficult for one or more of SPR, NPC, or SPPC to continue to operate outside of bankruptcy. See Regulation and Rate Proceedings, later, for additional discussion of the regulatory process under way to recover these deferred costs.

If not for deferred energy accounting during 2001 and 2002, SPR's, NPC's, and SPPC's results of operations, financial condition, liquidity, and capital resources would have been materially adversely affected. For example, without the current deferrals permitted by the deferred energy accounting provisions of AB 369, the reported net losses of SPR, NPC, and SPPC for 2002 of ($307.5) million, ($235.1) million, and ($17.9) million would have been (net of income tax) reported as net losses (including the write-offs resulting from the disallowances discussed above) of ($495.9) million, ($379.7) million, and ($61.6) million, respectively. Similarly, without the deferred energy accounting provisions of AB 369, the 2001 reported net income of SPR, NPC, and SPPC of $56.7 million, $63.4 million, and $45.9 million would have been (net of income tax) reported as net losses of ($715.4) million, ($573.6) million, and ($89.1) million, respectively.

Accounting for Goodwill and Merger Costs

The order issued by the PUCN in December 1998 approving the merger of SPR and NPC directed both NPC and SPPC to defer three categories of merger costs to be reviewed for recovery through future rates. That order specifically directed both Utilities to defer merger transaction costs, transition costs, and goodwill costs for a three-year period. The deferral of these costs was intended to allow adequate time for the anticipated savings from the merger to develop. At the end of the three-year period, the order instructs the Utilities to propose an amortization period for the merger costs and allows the Utilities to recover the costs to the extent they are offset by merger savings.

Costs deferred as a result of the PUCN order were $331.2 million of goodwill and $62.2 million in other merger costs as of December 31, 2002. The deferred other merger costs consist of $40.5 million of transaction and transition costs and $21.7 million of employee separation costs. Employee separation costs were comprised of $17.2 million of employee severance, relocation and related costs, and $4.5 million of pension and postretirement benefits net of plan curtailment gains.

On October 1, 2001, and November 30, 2001, NPC and SPPC, respectively, filed applications with the PUCN for general rate increases that included, among other items, requests to recover deferred merger costs, including goodwill. In its decisions dated March 27, 2002, and May 28, 2002, for NPC and SPPC, respectively, the PUCN decided not to make any determination on the recovery of merger costs until general rate cases are filed with test years ending on or after December 31, 2002. However, the PUCN did instruct the Utilities to continue to recognize these costs as deferred assets without carrying charges.

The extent to which goodwill and merger costs will be recovered in future revenues and the timing of those recoveries is expected to be determined in general rate cases that are required to be filed in 2003. To the extent that the Utilities are not permitted to recover any portion of goodwill in future rates, the amount not recoverable will be reviewed for impairment and accounted for under the provisions of SFAS No. 142. A significant disallowance of goodwill or merger costs by the PUCN could have a material adverse affect on the future financial condition, results of operations and liquidity of SPR, NPC, and SPPC and could make it difficult for one or more of SPR, NPC, or SPPC to continue to operate outside of bankruptcy.

Accounting for Generation Divestiture Costs

As a condition to its approval of the merger between SPR and NPC, the Utilities filed, and in February 2000 the PUCN approved, a revised Divestiture Plan stipulation for the sale of the Utilities' generation assets. In May 2000, an agreement was announced for the sale of NPC's 14% undivided interest in the Mohave Generating Station ("Mohave"). In the fourth quarter of 2000, the Utilities announced agreements to sell six additional bundles of generation assets described in the approved Divestiture Plan. The sales were subject to approval and review by various regulatory agencies.

AB 369, which was signed into law on April 18, 2001, prohibits until July 2003 the sale of generation assets and directs the PUCN to vacate any of its orders that had previously approved generation divestiture transactions. In January 2001, California enacted a law that prohibits until 2006 any further divestiture of generation properties by California utilities, including SPPC, and could also affect any sale of NPC's interest in Mohave after July 2003 since the majority owner of that project is Southern California Edison. SPPC's request for an exemption from the requirements of a separate California law requiring approval of the CPUC to divest its plants was denied. In September 2002, the California Legislature approved an exemption to AB 6 that would allow SPPC to complete the sale of the hydroelectric units to TMWA subject to review and approval of the sale by the CPUC.

The sales agreements for the six bundles provided that they terminate eighteen months after their execution, and all of the agreements have now terminated in accordance with their respective provisions.

As of December 31, 2002, NPC and SPPC had incurred costs of approximately $20.1 million and $12.2 million, respectively, in order to prepare for the sale of generation assets. In the fourth quarter of 2001 each Utility requested recovery of its respective costs in its application for a general rate increase filed with the PUCN. In 2002 the PUCN delayed recovery of divestiture costs to future rate case requests but did grant a carrying charge on the costs until such time as recovery is allowed. To the extent that the Utilities are not permitted to recover any portion of these costs in future rates, the disallowed costs and related carrying charges would be required to be written off in current period earnings.

Impairment of Long-Lived Assets

SPR and the Utilities evaluate their Utility Plant and definite-lived tangible assets for impairment whenever indicators of impairment exist.

As discussed in more detail in Note 21 of Notes to Financial Statements, Piñon Pine, SPPC owns a combined cycle generation facility, a post-gasification facility, and, through its wholly owned subsidiaries, owns a gasifier that are collectively referred to as the Piñon Pine Power Project ("Piñon Pine"). Construction of Piñon Pine was completed in June 1998. Included in the Consolidated Balance Sheets of SPR and SPPC is the net book value of the gasifier and related assets, which is approximately $100 million as of December 31, 2002.

To date, SPPC has not been successful in obtaining sustained operation of the gasifier. In 2001 SPPC retained an independent engineering consulting firm to complete a comprehensive study of the Piñon Pine gasification plant. SPPC received a final report of the study in November 2002. SPPC is reviewing the various options outlined in the study. If after evaluating the options presented in the draft report, SPPC decides not to pursue modifications intended to make the facility operational, SPPC intends to seek recovery, net of salvage, through regulated rates in its next general rate case based, in part, on the PUCN's approval of Piñon Pine as a demonstration project in an earlier resource plan. However, if SPPC is unsuccessful in obtaining recovery, there could be a material adverse effect on SPPC's and SPR's financial condition and results of operations.

Accounting for Derivatives and Hedging Activities

Effective January 1, 2001, SPR, SPPC, and NPC adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138. As amended, SFAS No. 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position, measure those instruments at fair value, and recognize changes in the fair value of the derivative instruments in earnings in the period of change unless the derivative qualifies as an effective hedge.

In order to manage loads, resources and energy price risk, the Utilities buy fuel and power under forward contracts. In addition to forward fuel and power purchase contracts, the Utilities also use options and swaps to manage price risk. All of these instruments are considered to be derivatives under SFAS No. 133. The risk management assets and liabilities recorded in the balance sheets of the Utilities and SPR are primarily comprised of the fair value of these forward fuel and power purchase contracts and other energy related derivative instruments.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Fuel and purchased power costs are subject to deferred energy accounting. Accordingly, the energy related risk management assets and liabilities and the corresponding unrealized gains and losses (changes in fair value) are offset with a regulatory asset or liability rather than recognized in the statements of operations and comprehensive income. Upon settlement of a derivative instrument, actual fuel and purchased power costs are recognized if they are currently recoverable or deferred if they are recoverable or payable through future rates.

The fair values of the forward contracts and swaps are determined based on quotes obtained from independent brokers and exchanges. The fair values of options are determined using a pricing model which incorporates assumptions such as the underlying commodity's forward price curve, time to expiration, strike price, interest rates, and volatility. The use of different assumptions and variables in the model could have a significant impact on the valuation of the instruments.

At December 31, 2002, the fair value of the derivatives resulted in the recording of $30 million, $29 million, and $1 million in risk management assets and $74 million, $30 million, and $44 million in risk management liabilities in the Consolidated Balance Sheets of SPR, NPC, and SPPC, respectively. Net risk management regulatory assets of $45 million, $2 million, and $44 million were recorded in the Consolidated Balance Sheets of SPR, NPC, and SPPC, respectively at December 31, 2002.

SPR and the Utilities have other non-energy related derivative instruments such as interest rate swaps. The transition adjustment related to these types of derivative instruments resulting from the adoption of SFAS No. 133 was reported as the cumulative effect of a change in accounting principle in Other Comprehensive Income. Additionally, the changes in fair values of these non-energy related derivatives are also reported in Other Comprehensive Income until the related transactions are settled or terminate, at which time the amounts are reclassified into earnings. On April 1, 2002, SPR paid $9.5 million to terminate an interest rate swap related to $200 million of SPR floating rate notes maturing April 20, 2003, of which $7.3 million was reclassified into earnings during the twelve-month period ended December 31, 2002.

Environmental Contingencies

SPR and its subsidiaries are subject to federal, state and local regulations governing air and water quality, hazardous and solid waste, land use, and other environmental considerations. Nevada's Utility Environmental Protection Act requires approval of the PUCN prior to construction of major utility, generation, or transmission facilities. The United States Environmental Protection Agency (EPA), Nevada Division of Environmental Protection (NDEP), and Clark County Health District (CCHD) administer regulations involving air and water quality, solid and hazardous and toxic waste.

SPR and its subsidiaries are subject to rising costs that result from a steady increase in the number of federal, state, and local laws and regulations designed to protect the environment. These laws and regulations can result in increased capital, operating, and other costs as a result of compliance, remediation, containment, and monitoring obligations, particularly with laws relating to power plant emissions. In addition, SPR or its subsidiaries may be a responsible party for environmental cleanup at a site identified by a regulatory body. The management of SPR and its subsidiaries cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating cleanup costs and compliance and the possibility that changes will be made to the current environmental laws and regulations. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. SPR and its subsidiaries accrue for environmental costs only when they can conclude that it is probable that they have an obligation for such costs and can reasonably determine the amount of such costs.

Note 17 of Notes to Financial Statements, Commitments and Contingencies, discusses the environmental matters of SPR and its subsidiaries that have been identified, and the estimated financial effect of those matters. To the extent that (1) actual results differ from the estimated financial effects, (2) there are environmental matters not yet identified for which SPR or its subsidiaries are determined to be responsible, or (3) the Utilities are unable to recover through future rates the costs to remediate such environmental matters, there could be a material adverse effect on the financial condition and future liquidity and results of operations of SPR and its subsidiaries.

Litigation Contingencies

Note 17 of Notes to Financial Statements, Commitments and Contingencies, discusses the significant legal matters of SPR and its subsidiaries. SPR and its subsidiaries, through the course of their normal business operations, are currently involved in a number of other legal actions, none of which has had or, in the opinion of management, is expected to have a significant impact on its financial position or results of operations.

Defined Benefit Plans and Other Postretirement Plans

As further explained in Note 14 of Notes to Financial Statements, Retirement Plan and Postretirement Benefits, SPR maintains a pension plan as well as other postretirement benefit plans that provide health and life insurance for retired employees. All employees are eligible for these benefits if they reach retirement age while still working for SPR or its subsidiaries. These costs are determined in accordance with the provisions of SFAS No. 87, "Employers' Accounting for Pensions," and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," and ultimately collected in rates billed to customers. The amounts funded are then used to meet benefit payments to plan participants. SPR contributed $41.1 million and $13.8 million to its pension plan, and $0.2 million and $0.7 million to the other postretirement benefits plan in 2002 and 2001, respectively. Due to the sharp decline in United States equity markets since the third quarter of 2000, the value of a significant portion of the assets held in the plans' trusts to satisfy the obligations of the plans has decreased significantly. As a result, additional contributions may be required in the future to meet the requirements of the plan to pay benefits to plan participants.

Pension Plans

SPR's reported costs of providing noncontributory defined pension benefits (described in Note 14 of Notes to Financial Statements, Retirement Plan and Postretirement Benefits) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

For example, pension costs are impacted by actual employee demographics (including age and employment periods), the level of contributions SPR makes to the plan, and earnings on plan assets. Changes made to the provisions of the plan may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

In accordance with SFAS No. 87, changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. For the twelve months ended December 31, 2002, 2001, and 2000, SPR recorded pension benefit expense of approximately $22.5 million, $14.2 million, and $12.5 million, respectively, in accordance with the provisions of SFAS No. 87. Actual payments of benefits made to retirees for the twelve months ended September 30, 2002 and 2001, were $30.0 million and $36.4 million, respectively.

SPR has made no changes to pension plan provisions in 2002, 2001, and 2000 that have had any significant impact on recorded pension amounts. As further described in Note 14 of Notes to Financial Statements, Retirement Plan and Postretirement Benefits, SPR has revised the discount rate in 2002 as compared to 2001 and 2000. This change did not have a significant impact on reported pension costs in 2002.

SPR's pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased pension costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded pension costs.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage. While the chart below reflects an increase in the percentage for each assumption, SPR and its actuaries expect that the inverse of this change would impact the projected benefit obligation (PrBO) and the reported annual pension cost on the income statement (PeC) by a similar amount in the opposite direction. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption only.

Actuarial Assumption ($ millions)	Change in Assumption Increase/ (Decrease)	Impact on PrBO Increase/ (Decrease)	Impact on PeC Increase/ (Decrease)
Discount rate	1%	$(45.0)	$(4.9)
Rate of return on plan assets	1%	$ —	$(2.7)

In selecting an assumed discount rate, SPR considered the yield on high quality bonds as measured by the Moody's Investors Service, Inc. (Moody's) Aa composite bond index.

In selecting an assumed rate of return on plan assets, SPR considers past performance and economic forecasts for the types of investments held by the plan. The market value of SPR's plan assets has been affected by sharp declines in equity markets since the third quarter of 2000. Plan assets earned $51.1 million in 2000 and lost $39.3 million and $23.1 million in 2001 and 2002, respectively.

As a result of SPR's plan asset returns at September 30, 2002, SPR was required to recognize an additional minimum liability in the amount of $89.6 million, as prescribed by SFAS No. 87. The liability was recorded as a reduction to common equity through a charge to Accumulated Other Comprehensive Income and did not affect net income for 2002. The charge to Accumulated Other Comprehensive Income will be restored through common equity in future periods to the extent fair value of trust assets exceeds the accumulated benefit obligation.

Pension cost and cash funding requirements could increase in future years without a substantial recovery in the equity markets.

Other Postretirement Benefits

SPR's reported costs of providing other postretirement benefits (described in Note 14 of Notes to Financial Statements, Retirement Plan and Postretirement Benefits) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

For example, other postretirement benefit costs are impacted by actual employee demographics (including age and employment periods), the level of contributions made to the plan, earnings on plan assets, and health care cost trends. Changes made to the provisions of the plan may also impact current and future other postretirement benefit costs. Other postretirement benefit costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the postretirement benefit obligation and postretirement costs.

For the twelve months ended December 31, 2002, 2001, and 2000, SPR recorded other postretirement benefit expense of approximately $3.1 million, $2.5 million, and $2.6 million, respectively, in accordance with the provisions of SFAS No. 106. Actual payments of benefits made to retirees for the twelve months ended September 30, 2002 and 2001, were $6.9 million and $4.6 million, respectively.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

SPR has made no changes to other postretirement benefit plan provisions in 2002, 2001, and 2000 that have had any significant impact on recorded benefit plan amounts. As further described in Note 14 of Notes to Financial Statements, Retirement Plan and Postretirement Benefits, SPR has revised the discount rate in 2002 as compared to 2001 and 2000. This change did not have a significant impact on reported other postretirement benefit costs in 2002. However, in determining the other postretirement benefit obligation and related cost, these assumptions can change from period to period, and such changes could result in material changes to such amounts.

SPR's other postretirement benefit plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased other postretirement benefit costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded other postretirement benefit costs.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage. While the chart below reflects an increase in the percentage for each assumption, SPR and its actuaries expect that the inverse of this change would impact the projected accumulated other postretirement benefit obligation (APBO) and the reported annual other postretirement benefit cost on the income statement (PBC) by a similar amount in the opposite direction. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption only.

Actuarial Assumption ($ millions)	Change in Assumption Increase/ (Decrease)	Impact on APBO Increase/ (Decrease)	Impact on PBC Increase/ (Decrease)
Discount rate	1%	$(15.7)	$(1.5)
Health Care cost trend rate	1%	$ 14.9	$ 1.5
Rate of return on plan assets	1%	N/A	$(0.5)

In selecting an assumed discount rate, SPR considered the yield on high quality bonds as measured by Moody's Aa composite bond index.

In selecting an assumed rate of return on plan assets, SPR considers past performance and economic forecasts for the types of investments held by the plan. The market value of the SPR's plan assets has been affected by sharp declines in equity markets since the third quarter of 2000. Plan assets increased in value $17.3 million in 2000 and lost $15.8 million and $6.8 million in 2001 and 2002, respectively.

Also, other postretirement benefit cost and cash funding requirements could increase in future years without a substantial recovery in the equity markets.

Cost Capitalization Policies

The Utilities continue to devote substantial resources in 2003 on the Centennial Transmission project at NPC and the Falcon to Gonder Transmission project at SPPC. In addition, certain operating units of the Utilities are charged with maintaining, repairing and replacing components of generation, transmission and distribution systems both on a scheduled basis and on an as-needed basis. As described in Note 1 of Notes to Financial Statements, Summary of Significant Accounting Policies, the cost of additions, including betterments and replacements of units of property, is charged to utility plant. When units of property are replaced, renewed or retired, their cost, plus removal or disposal costs less salvage, is charged to accumulated depreciation. Certain direct and indirect costs are capitalized, including the cost of debt and equity capital associated with construction and retirement activity as prescribed by Generally Accepted Accounting Principles (GAAP) and the FERC's Uniform System of Accounts.

The indirect construction overhead costs capitalized are based upon the following cost components: the cost of time spent by administrative employees in planning and directing construction; property taxes; employee benefits including such costs as pensions, postretirement, and postemployment benefits, vacations and payroll taxes; and an allowance for funds used during construction (AFUDC). The level of indirect construction overhead costs capitalized by the Utilities is based upon real-time construction activity. Accordingly, payroll and other costs capitalized will fluctuate based upon seasonal construction activities and the deployment of resources to those efforts. During periods of higher maintenance levels, these payroll and other costs will not be capitalized. As such, operating income could be impacted by the manner in which payroll and related costs are deployed. However, the total cash flow of the Utilities is not impacted by the allocation of these costs to various construction or maintenance activities.

In 2002, the Utilities capitalized approximately $5.2 million of AFUDC as a result of construction activity financed primarily by their debt. This amount is a noncash component reflected in the Consolidated Statements of Operations and has no impact on the operating cash flow. Recognition of AFUDC as a cost of utility plant is in accordance with established regulatory ratemaking practices. Such practices permit the Utility to earn a fair return on, and recover in rates, all capital costs charged for Utility services.

Depreciation Expense

The Utilities have a significant investment in electric plant. SPPC also has an investment in gas distribution plant. Depreciable assets of generation, transmission and distribution operations represent approximately 92% of the Utilities' investment in utility plant. As described in Note 1 to Notes to Financial Statements, Summary of Significant Accounting Policies, the Utilities depreciate these assets utilizing a composite rate, which currently includes a component for net negative salvage. These assets are depreciated on a straight-line basis over the remaining useful life of the related assets, which approximates the anticipated physical lives of these assets in most cases. The Nevada Administrative Code requires the Utilities to provide a depreciation study every four years in order to substantiate the remaining physical lives of their investment in utility plant. Adjustments to the estimated depreciable lives of the Utilities' plant are recorded on a prospective basis, as prescribed by GAAP and the FERC's Uniform System of Accounts.

Substantially all of the Utilities' plant is subject to the ratemaking jurisdiction of the PUCN or the FERC and, in the case of SPPC, the CPUC, which also approves any changes the Utilities may make to depreciation rates utilized for this property. Because the Utilities' periodic depreciation expense is included as a component of the revenue requirement utilized in the development of the Utilities' tariff rates, revenue reflects collection of the recognized depreciation expense. Accordingly, the impact of depreciation on net income is not significant. However, operating cash flows are positively affected by the amount of depreciation collected in rates, since depreciation expense is not a current cash outlay for the Utilities.

Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities will be recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities due to the passage of time will be an operating expense. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes written or oral contracts, including obligations arising under the doctrine of promissory estoppel. The Utilities adopted SFAS No. 143 on January 1, 2003.

Prior to adopting SFAS No. 143, costs for removal of most utility assets were accrued as an additional component of depreciation expense. Under SFAS No. 143, only the costs to remove an asset with legally binding retirement obligations will be accrued over time through accretion of the asset retirement obligation and depreciation of the capitalized asset retirement cost.

Management's methodology to assess its legal obligation included an inventory of assets by system and components, and a review of right of ways and easements, regulatory orders, leases and federal, state, and local environmental laws. Management assumed in determining its Asset Retirement Obligations that transmission, distribution and communications systems will be operated in perpetuity and would continue to be used or sold without land remediation; and, mass asset properties that are replaced or retired frequently would be considered normal maintenance.

Management has identified a legal obligation to retire generation plant assets specified in land leases for NPC's jointly-owned Navajo generating station. The land on which the Navajo generating station resides is leased from the Navajo Nation. The provisions of the leases require the lessees to remove the facilities upon request of the Navajo Nation at the expiration of the leases. Management has determined that the present value of NPC's Navajo Asset Retirement Obligation will not have a material effect on the financial position or results of operations of SPR or NPC. SPPC has no significant asset retirement obligations.

The Utilities have various transmission and distribution lines as well as substations that operate under various rights of way that contain end dates and restorative clauses. Management operates the transmission and distribution system as though they will be operated in perpetuity and will continue to be used or sold without land remediation. As a result, the Utilities have not recorded any costs associated with the removal of the transmission and distribution systems.

Stock Compensation Plans

In December 2002, the FASB released SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure," as an amendment to SFAS No. 123, "Accounting for Stock-Based Compensation." SPR has previously adopted the disclosure-only provisions of SFAS No. 123, and as of December 31, 2002, has adopted the updated disclosure requirements set forth in SFAS No. 148. Pursuant to those updated disclosure requirements, SPR has included the following discussion on the stock compensation plans. For additional information on SPR's stock compensation plans, see Note 1 of Notes to Financial Statements, Summary of Significant Accounting Policies, and Note 15, Stock Compensation Plans.

At December 31, 2002, SPR had several stock-based compensation plans. SPR applies Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," in accounting for its stock option plans. Accordingly, no compensation cost has been recognized for nonqualified stock options and the employee stock purchase plan. SPR has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," and its related amendment(s). Had compensation cost for SPR's nonqualified stock options and the employee stock purchase plan been determined based on the fair value at the grant dates for awards under those plans, consistent with the provisions of SFAS No. 123, SPR's income applicable to common stock would have been decreased to the pro forma amounts indicated below (dollars in thousands, except per share amounts):

		2002	2001	2000
Stock compensation cost included in net income as reported, net of related tax effects	As reported	**$ (1,567)**	$ 346	$ (152)
Net income (loss)	As reported	**$(307,521)**	$56,733	$(39,780)
Less: Stock compensation cost, net of related tax effects	Pro forma	**2,047**	1,209	695
Net income (loss)	Pro forma	**$(309,568)**	$55,524	$(40,475)
Basic earnings per share	As reported	**$ (3.01)**	$ 0.65	$ (0.51)
	Pro forma	**$ (3.03)**	$ 0.63	$ (0.52)
Diluted earnings per share	As reported	**$ (3.01)**	$ 0.65	$ (0.51)
	Pro forma	**$ (3.03)**	$ 0.63	$ (0.52)

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Unbilled Receivables

Revenues related to the sale of energy are recorded based on meter reads, which occur on a systematic basis throughout a month, rather than when the service is rendered or energy is delivered. At the end of each month, the energy delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of energy procured and generated during that month, historical customer class usage patterns and the Utilities' current tariffs. Customer accounts receivable as of December 31, 2002, include unbilled receivables of $60 million and $63 million for NPC and SPPC, respectively. Customer accounts receivable as of December 31, 2001, include unbilled receivables of $49 million and $63 million for NPC and SPPC, respectively.

Provision for Uncollectible Accounts

The Utilities reserve for doubtful accounts based on past experience writing off uncollectible customer accounts. The adequacy of these reserves will vary to the extent that future collections differ from past experience.

MAJOR FACTORS AFFECTING RESULTS OF OPERATIONS

As discussed in the results of operations sections that follow, operating results for the year ended December 31, 2002, were severely affected by the PUCN's March 29, 2002, decision in NPC's deferred energy rate case to disallow $434 million of deferred purchased fuel and power costs. The PUCN concluded that NPC was imprudent in entering into certain transactions and also imprudent in not entering into other transactions: in particular, that NPC should have purchased 25% of its projected 2001 load in 1999 when prices were lower, and that it purchased 3% too much supply for summer 2001 and should have sold the excess at an earlier date. NPC has appealed this decision to the First Judicial District Court of Nevada. Arguments were heard on March 14, 2003, and a decision is expected in the second quarter. As a result of this disallowance, NPC wrote off approximately $465 million of deferred energy costs and related carrying charges. In addition, the decision of the PUCN on May 28, 2002, in SPPC's deferred energy rate case to disallow $53 million of deferred purchased fuel and power costs accumulated between March 1, 2001, and November 30, 2001, had a significant negative impact on the results of operations of SPR and SPPC for the year ended December 31, 2002. The PUCN concluded that SPPC was imprudent for buying too much power for summer 2001, and for failing to buy 33% of its total summer 2001 supplies on an index price instead of a firm price. SPPC has appealed this decision to First Judicial District Court of Nevada and arguments are scheduled to be heard in October 2003. As a result of this disallowance, SPPC wrote off approximately $58 million of deferred energy costs and related carrying charges. The discussion below provides the context in which these decisions were made.

In an effort to mitigate the effects of higher fuel and purchased power costs that developed in the western United States in 2000, the Utilities entered into the Global Settlement with the PUCN in July 2000 which established a mechanism that initiated incremental rate increases for each Utility. Cumulative electric rate increases under the Global Settlement were $127 million and $65 million per year for NPC and SPPC, respectively.

However, because the rate adjustment mechanism of the Global Settlement was subject to certain caps and could not keep pace with the continued escalation of fuel and purchased power prices, on January 29, 2001, the Utilities filed a Comprehensive Energy Plan (CEP) with the PUCN. The CEP included a request for emergency rate increases (CEP Riders). On March 1, 2001, the PUCN permitted the requested CEP Riders to go into effect subject to later review. The CEP Riders provided further rate increases of $210 million and $104 million per year, respectively, for NPC and SPPC.

Notwithstanding the increases under the Global Settlement and the CEP Riders, the Utilities' revenues for fuel and purchased power recovery continued to be less than the related expenses. Accordingly, the Utilities sought additional relief pursuant to legislation.

On April 18, 2001, the Governor of Nevada signed into law Assembly Bill 369 (AB 369). The provisions of AB 369 include a moratorium on the sale of generation assets by electric utilities until July 2003, the repeal of electric industry restructuring, and beginning March 1, 2001, a reinstatement of deferred energy accounting for fuel and purchased power costs incurred by electric utilities. The stated purposes of this emergency legislation included, among others, to control volatility in the price of electricity in the retail market in Nevada and to ensure that the Utilities had the necessary financial resources to provide adequate and reliable electric service under the then present market conditions.

As discussed above in Critical Accounting Policies, deferred energy accounting allows the Utilities an opportunity to recover in future periods that portion of their costs for fuel and purchased power not recovered by current rates and defers to future periods the expense associated with the amounts by which fuel and purchased power costs exceed the costs to be recovered in current rates. Recovery is subject to PUCN review as to prudency and other matters.

AB 369 requires each Utility to file general rate applications and deferred energy applications with the PUCN by specific dates. On November 30, 2001, NPC filed a deferred energy application seeking to establish a Deferred Energy Accounting Adjustment (DEAA) rate to clear purchased fuel and power costs of $922 million accumulated between March 1, 2001, and September 30, 2001, and to spread the cost recovery over a period of not more than three years. On February 1, 2002, SPPC filed a deferred energy application seeking to establish a DEAA rate to clear purchased fuel and power costs of $205 million accumulated between March 1, 2001, and November 30, 2001, and to spread the cost recovery over a period of not more than three years. See Regulation and Rate Proceedings, later, for a discussion of the Utilities' general rate case filings and decisions.

The March 29, 2002, decision of the PUCN on NPC's deferred energy rate case to disallow $434 million of deferred purchased fuel and power costs accumulated between March 1, 2001, and September 30, 2001, had a significant negative impact on the results of operations of SPR and NPC for the year ended December 31, 2002. The PUCN's decision also caused the two major national rating agencies to issue immediate downgrades of the credit ratings on SPR's, NPC's and SPPC's debt securities (followed by further downgrades late in April). Following those events, the market price of SPR's common stock fell substantially; NPC and SPPC were obliged within five business days of the downgrades to issue General and Refunding Mortgage Bonds to secure their bank lines of credit; NPC was obliged to obtain a waiver and amendment from its credit facility banks before it was permitted to draw down on the facility; NPC and SPPC were no longer able to issue commercial paper; a number of NPC's power suppliers contacted NPC regarding its ability to pay the purchase price of outstanding contracts; and several power suppliers, including a subsidiary of Enron Corp., terminated their power supply agreements with one or both of the Utilities. As discussed later under Regulation and Rate Proceedings, the PUCN's March 29, 2002, decision on NPC's deferred energy application is being challenged by NPC in a lawsuit filed in the First District Court of Nevada. Arguments were heard on March 14, 2003 and a decision is expected in the second quarter. The Bureau of Consumer Protection (BCP) of the Nevada Attorney Generals Office has since filed a petition in NPC's pending state court case seeking additional disallowances.

The May 28, 2002, decision of the PUCN on SPPC's deferred energy rate case to disallow $53 million of deferred purchased fuel and power costs accumulated between March 1, 2001, and November 30, 2001, also had a significant negative impact on the results of operations of SPR and SPPC for the year ended December 31, 2002. The PUCN's decision on SPPC's deferred energy application is being challenged by SPPC in a lawsuit filed August 22, 2002, in Nevada state court, which is discussed later under Regulation and Rate Proceedings, and arguments are scheduled to be heard in October 2003. The BCP of the Nevada Attorney Generals Office has since filed a petition in SPPC's state action seeking additional disallowances.

On November 14, 2002, NPC filed an application with the PUCN seeking to clear deferred balances of $195.7 million for purchased fuel and power costs accumulated between October 1, 2001, and September 30, 2002, and to spread the recovery of the deferred costs, together with a carrying charge, over a period of not more than three years. On January 14, 2003, SPPC filed an application with the PUCN seeking to clear deferred balances of $15.4 million for purchased fuel and power costs accumulated between December 1, 2001, and November 30, 2002, and to spread the recovery of the deferred costs, together with a carrying charge, over a period of not more than three years. See "Critical Accounting Policies—Deferred Energy Accounting" above for more detail.

A significant disallowance in either or both of these deferred energy rate cases or in future cases to be filed by either Utility could further weaken the financial condition, liquidity, and capital resources of SPR, NPC, and SPPC. In particular, such a decision or decisions could cause further downgrades of debt securities by the rating agencies, could make it impracticable to access the capital markets, and could cause additional power suppliers to terminate purchased power contracts and seek liquidated damages. Under such circumstances, it could be difficult for one or more of SPR, NPC, or SPPC to operate outside of bankruptcy.

SIERRA PACIFIC RESOURCES

Results of Operations

SPR incurred a net loss of ($307.5) million for the year ended December 31, 2002, compared to net income of $56.7 million in 2001, and a net loss of ($39.8) million in 2000. SPR's operating results for 2002 reflect the write-off of $527 million (before taxes) of deferred energy costs and related carrying charges as a result of the PUCN's decisions in NPC's and SPPC's deferred energy rate cases to disallow $434 million and $57 million, respectively, of deferred purchased power, fuel, and gas costs.

On March 15, 2002, SPR paid $20.6 million in common stock dividends. NPC declared and paid a common stock dividend of $10 million to its parent, SPR, in the first quarter of 2002. During 2002, SPPC paid common stock dividends of $44.9 million to its parent, SPR, and $3.9 million in dividends to holders of its preferred stock. NPC and SPPC each received a capital contribution of $10 million from SPR in March 2002.

Analysis of Cash Flows

SPR's consolidated net cash flows improved in 2002 compared to 2001, resulting from an increase in cash flows from operating activities offset in part by decreases in cash flows from investing and financing activities. Although SPR recorded a net loss during 2002 compared to net income in 2001, the current year's loss resulted largely from the write-off of disallowed deferred energy costs at the utilities for which the cash outflow had occurred in 2001. Other factors contributing to 2002's improved cash flows from operating activities include the collection of deferred energy costs from customers and lower energy prices. Also, cash flows from operating activities in the current year reflect the receipt of an income tax refund. Cash flows from investing activities decreased in 2002 because 2001 investing activities included cash provided from the sale of the assets of SPPC's water business. Also, cash flows from investing activities decreased because of additional cash utilized for construction activities during 2002 compared to 2001. Cash flows from financing activities were lower in 2002 because of decreases in net long-term debt issued, decreases in short-term borrowings and reduced proceeds from the sale of common stock.

SPR's consolidated net cash flows during 2001 were comparable to 2000. An increase in net cash flows used for operating activities was offset by a decrease in cash used for investing activities and an increase in cash provided from financing activities. The increase in cash used in operating activities resulted substantially from the payment of higher energy and natural gas costs. The decrease in cash used for investing activities resulted from the sale of SPPC's water business. The increase in cash provided from financing activities resulted from a reduction in net retirements of short-term debt and proceeds from the sale of common stock. Cash provided by financing activities was substantially utilized for the payment of higher energy costs in 2001. See Note 7, Common Stock and Other Paid-In Capital, and Note 12, Short-Term Borrowings, of Notes to Financial Statements for detailed financing information.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Liquidity and Capital Resources (SPR Consolidated)

SPR, on a stand-alone basis, had cash and cash equivalents of approximately $1.5 million at December 31, 2002, and approximately $179.3 million at February 28, 2003.

SPR's future liquidity and its ability to pay the principal of and interest on its indebtedness depend on SPPC's ability to continue to pay dividends to SPR, on NPC's financial stability and the restoration of its ability to pay dividends to SPR, and on SPR's ability to access the capital markets or otherwise refinance maturing debt. Further adverse developments at NPC or SPPC, including a material disallowance of deferred energy costs in current and future rate cases or an adverse decision in the pending lawsuit by Enron, could make it difficult for SPR to operate outside of bankruptcy.

Dividends from Subsidiaries

Since SPR is a holding company, substantially all of its cash flow is provided by dividends paid to SPR by NPC and SPPC on their common stock, all of which is owned by SPR. Since NPC and SPPC are public utilities, they are subject to regulation by state utility commissions which may impose limits on investment returns or otherwise impact the amount of dividends that the Utilities may declare and pay, and to federal statutory limitation on the payment of dividends. In addition, certain agreements entered into by the Utilities set restrictions on the amount of dividends they may declare and pay and restrict the circumstances under which such dividends may be declared and paid. The specific restrictions on dividends contained in agreements to which NPC and SPPC are party, as well as specific regulatory limitations on dividends, are summarized below.

- NPC's first mortgage indenture limits the cumulative amount of dividends and other distributions that NPC may pay on its capital stock to the cumulative net earnings of NPC since 1953, subject to adjustments for the net proceeds of sales of capital stock since 1953. At the present time, this restriction precludes NPC from making further payments of dividends on NPC's common stock and will continue to bar dividends until NPC, over time, generates sufficient earnings to eliminate the deficit under this provision (which was approximately $237 million as of December 31, 2002), unless the restriction is earlier waived, amended, or removed by the consent of the first mortgage bondholders, or the first mortgage bonds are redeemed or defeased. There can be no assurance that any such consent could be obtained or that any first mortgage bonds could be redeemed prior to their stated maturity. Under this provision, NPC continues to have capacity to repurchase or redeem shares of its capital stock, although other restrictions set forth below would limit the amount of any such repurchases or redemptions.
- NPC's 10⅞% General and Refunding Mortgage Notes, Series E, due 2009, which were issued on October 29, 2002, limit the amount of payments in respect of common stock that NPC may pay to SPR. However, that limitation does not apply to payments by NPC to enable SPR to pay its reasonable fees and expenses (including, but not limited to, interest on SPR's indebtedness and payment obligations on account of SPR's Premium Income Equity Securities (PIES)) provided that:
  - those payments do not exceed $60 million for any one calendar year,
  - those payments comply with any regulatory restrictions then applicable to NPC, and
  - the ratio of consolidated cash flow to fixed charges for NPC's most recently ended four full fiscal quarters immediately preceding the date of payment is at least 1.75 to 1.

  The terms of the Series E Notes also permit NPC to make payments to SPR in an aggregate amount not to exceed $15 million from the date of the issuance of the Series E Notes. In addition, NPC may make payments to SPR in excess of the amounts described above so long as, at the time of payment and after giving effect to the payment:

  - there are no defaults or events of default with respect to the Series E Notes,
  - NPC has a ratio of consolidated cash flow to fixed charges for NPC's most recently ended four full fiscal quarters immediately preceding the payment date of at least 2.0 to 1, and
  - the total amount of such dividends is less than:
    - the sum of 50% of NPC's consolidated net income measured on a quarterly basis cumulative of all quarters from the date of issuance of the Series E Notes, plus
    - 100% of NPC's aggregate net cash proceeds from contributions to its common equity capital or the issuance or sale of certain equity or convertible debt securities of NPC, plus
    - the lesser of cash return of capital or the initial amount of certain restricted investments, plus
    - the fair market value of NPC's investment in certain subsidiaries.

  If NPC's Series E Notes are upgraded to investment grade by both Moody's Investors Service, Inc. (Moody's) and Standard & Poor's Rating Group, Inc. (S&P), these restrictions will be suspended and will no longer be in effect so long as the Series E Notes remain investment grade.

- On October 29, 2002, NPC established an accounts receivables purchase facility. The agreements relating to the receivables purchase facility contain various conditions, including a limitation on payments in respect of common stock by NPC to SPR that is identical to the limitation contained in NPC's General and Refunding Mortgage Notes, Series E, described above.
- The PUCN issued a Compliance Order, Docket No. 02-4037, on June 19, 2002, relating to NPC's request for authority to issue long-term debt. The PUCN order requires that until such time as the order's authorization expires (December 31, 2003), NPC must either receive the prior approval of the PUCN or reach an equity ratio of 42% before paying any dividends to SPR. If NPC achieves a 42% equity ratio prior to December 31, 2003, the dividend restriction ceases to have effect. As of December 31, 2002, NPC's equity ratio was 36.1%.
- The terms of NPC's preferred trust securities provide that no dividends may be paid on NPC's common stock if NPC has elected to defer payments on the junior subordinated debentures issued in conjunction with the preferred trust securities. At this time, NPC has not elected to defer payments on the junior subordinated debentures.
- SPPC's Term Loan Agreement dated October 30, 2002, which expires October 31, 2005, limits the amount of payments that SPPC may pay to SPR. However, that limitation does not apply to payments by SPPC to enable SPR to pay its reasonable fees and expenses (including, but not limited to, interest on SPR's indebtedness and payment obligations on account of SPR's PIES) provided that those payments do not exceed $90 million, $80 million and $60 million in the aggregate for the twelve month periods ending on October 30, 2003, 2004 and 2005, respectively. The Term Loan Agreement also permits SPPC to make payments to SPR in an aggregate amount not to exceed $10 million during the term of the Term Loan Agreement. In addition, SPPC may make payments to SPR in excess of the amounts described above so long as, at the time of the payment and after giving effect to the payment, there are no defaults or events of default under the Term Loan Agreement, and such amounts, when aggregated with the amount of payments to SPR by SPPC since the date of execution of the Term Loan Agreement, do not exceed the sum of:
    - 50% of SPPC's Consolidated Net Income for the period commencing January 1, 2003, and ending with last day of fiscal quarter most recently completed prior to the date of the contemplated dividend payment, *plus*
    - the aggregate amount of cash received by SPPC from SPR as equity contributions on its common stock during such period.
- On October 29, 2002, SPPC established an accounts receivables purchase facility. The agreements relating to the receivables purchase facility contain various conditions, including a limitation on the payment of dividends by SPPC to SPR that is identical to the limitation contained in SPPC's Term Loan Agreement, described above.
- SPPC's Articles of Incorporation contain restrictions on the payment of dividends on SPPC's common stock in the event of a default in the payment of dividends on SPPC's preferred stock. SPPC's Articles also prohibit SPPC from declaring or paying any dividends on any shares of common stock (other than dividends payable in shares of common stock), or making any other distribution on any shares of common stock or any expenditures for the purchase, redemption, or other retirement for a consideration of shares of common stock (other than in exchange for or from the proceeds of the sale of common stock) except from the net income of SPPC, and its predecessor, available for dividends on common stock accumulated subsequent to December 31, 1955, less preferred stock dividends, plus the sum of $500,000. At the present time, SPPC believes that these restrictions do not materially limit its ability to pay dividends and/or to purchase or redeem shares of its common stock.
- The Utilities are subject to the provision of the Federal Power Act that states that dividends cannot be paid out of funds that are properly included in capital account. Although the meaning of this provision is not clear, it could be interpreted to impose an additional material limitation on a utility's ability, in the absence of retained earnings, to pay dividends.

Management intends to seek a modification of the financial covenant, contained in NPC's first mortgage indenture, in the near future. The regulatory limitation contained in the PUCN's Compliance Order, Docket No. 02-4037, dated June 19, 2002, expires on December 31, 2003. Prior to the expiration date of the Compliance Order, management may seek PUCN approval for a payment of dividends by NPC or may seek a waiver from the PUCN of the dividend restriction.

Effects of Rate Case Decisions

On March 29 and April 1, 2002, S&P and Moody's lowered the unsecured debt ratings of SPR, NPC, and SPPC to below investment grade in response to the decision of the PUCN with respect to NPC's rate cases. On April 23 and 24, 2002, the unsecured debt ratings of SPR and the Utilities were further downgraded by both rating agencies, and the Utilities' secured debt ratings were downgraded to below investment grade. The downgrades affected SPR's, NPC's and SPPC's liquidity primarily in two principal areas: (1) their respective financing arrangements, and (2) NPC's and SPPC's contracts for fuel, for purchase and sale of electricity and for transportation of natural gas.

Credit Facility. As a result of the ratings downgrades, SPR's ability to access the capital markets to raise funds was severely limited. On April 3, 2002, SPR terminated its $75 million unsecured revolving credit facility as a condition to the banks agreeing to an amendment of NPC's former $200 million unsecured revolving credit facility that permitted NPC to draw down funds under that facility. See NPC, Liquidity and Capital Resources, for more information.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Power Supplier Issues. With respect to NPC's and SPPC's contracts for purchased power, NPC and SPPC purchase and sell electricity with counterparties under the Western Systems Power Pool (WSPP) agreement, an industry standard contract that NPC and SPPC are required to use as members of the WSPP. The WSPP contract is posted on the WSPP website. These contracts provide that a material adverse change may give rise to a right to request collateral, which, if not provided within 3 business days, could cause a default. A default must be declared within 30 days of the event, giving rise to the default becoming known. A default will result in a termination payment equal to the present value of the net gains and losses for the entire remaining term of all contracts between the parties aggregated to a single liquidated amount due within 3 business days following the date the notice of termination is received. The mark-to-market value, which is substantially based on quoted market prices, can be used to roughly approximate the termination payment and benefit at any point in time. The net mark-to-market value as of February 28, 2003, for all suppliers continuing to provide power under a WSPP agreement was an approximate $17.0 million benefit for NPC and an approximate $7.8 million payment for SPPC.

Following the PUCN decisions, a number of power suppliers requested collateral from the Utilities. On April 4, 2002, the Utilities sent a letter to their suppliers advising them that, assuming the Utilities could access the capital markets for secured debt and no other significant negative developments occurred, the Utilities expected to be able to honor their obligations under the power supply contracts. However, the Utilities noted that a simultaneous call for 100% mark-to-market collateral in the short term would likely not be met. On April 24, 2002, the Utilities met with representatives of various suppliers to discuss SPR's and the Utilities' financial situation and plans and indicated that they intended to propose extended payment terms for the above-market portions of NPC's existing power contracts. Such extended payment terms were proposed to NPC's suppliers in a letter dated May 2, 2002, in which NPC proposed paying less than contract prices, but more than market prices plus interest, for the period May 1 to September 15, 2002, and paying any balances remaining prior to December 2003. NPC also agreed to extend the suppliers' rights under the WSPP agreement. As of October 29, 2002, NPC paid all remaining outstanding balances owed to its continuing suppliers.

In early May of 2002, Enron Power Marketing Inc. (Enron), Morgan Stanley Capital Group Inc. (MSCG), Reliant Energy Services, Inc., and several smaller suppliers terminated their power deliveries to NPC and SPPC. These terminating suppliers asserted their contractual right under the WSPP agreement to terminate deliveries based upon the Utilities' alleged failure to provide adequate assurance of their performance under the WSPP agreement to any of their suppliers. Each of these terminating suppliers has asserted, or has indicated that it will assert, claims for liquidated damages against the Utilities under the terminated power supply contracts.

Enron filed a complaint with the United States Bankruptcy Court for the Southern District of New York seeking to recover approximately $216 million and $93 million against NPC and SPPC, respectively, for liquidated damages for power supply contracts terminated by Enron in May 2002 and for power previously delivered to the Utilities. The Utilities have denied liability on numerous grounds, including deceit and misrepresentation in the inducement, (including, but not limited to, misrepresentation as to Enron's ability to perform), and for fraud, unfair trade practices, and market manipulation. The Utilities filed motions to dismiss for lack of jurisdiction and/or for a stay of all proceedings pending the actions of the Utilities' proceedings under Section 206 of the Federal Power Act at the FERC (see Regulation and Rate Proceedings). The Utilities have also filed proofs of claims and counterclaims against Enron for the full amount of the approximately $300 million claimed to be owed and additional damages as well as for unspecified damages to be determined during the case as a result of acts and omissions of Enron in manipulating the power markets.

On December 19, 2002, the bankruptcy judge granted Enron's motion for partial summary judgment on Enron's claim for $17.7 million and $6.7 million, respectively, for energy delivered by Enron in April 2002, for which NPC and SPPC did not pay. The court ordered this money to be deposited into an escrow account not subject to claims of Enron's creditors and subject to refund depending on the outcome of the Utilities' FERC cases on the merits. The Utilities made the deposits as ordered. The bankruptcy court denied the Utilities' motion to stay the proceeding pending the outcome of the Utilities' Section 206 case at the FERC and denied the Utilities' motion to dismiss for lack of jurisdiction as to Enron's claims for power previously delivered to the Utilities. The court stated that it would rule in due course on Enron's motion for partial summary judgment to require NPC and SPPC to post $200 million and $87 million, respectively, pending the outcome of the case on the merits, and for judgment on the merits on Enron's liquidated damage claim (contract price less market price on the date of termination) relating to power it did not deliver under contracts terminated by Enron in May 2002. The court took under advisement the Utilities' motion to stay or dismiss Enron's claim for liquidated damages relating to the undelivered power and set a hearing on Enron's motion to dismiss the Utilities' counterclaims for April 3, 2003. The United States District Court for the Southern District of New York also denied the Utilities' motion to withdraw reference of the matter to the bankruptcy court without prejudice.

The bankruptcy court currently has under submission (1) Enron's motion to dismiss the Utilities' counterclaims, (2) Enron's motion for partial summary judgment regarding the amounts alleged to be due for undelivered power and the posting of collateral for undelivered power, and (3) the Utilities' motion to dismiss or stay proceeding on Enron's claims relating to delivered power. Enron's motion to dismiss the Utilities' counterclaims is set for hearing on April 3, 2003. The Utilities are unable to predict the outcome of the motions. A decision adverse to the Utilities on Enron's motion for partial summary judgment, or an adverse decision in the lawsuit with respect to liability as to Enron's claims on the merits for undelivered power, would have a material adverse effect on SPR's and the Utilities' financial condition and liquidity and could make it difficult to continue to operate outside of bankruptcy.

On June 10, 2002, Duke Energy Trading and Marketing (Duke) entered into an agreement with SPR and the Utilities to supply up to 1,000 megawatts of electricity per hour, as well as natural gas, to fulfill the Utilities' power requirements during the peak summer period. The effect of the Duke agreement was to replace the amount of contracted power and natural gas that would have been supplied by the various terminating suppliers, including Enron. Duke also agreed to accept deferred payment for a portion of the amount due under its existing power contracts with NPC for purchases made through September 15, 2002. On October 25, 2002, Duke was paid the full amount of the deferred payments.

On September 5, 2002, MSCG initiated an arbitration pursuant to the arbitration provisions in various power supply contract terminated by MSCG in April 2002. In the arbitration, MSCG is requesting that the arbitrator compel NPC to pay MSCG $25 million pending the outcome of any dispute regarding the amount owed under the contracts. NPC claims that nothing is owed under the contracts on various grounds, including breach by MSCG in terminating the contracts, and further, that the arbitrator does not have jurisdiction over NPC's contract claims and defenses. In March 2003, the arbitrator ruled in NPC's favor and dismissed the arbitration in its entirety for lack of jurisdiction.

On September 30, 2002, El Paso Merchant Energy Group (EPME) notified NPC that it was terminating all transactions entered into with NPC under the WSPP agreement. On October 8, 2002, NPC received a letter from EPME seeking a termination payment of approximately $36 million with respect to the terminated WSPP agreement transactions. At the present time, NPC disagrees with EPME's calculation and expects that net gains and losses relating to the terminated transactions, including a delayed payment amount of approximately $19 million that was owed to EPME for power deliveries through September 15, 2002, will result in a net payment due to NPC.

Gas Supplier Issues. With respect to the purchase and sale of natural gas, NPC and SPPC use several types of contracts. Standard industry sponsored agreements include:

- the Gas Industry Standards Board (GISB) agreement which is used for physical gas transactions,
- the North American Energy Standards Board (NAESB) agreement which is used for physical gas transactions,
- the Gas EDI Base Contract for Short-Term Sale and Purchase of Natural Gas which is also used for physical gas transactions,
- the International Swap Dealers Association (ISDA) agreement which is used for financial gas transactions.

Alternatively, the gas transactions might be governed by a non-standard bilateral master agreement negotiated between the parties, or by the confirmation associated with the transaction. The natural gas contract terms and conditions are more varied than the electric contracts. Consequently, some of the contracts contain language similar to that found in the WSPP agreement and other agreements have unique provisions dealing with material adverse changes.

Gas transmission services are provided under the FERC Gas Tariff or a custom agreement. These contracts require the entities to establish and maintain creditworthiness to obtain service. These contracts are subject to FERC approved tariffs, which, under certain circumstances, require the Utilities to provide collateral to continue receiving service. To date, a letter of credit has been provided to one of SPPC's gas suppliers.

Construction Projects. In response to the decisions by the PUCN in NPC's rate cases, SPR implemented certain measures that positively impacted cash flow by $101.4 million in 2002. Two major transmission construction projects, the Centennial Plan and the Falcon to Gonder Project, were delayed for a total 2002 capital preservation impact of $71.9 million. The delay in NPC's Centennial Plan had an impact of $38.4 million and the delay of SPPC's Falcon to Gonder Project had an impact of $33.5 million. An additional $29.5 million was reduced from the Utilities' 2002 capital budgets by curtailing or delaying other projects.

Federal Tax Refund

In March 2002, NPC received a federal income tax refund of $79.3 million. Additionally, SPR and the Utilities received $105.7 million of refunds in the second quarter of 2002. These refunds were the result of income tax losses generated in 2001. Federal legislation passed in March 2002 changed the allowed carryback of these losses from two years to five years. This change permitted SPR and the Utilities to accelerate the receipt of a portion of their income tax receivables sooner than expected. The remaining income tax losses of $281.9 million as of December 31, 2002, may be utilized in future periods to reduce taxes payable to the extent that SPR and the Utilities recognize taxable income. The carryforward period for net operating losses incurred is 20 years, and as such, the losses incurred in the years ended December 31, 2000, 2001, and 2002 will expire in 2020, 2021, and 2022, respectively.

Accounts Receivable Facility

On October 29, 2002, NPC and SPPC established accounts receivable purchase facilities of up to $125 million and $75 million, respectively, which expire on August 28, 2003, unless either NPC or SPPC has activated its respective facility before that date, in which case such facility will be automatically extended to, and will expire on, October 28, 2003. If NPC or SPPC elect to activate their receivables purchase facilities, they will sell all of their accounts receivable generated from the sale of electricity and natural gas to customers to their newly created bankruptcy remote special purpose subsidiaries. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiaries will, in turn, sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables. Lehman Brothers Holdings, Inc. has committed to be the sole initial committed purchaser of all of the variable rate revolving notes.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The agreements relating to the receivables purchase facilities contain various conditions to purchase, covenants and trigger events, and other provisions customary in receivables transactions. In addition to customary termination and mandatory repurchase events, each Utility's receivables purchase facility may terminate in the event that the Utility or SPR defaults (i) on the payment of indebtedness, or (ii) on the payment of amounts due under a swap agreement, and such defaults aggregate to greater than $10 million and $5 million for the Utility and SPR, respectively. Under the terms of the agreements relating to the receivables purchase facility, each Utility's facility may not be activated or, if activated, will be terminated in the event of a material adverse change in the condition, operations or business prospects of the Utility. SPR has agreed to guarantee the performance by NPC and SPPC of certain obligations as sellers and servicers under the receivables purchase facilities. NPC and SPPC intend to use their accounts receivables purchase facilities as back-up liquidity facilities and do not plan to activate these facilities in the foreseeable future.

Cross-Default Provisions

Certain financing agreements of SPR and the Utilities contain cross-default provisions that would result in an event of default under such financing agreements if there is a failure under other financing agreements of SPR and the Utilities to meet payment terms or to observe other covenants that would result in an acceleration of payments due. Most of these default provisions (other than ones relating to a failure to pay other indebtedness) provide for a cure period of 30-60 days from the occurrence of a specified event during which time SPR or the Utilities may rectify or correct the situation before it becomes an event of default. The primary cross-default provisions in SPR's and the Utilities' various financing agreements are briefly summarized below:

- The indenture pursuant to which SPR issued its 7.25% Convertible Notes due 2010 provides for an event of default if SPR or any of its significant subsidiaries (NPC and SPPC) fails to pay indebtedness in excess of $10 million or has any indebtedness of $10 million or more accelerated and declared due and payable;
- NPC's General and Refunding Mortgage Indenture provides for an event of default if a matured event of default under NPC's First Mortgage Indenture occurs;
- The terms of NPC's Series E Notes provide that a default with respect to the payment of principal, interest, or premium beyond the applicable grace period under any mortgage, indenture, or other security instrument by NPC or any of its restricted subsidiaries relating to debt in excess of $15 million triggers a right of the holders of the Series E Notes to require NPC to redeem the Series E Notes at a price equal to 100% of the aggregate principal amount plus accrued and unpaid interest and liquidated damages, if any, upon notice given by at least 25% of the outstanding Series E Notes holders;
- NPC's receivables purchase facility may terminate in the event that either NPC or SPR defaults (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million and $5 million for NPC and SPR, respectively;
- SPPC's General and Refunding Mortgage Indenture provides for an event of default if a matured event of default under SPPC's First Mortgage Indenture occurs;
- SPPC's Term Loan Agreement provides for an event of default if (a) SPPC or any of its subsidiaries default (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million, or (b) SPPC's General and Refunding Mortgage Indenture ceases to be enforceable; and
- SPPC's receivables purchase facility may terminate in the event that either SPPC or SPR defaults (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million and $5 million for SPPC and SPR, respectively.

Pension Plan Matters

SPR has a qualified pension plan that covers substantially all employees of SPR, NPC, and SPPC. The annual net benefit cost for the plan will increase for 2003 by approximately $16.1 million over the 2002 cost of $18.4 million. As of September 30, 2002, the plan had assets with a fair value that was less than the present value of the accumulated benefit obligation under the plan. On December 6, 2002, SPR and the Utilities contributed a total of $24 million to meet their funding obligations under the plan. At the present time, SPR and the Utilities do not expect that any near term funding obligation will have a material adverse effect on their liquidity.

Financing Transactions

In January 2003, SPR acquired $8.75 million aggregate principal amount of its Floating Rate Notes due April 20, 2003, in exchange for 1.30 million shares of its common stock in two privately negotiated transactions exempt from the registration requirements of the Securities Act of 1933.

On February 5, 2003, SPR issued 13.66 million shares of common stock in exchange for a total of 2,095,650 of its PIES in five privately negotiated transactions exempt from the registration requirements of the Securities Act of 1933.

On February 14, 2003, SPR issued and sold $300 million of its 7.25% Convertible Notes due 2010. Approximately $53.4 million of the net proceeds from the sale of the notes were used to purchase U.S. government securities that were pledged to the trustee for the first five interest payments on the notes payable during the first two and one-half years. A portion of the remaining net proceeds of the notes have been used to repurchase approximately $58.5 million of SPR's Floating Rate Notes due April 20, 2003. The remaining portion of the net proceeds will be used to repay the remainder of SPR's Floating Rate Notes due April 20, 2003 at maturity and for general corporate purposes. The Convertible Notes were issued with registration rights.

The Convertible Notes will not be convertible prior to August 14, 2003. At any time on or after August 14, 2003, through the close of business February 14, 2010, holders of the Convertible Notes may convert each $1,000 principal amount of their notes into 219.1637 shares of SPR's common stock, subject to adjustment upon the occurrence of certain dilution events. Until SPR has obtained shareholder approval to fully convert the Convertible Notes into shares of common stock, holders of the Convertible Notes will be entitled to receive 76.7073 shares of common stock and a remaining portion in cash based on the average closing price of SPR's common stock over five consecutive trading days for each $1,000 principal amount of notes surrendered for conversion. At an assumed five-day average closing price of $3.20 (the last reported sale price of SPR's common stock on March 17, 2003), the total amount of the cash payable on conversion of the Convertible Notes would be approximately $137 million. If SPR does obtain shareholder approval, it may elect to satisfy the cash payment component of the conversion price of the Convertible Notes solely with shares of common stock. SPR has agreed to use reasonable efforts to obtain shareholder approval, not later than 180 days after the date of issuance of the Convertible Notes, for approval to issue and deliver shares of SPR's common stock in lieu of the cash payment component of the conversion price of the Convertible Notes. If SPR does not obtain shareholder approval, SPR will be required to pay the cash portion of any Convertible Notes as to which the holders request conversion on or after August 14, 2003. Although management does not believe it is likely that a significant amount of the Convertible Notes will be converted in the foreseeable future, in the event that SPR does not have available funds to pay the cash portion of the Convertible Notes upon the requested conversion, SPR may have to issue additional debt to raise the necessary funds. There can be no assurance that SPR will be able to access the capital markets to issue such additional debt.

The indenture under which the Convertible Notes were issued does not contain any financial covenants or any restrictions on the payment of dividends, the repurchase of SPR's securities or the incurrence of indebtedness. The indenture does allow the holders of the Convertible Notes to require SPR to repurchase all or a portion of the holders' Convertible Notes upon a change of control.

Currently, SPR (on a stand-alone basis) has a substantial amount of debt and other obligations including, but not limited to: $133 million of its unsecured Floating Rate Notes due April 20, 2003; $300 million of its unsecured 8.75% Senior Notes due 2005; $240 million of its unsecured 7.93% Senior Notes due 2007; and $300 million of its 7.25% Convertible Notes due 2010. SPR intends to pay off the remaining principal balance of its Floating Rate Notes due April 20, 2003, with cash currently on hand.

Effect of Holding Company Structure

Due to the holding company structure, SPR's right as a common shareholder to receive assets of any of its direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiary by its creditors and preferred stockholders. Therefore, SPR's debt obligations are effectively subordinated to all existing and future claims of its subsidiaries' creditors, particularly those of NPC and SPPC, including trade creditors, debt holders, secured creditors, taxing authorities, guarantee holders, NPC's preferred trust security holders and SPPC's preferred stockholders. As of December 31, 2002, NPC, SPPC, and their subsidiaries had approximately $2.86 billion of debt and other obligations outstanding and approximately $238.9 million of outstanding preferred securities. Although the Utilities are parties to agreements that limit the amount of additional indebtedness they may incur, the Utilities retain the ability to incur substantial additional indebtedness and other liabilities.

Construction Expenditures and Financing (SPR Consolidated)

The table below provides SPR's consolidated cash construction expenditures and internally generated cash, net for 2000 through 2002 (dollars in thousands):

	2002	2001	2000	Total
Cash construction expenditures	**$343,474**	$ 302,025	$329,346	$ 974,845
Net cash flow from operating activities	**$458,826**	$(1,043,341)	$188,246	$(396,269)
Less common & preferred cash dividends	**24,485**	64,917	83,057	172,459
Internally generated cash	**$434,341**	$(1,108,258)	$105,189	$(568,728)
Internally generated cash as a percentage of cash construction expenditures	**126%**	N/A	32%	N/A

SPR's consolidated cash construction expenditures for 2003 through 2007 are estimated to be $1.6 billion. Construction expenditures for 2003 are projected to be $344 million and are expected to be financed by internally generated funds, including the recovery of deferred energy at the Utilities. It is anticipated that no capital contributions from SPR will be used to fund construction expenditures at the Utilities.

Cash provided by internally generated funds during 2003 assumes, among other things, no disallowances on the Utilities' currently-filed deferred energy rate cases and the full recovery of such deferred energy amounts over three years, no additional disallowances related to the Utilities' appeals of their prior deferred energy cases and no adverse decision in the lawsuit filed by Enron against the Utilities seeking $200 million and $87 million in termination payments from NPC and SPPC, respectively. Material disallowances of currently-filed or previously-filed deferred energy costs or a decision adverse to the Utilities with respect to the Enron lawsuit would have a material adverse effect on SPR's and the Utilities financial condition and future results of operations, and could cause additional downgrades of their securities by the rating agencies and make it significantly more difficult to finance operations and to buy fuel and purchased power from third parties. See Regulation and Rate Proceedings, Nevada Matters, for additional information regarding the Utilities' recently filed deferred energy rate cases and prior deferred energy rate cases and Liquidity and Capital Resources for additional information regarding the Enron lawsuit and the potential impact of a negative outcome with respect to any of these uncertainties.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

In the event that SPR's and/or the Utilities' financial conditions worsen, they may be unable to finance their construction expenditures with internally generated funds and instead may need to raise all or a portion of the necessary funds through the capital markets or from activating the Utilities' accounts receivable purchase facilities to provide additional liquidity. For additional information regarding the accounts receivable purchase facilities, see Liquidity and Capital Resources. Each of the Utilities may activate its receivables purchase facility within five days upon the delivery of certain customary funding documentation and the delivery of General and Refunding Mortgage Bonds to secure the facility. If a material adverse event were to occur for either of the Utilities, it could potentially trigger a termination event with respect to the receivables facility and would also make it more difficult for the Utilities or SPR to access the capital markets for any such financing needs.

Contractual Obligations (SPR Consolidated)

The table below provides SPR's contractual obligations on a consolidated basis (except as otherwise indicated), not including estimated construction expenditures described above, as of December 31, 2002, that SPR expects to satisfy through a combination of internally generated cash and, as necessary, through the issuance of short-term and long-term debt (dollars in thousands):

Payment Due By Period

	2003	2004	2005	2006	2007	Thereafter	Total
NPC/SPPC Other Long-Term Debt	$ 472,963	$153,468	$106,491	$ 58,909	$ 8,349	$2,108,634	$ 2,908,814
SPR Long-Term Debt	200,000	—	300,000	—	345,000	—	845,000
NPC Preferred Trust Securities	—	—	—	—	—	188,872	188,872
Purchased Power	547,459	284,925	249,217	234,072	220,391	3,494,648	5,030,712
Coal and Natural Gas	167,856	145,341	110,382	101,251	80,223	659,834	1,264,887
Operating Leases	11,100	8,726	7,674	6,505	6,439	57,698	98,142
Other Long-Term Obligations	75	100	—	—	—	—	175
Total Contractual Cash Obligations	$1,399,453	$592,560	$773,764	$400,737	$660,402	$6,509,686	$10,336,602

Capital Structure (SPR Consolidated)

On April 3, 2002, SPR terminated its $75 million unsecured revolving credit facility in connection with the amendment of NPC's $200 million unsecured revolving credit facility, as discussed in Nevada Power Company, Liquidity and Capital Resources.

SPR's actual capital structure on a consolidated basis (except as otherwise indicated) at December 31, 2002 and 2001, was as follows (dollars in thousands):

	2002		2001	
Short-Term Debt(1)	**$ 672,963**	**13%**	$ 299,010	5%
Long-Term Debt	**3,062,883**	**58%**	3,376,105	60%
Preferred Stock	**50,000**	**1%**	50,000	1%
Preferred Trust Securities	**188,872**	**3%**	188,872	4%
Common Equity	**1,327,166**	**25%**	1,695,336	30%
TOTAL	**$5,301,884**	**100%**	$5,609,323	100%

(1) Including current maturities of long-term debt and $200 million of SPR holding company debt.

NEVADA POWER COMPANY

Results of Operations

NPC incurred a net loss of ($235.1) million in 2002 compared to net income of $63.4 million in 2001 and a net loss of ($7.9) million in 2000. NPC's operating results for 2002 reflect the write-off of approximately $465 million (before taxes) of deferred energy costs and related carrying charges as a result of the PUCN's March 29, 2002, decision in NPC's deferred energy rate case to disallow $434 million of deferred purchased fuel and power costs. The PUCN's decision is being challenged by NPC in a lawsuit filed in Nevada state court.

In the first quarter of 2002, NPC paid $10 million in dividends on its common stock to its parent, SPR, all of which was reinvested in NPC as a contribution to capital. No other dividend payments or capital contributions occurred in 2002. Currently, NPC is restricted from paying dividends to SPR under the terms of certain financing agreements and a recent order of the PUCN. See Liquidity and Capital Resources for a discussion of these restrictions.

The causes for significant changes in specific lines comprising the results of operations for NPC for the respective years ended are provided below (dollars in thousands, except for amounts per unit):

Electric Operating Revenue

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
ELECTRIC OPERATING REVENUES					
Residential	**$ 675,837**	**4.8%**	$ 644,875	31.0%	$ 492,365
Commercial	**345,342**	**14.1%**	302,682	32.9%	227,790
Industrial	**520,116**	**16.2%**	447,766	37.0%	326,916
Retail revenues	**1,541,295**	**10.5%**	1,395,323	33.3%	1,047,071
Other(1)	**359,739**	**-77.9%**	1,629,780	483.9%	279,121
TOTAL REVENUES	**$1,901,034**	**-37.2%**	$3,025,103	128.1%	$1,326,192
Retail sales in thousands of megawatt-hours (MWh)	**17,197**	**2.4%**	16,799	2.7%	16,363
Average retail revenue per MWh	**$ 89.63**	**7.9%**	$ 83.06	29.8%	$ 63.99

(1) Primarily wholesale, as discussed below.

NPC's retail revenues increased in 2002 primarily due to a combination of customer growth and a net rate increase resulting from NPC's General Rate and Deferred Energy Cases (see Regulation and Rates Proceedings, later). The number of residential, commercial, and industrial customers increased over 2001 by 4.9%, 5.7% and 2.1%, respectively. Commercial and industrial growth is attributable to the opening of several new schools, shopping centers, and casinos in the Las Vegas area. Effective April 1, 2002, the PUCN authorized an increase in energy related rates that are used to recover current and previously incurred fuel and purchased power costs. In addition to that rate increase, the PUCN also granted NPC the authority to increase its energy recovery rate by one cent per kilowatt-hour for the month of June 2002 only. This one-time increase in rates generated approximately $16 million, which was used to accelerate the recovery of previously incurred fuel and purchased power costs. The decrease in the 2002 Other revenues was primarily due to the lower sales resulting from a reduction in transactions entered into for hedging purposes and the optimization of purchased power costs. See Energy Supply, later, for a discussion of the Utilities' purchased power procurement strategies.

NPC's retail revenues increased in 2001 due to a combination of customer growth and rate increases resulting from the Global Settlement and Comprehensive Energy Plan (see Regulation and Rates Proceedings, later). The number of residential, commercial, and industrial customers increased over the prior year by 4.8%, 4.4%, and 6.5%, respectively. Substantially all of the increase in the Other electric revenues was due to the sale of wholesale electric power to other utilities. NPC's increase in wholesale sales compared to 2000 was a result of market conditions and NPC's power procurement activities. See Energy Supply, later, for a discussion of the Utilities' purchased power procurement strategies.

Purchased Power

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
PURCHASED POWER	**$1,241,783**	**-59.0%**	$3,026,336	350.8%	$671,396
Purchased power in thousands of MWh	**12,908**	**-33.0%**	19,268	99.5%	9,659
Average cost per MWh of purchased power(1)	**$ 78.46**	**-50.0%**	$ 157.07	126.0%	$ 69.51

(1) Not including contract termination costs, discussed below.

NPC's purchased power costs were significantly lower in 2002 compared to 2001 due to substantial decreases in prices and volumes. Per unit costs of power decreased 50.0% primarily due to lower Short-Term Firm energy prices. These price decreases were the result of a less volatile energy market. The overall decrease in the cost of purchased power was offset, in part, by a $228 million reserve provision recorded for terminated contracts. See Liquidity and Capital Resources, later, for a discussion of these terminated power contracts. Volumes purchased decreased by 33.0% as a result of a reduction in hedging activities due to a change in risk management activities and energy supply strategies described later in Energy Supply. Purchases associated with risk management activities, which are included in Short-Term Firm energy, decreased significantly in both volume and price in 2002. Wholesale sales associated with risk management activities decreased in volume by approximately 58%. Risk management activities include transactions entered into for hedging purposes and to optimize purchased power costs. See Energy Supply, later, for a discussion of the Utilities' purchased power procurement strategies.

Purchased power costs were higher in 2001 as compared to 2000 due to a 99.5% increase in the volume purchased and an increase in the per unit cost of power of 126%. Purchased power costs were higher primarily due to higher Short-Term Firm energy prices. These price increases were the result of much higher fuel costs, combined with increased demand and limited power supplies.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Fuel for Power Generation

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
FUEL FOR POWER GENERATION	**$309,293**	**-30.0%**	$441,990	50.9%	$292,787
Thousands of MWhs generated	**10,147**	**2.5%**	9,899	-7.9%	10,744
Average fuel cost per MWh of generated power	**$ 30.48**	**-31.7%**	$ 44.64	63.8%	$ 27.25

NPC's 2002 fuel expense decreased 30% compared to 2001 primarily due to a substantial decrease in natural gas prices. This was slightly offset by an increase in coal prices and an overall increase in MWhs generated. In 2001, NPC's fuel expense increased over 50.9% compared to 2000 primarily due to a substantial increase in natural gas prices, offset in part by decreased generation late in 2001 when the cost of purchased power was more economical than generation.

Deferral of Energy Costs—Net

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
DEFERRAL OF ENERGY COSTS—ELECTRIC—NET	**$(179,182)**	**-80.9%**	$(937,322)	N/A	$16,719
DEFERRED ENERGY COSTS DISALLOWED	**434,123**	**N/A**	—	N/A	—
	$ 254,941	**N/A**	$(937,322)	N/A	$16,719

The change in Deferral of energy costs—electric—net for the twelve months ended December 31, 2002, compared to the same period in the prior year, reflects the amortization in 2002 of prior deferred costs pursuant to the PUCN's decision on NPC's deferred energy rate case, which resulted in increased rates beginning April 1, 2002, and the one-time rate increase of $0.01 per kilowatt-hour for the month of June 2002. The amortization was offset, in part, by the recording of current year deferrals of electric energy costs, reflecting the extent to which actual fuel and purchased power costs exceeded the fuel and purchased power costs recovered through current rates. Deferral of energy costs—electric—net also reflects the deferral in the second and fourth quarter of 2002 of approximately $228 million for contract termination costs as described in more detail in Note 17 of Notes to Financial Statements, Commitments and Contingencies. Deferred energy costs disallowed reflects the second quarter write-off of $434 million of electric deferred energy costs incurred in the seven months ended September 30, 2001, that were disallowed by the PUCN in its March 29, 2002 decision on NPC's deferred energy rate case.

NPC recorded Deferral of energy costs—electric—net in 2001 due to the implementation of deferred energy accounting beginning March 1, 2001. The amounts reflect the extent to which actual fuel and purchased power costs exceeded the fuel and purchased power costs recovered through current rates. Deferral of energy costs—electric—net for 2000 represent energy costs that had been deferred in prior periods and were then recovered in 2000 as a result of deferred energy rate increases granted in 1999.

See Critical Accounting Policies, earlier, and Note 1 of Notes to Financial Statements, Summary of Significant Accounting Policies for more information regarding deferred energy accounting.

Allowance for Funds Used During Construction (AFUDC)

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
ALLOWANCE FOR OTHER FUNDS USED DURING CONSTRUCTION	**$ (153)**	**-59.9%**	$ (382)	-115.6%	$ 2,456
ALLOWANCE FOR BORROWED FUNDS USED DURING CONSTRUCTION	**3,412**	**59.4%**	2,141	-72.7%	7,855
	$3,259	**85.3%**	$1,759	–82.9%	$10,311

AFUDC for NPC is higher in 2002 compared to 2001 because of an increase in construction work-in-progress (CWIP) and the adjustments in 2001 to amounts assigned to specific components of facilities that were completed in different periods. This increase was offset by a small decrease in the AFUDC rate compared to 2001 due to an increase in short-term debt. In 2001, AFUDC is lower compared to 2000 because of adjustments to amounts assigned to specific components of facilities that were completed in different periods.

Other (Income) and Expenses

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
OTHER OPERATING EXPENSE	**$167,768**	**-1.0%**	$169,442	21.3%	$139,723
MAINTENANCE EXPENSE	**41,200**	**-8.7%**	45,136	32.5%	34,057
DEPRECIATION AND AMORTIZATION	**98,198**	**5.5%**	93,101	8.3%	85,989
INCOME TAXES	**(133,411)**	**-850.6%**	17,775	N/A	(12,162)
INTEREST CHARGES ON LONG-TERM DEBT	**98,886**	**21.2%**	81,599	26.5%	64,513
INTEREST CHARGES—OTHER	**21,395**	**61.9%**	13,219	-3.7%	13,732
INTEREST ACCRUED ON DEFERRED ENERGY	**(12,414)**	**-71.0%**	(42,743)	N/A	—
OTHER INCOME	**(273)**	**-93.5%**	(4,200)	-4.8%	(4,413)
OTHER EXPENSE	**9,933**	**110.9%**	4,709	112.5%	2,216
INCOME TAXES—OTHER INCOME AND EXPENSE	**1,627**	**-89.1%**	14,962	1145.8%	1,201

The decrease in Other operating expense for 2002 reflects $10.0 million of reserve provisions which were established in 2001 for retail uncollectible accounts in NPC's service territory and $12.6 million for uncollectible amounts associated with the California Power Exchange, which NPC continues to pursue for collection. Additional factors that resulted in lower Other operating expenses during 2002 include the reversal of a $6 million reserve originally established in 2001 pursuant to the PUCN order for costs associated with the conclusion of electric industry restructuring. NPC had no 2002 short-term incentive plan expense compared to $5.5 million in 2001. Increases in Other operating expense during 2002 include $14.7 million in legal and advisory fees associated with liquidity issues and the consequences of the PUCN's deferred energy rate case decision. Additional increases in Other operating expense in 2002 included $12.1 million related to collection for and write-off of uncollectible accounts.

Other operating expense increased in 2001 compared to 2000 due to a $16.6 million larger addition to the provision for uncollectible customer accounts than in 2000, reflecting the impact of the weakening economy and disruption to the leisure travel industry after September 11, 2001. Other operating expense also increased due to the addition of $12.6 million to the uncollectible provision related to receivables from the California Power Exchange (PX) and California's Independent System Operator (ISO).

The level of NPC's maintenance and repair expenses fluctuates primarily upon the scheduling, magnitude, and number of generation unit overhauls at NPC's generating stations. As a result of an outage delay at Reid-Gardner and deferred outage at Clark Station, maintenance costs were decreased by $6.1 million in 2002. These decreases were partially offset by miscellaneous increases at Mohave and Navajo totaling $1.4 million. Maintenance expense for 2001 increased from the prior year as a result of increased outage work at Reid-Gardner, additional expenditures for repairs and outages at Clark Station, and increased work at Mohave.

An increase in the computer depreciation rate pursuant to a PUCN order and additions to plant-in-service were the primary cause of NPC's increase in depreciation and amortization expense in 2002 compared to 2001. Depreciation and amortization were also higher in 2001 than 2000 due to an increase in plant-in-service.

As a result of net losses recognized during 2002 and 2000, NPC recorded an income tax benefit for those years. As a result of net income for 2001, NPC incurred income tax expense. See Note 10 of Notes to Financial Statements, Taxes, for additional information regarding the computation of income taxes.

NPC's interest charges on long-term debt increased in 2002 compared to 2001 due to additional issuances of long-term debt at higher interest rates during 2002 and to the payment of a full year of interest on $100 million of long-term debt issued throughout 2001. In 2002, NPC redeemed $15 million in debt and issued additional debt of $250 million. For 2001 compared to 2000, NPC's increased interest charges were attributable to the issuance of $700 million of long-term debt mentioned above. See Note 9 of Notes to Financial Statements, Long-Term Debt for additional information regarding long-term debt.

NPC's interest charges—other increased in 2002 compared to 2001 due primarily to interest on extended payments to fuel and power suppliers resulting from renegotiated purchased power and fuel contracts. Increased credit facility fees also contributed to the increase in 2002 over the prior year (Refer to Liquidity and Capital Resources for further discussion of power and fuel contracts and the credit facilities). Interest charges—other for the year 2001 were comparable to 2000.

NPC's interest accrued on deferred energy decreased during 2002, compared to 2001 due to a significant decline in the related deferred fuel and purchased power balances. For the period 2001 compared to 2000, the increase in these carrying charges was attributable to the related increases in deferred fuel and purchased power balances. (Refer to Regulation and Rate Proceedings for further discussion of deferred energy accounting issues).

NPC's other income for the year 2002 decreased from 2001 due, primarily to an expense adjustment related to sale of SO2 emission allowances ordered by the PUCN. Other income for the year 2001 was comparable to 2000. For the year 2001 compared to 2000, the decrease was primarily attributable to the classification, in 2001, of lease revenues as operating income, while in 2000 these revenues were classified as non-operating.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

NPC's other expense increased in 2002 compared to 2001 due primarily to costs associated with NPC's contribution to a group opposed to the inclusion of an Electric Utility Advisory Question to the November 2002 general election ballot. NPC also incurred increased costs for assistance programs, corporate advertising, and miscellaneous customer information activities. For the year 2001, compared to 2000, NPC's other expense increased as a result of increased expenditures to its low-income energy assistance programs.

Income Taxes—Other Income and Expense decreased in 2002 as a result of lower other income and expense than 2001 primarily due to lower accrued interest on deferred energy costs. The increase from 2000 to 2001 was also caused by the corresponding increase in other income and expense from 2000 to 2001.

Analysis of Cash Flows

NPC's net cash flows improved in 2002 compared to 2001, resulting from an increase in cash flows from operating activities offset in part by decreases in cash flows from investing and financing activities. Although NPC recorded a substantial loss for 2002, compared to net income in 2001, the current year's loss resulted largely from the write-off of disallowed deferred energy costs for which the cash outflow had occurred in 2001. Other factors contributing to 2002's improved cash flows from operating activities include the collection of deferred energy costs from customers and lower energy prices. Cash flows from operating activities in the current year also reflect the receipt of an income tax refund. Cash flows from investing activities decreased because of additional cash utilized for construction activities during 2002 compared to 2001. Cash flows from financing activities were lower because of decreases in net long-term debt issued, decreases in short-term borrowings, and less cash invested by NPC's parent, SPR, during 2002.

NPC's net cash flows decreased in 2001 compared to 2000. The net decrease in cash resulted from a significant increase in cash flows used in operating activities combined with cash used in investing activities, both partially offset by an increase in cash provided by external financing sources. The increase in cash flows used in operating activities resulted substantially from the payment of significantly higher energy costs during 2001. Net cash used in investing activities was comparable between 2001 and 2000. Net cash provided by financing activities was higher in 2001 as a result of cash provided by the issuance of short-term and long-term debt, as described in Note 9, Long-Term Debt, and Note 12, Short-Term Borrowings, of the Notes to Financial Statements, and additional capital contributions from SPR. Cash provided by financing activities was substantially utilized for the payment of higher energy costs in 2001.

Liquidity and Capital Resources

NPC had cash and cash equivalents of approximately $95 million at December 31, 2002, and approximately $96 million at February 28, 2003.

As discussed in Construction Expenditures and Financing and Capital Structure that follow, NPC anticipates external capital requirements for construction costs and for the repayment of maturing long-term debt during 2003 totaling approximately $578 million, which NPC expects to finance with internally generated funds, including the recovery of deferred energy, and the issuance of debt.

NPC's liquidity would be significantly affected by an adverse decision in the lawsuit by Enron or by unfavorable rulings by the PUCN in pending or future NPC or SPPC rate cases. S&P and Moody's have NPC's credit ratings on "negative outlook" and "stable," respectively. Future downgrades by either S&P or Moody's could preclude NPC's access to the capital markets and could adversely affect NPC's ability to continue to purchase power and fuel. Adverse developments with respect to any one or a combination of the foregoing could have a material adverse effect on NPC's financial condition and liquidity, and could make it difficult for NPC to operate outside of bankruptcy.

Effect of Rate Case Decisions

On March 29 and April 1, 2002, following the decision by the PUCN in NPC's deferred energy rate case, S&P and Moody's lowered NPC's unsecured debt ratings to below investment grade. On April 23 and 24, 2002, NPC's unsecured debt ratings were further downgraded and its secured debt ratings were downgraded to below investment grade. As a result of these downgrades, NPC's ability to access the capital markets to raise funds were severely limited. Since SPR's credit ratings were similarly downgraded, SPR's ability to make capital contributions to NPC also became severely limited.

Commercial Paper and Credit Facilities. In connection with the credit downgrades by S&P and Moody's, NPC lost its A2/P2 commercial paper ratings and can no longer issue commercial paper. At the time, NPC had a commercial paper balance outstanding of $198.9 million with a weighted average interest rate of 2.52%. Since NPC was no longer able to issue its commercial paper, it paid off its maturing commercial paper with the proceeds of borrowings under its credit facility and terminated its commercial paper program on May 28, 2002. NPC does not expect to have direct access to the commercial paper market for the foreseeable future.

NPC's $200 million unsecured revolving credit facility was also affected by the decision in the deferred energy rate case. Following the announcement of that decision, the banks participating in NPC's credit facility determined that a material adverse event had occurred with respect to NPC, thereby precluding NPC from borrowing funds under its credit facility. The banks agreed to waive the consequences of the material adverse event in a waiver letter and amendment that was executed on April 3, 2002. As required under the waiver letter and amendment, NPC issued and delivered its General and Refunding Mortgage Bond, Series C, due November 28, 2002, in the principal amount of $200 million, to the Administrative Agent as security for the credit facility. This facility was paid in full and terminated on October 30, 2002, with proceeds from the issuance of NPC's $250 million 10⅞% General and Refunding Mortgage Notes, Series E, due 2009.

Power Supplier Issues. Historically, NPC has purchased a significant portion of the power that it sells to its customers from power suppliers. As discussed under Sierra Pacific Resources, Liquidity and Capital Resources, following the PUCN's decision on March 29, 2002, in NPC's deferred energy rate case, a number of power suppliers requested collateral from NPC under the WSPP standard contract. NPC informed such suppliers that a simultaneous call for 100% mark-to-market collateral in the short term would likely not be met and proposed extended payment terms for the above-market portions of NPC's existing power contracts. Although several power suppliers terminated their contracts with NPC (as discussed below), the remaining suppliers accepted the deferred payments, which were paid in full by October 29, 2002.

In early May of 2002, Enron, MSCG, Reliant Energy Services, Inc., and several smaller suppliers terminated their power deliveries to NPC. These terminating suppliers asserted their contractual right under the WSPP agreement to terminate deliveries based upon NPC's alleged failure to provide adequate assurance of its performance under the WSPP agreement to any of its suppliers. Each of these terminating suppliers has asserted a claim for liquidated damages under the terminated power supply contracts.

Enron filed a complaint with the United States Bankruptcy Court for the Southern District of New York seeking to recover approximately $216 million against NPC for liquidated damages for power supply contracts terminated by Enron in May 2002 and for power previously delivered to NPC. NPC has denied liability on numerous grounds, including deceit and misrepresentation in the inducement, (including, but not limited to misrepresentation as to Enron's ability to perform), and fraud, unfair trade practices, and market manipulation. NPC filed motions to dismiss for lack of jurisdiction and/or for a stay of all proceedings pending the actions of the Utilities' proceedings under Section 206 of the Federal Power Act at the FERC (see Regulation and Rate Proceedings). The Utilities have also filed proofs of claims and counterclaims against Enron for the full amount of the approximately $300 million claimed to be owed and additional damages, as well as for unspecified damages to be determined during the case as a result of acts and omissions of Enron in manipulating the power markets.

On December 19, 2002, the bankruptcy judge granted Enron's motion for partial summary judgment on Enron's claim for $17.7 million for energy delivered by Enron in April 2002 for which NPC did not pay. The court ordered this money to be deposited into an escrow account not subject to claims of Enron's creditors and subject to refund depending on the outcome of the Utilities' FERC cases on the merits. NPC made the deposit as ordered. The bankruptcy court denied NPC's motion to stay the proceeding pending the outcome of the Utilities' Section 206 case at the FERC and denied NPC's motion to dismiss for lack of jurisdiction as to Enron's claims for power previously delivered to the Utilities. The court stated that it would rule in due course on Enron's motion for partial summary judgment to require NPC to post $200 million pending the outcome of the case on the merits, and for judgment on the merits on Enron's liquidated damage claim (contract price less market price on the date of termination) relating to power it did not deliver under contracts terminated by Enron in May 2002. The court took under advisement the Utilities' motion to stay or dismiss Enron's claim for liquidated damages relating to the undelivered power and set a hearing on Enron's motion to dismiss the Utilities' counterclaims for April 3, 2003. The United States District Court for the Southern District of New York also denied the Utilities' motion to withdraw reference of the matter to the bankruptcy court without prejudice.

The bankruptcy court currently has under submission (1) Enron's motion to dismiss NPC's counterclaims, (2) Enron's motion for partial summary judgment regarding the amounts alleged to be due for undelivered power and the posting of collateral for undelivered power, and (3) NPC's motion to dismiss or stay proceeding on Enron's claims relating to delivered power. Enron's motion to dismiss NPC's counterclaims is set for hearing on April 3, 2003. NPC is unable to predict the outcome of the motions. A decision adverse to NPC on Enron's motion for partial summary judgment, or an adverse decision in the lawsuit with respect to liability as to Enron's claims on the merits for undelivered power, would have a material adverse effect on NPC's financial condition and liquidity and could make it difficult for NPC to continue to operate outside of bankruptcy.

On June 10, 2002, Duke entered into an agreement with NPC, SPR and SPPC to supply up to 1,000 megawatts of electricity per hour, as well as natural gas, to fulfill NPC's customers' power requirements during the peak summer period. The effect of the Duke agreement was to replace the amount of contracted power and natural gas that would have been supplied by the various terminating suppliers, including Enron. Duke also agreed to accept deferred payment for a portion of the amount due under its existing power contracts with NPC for purchases made through September 15, 2002. On October 25, 2002, Duke was paid the full amount of the deferred payments.

On September 5, 2002, MSCG initiated an arbitration pursuant to the arbitration provisions in various power supply contracts terminated by MSCG in April 2002. In the arbitration, MSCG is requesting that the arbitrator compel NPC to pay MSCG $25 million pending the outcome of any dispute regarding the amount owed under the contracts. NPC claims that nothing is owed under the contracts on various grounds, including breach by MSCG in terminating the contracts, and further that the arbitrator does not have jurisdiction over NPC's contracts claims and defenses. In March 2003, the arbitrator ruled in NPC's favor and dismissed the arbitration in its entirety for lack of jurisdiction.

On September 30, 2002, EPME notified NPC that it was terminating all transactions entered into with NPC under the WSPP agreement. On October 8, 2002, NPC received a letter from EPME seeking a termination payment of approximately $36 million with respect to the terminated WSPP agreement transactions. At the present time, NPC disagrees with EPME's calculation and expects that net gains and losses relating to the terminated transactions, including a delayed payment amount of approximately $19 million owed to EPME for power deliveries through September 15, 2002, will result in a net payment due to NPC.

If NPC continues to experience financial difficulty or if its credit ratings are further downgraded, NPC may experience considerable difficulty entering into new power supply contracts, particularly under traditional payment terms. If suppliers will not sell power to NPC under traditional payment terms, NPC may have to prepay its power requirements. If it does not have sufficient funds or access to liquidity to prepay its power requirements, particularly at the onset

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

of the summer months, and is unable to obtain power through other means, NPC's business, operations, and financial condition would be materially adversely affected, and could make it difficult to provide reliable service to its customers or to continue to operate outside of bankruptcy.

Accounts Receivable Facility

On October 29, 2002, NPC established an accounts receivable purchase facility of up to $125 million, which was arranged by Lehman Brothers. The receivables purchase facility expires on August 28, 2003, unless NPC has activated the facility prior to that date, in which case the facility will be automatically extended to, and will expire on, October 28, 2003. If NPC elects to activate the receivables purchase facility, NPC will sell all of its accounts receivable generated from the sale of electricity to customers to its newly created bankruptcy remote special purpose subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiary will, in turn, sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables. Lehman Brothers Holdings, Inc., has committed to be the sole initial committed purchaser of all of the variable rate revolving notes.

The agreements relating to the receivables purchase facility contain various conditions to purchase, covenants and trigger events, and other provisions customary in receivables transactions. In addition to customary termination and mandatory repurchase events, the receivables purchase facility may terminate in the event that either NPC or SPR defaults (i) in the payment of indebtedness, or (ii) in the payment of amounts due under a swap agreement, and such defaults aggregate to greater than $10 million and $5 million for NPC and SPR, respectively. Under the terms of the agreements relating to the receivables purchase facility, NPC's facility may not be activated or, if activated, will be terminated in the event of a material adverse change in the condition, operations or business prospects of NPC. In addition, the agreements contain a limitation on the payment of dividends by NPC to SPR that is identical to the limitation contained in NPC's General and Refunding Mortgage Notes, Series E, described below. SPR has agreed to guaranty NPC's performance of certain obligations as a seller and servicer under the receivables purchase facility.

NPC has agreed to issue $125 million principal amount of its General and Refunding Mortgage Bonds upon activation of the receivables purchase facility. The full principal amount of the bonds would secure certain of NPC's obligations as seller and servicer, plus certain interest, fees and expenses thereon to the extent not paid when due, regardless of the actual amounts owing with respect to the secured obligations. As a result, in the event of an NPC bankruptcy or liquidation, the holder of the bond securing the receivables purchase facility may recover more on a pro rata basis than the holders of other General and Refunding Mortgage Securities, who could recover less on a pro rata basis than they otherwise would recover. However, in no event will the holder of the bond recover more than the amount of obligations secured by the bond.

NPC intends to use the accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. NPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $125 million General and Refunding Mortgage Bonds.

Mortgage Indentures

NPC's first mortgage indenture creates a first priority lien on substantially all of NPC's properties. As of December 31, 2002, $372.5 million of NPC's first mortgage bonds were outstanding. NPC agreed in connection with its Series E Notes that it would not issue any more first mortgage bonds.

NPC's General and Refunding Mortgage Indenture creates a lien on substantially all of NPC's properties in Nevada that is junior to the lien of the first mortgage indenture. As of December 31, 2002, $870 million of NPC's General and Refunding Mortgage Securities were outstanding. Additional securities may be issued under the General and Refunding Mortgage Indenture on the basis of (1) 70% of net utility property additions, (2) the principal amount of retired General and Refunding Mortgage Bonds, and/or (3) the principal amount of first mortgage bonds retired after delivery to the indenture trustee of the initial expert's certificate under the General and Refunding Mortgage Indenture. As of December 31, 2002, NPC had the capacity to issue approximately $1.04 billion of additional General and Refunding Mortgage Securities. However, the financial covenants contained in the Series E Notes limits NPC ability to issue additional General and Refunding Mortgage Bonds or other debt. NPC has reserved $125 million of General and Refunding Mortgage Bonds for issuance upon the initial funding of NPC's receivables facility.

NPC also has the ability to release property from the liens of the two mortgage indentures on the basis of net property additions, cash and/or retired bonds. To the extent NPC releases property from the lien of its General and Refunding Mortgage Indenture, it will reduce the amount of bonds issuable under that indenture.

PUCN Order

On June 19, 2002, the PUCN issued a Compliance Order, Docket No. 02-4037 which requires that until such time as the order's authorization expires (December 31, 2003), NPC must either receive the prior approval of the PUCN or reach an equity ratio of 42% before paying any dividends to SPR. If NPC achieves a 42% equity ratio prior to December 31, 2003, the dividend restriction ceases to have effect. As of December 31, 2002, NPC's equity ratio was 36.1%.

On July 3, 2002, the BCP of the Nevada Attorney General's Office filed a petition with the PUCN requesting that the hearing in Docket No. 02-4037, be reopened to allow for the introduction of additional evidence or for the PUCN to reconsider its decision granting NPC the authority to issue long-term debt. On September 11, 2002, the PUCN denied the petition to reopen the proceeding and rescinded the portion of its Compliance Order that had previously required NPC to immediately issue $50 million to $100 million of debt.

Financing Transactions and Covenants

On October 25, 2002, NPC redeemed its 7⅝% Series L, First Mortgage Bonds due November 1, 2002, in the aggregate principal amount of $15 million.

On October 29, 2002, NPC issued and sold $250 million of its 10⅞% General and Refunding Mortgage Notes, Series E, due 2009, for a purchase price of $235.6 million. The Series E Notes were issued with registration rights. The proceeds of the issuance were used to pay off NPC's $200 million credit facility and for general corporate purposes.

The Series E Notes limit the amount of payments in respect of common stock that NPC may pay to SPR. However, that limitation does not apply to payments by NPC to enable SPR to pay its reasonable fees and expenses (including, but not limited to, interest on SPR's indebtedness and payment obligations on account of SPR's PIES) provided that those payments do not exceed $60 million for any one calendar year, those payments comply with any regulatory restrictions then applicable to NPC, and the ratio of consolidated cash flow to fixed charges for NPC's most recently ended four full fiscal quarters immediately preceding the date of payment is at least 1.75 to 1. The terms of the Series E Notes also permit NPC to make payments to SPR in an aggregate amount not to exceed $15 million from the date of the issuance of the Series E Notes. In addition, NPC may make dividend payments to SPR in excess of the amounts described above so long as at the time of payment and after giving effect to the payment: there are no defaults or events of default with respect to the Series E Notes, NPC can meet a fixed charge coverage ratio test, and the total amount of such dividends is less than (i) the sum of 50% of NPC's consolidated net income measured on a quarterly basis cumulative of all quarters from the date of issuance of the Series E Notes, plus (ii) 100% of NPC's aggregate net cash proceeds from the issuance or sale of certain equity or convertible debt securities of NPC, plus (iii) the lesser of cash return of capital or the initial amount of certain restricted investments, plus (iv) the fair market value of NPC's investment in certain subsidiaries.

The terms of the Series E Notes also restrict NPC from incurring any additional indebtedness unless (i) at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for NPC's most recently ended four-quarter period on a pro forma basis is at least 2 to 1, or (ii) the debt incurred is specifically permitted, which includes certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, and certain letters of credit issued to support NPC's obligations with respect to energy suppliers.

If NPC's Series E Notes are upgraded to investment grade by both Moody's and S&P, the dividend restrictions and the restrictions on indebtedness applicable to the Series E Notes will be suspended and will no longer be in effect so long as the Series E Notes remain investment grade.

Among other things, the Series E Notes also contain restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. In the event of a change of control of NPC, the holders of Series E Notes are entitled to require that NPC repurchase the Series E Notes for a cash payment equal to 101% of the aggregate principal amount plus accrued and unpaid interest. The Series E Notes will mature October 15, 2009.

Cross-Default Provisions

Certain financing agreements of NPC contain cross-default provisions that would result in an event of default under such financing agreements if there is a failure under other financing agreements of NPC and SPR to meet payment terms or to observe other covenants that would result in an acceleration of payments due. Most of these default provisions (other than ones relating to a failure to pay other indebtedness) provide for a cure period of 30-60 days from the occurrence of a specified event, during which time NPC or SPR may rectify or correct the situation before it becomes an event of default. The primary cross-default provisions in NPC's various financing agreements are briefly summarized below:

- NPC's General and Refunding Mortgage Indenture provides for an event of default if a matured event of default under NPC's First Mortgage Indenture occurs;
- The terms of NPC's Series E Notes provide that a default with respect to the payment of principal, interest, or premium beyond the applicable grace period under any mortgage, indenture, or other security instrument by NPC or any of its restricted subsidiaries relating to debt in excess of $15 million triggers a right of the holders of the Series E Notes to require NPC to redeem the Series E Notes at a price equal to 100% of the aggregate principal amount plus accrued and unpaid interest and liquidated damages, if any, upon notice given by at least 25% of the outstanding Series E Notes holders; and
- NPC's receivables purchase facility may terminate in the event that either NPC or SPR defaults (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million and $5 million for NPC and SPR, respectively.

Pension Plan Matters

SPR has a qualified pension plan that covers substantially all employees of SPR, NPC, and SPPC. The annual net benefit cost for the plan will increase for 2003 by approximately $16.1 million over the 2002 cost of $18.4 million. As of September 30, 2002, the measurement date, the plan had assets with a fair value that was less than the present value of the accumulated benefit obligation under the plan. On December 6, 2002, NPC contributed a total of $13.05 million to meet its funding obligations under the plan. At the present time, NPC does not expect that any near term funding obligation will have a material adverse effect on its liquidity.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Construction Expenditures and Financing

The table below provides NPC's consolidated cash construction expenditures and internally generated cash, net for 2000 through 2002 (dollars in thousands):

	2002	2001	2000	Total
Cash construction expenditures	**$250,441**	$ 196,896	$196,636	$ 643,973
Net cash flow from operating activities	**$253,757**	$(757,402)	$113,711	$(389,934)
Common and preferred cash dividends paid	**10,000**	33,014	88,308	131,322
Internally generated cash	**243,757**	(790,416)	25,403	(521,256)
Investment by parent company	**10,000**	474,921	137,000	621,921
Total cash available	**$253,757**	$(315,495)	$162,403	$ 100,665
Internally generated cash as a percentage of cash construction expenditures	**97%**	N/A	13%	N/A
Total cash generated (used) as a percentage of cash construction expenditures	**101%**	N/A	83%	16%

NPC's estimated cash construction expenditures for 2003 through 2007 are $1.068 billion. Construction expenditures for 2003 are projected to be $223 million and are expected to be financed by internally generated funds, including the recovery of deferred energy.

Cash provided by internally generated funds during 2003 assumes, among other things, no disallowances on NPC's currently filed deferred energy rate case and the full recovery of such deferred energy amounts over three years, no additional disallowances related to NPC's appeal of its prior deferred energy case, and no adverse decision in the lawsuit filed by Enron against NPC seeking $200 million in termination payments. Material disallowances of currently-filed or previously-filed deferred energy costs or an adverse decision with respect to the Enron lawsuit would have a material adverse effect on NPC's financial condition and future results of operations and could cause additional downgrades of its securities by the rating agencies and make it significantly more difficult to finance operations and to buy fuel and purchased power from third parties. See Regulation and Rate Proceedings, Nevada Matters, for additional information regarding NPC's recently filed deferred energy rate case and prior deferred energy rate case and Liquidity and Capital Resources for additional information regarding the Enron lawsuit and the potential impact of a negative outcome with respect to any of these uncertainties.

In the event that NPC's financial condition worsens, it may be unable to finance its construction expenditures with internally generated funds and instead may need to raise all or a portion of the necessary funds through the capital markets or from activating its accounts receivables purchase facility to provide additional liquidity. For additional information regarding the accounts receivables purchase facility, see Liquidity and Capital Resources. NPC may activate its receivables purchase facility within five days upon the delivery of certain customary funding documentation and the delivery of $125 million of its General and Refunding Mortgage Bonds to secure the facility. If a material adverse event were to occur, it could potentially trigger a termination event with respect to the receivables facility and would also make it more difficult for NPC to access the capital markets for any such financing needs.

Contractual Obligations

The table below provides NPC's consolidated contractual obligations, not including estimated construction expenditures described above, as of December 31, 2002, that NPC expects to satisfy through a combination of internally generated cash and, as necessary, through the issuance of short-term and long-term debt (dollars in thousands):

Payment Due By Period

	2003	2004	2005	2006	2007	Thereafter	Total
Long-Term Debt	$354,677	$135,570	$ 6,091	$ 6,509	$ 5,949	$1,348,384	$1,857,180
Preferred Trust Securities	—	—	—	—	—	188,872	188,872
Purchased Power	408,656	241,957	220,343	204,666	189,434	3,456,297	4,721,353
Coal and Natural Gas	74,424	69,326	38,552	31,775	29,953	341,341	585,371
Operating Leases	2,263	1,170	869	181	119	459	5,061
Other Long-Term Obligations	75	100	—	—	—	—	175
Total Contractual Cash Obligations	$840,095	$448,123	$265,855	$243,131	$225,455	$5,335,353	$7,358,012

Capital Structure

As of December 31, 2002, NPC had no short-term debt outstanding.

On October 29, 2002, NPC established an accounts receivable purchase facility of up to $125 million, which was arranged by Lehman Brothers. If NPC elects to activate the receivables purchase facility, NPC will sell all of its accounts receivable generated from the sale of electricity to customers to its newly created bankruptcy remote special purpose subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiary will, in turn, sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables. Lehman Brothers Holdings, Inc. has committed to be the sole initial purchaser of all of the variable rate revolving notes.

NPC intends to use the accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. NPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of a $125 million General and Refunding Mortgage Bond. See Liquidity and Capital Resources for additional information regarding the terms and conditions of the accounts receivable purchase facility.

NPC's actual consolidated capital structure at December 31, 2002 and 2001, was as follows (dollars in thousands):

	2002		2001	
Short-Term Debt[1]	**$ 354,677**	**11%**	$ 149,880	4%
Long-Term Debt	**1,488,597**	**47%**	1,607,967	48%
Preferred Trust Securities	**188,872**	**6%**	188,872	6%
Common Equity	**1,149,131**	**36%**	1,393,583	42%
TOTAL	**$3,181,277**	**100%**	$3,340,302	100%

(1) Including current maturities of long-term debt.

Other Matters

On July 7, 2002, the Board of County Commissioners of Clark County, Nevada, added an Electric Utility Advisory Question to its November 5, 2002, general election ballot which asked voters in a non-binding initiative whether "the Nevada Legislature should take appropriate action to enable the electrical energy provider for southern Nevada to be a locally controlled, not-for-profit public utility." The Company and various private entities and public interest groups strongly opposed the measure. Although passing by a 57% majority, this was substantially below the level of support indicated in early polls. No bills related to this issue were introduced in the 2003 Nevada legislative session.

On August 22, 2002, SPR received a letter from the Southern Nevada Water Authority ("SNWA") stating that it was prepared to enter into good faith negotiations of definitive agreements to acquire NPC in some undetermined way (stock purchase or all or some of its assets) and to assume some unspecified amount of indebtedness at a purchase price subject to adjustment at SNWA's discretion at the conclusion of negotiations and due diligence. On September 12, 2002, SPR responded with a letter stating that it did not view the SNWA's letter as an offer and expressing concerns with the SNWA's financing plans, certain significant legal issues with the proposal, SNWA's lack of utility management experience, and ambiguity in the proposal. SPR was served with a complaint by a shareholder seeking class action status to require SPR to enter into negotiations. See Legal Proceedings for further details.

SIERRA PACIFIC POWER COMPANY

Results of Operations

SPPC incurred a net loss from continuing operations of ($14.0) million in 2002, compared to net income of $22.7 million in 2001 and a net loss of ($4.1) million in 2000. SPPC's operating results for 2002 reflect the write-off of approximately $58 million (before taxes) of deferred energy costs and related carrying charges as a result of the PUCN's May 28, 2002, decision in SPPC's deferred energy rate case to disallow $53 million of deferred purchased fuel and power costs. The PUCN's decision is being challenged by SPPC in a lawsuit filed in Nevada state court.

During 2002, SPPC paid $44.9 million in common stock dividends to its parent, SPR, $10 million of which was reinvested in SPPC as a contribution to capital. SPPC also paid $3.9 million in dividends to holders of its preferred stock.

SPPC closed the sale of its water utility business in June 2001. Accordingly, the water business is reported as a discontinued operation and the continuing operating results have been reclassified to report separately the net results of operations from the water business.

The components of gross margin are (dollars in thousands):

	2002	2001	2000
Operating Revenues:			
Electric	**$ 931,251**	$1,401,778	$894,919
Gas	**149,783**	145,652	100,803
Total revenues	**$1,081,034**	$1,547,430	$995,722
Energy Costs:			
Electric	**687,652**	1,113,634	678,727
Gas	**120,603**	113,364	67,035
Total energy costs	**808,255**	1,226,998	745,762
Gross margin	**$ 272,779**	$ 320,432	$249,960
Gross Margin by Segment:			
Electric	**243,599**	288,144	216,192
Gas	**29,180**	32,288	33,768
Total	**$ 272,779**	$ 320,432	$249,960

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The causes for significant changes in specific lines comprising the results of operations for the years ended are provided below (dollars in thousands, except for amounts per unit):

Electric Operating Revenue

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
ELECTRIC OPERATING REVENUES					
Residential	**$218,663**	**4.0%**	$ 210,350	17.7%	$178,701
Commercial	**268,631**	**10.1%**	243,883	23.9%	196,846
Industrial	**269,610**	**6.2%**	253,936	29.5%	196,143
Retail revenues	**756,904**	**6.9%**	708,169	23.9%	571,690
Other(1)	**174,347**	**-74.9%**	693,609	114.6%	323,229
TOTAL REVENUES	**$931,251**	**-33.6%**	$1,401,778	56.6%	$894,919
Retail sales in thousands of megawatt-hours (MWh)	**8,692**	**-0.4%**	8,729	-0.9%	8,807
Average retail revenue per MWh	**$ 87.08**	**7.3%**	$ 81.13	25.0%	$ 64.91

(1) Primarily wholesale, as discussed below.

SPPC's retail revenues were higher in 2002 primarily as a result of a net rate increase resulting from SPPC's general rate and deferred energy cases (refer to Regulation and Rates Proceedings, later). Effective June 1, 2002, the PUCN authorized an increase in SPPC's energy related rates that are used to recover current and previously incurred fuel and purchased power costs. The decrease in 2002 Other revenues was primarily due to the lower sales resulting from a reduction in transactions entered into for hedging purposes and the optimization of purchased power costs. See Energy Supply, later, for a discussion of the Utilities' purchased power procurement strategies.

The increase in SPPC's 2001 retail revenues was primarily due to rate increases resulting from the Global Settlement and Comprehensive Energy Plan (refer to Regulation and Rate Proceedings, later). These increases in rates were used to recover fuel and purchased power costs. Substantially all of the increase in Other electric revenues was due to the sale of wholesale electric power to other utilities. SPPC's increase in wholesale sales compared to 2000 was a result of market conditions and SPPC's power procurement activities. See Energy Supply, later, for a discussion of the Utilities' purchased power procurement strategies.

Gas Operating Revenues

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
GAS OPERATING REVENUES					
Residential	**$ 76,400**	**19.7%**	$ 63,815	46.6%	$ 43,541
Commercial	**37,018**	**20.7%**	30,680	43.6%	21,368
Industrial	**20,252**	**12.9%**	17,941	58.7%	11,307
Retail revenues	**133,670**	**—%**	112,436	—%	76,216
Wholesale	**16,113**	**-51.6%**	33,298	46.0%	22,805
Miscellaneous	**—**	**-100.0%**	(82)	-104.6%	1,782
TOTAL REVENUES	**$149,783**	**2.8%**	$ 145,652	44.5%	$100,803
Retail sales in thousands of decatherms	**14,030**	**-1.7%**	14,276	7.8%	13,240
Average retail revenues per decatherm	**$ 9.53**	**20.9%**	$ 7.88	36.8%	$ 5.76

2002 retail gas revenues were significantly higher than the prior year primarily due to a rate increase resulting from SPPC's purchased gas adjustment filing. Effective November 5, 2001, the PUCN authorized this increase in energy related rates that are used to recover current and previously incurred purchased gas. Other gas revenues were significantly lower in 2002 due to lower wholesale prices and sales.

Gas revenues rose in 2001 as compared to 2000 primarily due to the fact that the PUCN allowed SPPC to implement two gas rate increases. These increases were the result of higher gas costs that SPPC incurred. Revenues were also higher due to increases of 5.0%, 3.1%, and 10.6%, respectively, in residential, commercial, and industrial customers. Other revenues were higher due to an increase in wholesale gas sales.

Purchased Power

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
PURCHASED POWER	**$545,040**	**-46.9%**	$1,025,741	130.5%	$444,979
Purchased power in thousands of MWh	**7,206**	**-5.1%**	7,591	3.3%	7,349
Average cost per MWh of purchased power(1)	**$ 63.59**	**-52.9%**	$ 135.13	123.2%	$ 60.55

(1) Not including contract termination costs, discussed below.

Purchased power costs decreased dramatically in 2002 due to overall purchase power prices decreasing by 52.9%. These price decreases were the result of a less volatile energy market. The overall decrease in the cost of purchased power was offset in part by an $86.8 million reserve provision recorded in the second quarter for terminated contracts. Purchased power costs also reflect a 40% decrease in wholesale sales activity. Purchases associated with risk management activities, which include transactions entered into for hedging purposes and to optimize purchased power costs, are included in the purchased power amounts. See Energy Supply, later, for a discussion of the Utilities' purchased power procurement strategies.

Purchased power costs were higher in 2001 than 2000 primarily because prices per MWh were double that of the prior year and purchased power was relied on to accommodate increased system load. Purchased power costs were also higher during 2001 due to hedging activities in response to higher purchased power prices.

Fuel for Power Generation

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
FUEL FOR POWER GENERATION	**$144,143**	**-49.7%**	$286,719	22.7%	$233,748
Thousands of MWh generated	**4,699**	**-21.5%**	5,986	4.0%	5,756
Average fuel cost per MWh of generated power	**$ 30.67**	**-36.0%**	$ 47.90	18.0%	$ 40.61

Fuel for power generation costs decreased 49.7% in 2002 as compared to 2001 due primarily to decreased natural gas prices and, to a lesser extent, to lower system load requirements.

Fuel for generation costs in 2001 were higher than 2000 due to higher gas prices and an increase in volumes purchased to accommodate greater system load.

Gas Purchased for Resale

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
GAS PURCHASED FOR RESALE	**$91,961**	**-32.6%**	$136,534	64.1%	$83,199
Gas Purchased for Resale (in thousands of decatherms)	**17,930**	**7.0%**	16,756	-9.2%	18,457
Average cost per decatherm	**$ 5.13**	**-37.1%**	$ 8.15	80.7%	$ 4.51

The cost of gas purchased for resale decreased in 2002 as compared to 2001 primarily as a result of lower unit prices more than offsetting an increase in quantities. The significant gas price decreases are consistent with the increase in availability. Although there was a lower demand by retail customers as a result of warmer weather, SPPC sold more volume to wholesale customers, causing the increase in quantities.

As compared to 2000, the cost of gas purchased for resale increased in 2001 because a decrease in quantities of gas purchased was more than offset by large increases in unit prices. The decrease in quantities purchased was the result of increased plant consumption of gas, thereby decreasing the availability of gas for wholesale activities. The higher unit prices were attributable to increased demand for gas in the Pacific Northwest and additional transportation fees.

Deferral of Energy Costs—Net

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
DEFERRAL OF ENERGY COSTS—ELECTRIC—NET	**$(54,632)**	**-72.5%**	$(198,826)	N/A	$ —
DEFERRED ENERGY COSTS DISALLOWED	**56,958**	**N/A**	—	N/A	—
DEFERRED ENERGY COSTS—GAS—NET	**24,785**	**N/A**	(23,170)	43.3%	(16,164)
TOTAL	**$ 27,111**	**N/A**	$(221,996)	N/A	$(16,164)

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The change in Deferred of energy costs—electric—net for the twelve months ended December 31, 2002, compared to the same period the prior year, reflects the amortization in 2002 of prior deferred costs pursuant to the PUCN's decision on SPPC's deferred energy rate case, which resulted in increased rates beginning June 1, 2002. The amortization was offset in part by the recording of current year deferrals of electric energy costs, reflecting the extent to which actual fuel and purchased power costs exceeded the fuel and purchased power costs recovered through current rates. Deferral of energy costs—net also reflects the deferral in the second quarter of 2002 of approximately $82 million for contract termination costs and the second quarter 2002 write-off of $53 million of electric deferred energy costs incurred in the nine months ended November 30, 2001, that were disallowed by the PUCN in their May 28, 2002, decision on SPPC's deferred energy rate case. See more detail in Note 17 of Notes to Financial Statements, Commitments and Contingencies.

In January 2000, after the expiration of a rate freeze that was in effect from 1997 through 1999, SPPC began deferring natural gas costs in excess of that allowed in the tariff for its gas local distribution company (LDC). In 2001, the deferral increased due to higher gas costs incurred by SPPC. The significant change from 2001 is attributed to lower gas costs in 2002 combined with the recovery of fuel and purchased power costs through current rates, which exceeded the actual fuel and purchase power costs. Deferred energy costs disallowed reflects a write-off of $4 million in gas costs, incurred in the twelve months ended April 2002, that were disallowed by the PUCN in their December 23, 2002, decision on SPPC's Purchase Gas Adjustment rate case.

See Critical Accounting Policies, earlier, and Note 1 of Notes to Financial Statements, Summary of Significant Accounting Policies for more information regarding deferred energy accounting.

Allowance for Funds Used During Construction (AFUDC)

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
ALLOWANCE FOR OTHER FUNDS USED DURING CONSTRUCTION	**$ 117**	**-86.3%**	$ 856	139.8%	$ 357
ALLOWANCE FOR BORROWED FUNDS USED DURING CONSTRUCTION	**1,858**	**181.5%**	660	-76.3%	2,779
	$1,975	**30.3%**	$1,516	-51.7%	$3,136

AFUDC for SPPC is higher in 2002 compared to 2001 due to an increase in construction work-in-progress (CWIP) and because AFUDC in 2001 reflected an adjustment to refine amounts assigned to specific components of facilities that were completed in different periods. This increase was offset in part by a decrease in the AFUDC rate. AFUDC is lower in 2001 compared to 2000 because of adjustments to amounts assigned to specific components of facilities that were completed in different periods offset by an increase in the AFUDC rate.

Other (Income) and Expenses

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
OTHER OPERATING EXPENSE	**$106,122**	**-10.5%**	$118,526	22.2%	$97,021
MAINTENANCE EXPENSE	**23,240**	**-4.6%**	24,363	32.3%	18,420
DEPRECIATION AND AMORTIZATION	**76,373**	**5.9%**	72,103	0.7%	71,630
INCOME TAXES	**(6,922)**	**-181.4%**	8,507	N/A	(672)
INTEREST CHARGES ON LONG-TERM DEBT	**66,474**	**20.4%**	55,199	49.7%	36,865
INTEREST CHARGES—OTHER	**10,663**	**43.5%**	7,433	-34.3%	11,312
INTEREST ACCRUED ON DEFERRED ENERGY	**(10,644)**	**-14.6%**	(12,461)	5978.5%	(205)
OTHER INCOME	**(4,266)**	**101.9%**	(2,113)	-37.9%	(3,405)
OTHER EXPENSE	**6,577**	**6.5%**	6,176	23.4%	5,003
INCOME TAXES—OTHER INCOME AND EXPENSE	**2,431**	**N/A**	(91)	-86.8%	(690)

The decrease in Other operating expense for 2002 reflects $8.6 million of reserve provisions which were established in 2001 for retail uncollectible accounts in SPPC's service territory and uncollectible amounts associated with the California Power Exchange. Additional factors that resulted in lower Other operating expenses during 2002 include the reversal of a $7.0 million reserve originally established in 2001 pursuant to the PUCN order for costs associated with the conclusion of electric industry restructuring. SPPC had no 2002 short-term incentive plan expense compared to $4.2 million in 2001. Increases in Other operating expense during 2002 include $9.0 million in legal and advisory fees associated with liquidity issues and the consequences of the PUCN's deferred energy rate case decision.

Other operating expense increased in 2001 compared to 2000 due to a $7 million larger addition to the provision for uncollectible customer accounts than in 2000, and a $3.5 million reserve provision established as a result of AB 369. Additionally, there were increased expenses related to the startup of the Piñon Gasifier in 2001.

Maintenance costs in 2001 were higher due to additional turbine repairs and no major overhauls in 2000 at Valmy. There was also a shift from divestiture in 2000 to maintenance activities in 2001 at Tracy as well as unplanned maintenance on the diesel generators.

Depreciation and amortization were higher in 2002 than 2001 due to an increase in plant-in-service and an increase to depreciation of $1.8 million to reflect an adjustment to depreciation rates related to combustion turbines. These increases were offset in part by a PUCN-ordered reduction in depreciation rates that was implemented June 1, 2002. Depreciation and amortization were also higher in 2001 than 2000 due to an increase in plant-in-service.

As a result of net losses from continuing operations recognized during 2002 and 2000, SPPC recorded an income tax benefit for those years. Due to net income from continuing operations, SPPC recorded income tax expense for 2001.

SPPC's Interest charges on long-term debt increased in 2002 compared to 2001 due to additional issuances of long-term debt at higher interest rates and to the payment of a full year of interest on $320 million of long-term debt issued in May 2001. In 2002, SPPC redeemed approximately $4 million in debt and issued additional debt of $100 million. For 2001 compared to 2000, SPPC's increased interest charges were attributable to the issuance of $320 million of long-term debt.

SPPC's Interest charges—other increased in 2002 compared to 2001 due to interest on extended payments to fuel and power suppliers resulting from renegotiated purchased power and fuel contracts, interest on short-term notes, and credit facility fees (refer to Liquidity and Capital Resources for further discussion of power and fuel contracts and the credit facilities). SPPC's interest charges—other decreased in 2001 compared to 2000 due to a decrease in commercial paper balances in 2001.

SPPC's interest accrued on deferred energy decreased in 2002, compared to 2001 due to a decline in carrying charges on deferral of fuel and purchased power balances in 2002 as compared to 2001. For 2001, the increase over 2000 was due to the increases in deferred fuel and purchased power balances pursuant to AB 369. (Refer to Regulation and Rate Proceedings for discussion of deferred energy issues.)

SPPC's Other income for 2002 compared to 2001 increased due to increased interest and dividend income and gains on disposition of property. For 2001 as compared to 2000, the decrease was attributable to reductions in lease revenues, interest and dividend income, and miscellaneous gains on dispositions of property.

SPPC's Other expense increased in 2002 compared to 2001 due primarily to increased expenditures to its low-income energy assistance programs. For 2001 as compared to 2000, Other expense increased due to increased expenses attributable to SPPC's subsidiaries, and by costs relating to SPPC's divestiture of its water business.

Net tax expense on other income and expense increased in 2002 over 2001 because in 2001 certain benefits related to sale of the water utility business were recorded in other income and expense. These benefits were the result of the true-up of the 2000 tax return recorded in 2001.

In 2001, a net tax benefit was recorded due to the net excess of other expenses over other income for the year.

Discontinued Operations

	2002		2001		2000
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Income from operations of water business	**$ —**	**-100.0%**	$1,022	-89.4%	$9,634

SPPC closed the sale of its water utility business in 2001. Accordingly, the water business is reported as a discontinued operation. Income from operations of the water business decreased in 2001 compared to 2000 as a result of the sale of the water business in June 2001 prior to the seasonal increase in revenues resulting from higher water send-out.

Analysis of Cash Flows

SPPC's net cash flows improved in 2002 compared to 2001, resulting primarily from an increase in cash flows from operating activities offset in part by a decrease in cash flows from investing activities. Although SPPC recorded a net loss during 2002 compared to net income in 2001 the current year's loss resulted largely from the write-off of disallowed deferred energy costs for which the cash outflow had occurred in 2001. Other factors contributing to 2002's improved cash flows from operating activities include the collection of deferred energy costs from customers and lower energy prices. Also, cash flows from operating activities in the current year reflect the receipt of an income tax refund. Cash flows from investing activities decreased in 2002 because 2001 investing activities included cash provided from the sale of the assets of SPPC's water business. Cash flows from financing activities during 2002 were comparable to 2001.

SPPC's net cash flows during 2001 were comparable to 2000. For 2001, an increase in net cash flows from investing activities was substantially offset by a decrease in net cash flows from operating activities. The increase in net cash flows from investing activities resulted from the sale of the assets of SPPC's water business. The decrease in cash flows from operating activities resulted substantially from the payment of significantly higher energy and resale natural gas costs. These uses of cash flows were partially offset by a decrease in accounts payable in 2001. The decrease in cash flows from financing activities was due to reduced reliance on commercial paper in 2001 and the retirement of preferred stock as described in Note 8 of

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Notes to the Financial Statements, Preferred Stock and Preferred Trust Securities, offset in part by capital contributions from SPR.

Liquidity and Capital Resources

SPPC had cash and cash equivalents of approximately $88.9 million at December 31, 2002, and approximately $104.2 million at February 28, 2003.

As discussed in Construction Expenditures and Financing and Capital Structure, SPPC anticipates having capital requirements for construction costs and for the repayment of maturing long-term debt during 2003 totaling approximately $222 million, which SPPC expects to finance with internally generated funds, including the recovery of deferred energy and the issuance of debt.

SPPC's future liquidity could be significantly affected by unfavorable rulings by the PUCN in pending or future SPPC or NPC rate cases. S&P and Moody's have SPPC's credit ratings on "negative outlook" and "stable," respectively. Future downgrades by either S&P or Moody's could preclude SPPC's access to the capital markets and could adversely affect SPPC's ability to continue purchasing power and fuel. Adverse developments with respect to any one or a combination of the factors and contingencies set forth above could have a material adverse effect on SPPC's financial condition and liquidity and could make it difficult to continue to operate outside of bankruptcy.

Effect of Rate Case Decisions

On March 29 and April 1, 2002, following the decision by the PUCN in NPC's deferred energy rate case, S&P and Moody's lowered SPPC's unsecured debt ratings to below investment grade. On April 23 and 24, 2002, SPPC's unsecured debt ratings were further downgraded and its secured debt ratings were downgraded to below investment grade. The decision of the PUCN on May 29, 2002, on SPPC's deferred energy application to disallow $53 million of deferred purchased fuel and power costs accumulated between March 1, 2001, and November 30, 2001, did not result in any further downgrades of SPPC's securities. As a result of the downgrades, SPPC's ability to access the capital markets to raise funds is severely limited. Since SPR's credit ratings were similarly downgraded, SPR's ability to make capital contributions to SPPC also became severely limited.

Commercial Paper and Credit Facilities. In connection with the credit ratings downgrades referenced above, SPPC lost its A2/P2 commercial paper ratings and can no longer issue commercial paper. At the time, SPPC had a commercial paper balance outstanding of $47.7 million with a weighted average interest rate of 2.49%. SPPC paid off its maturing commercial paper with the proceeds of borrowings under its credit facility and terminated its commercial paper program on May 28, 2002. SPPC does not expect to have direct access to the commercial paper market for the foreseeable future.

SPPC's $150 million unsecured revolving credit facility was also affected by the downgrade in SPPC's credit rating. Under this facility, SPPC was required, in the event of a ratings downgrade of its senior unsecured debt, to secure the facility with General and Refunding Mortgage Bonds. In satisfaction of its obligation to secure the credit facility, on April 8, 2002, SPPC issued and delivered its General and Refunding Mortgage Bond, Series B, due November 28, 2002, in the principal amount of $150 million, to the Administrative Agent for the credit facility. As of May 10, 2002, SPPC had borrowed the entire $150 million of funds available under its credit facility to, in part, pay off maturing commercial paper, maintaining a cash balance at SPPC. This facility was paid in full and terminated on October 31, 2002, with available cash and proceeds from SPPC's $100 million Term Loan Facility.

Power Supplier Issues. Historically, SPPC has purchased a significant portion of the power that it sells to its customers from power suppliers. As discussed under Sierra Pacific Resources, Liquidity and Capital Resources, following the PUCN's decision on March 29, 2002 in NPC's deferred energy rate case, a number of power suppliers requested collateral from SPPC and NPC under the WSPP standard contract. Both SPPC and NPC informed such suppliers that a simultaneous call for 100% mark-to-market collateral in the short term would likely not be met. Several power suppliers terminated their contacts with SPPC (as discussed above).

In early May of 2002, Enron, MSCG, Reliant Energy Services, Inc., and several smaller suppliers terminated their power deliveries to SPPC. These terminating suppliers asserted their contractual right under the WSPP agreement to terminate deliveries based upon SPPC's alleged failure to provide adequate assurance of its performance under the WSPP agreement to any of its suppliers. Each of these terminating suppliers has asserted, or has indicated that it will assert, a claim for liquidated damages under the terminated power supply contracts.

Enron filed a complaint with the United States Bankruptcy Court for the Southern District of New York seeking to recover approximately $93 million against SPPC for liquidated damages for power supply contracts terminated by Enron in May 2002 and for power previously delivered to SPPC. SPPC has denied liability on numerous grounds, including deceit and misrepresentation in the inducement, (including, but not limited to, Enron's ability to perform), and for fraud, unfair trade practices, and market manipulation. SPPC filed motions to dismiss for lack of jurisdiction and/or for a stay of all proceedings pending the actions of the Utilities' 206 actions at the FERC (see Regulation and Rate Proceedings). The Utilities have also filed proofs of claims and counterclaims against Enron for the full amount of the approximately $300 million claimed to be owed and additional damages for unspecified damages to be determined during the case as a result of acts and omissions of Enron in manipulating the power markets.

On December 19, 2002, the bankruptcy judge granted Enron's motion for partial summary judgment on Enron's claim for $6.7 million for energy delivered by Enron in April 2002 for which SPPC did not pay. The court ordered this money to be deposited into an escrow account not subject to claims of Enron's creditors and subject to refund depending on the outcome of the Utilities' FERC cases on the merits. The bankruptcy court denied SPPC's motion to stay the proceeding pending the outcome of the Utilities' Section 206 case at the FERC and denied SPPC's motion to dismiss for lack of jurisdiction as to Enron's claims for power previously delivered to the Utilities. The court stated that it would rule in due course on Enron's motion for partial summary judgment to require SPPC to post $87 million pending the outcome of the case on the merits and for judgment on the merits on Enron's liquidated damage claim (contract price less market price on the date of termination) relating to power it did not deliver under contracts terminated by Enron in May 2002. The court took under advisement the Utilities' motion to stay or dismiss Enron's claim for liquidated damages relating to the undelivered power and set a hearing on Enron's motion to dismiss the Utilities' counterclaims for April 3, 2003. The United States District Court for the Southern District of New York also denied the Utilities' motion to withdraw reference of the matter to the bankruptcy court without prejudice.

The bankruptcy court currently has under submission (1) Enron's motion to dismiss SPPC's counterclaims, (2) Enron's motion for partial summary judgment regarding the amounts alleged to be due for undelivered power and the posting of collateral for undelivered power, and (3) SPPC's motion to dismiss or stay proceeding on Enron's claims relating to delivered power. Enron's motion to dismiss SPPC's counterclaims is set for hearing on April 3, 2003. SPPC is unable to predict the outcome of the motions. A decision adverse to SPPC on Enron's motion for partial summary judgment, or an adverse decision in the lawsuit with respect to liability as to Enron's claims on the merits for undelivered power, would have a material adverse effect on SPPC's financial condition and liquidity and could make it difficult to continue to operate outside of bankruptcy.

If SPPC continues to experience financial difficulty or if its credit ratings are further downgraded, SPPC may experience considerable difficulty entering into new power supply contracts, particularly under traditional payment terms. If suppliers will not sell power to SPPC under traditional payment terms, SPPC may have to prepay its power requirements. If it does not have sufficient funds or access to liquidity to prepay its power requirements, SPPC's business, operations and financial condition will be materially adversely affected and could make it difficult for SPPC to provide reliable service to its customers or to continue to operate outside of bankruptcy.

Accounts Receivable Facility

On October 29, 2002, SPPC established an accounts receivable purchase facility of up to $75 million, which was arranged by Lehman Brothers. The receivables purchase facility expires on August 28, 2003 unless SPPC has activated the facility prior to that date, in which case the facility will be automatically extended to, and will expire on, October 28, 2003. If SPPC elects to activate the receivables purchase facility, SPPC will sell all of its accounts receivable generated from the sale of electricity and natural gas to customers to its newly created bankruptcy remote special purpose subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiary will, in turn, sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables. Lehman Brothers Holdings, Inc. has committed to be the sole initial committed purchaser of all of the variable rate revolving notes.

The agreements relating to the receivables purchase facility contain various conditions to purchase, covenants and trigger events, and other provisions customary in receivables transactions. In additional to customary termination and mandatory repurchase events, the receivables purchase facility may terminate in the event that either SPPC or SPR defaults (i) on the payment of indebtedness, or (ii) on the payment of amounts due under a swap agreement, and such defaults aggregate to greater than $10 million and $5 million for SPPC and SPR, respectively. Under the terms of the agreements relating to the receivables purchase facility, SPPC's facility may not be activated or, if activated, will be terminated in the event of a material adverse change in the condition, operations, or business prospects of SPPC. In addition, the agreements contain a limitation on the payment of dividends by SPPC to SPR that is identical to the limitation contained in SPPC's Term Loan Agreement, described below. SPR has agreed to guaranty SPPC's performance of certain obligations as a seller and servicer under the receivables purchase facility.

SPPC has agreed to issue $75 million principal amount of its General and Refunding Mortgage Bonds upon activation of the receivables purchase facility. The full principal amount of the bonds would secure certain of SPPC's obligations as seller and servicer, plus certain interest, fees and expenses thereon to the extent not paid when due, regardless of the actual amounts owing with respect to the secured obligations. As a result, in the event of an SPPC bankruptcy or liquidation, the holder of the bond securing the receivables purchase facility may recover more on a pro rata basis than the holders of other General and Refunding Mortgage Securities, who could recover less on a pro rata basis than they otherwise would recover. However, in no event will the holder of the bond recover more than the amount of obligations secured by the bond.

SPPC intends to use the accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. SPPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $75 million General and Refunding Mortgage Bonds.

Mortgage Indentures

SPPC's First Mortgage Indenture creates a first priority lien on substantially all of SPPC's properties in Nevada and California. As of December 31, 2002, $505.3 million of SPPC's first mortgage bonds were outstanding. SPPC agreed in its General and Refunding Mortgage Indenture that it would not issue any additional first mortgage bonds.

SPPC's General and Refunding Mortgage Indenture creates a lien on substantially all of SPPC's properties in Nevada that is junior to the lien of the first mortgage indenture. As of December 31, 2002, $420 million of SPPC's General and Refunding Mortgage Bonds were outstanding. Additional securities may be issued under the General and Refunding Mortgage Indenture on the basis of (i) 70% of net utility property additions, (ii) the principal amount of retired General and Refunding Mortgage Bonds, and/or (iii) the principal amount of first mortgage bonds retired after delivery to the indenture trustee of the initial expert's certificate under the General and Refunding Mortgage Indenture. At December 31, 2002, SPPC had

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

the capacity to issue approximately $427 million of additional General and Refunding Mortgage Securities. However, the financial covenants contained in SPPC's Term Loan Agreement and Receivable Purchase Facility Agreements limit SPPC's ability to issue additional General and Refunding Mortgage Securities or other debt. SPPC has reserved $75 million of General and Refunding Mortgage Bonds for issuance upon the initial funding of its receivables purchase facility.

SPPC also has the ability to release property from the liens of the two mortgage indentures on the basis of net property additions, cash and/or retired bonds. To the extent SPPC releases property from the lien of its General and Refunding Mortgage Indenture, it will reduce the amount of bonds issuable under that indenture.

Financing Transactions and Covenants

On May 23, 2002, SPPC satisfied its obligations with respect to its 2% First Mortgage Bonds due 2011, 5% Series Y First Mortgage Bonds due 2024, and 2% Series Z First Mortgage Bonds due 2004, by depositing $1.2 million, $3.1 million, and $45,000, respectively, with its First Mortgage Trustee. These First Mortgage Bonds were issued to secure loans made to SPPC by the United States under the Rural Electrification Act of 1936, as amended.

On October 30, 2002, SPPC entered into a $100 million Term Loan Agreement with several lenders and Lehman Commercial Paper Inc., as Administrative Agent. The net proceeds of $97 million from the Term Loan Facility, along with available cash, were used to pay off SPPC's $150 million credit facility, which was secured by a Series B General and Refunding Mortgage Bond. SPPC's Term Loan Agreement limits the amount of dividends that SPPC may pay to SPR. However, that limitation does not apply to payments by SPPC to enable SPR to pay its reasonable fees and expenses (including, but not limited to, interest on SPR's indebtedness and payment obligations on account of SPR's premium income equity securities) provided that those payments do not exceed $90 million, $80 million, and $60 million in the aggregate for the twelve-month periods ending on October 30, 2003, 2004, and 2005, respectively.

The Term Loan Agreement also permits SPPC to make dividend payments to SPR in an aggregate amount not to exceed $10 million during the term of the Term Loan Agreement. In addition, SPPC may make dividend payments to SPR in excess of the amounts described above so long as at the time of the payment and after giving effect to the payment there are no defaults or events of default under the Term Loan Agreement, and such amounts, when aggregated with the amount of dividends paid to SPR by SPPC since the date of execution of the Term Loan Agreement, does not exceed the sum of (i) 50% of SPPC's Consolidated Net Income for the period commencing January 1, 2003, and ending with last day of fiscal quarter most recently completed prior to the date of the contemplated dividend payment, *plus* (ii) the aggregate amount of cash received by SPPC from SPR as equity contributions on its common stock during such period.

SPPC's Term Loan Agreement requires that SPPC maintain a ratio of consolidated total debt to consolidated total capitalization at all times during each of the following quarters in an amount not to exceed (i) .650 to 1.0 for the fiscal quarters ended December 31, 2002 through December 31, 2003, (ii) .625 to 1.0 for the fiscal quarters ended March 31, 2004, through December 31, 2004, and (iii) .600 to 1.0 for the fiscal quarter ended March 31, 2005, and for each fiscal quarter thereafter. SPPC's Term Loan Agreement also requires that SPPC maintain a consolidated interest coverage ratio for any four consecutive fiscal quarters ending with the fiscal quarter set forth below of not less than (i) 1.75 to 1.00 for the fiscal quarters ended December 31, 2002, and March 31, 2003, (ii) 2.50 to 1.0 for the fiscal quarters ended June 30, 2003, through December 31, 2003, (iii) 2.75 to 1.0 for the fiscal quarters ended March 31, 2004, through September 30, 2004, and (iv) 3.00 to 1.0 for the fiscal quarter ended December 31, 2004, and for each fiscal quarter thereafter. As of December 31, 2002, SPPC was in compliance with these financial covenants. The Term Loan Facility, which is secured by a $100 million Series C General and Refunding Mortgage Bond, will expire October 31, 2005.

SPPC's Washoe County, Nevada, Water Facilities Refunding Revenue Bonds, Series 2001 in the aggregate principal amount of $80 million, will be subject to remarketing on May 1, 2003. In the event that these bonds cannot be successfully remarketed on that date, SPPC will be required to purchase the outstanding bonds at a price of 100% of the principal amount, plus accrued interest.

Cross-Default Provisions

Certain financing agreements of SPPC contain cross-default provisions that would result in an event of default under such financing agreements if there is a failure under other financing agreements of SPPC and SPR to meet payment terms or to observe other covenants that would result in an acceleration of payments due. Most of these default provisions (other than ones relating to a failure to pay other indebtedness) provide for a cure period of 30-60 days from the occurrence of a specified event during which time SPPC or SPR may rectify or correct the situation before it becomes an event of default. The primary cross-default provisions in SPPC's various financing agreements are briefly summarized below:

- SPPC's General and Refunding Mortgage Indenture provides for an event of default if a matured event of default under SPPC's First Mortgage Indenture occurs;
- SPPC's Term Loan Agreement provides for an event of default if (a) SPPC or any of its subsidiaries default (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million, or (b) SPPC's General and Refunding Mortgage Indenture ceases to be enforceable; and
- SPPC's receivables purchase facility may terminate in the event that either SPPC or SPR defaults (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million and $5 million for SPPC and SPR, respectively.

Pension Plan Matters

SPR has a qualified pension plan that covers substantially all employees of SPR, NPC, and SPPC. The annual net benefit cost for the plan will increase for 2003 by approximately $16.1 million over the 2002 cost of $18.4 million. As of September 30, 2002, the plan had assets with a fair value that was less than the present value of the accumulated benefit obligation under the plan. On December 6, 2002, SPPC contributed a total of $10.53 million to meet its funding obligations under the plan. At the present time, SPPC does not expect that any near term funding obligation will have a material adverse effect on its liquidity.

Construction Expenditures and Financing

The table below provides SPPC's consolidated cash construction expenditures and internally generated cash, net for 2000 through 2002 (dollars in thousands):

	2002	2001	2000	Total
Cash construction expenditures	**$ 93,033**	$ 105,129	$132,710	$ 330,872
Net cash flow from operating activities	**$163,995**	$(211,699)	$114,360	$ 66,656
Common and preferred cash dividends paid	**48,805**	89,901	84,899	223,605
Internally generated cash	**115,190**	(301,600)	29,461	(156,949)
Investment by parent company	**10,000**	104,948	14,000	128,948
Total cash available	**$125,190**	$(196,652)	$ 43,461	$ (28,001)
Internally generated cash as a percentage of cash construction expenditures	**124%**	N/A	22%	N/A
Total cash generated (used) as a percentage of cash construction expenditures	**135%**	N/A	33%	N/A

SPPC's estimated cash construction expenditures for 2003 through 2007 are $483 million. Construction expenditures for 2003 are projected to be $121 million and are expected to be financed by internally generated funds, including the recovery of deferred energy at the Utilities.

Cash provided by internally generated funds during 2003 assumes, among other things, no disallowances on SPPC's currently filed deferred energy rate case and the full recovery of such deferred energy amounts over three years, no additional disallowances related to SPPC's appeal of its prior deferred energy case, and no adverse decision in the lawsuit filed by Enron against SPPC seeking $87 million in termination payments. Material disallowances of currently-filed or previously-filed deferred energy costs or an adverse decision with respect to the Enron lawsuit would have a material adverse effect on SPPC's financial condition and future results of operations and could cause additional downgrades of its securities by the rating agencies and make it significantly more difficult to finance operations and to buy fuel and purchased power from third parties. See Regulation and Rate Proceedings, Nevada Matters, for additional information regarding SPPC's recently filed deferred energy rate case and prior deferred energy rate case and Liquidity and Capital Resources for additional information regarding the Enron lawsuit and the potential impact of a negative outcome with respect to any of these uncertainties.

In the event that SPPC's financial condition worsens, it may be unable to finance its construction expenditures with internally generated funds and instead may need to raise all or a portion of the necessary funds through the capital markets or from activating its accounts receivables purchase facility to provide additional liquidity. For additional information regarding the accounts receivables purchase facility, see Liquidity and Capital Resources. SPPC may activate its receivables purchase facility within five days upon the delivery of certain customary funding documentation and the delivery of $75 million of its General and Refunding Mortgage Bonds to secure the facility. If a material adverse event were to occur, it could potentially trigger a termination event with respect to the receivables facility and would also make it more difficult for SPPC to access the capital markets for any such financing needs.

Contractual Obligations

The table below provides SPPC's contractual obligations, not including estimated construction expenditures described above, as of December 31, 2002, that SPPC expects to satisfy through a combination of internally generated cash and, as necessary, through the issuance of short-term and long-term debt (dollars in thousands):

Payment Due By Period

	2003	2004	2005	2006	2007	Thereafter	Total
Long-Term Debt	$101,400	$ 3,400	$100,400	$ 52,400	$ 2,400	$ 760,250	$1,020,250
Purchased Power	138,803	42,968	28,874	29,406	30,957	38,351	309,359
Coal and Natural Gas	93,432	76,016	71,830	69,476	50,270	318,493	679,517
Operating Leases	8,357	7,080	6,425	6,177	6,173	55,153	89,365
Total Contractual Cash Obligations	$341,992	$129,464	$207,529	$157,459	$89,800	$1,172,247	$2,098,491

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Capital Structure

As of December 31, 2002, SPPC had no short-term debt outstanding.

On October 29, 2002, SPPC established an accounts receivable purchase facility of up to $75 million, which was arranged by Lehman Brothers. If SPPC elects to activate the receivables purchase facility, SPPC will sell all of its accounts receivable generated from the sale of electricity to customers to its newly created bankruptcy-remote special purpose subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiary will in turn sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables. Lehman Brothers Holdings, Inc., has committed to be the sole initial purchaser of all of the variable rate revolving notes.

SPPC intends to use the accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. SPPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $75 million General and Refunding Mortgage Bond. See Liquidity and Capital Resources for additional information regarding the terms and conditions of the accounts receivable purchase facility.

SPPC's actual capital structure at December 31, 2002 and 2001, was as follows (dollars in thousands):

	2002		2001	
Short-Term Debt(1)	**$ 101,400**	**6%**	$ 49,130	3%
Long-Term Debt	**914,788**	**54%**	923,070	54%
Preferred Stock	**50,000**	**3%**	50,000	3%
Common Equity	**639,295**	**37%**	692,901	40%
TOTAL	**$1,705,483**	**100%**	$1,715,101	100%

(1) Including current maturities of long-term debt.

ENERGY SUPPLY (NPC AND SPPC)

The energy supply function at the Utilities encompasses the reliable and efficient operation of the Utilities' owned generation, the procurement of all fuels and purchased power, and resource optimization (i.e., physical and economic dispatch). The Utilities have undertaken a rigorous review of the energy supply function and have implemented policy, planning and organizational changes to address the dramatic changes that have and are occurring in the energy industry.

The structure of the western wholesale energy market has seen dramatic changes in recent months. Significant amongst these are the collapse of the energy trading model and the merchant energy sector, which has resulted in reduced liquidity in the traded spot and forward markets for standard products. In addition, a credit crisis in the broader energy sector has resulted in a series of cancellations of new generation projects, putting intermediate term capacity margins in the broader region and within both Utilities' sub-region in jeopardy. The Utilities also face energy supply challenges for their respective load control areas. There is the potential for continued price volatility in each Utility's service territory, particularly during peak periods. A greater dependence on gas-fired generation in the service territory subjects power prices to gas price volatilities. Both Utilities face load obligation uncertainty due to the potential for customer switching. Counterparties in these areas have significant credit difficulties, representing credit risk to the Utilities. Finally, each Utility's own credit situation can have an impact on its ability to enter into transactions.

In response to these energy supply challenges, the Utilities have adopted an approach to managing the energy supply function that has three primary elements. The first element is a set of management guidelines to procuring and optimizing the supply portfolio that is consistent with the requirements of a load serving entity with a full requirements obligation. The second element is an energy risk-management and risk-control approach that ensures clear separation of roles between the day-to-day management of risks and compliance monitoring and control, and ensures clear distinction between policy setting (or planning) and execution. Lastly, the Utilities will pursue a process of ongoing regulatory involvement and acknowledgement of the resource portfolio management plans.

Energy Supply Planning

Within the energy supply planning process, there are three key components covering different time frames:

(1) the PUCN-approved long-term integrated resource plan has a twenty-year planning horizon;

(2) the energy supply plan, which is an intermediate term resource procurement and risk management plan that establishes the supply portfolio parameters within which intermediate term resource requirements will be met, has a one-to three-year planning horizon; and

(3) tactical execution activities with a one-month to twelve-month focus.

The energy supply plan will operate in conjunction with the PUCN-approved twenty-year integrated resource plan. It will serve as a guide for near-term execution and fulfillment of energy needs. When the energy supply plan calls for executing contracts of duration of more than three years, the plan will require PUCN approval as part of the integrated resource planning process.

In developing energy supply plans and implementing on those plans, management guidelines followed by the Utilities include:

- Maintaining an energy supply plan that balances costs, risks, price volatility, reliability, and predictability of supply.
- Investigating feasible commercial options to implement against the energy supply plan.
- Applying quantitative techniques and diligence commensurate with risk to evaluate and execute each transaction.

- Implementing the approved energy supply plan in a manner that manages ratepayer risk in terms of reliability, volatility and cost.
- Monitoring the portfolio against evolving market conditions and managing the resource optimization options.
- Ensuring simple, transparent, and well-documented decisions and execution processes.

Energy Risk Management and Control

The Utilities' efforts to manage energy commodity (electricity, natural gas, coal and oil) price risk are governed by a Board of Directors' revised and approved Enterprise Risk Management and Control Policy. That policy created the Enterprise Risk Oversight Committee (EROC) and made that committee responsible for the overall policy direction of the Utilities' risk management and control efforts. That policy further instructed the EROC to oversee the development of appropriate risk management and control policies including the Energy Supply Risk Management and Control Policy.

The Utilities' commodity risk management program establishes a control framework based on existing commercial practices. The program creates predefined risk limits and delineates management responsibilities and organizational relationships. The program requires that transaction accounting systems and procedures be maintained for systematically identifying, measuring, evaluating and responding to the variety of risks inherent in the Utilities' commercial activities. The program's control framework consists of a disclosure and reporting mechanism designed to keep management fully informed of the operation's compliance with portfolio and credit limits.

The Utilities, through the purchase and sale of financial instruments and physical products, maintain an energy risk management program that limits energy risk to levels consistent with energy supply plans approved by the Chief Executive Officer and the EROC.

Regulatory Issues

The Utilities' long-term integrated resource plans are filed with the PUCN for approval every three years. Nevada law provides that resource additions approved by the PUCN in the resource planning process are deemed prudent for ratemaking purposes. The Utilities resource plans will be filed with the PUCN on July 1, 2003 and 2004 for NPC and SPPC, respectively. Between resource plan filings, the Utilities are required to seek PUCN approval for power purchases with terms of three years or greater by filing amendments to prior resource plan filings.

The Utilities will also seek regulatory input and acknowledgement of intermediate term energy supply plans. The Utilities feel this is necessary to ensure that the appropriate levels of risks are being mitigated at reasonable costs, the appropriate levels of risks are being retained in the portfolio, and decisions to manage risks with best available information at the point in time when decisions are made are subject to reasonable mechanisms for rate recovery.

Intermediate Term Energy Supply Plans

The Utilities are in the process of developing and implementing their intermediate term energy supply plans. Those plans cover the years 2003 through 2005 and require Enterprise Risk Oversight Committee and CEO approval prior to implementation. The energy supply plans will operate within the framework of the PUCN-approved twenty-year integrated resource plans. They serve as a guide for near-term execution and fulfillment of energy needs. When the energy supply plans call for the execution of contracts of duration of more than three years, an amended resource plan will be prepared and submitted for PUCN approval. The energy supply plans will be updated at least annually.

NPC's energy supply plan has been approved internally and was filed with the PUCN on January 31, 2003 for informational purposes. SPPC's plan is in the final stages of development and also will be filed with the PUCN for informational purposes. Key features of NPC's plan are:

- Weigh the intermediate-term portfolio mix heavily toward peaking and seasonal capacity or synthetic tolling based contracts (i.e., power prices indexed to gas prices), to meet the following requirements:
  - Optimize the tradeoff between overall fuel and purchase power cost and market price risk.
  - Pursue in-region capacity to enhance long-term regional reliability.
  - Represent the set of transactions/products available in the market.
  - Reduce credit risk—in a market with weak counter-party financials.
  - Procure to match the difficult load profile to the extent possible.
- Hedge the gas price risk exposure in the fuel portfolio through the purchase of call options.
- Manage off-peak and shoulder month energy price risk through ongoing intermediate and short-term optimization activities (e.g., optimizing the dispatch of NPC generation and/or buying directly from the market).

SPPC's energy supply plan will have many of the same features of NPC's plan with respect to managing fuel and purchased power cost and risk exposure, but SPPC's plan is being specifically tailored to its load obligation and the energy supply characteristics of its sub-region.

Both of the energy supply plans represent a change in procurement strategy from previous years. The strategy now focuses on executing contracts for power deliveries to the Utilities' physical points of delivery. In previous years, the Utilities used hedges to reduce price and commodity risk for future purchases by executing power contracts at so-called "liquid" trading points. A typical hedge transaction involved the purchase of power at one of the major trading hubs where prices were highly correlated with a physical delivery point to the Utility. The hedged purchase was either delivered to the Utilities' service territories to service their customers or, if the hedged purchase was not needed to fulfill power requirements, resold in the liquid market. With the significant drop in liquidity in

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

wholesale markets, the Utilities have changed their procurement strategy to focus on power deliveries to the Utilities' physical points of delivery.

Recent Procurement Activities

As part of the implementation of NPC's energy supply plan, NPC in January 2003 entered into long-term purchase agreements with three companies—Panda Gila River LP, Calpine Energy Services and Mirant Americas Energy Marketing LP.

The agreement with Panda Gila River LP provides 200 megawatts (MW) of power to be delivered from Gila River Power Station in Gila Bend, Arizona, during the summer months of 2003, 2004, and 2005. Panda Gila River LP is a joint venture between TECO Power Services Corporation and Panda Energy International, Inc. Currently under construction, the 2,145-megawatt facility will come on line in four phases, starting in the spring of 2003.

Calpine Energy Services, a wholly owned subsidiary of Calpine Corporation, has agreed to deliver 100 MW of energy between the hours of 9 a.m. and midnight and 50 MW of energy from 1 a.m. to 8 a.m., seven days a week from June 1, 2003, through May 31, 2006. Energy will be delivered from Calpine's South Point Energy Center. All three contracts, Panda, Calpine, and Mirant, involve energy deliveries to NPC's control area.

The arrangement with Mirant involves three separate agreements under which Mirant will provide a total of 325 MW of capacity and energy to NPC. Each agreement identifies specific delivery dates ranging from May of 2003 and continuing through April of 2008. A majority of the energy (225 MW) will be delivered from the Apex facility located in Las Vegas.

Those agreements are subject to PUCN approval and were filed by NPC with the PUCN on January 24, 2003.

In a separate development, NPC also signed an agreement with Reliant for a total of 400 MW to be delivered the summer of 2003 only. Because this is a short-term contract, it is not subject to advance approval by the PUCN.

Short-Term Resource Optimization Strategy

The Utilities' short-term resource optimization strategy involves both day-ahead (next day through the end of the current month) and real-time (next hour through the end of the current day) activities that require buying, selling and scheduling power resources to determine the most economical way to produce or procure the power resources needed to meet the retail customer load. After connecting generation units to the system, the Utilities dispatch the generation output based on the comparative economics of generation versus spot-market purchase opportunities and determine the amount of excess capacity, which is then sold on the wholesale market, or the amount of deficiency capacity, which must be procured on an hourly basis.

The day-ahead resource optimization begins with an analysis of projected loads and existing resources. Firm forward take-or-pay contracts are scheduled and counted toward meeting the capacity needs of the day being pre-scheduled. Any deficiency in the projected operating reserve for the next day, after consideration of available internal generation resources, is met by additional firm purchased power resources. The day-of resource optimization involves minimizing system production costs each hour by either changing the generation output or buying needed power and/or selling excess power in the wholesale market. Any sale of excess power priced above the incremental cost of producing such power reduces the net production cost of operating the electrical system and thereby benefits the end use customer. The Utilities endeavor to reduce the electrical systems' net production cost by selling the available excess power resources.

Real-time resource optimization requires an hourly determination of whether to run generation or purchase power in order to achieve the lowest production costs by calculating the projected incremental or detrimental cost of generation required to meet the forecast load in comparison to obtaining power in the wholesale power market. In the event that committed generators suffer a forced outage that is expected to last through the remaining monthly period, the operating cost of the next available generation resource is compared to purchase power options to determine the lowest cost option.

RESULTS OF OPERATIONS—SPR (HOLDING COMPANY), AND OTHER SUBSIDIARIES

Tuscarora Gas Pipeline Company

TGPC, a wholly owned subsidiary of SPR, contributed $3.3 million in net income for the twelve months ended December 31, 2002, $2.6 million in net income for the twelve months ended December 31, 2001, and $2.1 million in net income for the twelve months ended December 31, 2000.

Sierra Pacific Communications

SPC, a wholly owned subsidiary of SPR, incurred a net loss of ($5.9) million for the twelve months ended December 31, 2002, a net loss of ($2.9) million for the twelve months ended December 31, 2001, and a net loss of ($989,000) for the twelve months ended December 31, 2000. SPC's increased loss for the twelve months ended December 31, 2002, was due to interest charges and other costs associated with its exit from Sierra Touch America LLC, including the $2.3 million write-off of an uncollectible receivable. For additional information, see Note 9 of Notes to Financial Statements, Long-Term Debt.

e·three

e·three, a wholly owned subsidiary of SPR, incurred a net loss of ($1.2) million for the twelve months ended December 31, 2002, contributed $666,000 of net income for the twelve months ended December 31, 2001, and contributed $338,000 of net income for the twelve months ended December 31, 2000. e·three's loss for the twelve months ended December 31, 2002, is due primarily to a significant reduction in revenues attributable to a general decline in e·three's primary market and a transitional goodwill impairment charge of approximately $1.5 million.

Sierra Pacific Energy Company

SPE, a wholly owned subsidiary of SPR, incurred a net loss of ($295,000) for the twelve months ended December 31, 2002, a net loss of ($335,000) for the twelve months ended December 31, 2001, and a net loss of ($4.5) million for the twelve months ended December 31, 2000.

Lands of Sierra

LOS, a wholly owned subsidiary of SPR, contributed net income of $128,000 for the twelve months ended December 31, 2002, net income of $281,000 for the twelve months ended December 31, 2001, and net income of $191,000 for the twelve months ended December 31, 2000.

Sierra Pacific Resources (Holding Company)

The holding company's operating results included approximately $71.5 million, $55.8 million, and $44.5 million of interest costs for the twelve months ended December 31, 2002, 2001, and 2000, respectively, that resulted primarily from merger-related financing. The holding company's operating results for the twelve months ended December 31, 2001, also reflect a charge of $22 million in connection with SPR's terminated plans to purchase Portland General Electric Company, including approximately $7.5 million representing a termination payment for shared expenses.

REGULATION AND RATE PROCEEDINGS

The Utilities are subject to the jurisdiction of the PUCN and, in the case of SPPC, the California Public Utility Commission (CPUC) with respect to rates, standards of service, siting of and necessity for generation and certain transmission facilities, accounting, issuance of securities and other matters with respect to electric distribution and transmission operations. NPC and SPPC submit integrated resource plans to the PUCN for approval.

Under federal law, the Utilities and Tuscarora Gas Pipeline Company (TGPC) are subject to certain jurisdictional regulation, primarily by the FERC. The FERC has jurisdiction under the Federal Power Act with respect to rates, service, interconnection, accounting, and other matters in connection with the Utilities' sale of electricity for resale and interstate transmission. The FERC also has jurisdiction over the natural gas pipeline companies from which the Utilities take service.

As a result of regulation, many of the fundamental business decisions of the Utilities, as well as the rate of return they are permitted to earn on their utility assets, are subject to the approval of governmental agencies.

As with other utilities, NPC and SPPC are subject to federal, state and local regulations governing air and water quality, hazardous and solid waste, land use, and other environmental considerations. Nevada's Utility Environmental Protection Act requires approval of the PUCN prior to construction of major utility, generation, or transmission facilities. The United States Environmental Protection Agency (EPA), Nevada Division of Environmental Protection (NDEP), and Clark County Health District (CCHD) administer regulations involving air quality, water pollution, and solid, hazardous, and toxic waste. SPR's Board of Directors has a comprehensive environmental policy and separate board committee that oversees NPC's, SPPC's, and SPR's corporate performance and achievements related to the environment.

Nevada Legislation

On April 18, 2001, the Governor of Nevada signed into law AB 369. The provisions of AB 369 include a moratorium on the sale of generation assets by electric utilities, the repeal of electric industry restructuring, and a reinstatement of deferred energy accounting for fuel and purchased power costs incurred by electric utilities. The stated purposes of this emergency legislation were, among others, to control volatility in the price of electricity in the retail market in Nevada and to ensure that the Utilities have the necessary financial resources to provide adequate and reliable electric service under present market conditions. To achieve these purposes, AB 369 allows the Utilities to recover in future periods their current costs for wholesale power and fuel, which have risen dramatically over the past year. Deferred energy accounting has the effect of delaying additional rate increases to consumers while at the same time providing a method for the Utilities to recover their increased costs for fuel and purchased power. After the initial 2001 general rate applications described below under Nevada Matters, each Utility will be required to file future general rate applications at least every 24 months. Set forth below is a summary of key provisions of AB 369.

Generation Divestiture Moratorium

AB 369 prohibits all divestiture of generation assets by electric utilities until July 2003. After January 1, 2003, NPC or SPPC may seek PUCN permission to sell one or more generation assets with the sale to be effective on or after July 1, 2003. The PUCN may approve the request to divest only if it finds the transaction to be in the public interest. The PUCN may base its approval of the request upon such terms, conditions, or modifications as it deems appropriate.

AB 369 directs the PUCN to take all steps necessary to obtain federal approval for the prohibition on divestiture and to vacate any of its own orders that had previously approved generation divestiture transactions.

Deferred Energy Accounting

AB 369 required the Utilities to use deferred energy accounting for their respective electric operations beginning on March 1, 2001. The intent of deferred energy accounting is to ease the effect of fluctuations in the cost of purchased power and fuel. See Note 3 of Notes to Financial Statements, Regulatory Actions, for a discussion of the deferred energy accounting provisions of AB 369.

Restrictions on Mergers and Acquisitions

AB 369 imposes certain restrictions on mergers and acquisitions involving Nevada electric utilities. In particular, the PUCN may not approve a merger or acquisition involving an electric utility unless the utility complies with the generation divestiture provisions of AB 369.

In addition, AB 369 includes provisions that would have significantly affected the required regulatory approvals for the proposed acquisition of PGE from Enron. On April 26, 2001, Enron and SPR terminated, by mutual agreement, the proposed purchase and sale of PGE.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

AB 369 also provides that if an electric utility holding company acquires an interest in an out-of-state public utility prior to July 1, 2003, each electric utility in which the holding company holds a controlling interest shall not be entitled to the benefit of deferred energy accounting. Thus, in the event that SPR acquires an out-of-state public utility, NPC and SPPC would lose the ability to utilize deferred energy accounting.

Repeal of Electric Industry Restructuring

AB 369 repeals all statutes authorizing retail competition in Nevada's electric utility industry and voids any license issued to an alternative seller in connection with retail electric competition.

Other Legislation

SB 372, which increased renewable energy portfolio requirements, was enacted in the 2001 Nevada legislative session. Renewable resources include biomass, wind, solar, and geothermal projects. In 2003, the Utilities will be required to purchase 5% of their energy from renewable resources. These requirements increase to 15% by 2013. Prior law capped renewable energy requirements at 1%. Currently, SPPC obtains approximately 9% of its energy from renewable resources, while NPC obtains less than one percent from renewables. SB 372 requires the PUCN to establish standards for renewable energy contracts, including prices and other terms and conditions. If sufficient renewable energy contracts that meet PUCN standards are not available, the Utilities will not be required to meet the portfolio requirements. All renewable energy contracts meeting PUCN standards will be recoverable in the deferred energy accounts.

The 2001 Nevada legislature passed another key piece of legislation for the Nevada energy industry, AB 661. AB 661 allows commercial and governmental customers with an average demand greater than one MW to select new energy suppliers. A more detailed explanation appears in the section Customers File Under AB 661. AB 661 also contains new electric and gas energy surcharges for low-income assistance and weatherization programs. These surcharges are recoverable directly from customers as separate line items on their bills with the Utilities remitting collected surcharges to the PUCN. Various state agencies administer the disposition of the funds.

Nevada Matters

Nevada Power Company 2001 General Rate Case

On October 1, 2001, NPC filed an application with the PUCN, as required by law, seeking an electric general rate increase. On December 21, 2001, NPC filed a certification to its general rate filing updating costs and revenues pursuant to Nevada regulations. In the certification filing, NPC requested an increase in its general rates charged to all classes of electric customers designed to produce an increase in annual electric revenues of $22.7 million, or an overall 1.7% rate increase. The application also sought a return on common equity (ROE) for NPC's total electric operations of 12.25% and an overall rate of return (ROR) of 9.30%.

On March 27, 2002, the PUCN issued its decision on the general rate application, ordering a $43 million revenue decrease with an ROE of 10.1% and ROR of 8.37%. The effective date for the decision was April 1, 2002. The decision also resulted in adjustments increasing accumulated depreciation by $6.7 million and the inclusion of approximately $5 million of revenues related to SO2 Allowances. The PUCN delayed consideration of recovery of SPR/NPC merger costs until a future rate case. NPC was not granted a carrying charge on these deferred costs. NPC plans to renew its request to recover these costs in its next general rate case, which will be filed by the fourth quarter 2003. Recovery of costs related to the generation divestiture project, which supported Nevada's now-abandoned utility restructuring policy, were delayed until the plants are sold or some other mechanism is proposed to allow recovery of the costs. A carrying charge was allowed by the PUCN for the delayed recovery of divestiture costs.

On April 15, 2002, NPC filed a petition for reconsideration with the PUCN. On May 24, 2002, the PUCN issued an order on the petition for reconsideration. The PUCN modified its original order reversing the adjustment to accumulated depreciation of $6.7 million and decreased the SO2 allowance revenue amortization to $3.2 million per year. Revised rates for these changes went into effect on June 1, 2002.

Nevada Power Company 2001 Deferred Energy Case

On November 30, 2001, NPC filed an application with the PUCN seeking to clear deferred balances for purchased fuel and power costs accumulated between March 1, 2001, and September 30, 2001, as required by law. The application sought to establish a Deferred Energy Accounting Adjustment (DEAA) rate to clear accumulated purchased fuel and power costs of $922 million and spread the recovery of the deferred costs, together with a carrying charge, over a period of not more than three years.

On March 29, 2002, the PUCN issued its decision on the deferred energy application, allowing NPC to recover $478 million over a three-year period, but disallowing $434 million of deferred purchased fuel and power costs and $30.9 million in carrying charges, consisting of $10.1 million in carrying charges accrued through September 2001 and $20.8 million in carrying charges accrued from October 2001 through February 2002. The order stated that the disallowance was based on alleged imprudence in incurring the disallowed costs. On April 11, 2002, NPC filed a lawsuit in the First District Court of Nevada seeking to reverse portions of the PUCN's decision.

NPC's lawsuit requests that the District Court reverse portions of the PUCN's order and remand the matter to the PUCN with direction that the PUCN authorize NPC to immediately establish rates that would allow NPC to recover its entire deferred energy balance of $922 million, with a carrying charge, over three years. Arguments were heard on March 14, 2003 and a decision is expected in the second quarter. NPC is not able to predict the outcome of a decision in this matter.

Various interveners in NPC's deferred energy case before the PUCN filed petitions with the PUCN for reconsideration of the PUCN's order, seeking additional disallowances of between $12.8 million and $488 million. On May 24, 2002, the PUCN issued an order denying any further disallowances and granted NPC the authority to increase the deferred energy cost recovery charge for the month of June 2002 by one cent per kilowatt-hour. This increase accelerated the recovery of the deferred balance by approximately $16 million for the month of June 2002 only. The Bureau of Consumer Protection (BCP) of the Nevada Attorney General's Office has since filed a petition in NPC's pending state court case seeking additional disallowances.

Nevada Power Company 2002 Deferred Energy Case

On November 14, 2002, NPC filed an application with the PUCN seeking to clear deferred balances for purchased fuel and power costs accumulated between October 1, 2001, and September 30, 2002, as required by law. The application seeks to establish a rate to repay accumulated purchased fuel and power costs of $195.7 million, together with a carrying charge, over a period of not more than three years. The application also requests a reduction to the going-forward rate for energy, reflecting reduced wholesale energy costs. The combined effect of these two adjustments results in an overall rate reduction of 5.3%. A hearing is scheduled to begin on April 7, 2003 and a ruling is required by May 15, 2003.

Intervenors filed their direct testimony on March 7, calling for disallowances between approximately $83 and $300 million of the total fuel and purchased power costs. The largest of the proposed disallowances are based on the same alleged imprudence as found in the PUCN order for NPC's 2001 Deferred Energy Case relating to NPC's failure to enter into power contracts in 1999. Some Intervenors' testimony in the current case argue in favor of this disallowance based on the last Deferred order but did not quantify their proposals and in some cases would be additive to the ranges stated above. The PUCN Staff does not support this disallowance but calculated a range of $116 to $347 million in the event that the "PUCN disallows deferred energy costs based upon the same alleged imprudence cited by the PUCN in its 2001" decision relative to this issue.

While all Intervenors call for the PUCN to reduce NPC's requested energy rates for recovery of past energy costs, some also propose to increase customers' energy rates for purchases that will occur during the upcoming deferred accounting period.

Nevada Power Company Demand Reduction Programs

On November 14, 2002, NPC filed an application with the PUCN seeking recovery of expenses incurred in the implementation and operation of programs for energy conservation and load management. In the filing, NPC requested a one-year recovery of approximately $1.9 million. This would result in an average 0.12% increase in present rates. NPC asked for this increase to become effective simultaneously with the rate change to be ordered in its 2002 deferred energy case discussed above. NPC subsequently negotiated a settlement agreement with the Intervenors (PUCN Staff and Bureau of Consumer Protection), which is expected to be approved by the PUCN coincident with its 2002 Deferred Energy ruling. With the exception of a small disallowance ($14,673), the agreement called for approval of NPC's request for cost recovery.

Sierra Pacific Power Company 2001 General Rate Case

On November 30, 2001, as required by law, SPPC filed an application with the PUCN seeking an electric general rate increase. On February 28, 2002, SPPC filed a certification to its general rate filing, updating costs and revenues pursuant to Nevada regulations. In the certification filing, SPPC requested an increase in its general rates charged to all classes of electric customers, which were designed to produce an increase in annual electric revenues of $15.9 million representing an overall 2.4% rate increase. The application also sought an ROE for SPPC's total electric operations of 12.25% and an overall ROR of 9.42%.

On May 28, 2002, the PUCN issued its decision on the general rate application, ordering a $15.3 million revenue decrease with an ROE of 10.17% and ROR of 8.61%. The effective date of the decision was June 1, 2002. The PUCN delayed consideration of recovery of SPR/NPC merger costs until a future rate case, and SPPC was not granted a carrying charge on these deferred costs. SPPC is currently planning to renew its request to recover these costs in a general rate case to be filed by the fourth quarter of 2003. Recovery of costs related to the generation divestiture project, which supported Nevada's now-abandoned utility restructuring policy, were delayed until the plants are sold or some other mechanism is proposed to allow recovery of the costs. A carrying charge was allowed by the PUCN for the delayed recovery of divestiture costs.

Various parties to the case had filed petitions for reconsideration of the order. On July 18, 2002, the PUCN issued a final decision on the petitions for reconsideration, clarifying issues contained in its original order. As a result of the clarifications, SPPC was ordered to change the total annual electric revenue decrease from $15.3 million to $15.8 million.

On August 19, 2002, Barrick Goldstrike Mines (Barrick) filed a lawsuit in the First District Court of Nevada seeking to reverse portions of the decision. A stipulation of the parties was subsequently approved by the PUCN. In accordance with the stipulation, SPPC has reduced the electric service rates charged to Barrick and is accruing the reductions in a deferred account as a regulatory asset. The stipulation calls for a review of the subject rates during the next general rate case and a pass-through of the deferred costs to either Barrick or other customers.

Sierra Pacific Power Company 2002 Deferred Energy Case

On February 1, 2002, SPPC filed an application with the PUCN, as required by law, seeking to clear deferred balances for purchased fuel and power costs accumulated between March 1, 2001 and November 30, 2001. The application sought to establish a DEAA rate to clear accumulated purchased fuel and power costs of $205 million and spread the cost recovery over a period of not more than three years. It also sought to recalculate the Base Tariff Energy Rate to reflect anticipated ongoing purchased fuel and power costs.

On May 28, 2002, the PUCN issued its decision on the deferred energy application, allowing SPPC three years to collect $150 million but disallowing $53 million of deferred purchased fuel and power costs and $2 million in carrying charges.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

On August 22, 2002, SPPC filed a lawsuit in the First District Court of Nevada seeking to reverse portions of the decision of the PUCN denying the recovery of deferred energy costs incurred by SPPC on behalf of its customers in 2001 on the grounds that such power costs were not prudently incurred. SPPC's lawsuit requests that the District Court reverse portions of the order of the PUCN and remand the matter to the PUCN with direction that the PUCN authorize SPPC to immediately establish rates that would allow SPPC to recover its entire deferred energy balance of $205 million, with a carrying charge, over three years. A hearing date has been scheduled for October 2003.

On August 22, 2002, the BCP from the Nevada Attorney General's Office also filed a lawsuit in the First District Court of Nevada seeking to set aside the decision of the PUCN so that SPPC is not authorized to reflect in rates any costs for fuel and purchased power which may have been imprudently incurred. A hearing date has not yet been scheduled. At this time, SPPC is not able to predict the outcome or the timing of a decision in these matters.

Sierra Pacific Power Company 2003 Deferred Energy Case

On January 14, 2003, SPPC filed an application with the PUCN, as required by law, seeking to clear deferred balances for purchased fuel and power costs accumulated between December 1, 2001 and November 30, 2002. The application seeks to establish a DEAA rate to clear accumulated purchased fuel and power costs of $15.4 million and spread the cost recovery over a period of not more than three years. It also seeks to recalculate the Base Tariff Energy Rate to reflect anticipated ongoing purchased fuel and power costs. The total rate increase resulting from the requested DEAA would amount to 0.01%. A hearing is scheduled to begin on May 12, 2003, and a ruling is required before July 13, 2003.

Sierra Pacific Power Company Demand Reduction Programs

On January 14, 2003, SPPC filed with the PUCN an application seeking recovery of expenses incurred in the implementation and operation of programs for energy conservation and load management. In the filing, SPPC requested a one-year recovery of approximately $0.9 million. This would result in an average 0.12% increase in present rates. SPPC asked for this increase to become effective simultaneously with the rate change to be ordered in its 2003 deferred energy case discussed above.

Customers File Under AB 661 (NPC, SPPC)

Assembly Bill 661 (AB 661), passed by the Nevada legislature in 2001, allows commercial and governmental customers with an average demand greater than 1 MW to select new energy suppliers. The Utilities would continue to provide transmission, distribution, metering and billing services to such customers. AB 661 requires customers wishing to choose a new supplier to receive the approval of the PUCN and meet public interest standards. In particular, departing customers must secure new energy resources that are not under contract to the Utilities, the departure must not burden the Utilities with increased costs or cause any remaining customers to pay increased costs, and the departing customers must pay their portion of any deferred energy balances. The PUCN adopted regulations prescribing the criteria that will be used to determine if there will be negative impacts to remaining customers or the Utility. These regulations place certain limits upon the departure of NPC customers until 2003; most significantly, the amount of load departing is limited to approximately 1100 MW in peak conditions. Customers wishing to choose a new supplier must provide 180-day notice to the Utilities. AB 661 permitted customers to file applications with the PUCN beginning in the fourth quarter of 2001, and customers could begin to receive service from new suppliers by mid-2002.

On January 10, 2002, Barrick, an approximately 130 MW SPPC customer, filed a notice of intent with the PUCN indicating their desire to exit the system of SPPC and to purchase energy, capacity and ancillary services from a provider other than SPPC. Barrick has not yet filed a formal application with the PUCN but could do so at any time. Under the law, the earliest departure date would be 180 days after the application is filed.

During May 2002, Rouse Fashion Show Management LLC, Coast Hotels and Casinos Inc., Station Casinos, Inc., Gordon Gaming Corporation, MGM Mirage, and Park Place Entertainment filed separate applications with the PUCN to exit the system of NPC and to purchase energy, capacity and ancillary services from a provider other than NPC. The loads of these customers aggregate 260 MW on peak. Hearings on the applications of all the customers except Park Place Entertainment were completed on July 19, 2002, and the PUCN issued its decision on July 31, 2002. In its decision, the PUCN approved the applications of these customers to choose an energy supplier other than NPC. The earliest any of these customers could have begun taking energy from an alternative provider was November 1, 2002. If all five customers whose applications were approved had left its system on November 1, 2002, NPC would have incurred an annual estimated loss in revenue of $48 million, which would be offset by an estimated reduction in costs, primarily for fuel and purchased power, of $46 million with the difference being paid by exit fees from the departing customers. These customers would also be responsible for their share of balances in NPC's deferred energy accounts until the time they left and would have continued to pay their share of these balances after they left. For example, if all five customers whose applications were approved had left the system on November 1, 2002, their remaining share of NPC's previously approved deferred energy balance is estimated to have been $27 million. Additionally, these departing customers would have been responsible for paying their share of the yet to be approved accumulated deferred energy balances from October 1, 2001, to their date of departure. They also would have remained accountable to any rulings made by the District Court on legal actions brought in NPC's past deferred energy case. They could also have benefited from any refunds that might be granted on power contracts under review with the FERC.

A hearing on the application of Park Place Entertainment was held on August 2, 2002, and on August 12, 2002, the PUCN approved the application with terms and conditions similar to those described above for the aforementioned five customers.

All of the customers approved for departure were to address compliance items in their PUCN orders. None of these customers submitted the compliance items required by the PUCN on the required schedule and none of these customers provided official notice of departure. As a result, on February 11, 2003, these applications were closed. All of these customers have submitted new applications requesting a departure date of July 1, 2003. Decisions on these applications are anticipated by the end of the first quarter 2003.

Monte Carlo, Riviera, Imperial Palace, Stratosphere, and Potlach have also filed applications for departure in June or July of 2003. Decisions on these applications, other than the Riviera and Imperial Palace, are also anticipated by the end of the first quarter 2003.

On January 29, 2003, stipulations on the applications of the Imperial Palace and the Riviera were filed with the PUCN adopting most of the provisions that were previously decided in the PUCN's decision on July 31, 2002, with the exception of how the base tariff general rate (BTGR) and the base tariff energy rate (BTER) effects will be addressed in the computation of the exit fees and the related accounting treatment. On February 3, 2003, the PUCN held hearings on the applications and stipulations. On February 27, 2003, the PUCN issued an order approving the parties' stipulation as filed. Additionally, the PUCN ordered that the BTGR revenue impact associated with these customers leaving the system be addressed in NPC's next general rate case (GRC) following the customers departure and all BTER benefits of these customers leaving the system flow through the deferred energy process and accrue to remaining customers. The amount of BTGR revenues that would be lost as a result of these customers' departing, until NPC files its next GRC, is estimated at $500 thousand annually. The Imperial Palace and the Riviera are still required to pay their share of NPC's previously approved deferred energy balance, which is estimated at $1.7 million at June 1, 2003, their estimated departure date. Additionally, these customers will be responsible for paying their share of the yet to be approved accumulated deferred energy balances from October 1, 2001 through June 1, 2003, which is currently estimated at $541 thousand. They also will remain accountable to any rulings made by the District Court on legal actions brought in NPC's past deferred energy case. They could also benefit from any refunds that might be granted on power contracts under review with the FERC. On March 14, 2003, NPC filed for reconsideration of the February 27, 2003 PUCN order regarding the accounting for and computation of exit fees.

Any customer who departs NPC's system and later decides to return to NPC as their energy provider will be charged for their energy at a rate equivalent to NPC's incremental cost of service. A stipulation regarding the incremental cost of service tariff is currently pending before the PUCN.

Nevada Power Company Additional Finance Authority

On April 26, 2002, Nevada Power filed with the PUCN an application seeking additional finance authority. In the application, NPC asked for authority to issue secured long-term debt in an aggregate amount not to exceed $450 million through the period ending 2003. On June 19, 2002, the PUCN issued a Compliance Order, Docket No. 02-4037, authorizing NPC to issue $300 million of long-term debt. The PUCN order requires NPC, if it is able, to issue the $50 million of remaining authorized short-term debt before it issues any long-term debt authorized by the order. Moreover, the order provides that, if NPC is able to issue short-term debt at any point prior to September 1, 2002 (whether or not the issuance of short-term debt actually occurs), the amount of long-term debt authorized by the order will be automatically reduced to $250 million. The PUCN order also provides that NPC will bear the burden of demonstrating that any financings undertaken pursuant to the order, including any determination made regarding the length of such commitment, the type of security or rate, is reasonable. Until such time as the Order's authorization expires (December 31, 2003), NPC must either receive the prior approval of the PUCN or reach an equity ratio of 42% before paying any dividends to SPR. If NPC reaches a 42% equity ratio prior to December 31, 2003, the dividend restriction ceases to have effect.

On July 3, 2002, the BCP of the Nevada Attorney General's Office filed a petition with the PUCN requesting that the hearing in Docket No. 02-4037 be reopened to allow for the introduction of additional evidence or for the PUCN to reconsider its decision granting NPC the authority to issue long-term debt. On September 11, 2002, the PUCN denied the petition to reopen the proceeding and rescinded the portion of its Compliance Order that had previously required NPC to immediately issue $50 million to $100 million of debt.

Annual Purchased Gas Cost Adjustment (SPPC)

On July 1, 2002, SPPC filed a Purchased Gas Cost Adjustment application for its natural gas local distribution company. In the application, SPPC has asked for a reduction of $0.05421 to its Base Purchased Gas Rate (BPGR) and an increase in its Balancing Account Adjustment charge (BAA) by the same amount. This request would result in no change to revenues or customer rates. This docket was consolidated for hearing purposes with the Liquid Petroleum Gas Cost Adjustment below.

On December 23, 2002, the PUCN voted to decrease rates for SPPC's natural gas customers by approximately 3% ($3.2 million plus applicable carrying charges). The PUCN noted that the decrease was due primarily to lower gas costs for SPPC and to a disallowance for imprudent hedging practices. The PUCN adjusted SPPC's costs related to fixed floating hedging contracts. The PUCN also disallowed an alleged $0.7 million customer subsidy under an SPPC optional gas tariff. The new BAA is $0.12330 (which includes a three-year amortized BAA of $0.09998 from Docket 01-6050 and the current annual amortized BAA of $0.02332). SPPC had requested a total BAA of $0.15419. A BPGR of $0.61059 per therm was approved, a reduction from the previous BPGR of $0.66480. The new rates were implemented January 1, 2003.

SPPC has filed a petition for reconsideration of the decisions to disallow the $3.2 million hedging costs and the $0.7 million alleged customer subsidy. On February 6, 2003, the PUCN granted the petition for reconsideration and a decision is expected by the end of the first quarter 2003.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Liquid Petroleum Gas Cost Adjustment (SPPC)

On July 1, 2002, SPPC filed an application to adjust rates for its liquid petroleum gas (LPG) distribution company. In the application, SPPC has asked for an increase of $0.04133 to its current LPG rate and a decrease in its BAA by the same amount. This request would result in no change to revenues or customer rates. This docket was consolidated for hearing purposes with the annual Purchased Gas Cost Adjustment above.

The LPG and BAA rates were approved December 23, 2002, and resulted in no change in the overall level of rates.

California Matters (SPPC)

Rate Stabilization Plan

SPPC serves approximately 44,500 customers in California. On June 29, 2001, SPPC filed with the CPUC a Rate Stabilization Plan, which includes two phases. Phase One, which was also filed June 29, 2001, is an emergency electric rate increase of $10.2 million annually or 26%. If granted, the typical residential monthly electric bill for a customer using 650 kilowatt-hours would increase from approximately $47.12 to $60.12. On August 14, 2001, a pre-hearing conference was held, and a procedural order was established. On September 27, 2001, the Administrative Law Judge (ALJ) issued an order stating that no interim or emergency relief could be granted until the end of the "rate freeze" period mandated by the California restructuring law for recovery of stranded costs. In accordance with the ALJ's request, on October 26, 2001, SPPC filed an amendment to its application declaring the rate freeze period to be over. On December 5 and 11, 2001, hearings were held, and on January 11 and 25, 2002, opening briefs and reply briefs were filed. On July 17, 2002, the CPUC approved the requested 2-cent per kilowatt-hour surcharge, subject to refund and interest pending the outcome of Phase Two. The increase of $10 million, or 26%, is applicable to all customers except those eligible for low-income and medical-needs rates and went into effect July 18, 2002.

Phase Two of the Rate Stabilization Plan was filed with the CPUC on April 1, 2002, and includes a general rate case and requests the CPUC to reinstate the Energy Cost Adjustment Clause, which would allow SPPC to file for periodic rate adjustments to reflect its actual costs for wholesale energy supplies. Phase Two also includes a proposal to terminate the 10% rate reduction mandated by AB 1890, but does not include a performance-based, rate-making proposal. This request was for an additional overall increase in revenues of 17.1%, or $8.9 million annually.

On December 19, 2002, SPPC filed an amendment to the Phase Two application reducing the requested increase by $4.1 million to $4.8 million, or 9.2% annually. SPPC agreed to make certain changes to the application and file the amendment following discussions with the CPUC Office of Ratepayer Advocates. In February 2003, the Office of the Ratepayer Advocates (ORA) filed testimony proposing to reduce SPPC's request by $3.2 million resulting in a $1.6 million increase, or 3.3%. On March 14, 2003, SPPC filed rebuttal testimony. Hearings are scheduled to begin on April 9, 2003, and a decision by the CPUC is expected in late 2003.

California Assembly Bill 1235

On September 24, 2002, the Governor of California signed into law Assembly Bill 1235 (AB 1235), which allows the transfer of hydroelectric plants along the Truckee River from SPPC to the Truckee Meadows Water Authority (TMWA). AB 1235 effectively amends previous California legislation (AB 6X) that prevented private utilities from selling any power plants that provide energy to California customers until 2006. AB 1235 was effective September 24, 2002, and provides an exemption for the four "run-of-the-river" hydroelectric plants that SPPC sold to TMWA as part of the sale of its water business in June 2001.

On November 9, 2002, SPPC filed an application with the CPUC for authority to sell the four hydroelectric plants. On January 13, 2003, the CPUC issued a ruling that the California Environmental Quality Act applies to this proceeding and SPPC must supplement the application with a certified environmental document. SPPC has begun informal discussions with the CPUC on the environmental issues and cannot yet predict the outcome of this proceeding.

FERC Matters (NPC, SPPC)

FERC 206 complaints

In December 2001, the Utilities filed 10 wholesale purchased power complaints with the FERC under Section 206 of the Federal Power Act, seeking to reduce prices of certain forward power purchase contracts that the Utilities entered into prior to the price caps established by the FERC during the western United States utility crisis. The Utilities believe the prices under these purchased power contracts are unjust and unreasonable. The Utilities negotiated a settlement with Duke Energy Trading and Marketing, but were unable to reach agreement in bilateral settlement discussions with other respondents.

The Utilities have already paid the full contact price for all power actually delivered by these suppliers, but are contesting claims made by their terminated power suppliers, including Enron.

Hearings concluded on October 24, 2002, and an initial decision was issued by the Administrative Law Judge (ALJ) overseeing the proceedings on December 19, 2002. The ALJ stated that the Utilities' complaints did not meet the public interest standard of proof, which the ALJ believed applied to the reformation of the Utilities' contracts. The Utilities and others, including the PUCN, have filed Briefs on Exception to the ALJ's Initial Order with the FERC. If the initial order is not modified by the ALJ, it will be reviewed by the full FERC in the second quarter of 2003. Other provisions of the FERC's order are discussed in NPC's and SPPC's Liquidity and Capital Resources.

On March 26, 2003, the Staff of the FERC (FERC staff) concluded that supply-demand imbalance, flawed market design and inconsistent rules made significant market manipulation possible in the Western states in 2000 and 2001. The FERC has not decided how or if this manipulation impacted NPC's and SPPC's claims to the FERC in their Section 206 proceedings.

Additionally, the FERC staff recommended that certain market participants identified in the Cal ISO Report released January 6, 2003, including SPPC, be directed to show cause why their behavior did not constitute gaming in violation of the Cal ISO and Cal PX tariffs. In its report, the Cal ISO indicated that it was unclear as to the reason SPPC received certain revenues in the amount of $6,391. The total revenues for all companies for which the FERC staff recommended show cause orders is approximately $2.8 million. SPPC was one of the over 30 market participants included in the FERC staff's recommendation. The FERC has not yet decided whether to issue a show cause order to SPPC or to any of the other companies identified by the FERC staff. The FERC staff also recommended that the Cal ISO fully explain the screen that was used to identify the subject transactions and that the information should be made available to the public.

Open Access Transmission Tariff

On September 27, 2002, the Utilities filed with the FERC a revised Open Access Transmission Tariff (OATT) designated as Docket No ER02-2607-000. The purpose of the filing was to implement changes that are required to implement retail open access in Nevada. The Utilities requested the changes to become effective November 1, 2002, the date retail access was scheduled to commence in Nevada in accordance with provisions of AB 661, passed in the 2001 session of the Nevada Legislature.

On October 11, 2002, the Utilities filed with the FERC revised rates, terms, and conditions for ancillary services offered in the OATT designated Docket No. ER03-37-000. On November 25, 2002, the FERC suspended the rates in Docket No. ER03-37-000 for a nominal period and made them effective subject to refund on January 1, 2003, as requested by the Utilities.

On November 21, 2002, the FERC suspended the revised OATT in Docket No. ER02-2607-000 for a nominal period, made it effective subject to refund, set certain issues for hearing, and directed the Utilities to make a compliance filing. The compliance filing was submitted on December 23, 2002. This order additionally established hearing procedures and consolidated the two dockets for hearing. On March 11, 2003, all parties to these dockets reached a settlement in principle regarding all issues. The settlement agreement is expected to be filed with the FERC on or before May 2003.

Regional Transmission Organization

NPC and SPPC are members of the utility groups that are forming a proposed regional transmission organization (RTO West) and a proposed independent transmission company (TransConnect). On March 29, 2002, RTO West submitted to the FERC a Stage II compliance filing and supplemental material, which provided details of the formation of the RTO. RTO West, as proposed, would be a non-profit independent system operator of the regional transmission grid, governed by an independent board of directors. This filing was made in compliance with FERC Order 2000, which required all investor-owned utilities in the United States who own interstate transmission to file a proposal to participate in an RTO or an explanation of efforts and plans to participate in an RTO. On November 13, 2001, TransConnect submitted to the FERC a Stage II compliance filing and supplemental material, which provided details of the formation of the ITC, a member of RTO West. On September 18, and 23, 2002, FERC gave conditioned approval for both RTO West and TransConnect phase II filings. Both organizations remain subject to approvals from state regulators and the board of directors of each member company. The current filing utility members of RTO West are NPC, SPPC, Avista Corporation, British Columbia Hydro & Power Authority, Bonneville Power Administration (BPA), Idaho Power Company, The Montana Power Company, PacifiCorp, Portland General Electric, and Puget Sound Energy, Inc. The current filing utility members of TransConnect are NPC, SPPC, Avista Corporation, and Portland General Electric.

Standard Market Design NOPR

On July 31, 2002, the FERC issued a Standard Market Design Notice of Proposed Rulemaking. The FERC's intent is to standardize the practices and policies followed by all jurisdictional entities in the United States. This proposal is currently being reviewed and evaluated by interested parties. The Utilities have submitted comments on this proposed rule.

Alturas Intertie

Certain Northern California public power groups have challenged SPPC's filing with the FERC of the interconnection and operating agreements related to the Alturas Intertie in December 1998 and January 1999. The California groups alleged that the potential reduction in imports into California constitutes an impairment of reliability and therefore seek to force reductions in use of the Alturas Intertie during peak periods. SPPC (supported by BPA and PacifiCorp) has filed testimony before the FERC that the Alturas Intertie does not adversely affect reliability and that, under the FERC's Order No. 888, customers in Nevada are entitled to compete with customers in California for transmission capacity in the Pacific Northwest on a first-come, first-served basis. The FERC staff has agreed with SPPC's position on this matter.

The matter was tried by an ALJ in April and May 2000. In 2001, the ALJ agreed with SPPC's position but imposed a limitation on additional transfer capacity created by future upgrades to the system. The ALJ stated allocation of additional transfer capacity would require agreement among the parties. Both sides have appealed this decision to the full FERC.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

SPR, NPC, and SPPC have evaluated their risk related to financial instruments whose values are subject to market sensitivity. Such instruments are fixed and variable rate debt and preferred trust securities obligations. As reflected in the tables that follow, the fair market value of SPR's market-sensitive financial instruments declined approximately 8.5% during 2002 as a result of credit rating downgrades by Standard and Poor's and Moody's. Fair market value is determined using quoted market price for the same or similar issues or on the current rates offered for debt of the same remaining maturities.

	December 31, 2002					
	Expected Maturities Amounts (dollars in thousands)				Weighted Average Interest Rate(1)	Fair Market Value (dollars in thousands)
Expected Maturity Date	NPC	SPPC	SPR	Consolidated	Consolidated	Consolidated
FIXED RATE						
2003	$ 210,013	$ 101,400	$ 16,886	$ 328,299	6.03%	
2004	130,013	3,400	14,498	147,911	6.40%	
2005	15	100,400	300,000	400,415	9.16%	
2006	15	52,400	—	52,415	6.71%	
2007	17	2,400	345,000	347,417	7.92%	
Thereafter	1,188,848	760,250	—	1,949,098	7.65%	
Total Fixed Rate	$1,528,921	$1,020,250	$676,384	$3,225,555		$2,846,356
VARIABLE RATE						
2003	$ 140,000	$ —	$200,000	$ 340,000	2.94%	
2004	—	—	—	—		
2005	—	—	—	—		
2006	—	—	—	—		
2007	—	—	—	—		
Thereafter	115,000	—	—	115,000	1.74%	
	$ 255,000	$ —	$200,000	$ 455,000		$ 385,800
Preferred securities (fixed rate) after 2007	$ 188,872	$ —	$ —	$ 188,872	8.03%	$ 139,834
Total	$1,972,793	$1,020,250	$876,384	$3,869,427		$3,371,990

	December 31, 2001					
	Expected Maturities Amounts (dollars in thousands)				Weighted Average Interest Rate(1)	Fair Market Value (dollars in thousands)
Expected Maturity Date	NPC	SPPC	SPR	Consolidated	Consolidated	Consolidated
FIXED RATE						
2002	$ 15,000	$ 2,630	$ —	$ 17,630	7.40%	
2003	210,000	20,632	—	230,632	5.97%	
2004	130,000	2,621	—	132,621	6.10%	
2005	—	2,622	300,000	302,622	8.73%	
2006	—	52,629	—	52,629	6.71%	
Thereafter	938,835	845,527	345,000	2,129,362	6.87%	
Total Fixed Rate	$1,293,835	$926,661	$645,000	$2,865,496		$2,953,374
VARIABLE RATE						
2002	$ —	$ —	$100,000	$ 100,000	3.04%	
2003	140,000	—	200,000	340,000	3.43%	
2004	—	—	—	—		
2005	—	—	—	—		
2006	—	—	—	—		
Thereafter	115,000	—	—	115,000	1.82%	
	$ 255,000	$ —	$300,000	$ 555,000		$ 549,400
Preferred securities (fixed rate) after 2005	$ 188,872	$ —	$ —	$ 188,872	8.03%	$ 181,525
Total	$1,737,707	$926,661	$945,000	$3,609,368		$3,684,299

(1) Weighted average daily rate for months ended December 31, 2002 and 2001.

Commodity Price Risk

The Utilities are exposed to commodity price risk primarily related to changes in the market price of electricity as well as changes in fuel costs incurred to generate electricity. See Energy Supply in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for a discussion of the Utilities' purchased power procurement strategies.

The Utilities' efforts to manage energy commodity (electricity, natural gas, coal, and oil) price risk are governed by a Board of Directors' revised and approved Enterprise Risk Management and Control Policy. That policy created the EROC and made that committee responsible for the overall policy direction of the Utilities' risk management and control efforts. That policy further instructed the EROC to oversee the development of appropriate risk management and control policies including the Energy Supply Risk Management and Control Policy.

The Utilities' commodity risk management program establishes a control framework based on existing commercial practices. The program creates common predefined risk limits and delineates management responsibilities and organizational relationships. The program requires that transaction accounting systems and procedures be maintained for systematically identifying, measuring, evaluating, and responding to the variety of risks inherent in the Utilities' commercial activities. The program's control framework consists of a disclosure and reporting mechanism designed to keep management fully informed of the operation's compliance with portfolio and credit limits.

The Utilities, through the purchase and sale of the financial instruments and physical products, maintain an energy risk management program that limits energy risk to levels consistent with approved Energy Supply Plans. The program has provisions for the systematic identification, quantification, evaluation, and management of the energy risk inherent in the Utilities' operations and for the preparation of periodic reports to document the Utilities' efforts and to comply with legal and regulatory requirements. The Energy Supply Plans include recommended courses of action to be followed during the three-year period covered by the plan and:

- govern the purchase and sale of fuel and wholesale power and the associated transmission or transportation services;
- include assessments of projected loads and resources, assessments of expected market prices, and evaluations of relevant supply portfolio options available to the Utilities;
- evaluate the risk attributable to those supply portfolio options; and
- address the use of financial instruments for hedging in conjunction with energy purchases and sales.

Currently, commodity price increases due to changes in market conditions for purchased fuel and power and natural gas are recovered through the deferred energy accounting mechanism, with no anticipated effect on earnings. Commodity price risk is mitigated by the use of long-term fuel supply agreements, long-term purchase power agreements, and derivative instruments such as forwards, options, and swaps entered into to meet the anticipated fuel and power needs necessary to satisfy the jurisdictional load requirements of the Utilities. However, the Utilities are subject to regulatory risk related to commodity price changes due to the fact that the PUCN may disallow recovery for any of these costs that it considers imprudently incurred.

Credit Risk

The Utilities also monitor and manage credit risk with their trading counterparties. As of December 31, 2002, the Utilities had outstanding transactions with over 50 energy and financial services companies. The Utilities credit risk associated with these transactions was approximately $12 million as of December 31, 2002.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholders of
Sierra Pacific Resources
Reno, Nevada

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Sierra Pacific Resources and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of operations, comprehensive income (loss), common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Resources and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 23 to the Consolidated Financial Statements, during 2002 the Company changed its method of accounting for goodwill to conform to Statement of Accounting Standards No. 142, Accounting for Goodwill.

Deloitte & Touche LLP

Reno, Nevada
February 28, 2003

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of
Nevada Power Company
Reno, Nevada

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Nevada Power Company and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of operations, comprehensive income (loss), common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Nevada Power Company and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Reno, Nevada
February 28, 2003

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of
Sierra Pacific Power Company
Reno, Nevada

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Sierra Pacific Power Company and subsidiaries as of December 31, 2002 and 2001, and the related consolidated statements of operations, comprehensive income (loss), common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Power Company and subsidiaries as of December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Reno, Nevada
February 28, 2003

CONSOLIDATED BALANCE SHEETS—SIERRA PACIFIC RESOURCES

December 31,	**2002**	2001
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$5,989,701**	$5,744,041
Less accumulated provision for depreciation	**1,944,351**	1,783,773
	4,045,350	3,960,268
Construction work-in-progress	**263,346**	203,456
	4,308,696	4,163,724
Investments in subsidiaries and other property, net	**134,068**	73,573
Current Assets:		
Cash and cash equivalents	**193,386**	99,109
Restricted cash (Note 1)	**13,705**	—
Accounts receivable less provision for uncollectible accounts: 2002—$44,184; 2001—$39,335	**359,083**	394,489
Deferred energy costs—electric	**268,979**	333,062
Deferred energy costs—gas	**17,045**	19,805
Income tax receivable	**—**	185,011
Materials, supplies and fuel, at average cost	**87,840**	94,484
Risk management assets (Note 19)	**29,570**	286,509
Other	**48,960**	14,071
	1,018,568	1,426,540
Deferred Charges and Other Assets:		
Goodwill (Note 20)	**310,441**	312,145
Deferred energy costs—electric	**685,875**	854,778
Deferred energy costs—gas	**—**	23,248
Regulatory tax asset	**163,889**	169,738
Other regulatory assets (Note 1)	**136,933**	96,725
Risk management assets (Note 19)	**368**	61,058
Risk management regulatory assets—net (Note 19)	**44,970**	664,383
Other	**92,436**	146,164
	1,434,912	2,328,239
	$6,896,244	$7,992,076

(continued)

CONSOLIDATED BALANCE SHEETS—SIERRA PACIFIC RESOURCES (continued)

December 31,	**2002**	2001
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholders' equity	**$1,327,166**	$1,695,336
Preferred stock	**50,000**	50,000
NPC obligated mandatorily redeemable preferred trust securities	**188,872**	188,872
Long-term debt	**3,062,883**	3,376,105
	4,628,921	5,310,313
Current Liabilities:		
Short-term borrowings	**—**	177,000
Current maturities of long-term debt	**672,963**	122,010
Accounts payable	**233,099**	265,250
Accrued interest	**50,308**	37,565
Dividends declared	**1,045**	1,045
Accrued salaries and benefits	**20,828**	30,145
Deferred taxes	**126,228**	145,903
Risk management liabilities (Note 19)	**69,953**	855,301
Other current liabilities	**46,719**	15,678
	1,221,143	1,649,897
Commitments and Contingencies (Note 17)		
Deferred Credits and Other Liabilities:		
Deferred federal income taxes	**333,423**	508,329
Deferred investment tax credit	**48,492**	51,947
Regulatory tax liability	**42,718**	46,702
Customer advances for construction	**116,032**	108,179
Accrued retirement benefits	**107,580**	82,624
Risk management liabilities (Note 19)	**3,917**	163,636
Contract termination reserves (Note 17)	**312,594**	—
Other	**81,424**	70,449
	1,046,180	1,031,866
	$6,896,244	$7,992,076

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS—SIERRA PACIFIC RESOURCES

Year ended December 31,	**2002**	2001	2000
(dollars in thousands, except per share amounts)			
OPERATING REVENUES:			
Electric	**$ 2,832,285**	$ 4,426,881	$ 2,221,111
Gas	**149,783**	145,652	100,803
Other	**9,635**	18,841	14,199
	2,991,703	4,591,374	2,336,113
OPERATING EXPENSES:			
Operation:			
Purchased power	**1,786,823**	4,052,077	1,116,375
Fuel for power generation	**453,436**	728,619	526,535
Gas purchased for resale	**91,961**	136,534	83,199
Deferred energy costs disallowed	**491,081**	—	—
Deferral of energy costs—electric—net	**(233,814)**	(1,136,148)	16,719
Deferral of energy costs—gas—net	**24,785**	(23,170)	(16,164)
Other	**294,219**	332,860	261,079
Maintenance	**64,440**	69,499	52,477
Depreciation and amortization	**175,782**	166,385	158,315
Taxes:			
Income taxes	**(168,498)**	(1,230)	(31,022)
Other than income	**44,544**	43,079	42,215
	3,024,759	4,368,505	2,209,728
OPERATING INCOME (LOSS)	**(33,056)**	222,869	126,385
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**(36)**	474	2,813
Interest accrued on deferred energy	**23,058**	55,204	205
Other income	**10,578**	12,023	12,091
Other expense	**(18,386)**	(13,634)	(8,135)
Income taxes	**(4,058)**	(14,870)	(511)
	11,156	39,197	6,463
Total Income (Loss) Before Interest Charges	**(21,900)**	262,066	132,848

(continued)

CONSOLIDATED STATEMENTS OF OPERATIONS—SIERRA PACIFIC RESOURCES (continued)

Year ended December 31,	2002	2001	2000
(dollars in thousands, except per share amounts)			
INTEREST CHARGES:			
Long-term debt	**234,542**	188,370	134,596
Other	**35,711**	24,161	35,887
Allowance for borrowed funds used during construction and capitalized interest	**(5,270)**	(2,801)	(10,634)
	264,983	209,730	159,849
Dividend requirements of NPC obligated mandatorily redeemable preferred trust securities	**15,172**	18,770	18,914
INCOME (LOSS) FROM CONTINUING OPERATIONS	**(302,055)**	33,566	(45,915)
DISCONTINUED OPERATIONS:			
Income from operations of water business disposed of (net of income taxes of $888 and $3,426 in 2001 and 2000, respectively)	**—**	1,022	9,634
Gain on disposal of water business (net of income taxes of $18,237)	**—**	25,845	—
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, net of tax (Note 20)	**(1,566)**	—	—
NET INCOME (LOSS)	**(303,621)**	60,433	(36,281)
Preferred stock dividend requirements of subsidiary	**3,900**	3,700	3,499
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	**$ (307,521)**	$ 56,733	$ (39,780)
Basic and diluted earnings (loss) per share of common stock			
From continuing operations	**$ (3.00)**	$ 0.34	$ (0.63)
From discontinued operations	**—**	0.01	0.12
Gain on disposal of water business	**—**	0.30	—
Cumulative effect of change in accounting principle (net of tax)	**(0.01)**	—	—
Applicable to common stock	**$ (3.01)**	$ 0.65	$ (0.51)
Weighted Average Shares of Common Stock Outstanding	**102,126,079**	87,542,441	78,435,405
Dividends Paid Per Share of Common Stock	**$ 0.20**	$ 0.65	$ 1.00

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)— SIERRA PACIFIC RESOURCES

Year ended December 31,	**2002**	2001	2000
(dollars in thousands)			
NET INCOME (LOSS)	**$(303,621)**	$60,433	$(36,281)
OTHER COMPREHENSIVE INCOME (LOSS)			
Adoption of SFAS No. 133—Accounting for			
Derivative Instruments and Hedging Activities:			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of taxes of $1,035)	**—**	(1,923)	—
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $3,083 and $2,726 in 2002 and 2001, respectively)	**5,726**	(5,063)	—
Minimum pension liability adjustment (net of taxes of $24,904)	**(46,251)**	—	—
OTHER COMPREHENSIVE (LOSS)	**(40,525)**	(6,986)	—
COMPREHENSIVE INCOME (LOSS)	**$(344,146)**	$53,447	$(36,281)

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY— SIERRA PACIFIC RESOURCES

Year ended December 31,	**2002**	2001	2000
(dollars in thousands)			
COMMON STOCK:			
Balance at Beginning of Year	**$ 102,111**	$ 78,475	$ 78,414
Stock purchase and dividend reinvestment	**66**	23,636	61
Balance at End of Year	**102,177**	102,111	78,475
OTHER PAID-IN CAPITAL:			
Balance at Beginning of Year	**1,598,634**	1,295,221	1,293,990
Premium on sale of common stock	**—**	330,050	—
Common stock issuance costs	**—**	(13,910)	—
Purchase contract adjustment payment	**—**	(13,676)	—
CSIP, DRP, ESPP, and other	**390**	949	1,231
Balance at End of Year	**1,599,024**	1,598,634	1,295,221
RETAINED EARNINGS (ACCUMULATED DEFICIT):			
Balance at Beginning of Year	**1,577**	(13,984)	104,725
Income (loss) from continuing operations	**(302,055)**	33,566	(45,915)
Income from discontinued operations (before preferred dividend allocation of $200 and $401 in 2001 and 2000, respectively)	**—**	1,222	10,035
Cumulative effect of change in accounting principle, net of tax	**(1,566)**	—	—
Gain on disposal of water business	**—**	25,845	—
Preferred stock dividends declared	**(3,900)**	(3,900)	(3,900)
Common stock dividends declared	**(20,580)**	(41,172)	(78,929)
Balance at End of Year	**(326,524)**	1,577	(13,984)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(6,986)**	—	—
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of taxes of $1,035)	**—**	(1,923)	—
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $3,083 and $2,726 in 2002 and 2001, respectively)	**5,726**	(5,063)	—
Minimum pension liability adjustment (net of taxes of $24,904)	**(46,251)**	—	—
Balance at End of Year	**(47,511)**	(6,986)	—
TOTAL COMMON SHAREHOLDERS' EQUITY AT END OF YEAR	**$1,327,166**	$1,695,336	$1,359,712

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS—SIERRA PACIFIC RESOURCES

Year ended December 31,	**2002**	2001	2000
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	**$(303,621)**	$ 60,433	$ (36,281)
Preferred dividends included in discontinued operations	**—**	200	401
Noncash items included in income:			
Depreciation and amortization	**175,782**	169,866	165,136
Deferred taxes and deferred investment tax credit	**(18,410)**	85,917	(18,564)
AFUDC and capitalized interest	**(5,234)**	(3,285)	(13,858)
Amortization of deferred energy costs—electric	**176,718**	—	—
Amortization of deferred energy costs—gas	**13,231**	3,562	—
Deferred energy costs disallowed (net of taxes)	**320,484**	—	—
Early retirement and severance amortization	**2,706**	3,121	4,196
Gain on disposal of water business	**—**	(44,081)	—
Other noncash	**6,297**	2,290	31,550
Adjustment in value of Premium Income Equity Securities	**—**	(13,677)	—
Changes in certain assets and liabilities:			
Accounts receivable	**35,406**	(1,841)	(174,112)
Deferral of energy costs—electric	**(413,654)**	(1,187,840)	14,884
Deferral of energy costs—gas	**10,270**	(30,245)	(16,370)
Materials, supplies, and fuel	**6,644**	(18,654)	(1,858)
Other current assets	**(48,594)**	4,248	(52,125)
Accounts payable	**(32,151)**	(97,992)	224,794
Income tax receivable	**185,011**	—	—
Other current liabilities	**34,467**	14,752	16,359
Other assets	**(3,073)**	(9,315)	9,971
Other liabilities	**316,547**	19,200	34,123
Net Cash from Operating Activities	**458,826**	(1,043,341)	188,246
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	**(399,807)**	(333,606)	(360,130)
AFUDC and other charges to utility plant	**5,234**	3,285	15,227
Customer advances (refunds) for construction	**7,852**	815	(889)
Contributions in aid of construction	**43,247**	27,481	16,446
Net cash used for utility plant	**(343,474)**	(302,025)	(329,346)
Proceeds from sale of assets of water business	**—**	318,882	—
Investments in subsidiaries and other property—net	**(57,781)**	(9,065)	(30,050)
Net Cash from Investing Activities	**(401,255)**	7,792	(359,396)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Decrease in short-term borrowings	**(177,000)**	(36,074)	(547,310)
Proceeds from issuance of long-term debt	**350,000**	1,215,000	1,165,000
Retirement of long-term debt	**(112,269)**	(323,091)	(318,061)
Redemption of preferred stock	**—**	(48,500)	—
Sale of common stock	**460**	340,737	1,292
Dividends paid	**(24,485)**	(64,917)	(83,057)
Net Cash from Financing Activities	**36,706**	1,083,155	217,864
NET INCREASE IN CASH AND CASH EQUIVALENTS	**94,277**	47,606	46,714
Beginning Balance in Cash and Cash Equivalents	**99,109**	51,503	4,789
Ending Balance in Cash and Cash Equivalents	**$ 193,386**	$ 99,109	$ 51,503
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid (received) during period for:			
Interest	**$ 257,462**	$ 208,390	$ 167,158
Income taxes	**$(185,011)**	$ (55,022)	$ 12,730

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION—SIERRA PACIFIC RESOURCES

December 31,	**2002**	2001
(dollars in thousands)		
COMMON SHAREHOLDERS' EQUITY:		
Common stock $1.00 par value, authorized 250 million shares; issued and outstanding 2002: 102,177,000 shares; 2001, 102,111,000 shares	**$ 102,177**	$ 102,111
Other paid-in capital	**1,599,024**	1,598,634
Retained earnings accumulated (deficit)	**(326,524)**	1,577
Accumulated other comprehensive loss	**(47,511)**	(6,986)
Total Common Shareholders' Equity	**1,327,166**	1,695,336
PREFERRED STOCK OF SUBSIDIARIES:		
Not subject to mandatory redemption		
Outstanding at December 31 Class A Series 1; $1.95 dividend	**50,000**	50,000
PREFERRED TRUST SECURITIES OF SUBSIDIARIES:		
Obligated Mandatorily Redeemable Preferred Securities of NPC's Subsidiary Trust, NVP Capital I, holding solely $122.6 million principal amount of 8.2% Junior Subordinated Debentures of NPC, due 2037	**118,872**	118,872
Obligated Mandatorily Redeemable Preferred Securities of NPC's Subsidiary Trust, NVP Capital III, holding solely $72.2 million principal amount of 7.75% Junior Subordinated Debentures of NPC, due 2038	**70,000**	70,000
Total Preferred Securities of Subsidiaries	**188,872**	188,872
LONG-TERM DEBT:		
Unamortized bond premium and discount, net	**(17,968)**	(959)
Debt secured by First Mortgage Bonds		
7.63% Series L due 2002	**—**	15,000
6.70% Series V due 2022	**105,000**	105,000
6.60%Series W due 2019	**39,500**	39,500
7.20% Series X due 2022	**78,000**	78,000
8.50% Series Z due 2023	**35,000**	35,000
2.00% Series Z due 2004	**—**	56
2.00% Series O due 2011	**—**	1,281
6.35% Series FF due 2012	**1,000**	1,000
6.55% Series AA due 2013	**39,500**	39,500
6.30% Series DD due 2014	**45,000**	45,000
6.65% Series HH due 2017	**75,000**	75,000
6.65% Series BB due 2017	**17,500**	17,500
6.55% Series GG due 2020	**20,000**	20,000
6.30% Series EE due 2022	**10,250**	10,250
6.95% to 8.61% Series A MTN due 2022	**110,000**	110,000
7.10% and 7.14% Series B MTN due 2023	**58,000**	58,000
6.62% to 6.83% Series C MTN due 2006	**50,000**	50,000
5.90% Series JJ due 2023	**9,800**	9,800
5.90% Series KK due 2023	**30,000**	30,000
5.00% Series Y due 2024	**—**	3,072
6.70% Series II due 2032	**21,200**	21,200
5.50% Series D MTN due 2003	**5,000**	5,000
5.59% Series D MTN due 2003	**13,000**	13,000
Subtotal	**744,782**	781,200

(continued)

CONSOLIDATED STATEMENTS OF CAPITALIZATION—SIERRA PACIFIC RESOURCES (continued)

December 31,	**2002**	2001
(dollars in thousands)		
Industrial development revenue bonds		
5.90% Series 1997A due 2032	**52,285**	52,285
5.90% Series 1995B due 2030	**85,000**	85,000
5.60% Series 1995A due 2030	**76,750**	76,750
5.50% Series 1995C due 2030	**44,000**	44,000
6.20% Series 1999B due 2004	**130,000**	130,000
Subtotal	**388,035**	388,035
Pollution control revenue bonds		
6.38% due 2036	**20,000**	20,000
5.80% Series 1997B due 2032	**20,000**	20,000
5.30% Series 1995D due 2011	**14,000**	14,000
5.45% Series 1995D due 2023	**6,300**	6,300
5.35% Series 1995E due 2022	**13,000**	13,000
Subtotal	**73,300**	73,300
Variable rate notes		
Floating rate notes due 2003	**140,000**	140,000
IDRB Series 2000A due 2020	**100,000**	100,000
PCRB Series 2000B due 2009	**15,000**	15,000
Floating rate notes due 2002	**—**	100,000
Floating rate notes due 2003	**200,000**	200,000
Subtotal	**455,000**	555,000
Debt secured by General and Refunding Bonds		
8.25% Series A due 2011	**350,000**	350,000
10.88% Series E due 2009	**250,000**	—
8.00% Series A due 2008	**320,000**	320,000
10.50% (Variable) Series C due 2005	**100,000**	—
Subtotal	**1,020,000**	670,000
Other notes		
5.75% Series 2001 due 2036	**80,000**	80,000
6.00% Series B notes due 2003	**210,000**	210,000
8.75% Senior unsecured note Series 2000 due 2005	**300,000**	300,000
7.93% Senior unsecured notes due 2007	**345,000**	345,000
Subtotal	**935,000**	935,000
Obligations under capital leases	**73,259**	78,313
Current maturities and sinking fund requirements	**(672,963)**	(122,010)
Other	**46,470**	17,267
Total Long-Term Debt	**3,062,883**	3,376,105
TOTAL CAPITALIZATION	**$4,628,921**	$5,310,313

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED BALANCE SHEETS—NEVADA POWER COMPANY

December 31,	**2002**	2001
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$3,542,300**	$3,356,584
Less accumulated provision for depreciation	**1,017,494**	928,939
	2,524,806	2,427,645
Construction work-in-progress	**173,189**	134,706
	2,697,995	2,562,351
Investments in subsidiaries and other property, net	**20,295**	12,721
Current Assets:		
Cash and cash equivalents	**95,009**	8,505
Restricted cash (Note 1)	**3,850**	—
Accounts receivable less provision for uncollectible accounts: 2002—$33,841; 2001—$30,861	**202,590**	210,333
Deferred energy costs—electric	**213,193**	281,555
Income tax receivable	**—**	102,904
Materials, supplies and fuel, at average cost	**44,074**	48,511
Risk management assets (Note 19)	**28,173**	200,829
Other	**31,602**	6,698
	618,491	859,335
Deferred Charges and Other Assets:		
Deferred energy costs—electric	**524,345**	698,510
Regulatory tax asset	**106,071**	109,859
Other regulatory assets	**53,109**	27,694
Risk management assets (Note 19)	**368**	49,493
Risk management regulatory assets—net (Note 19)	**1,491**	351,264
Other	**46,357**	33,379
	731,741	1,270,199
	$4,068,522	$4,704,606

(continued)

CONSOLIDATED BALANCE SHEETS—NEVADA POWER COMPANY (continued)

December 31,	**2002**	2001
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholder's equity	**$1,149,131**	$1,393,583
NPC obligated mandatorily redeemable preferred trust securities	**188,872**	188,872
Long-term debt	**1,488,597**	1,607,967
	2,826,600	3,190,422
Current Liabilities:		
Short-term borrowings	**—**	130,500
Current maturities of long-term debt	**354,677**	19,380
Accounts payable	**143,002**	146,114
Accounts payable, affiliated companies	**4,287**	56,441
Accrued interest	**29,892**	19,310
Dividends declared	**78**	71
Accrued salaries and benefits	**7,781**	12,450
Deferred taxes	**90,616**	117,244
Risk management liabilities (Note 19)	**29,908**	522,508
Other current liabilities	**22,115**	17,710
	682,356	1,041,728
Commitments and Contingencies (Note 17)		
Deferred Credits and Other Liabilities:		
Deferred federal income taxes	**129,687**	237,916
Deferred investment tax credit	**21,902**	23,533
Regulatory tax liability	**17,300**	18,604
Customer advances for construction	**66,434**	61,454
Accrued retirement benefits	**54,216**	28,104
Risk management liabilities (Note 19)	**—**	78,558
Contract termination reserves (Note 17)	**225,816**	—
Other	**44,211**	24,287
	559,566	472,456
	$4,068,522	$4,704,606

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS—NEVADA POWER COMPANY

Year ended December 31,	**2002**	2001	2000
(dollars in thousands, except per share amounts)			
OPERATING REVENUES:			
Electric	**$1,901,034**	$3,025,103	$1,326,192
OPERATING EXPENSES:			
Operation:			
Purchased power	**1,241,783**	3,026,336	671,396
Fuel for power generation	**309,293**	441,900	292,787
Deferred energy costs disallowed	**434,123**	—	—
Deferral of energy costs—net	**(179,182)**	(937,322)	16,719
Other	**167,768**	169,442	139,723
Maintenance	**41,200**	45,136	34,057
Depreciation and amortization	**98,198**	93,101	85,989
Taxes:			
Income taxes	**(133,411)**	17,775	(12,162)
Other than income	**25,265**	24,371	23,501
	2,005,037	2,880,739	1,252,010
OPERATING INCOME (LOSS)	**(104,003)**	144,364	74,182
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**(153)**	(382)	2,456
Interest accrued on deferred energy	**12,414**	42,743	—
Other income	**273**	4,200	4,413
Other expense	**(9,933)**	(4,709)	(2,216)
Income taxes	**(1,627)**	(14,962)	(1,201)
	974	26,890	3,452
Total Income (Loss) Before Interest Charges	**(103,029)**	171,254	77,634
INTEREST CHARGES:			
Long-term debt	**98,886**	81,599	64,513
Other	**21,395**	13,219	13,732
Allowance for borrowed funds used during construction and capitalized interest	**(3,412)**	(2,141)	(7,855)
	116,869	92,677	70,390
Dividend requirements of NPC obligated mandatorily redeemable preferred trust securities	**15,172**	15,172	15,172
NET INCOME (LOSS)	**$ (235,070)**	$ 63,405	$ (7,928)

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)— NEVADA POWER COMPANY

Year ended December 31,	**2002**	2001	2000
(dollars in thousands)			
NET INCOME (LOSS)	**$(235,070)**	$63,405	$(7,928)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Adoption of SFAS No. 133—Accounting for			
Derivative Instruments and Hedging Activities:			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of taxes of $239)	**—**	444	—
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $213 and $41 in 2002 and 2001, respectively)	**(397)**	76	—
Minimum pension liability adjustment (net of taxes of $4,838)	**(8,985)**	—	—
OTHER COMPREHENSIVE INCOME (LOSS)	**(9,382)**	520	—
COMPREHENSIVE INCOME (LOSS)	**$(244,452)**	$63,925	$(7,928)

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY— NEVADA POWER COMPANY

Year ended December 31,	**2002**	2001	2000
(dollars in thousands)			
COMMON STOCK:			
Balance at Beginning of Year and End of year	**$ 1**	$ 1	$ 1
OTHER PAID-IN CAPITAL:			
Balance at Beginning of Year	**1,367,106**	892,185	755,185
Additional investment by parent company	**10,000**	474,921	137,000
Balance at End of Year	**1,377,106**	1,367,106	892,185
RETAINED EARNINGS (ACCUMULATED DEFICIT):			
Balance at Beginning of Year	**25,956**	(4,449)	67,746
Income (loss) for the year	**(235,070)**	63,405	(7,928)
Common stock dividends declared	**(10,000)**	(33,000)	(64,267)
Balance at End of Year	**(219,114)**	25,956	(4,449)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**520**	—	—
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of taxes of $239)	**—**	444	—
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $213 and $41 in 2002 and 2001, respectively)	**(397)**	76	—
Minimum pension liability adjustment (net of taxes of $4,838)	**(8,985)**	—	—
Balance at End of Year	**(8,862)**	520	—
TOTAL COMMON SHAREHOLDER'S EQUITY AT END OF YEAR	**$1,149,131**	$1,393,583	$887,737

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS—NEVADA POWER COMPANY

Year ended December 31,	**2002**	2001	2000
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	**$(235,070)**	$ 63,405	$ (7,928)
Noncash items included in income:			
Depreciation and amortization	**98,198**	93,102	85,989
Deferred taxes and deferred investment tax credit	**20,868**	55,085	(26,528)
AFUDC and capitalized interest	**(3,259)**	(1,759)	(10,311)
Amortization of deferred energy costs	**146,554**	—	—
Deferred energy costs disallowed (net of taxes)	**282,181**	—	—
Other noncash	**563**	264	20,101
Changes in certain assets and liabilities:			
Accounts receivable	**8,487**	(41,444)	(57,935)
Deferral of energy costs	**(338,152)**	(980,065)	14,884
Materials, supplies and fuel	**4,437**	(2,938)	(2,465)
Other current assets	**(28,691)**	3,507	(25,360)
Accounts payable	**(55,316)**	44,747	82,720
Income tax receivable	**102,904**	—	—
Other current liabilities	**10,317**	3,812	10,001
Other assets	**—**	—	3,521
Other liabilities	**239,736**	4,882	27,022
Net Cash from Operating Activities	**253,757**	(757,402)	113,711
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	**(294,480)**	(200,852)	(204,505)
AFUDC and other charges to utility plant	**3,259**	1,759	11,622
Customer advances (refunds) for construction	**4,980**	(4,134)	(3,753)
Contributions in aid of construction	**35,800**	6,331	—
Net cash used for utility plant	**(250,441)**	(196,896)	(196,636)
Investments in subsidiaries and other property—net	**(2,239)**	(115)	—
Net Cash from Investing Activities	**(252,680)**	(197,011)	(196,636)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Increase (decrease) in short-term borrowings	**(130,500)**	30,500	(82,000)
Proceeds from issuance of long-term debt	**250,000**	815,000	365,000
Retirement of long-term debt	**(34,073)**	(368,347)	(205,152)
Investment by parent company	**10,000**	474,921	137,000
Dividends paid	**(10,000)**	(33,014)	(88,308)
Net Cash from Financing Activities	**85,427**	919,060	126,540
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**86,504**	(35,353)	43,615
Beginning Balance in Cash and Cash Equivalents	**8,505**	43,858	243
Ending Balance in Cash and Cash Equivalents	**$ 95,009**	$ 8,505	$ 43,858
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid (received) during period for:			
Interest	**$ 109,679**	$ 90,280	$ 71,430
Income taxes	**$(102,904)**	$ (13,702)	$ 6,500

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION—NEVADA POWER COMPANY

December 31,	2002	2001
(dollars in thousands)		
COMMON SHAREHOLDER’S EQUITY:		
Common stock issued, stated value $1.00, 1,000 shares authorized, issued and outstanding	**$ 1**	$ 1
Other paid-in capital	**1,377,106**	1,367,106
Retained earnings accumulated (deficit)	**(219,114)**	25,956
Accumulated other shareholder’s equity	**(8,862)**	520
Total Common Shareholder’s Equity	**1,149,131**	1,393,583
PREFERRED TRUST SECURITIES:		
Obligated Mandatorily Redeemable Preferred Securities of NPC’s Subsidiary Trust, NVP Capital I, holding solely $122.6 million principal amount of 8.2% Junior Subordinated Debentures of NPC, due 2037	**118,872**	118,872
Obligated Mandatorily Redeemable Preferred Securities of NPC’s Trust, NVP Capital III, holding solely $72.2 million principal amount of 7.75% Junior Subordinated Debentures of NPC, due 2038	**70,000**	70,000
Total Preferred Securities	**188,872**	188,872
LONG-TERM DEBT:		
Unamortized bond premium and discount, net	**(13,906)**	2
Debt secured by First Mortgage Bonds:		
7.63% Series L due 2002	**—**	15,000
6.70% Series V due 2022	**105,000**	105,000
6.60% Series W due 2019	**39,500**	39,500
7.20% Series X due 2022	**78,000**	78,000
8.50% Series Z due 2023	**35,000**	35,000
Subtotal	**243,594**	272,502
Industrial development revenue bonds		
5.90% Series 1997A due 2032	**52,285**	52,285
5.90% Series 1995B due 2030	**85,000**	85,000
5.60% Series 1995A due 2030	**76,750**	76,750
5.50% Series 1995C due 2030	**44,000**	44,000
6.20% Series 1999B due 2004	**130,000**	130,000
Subtotal	**388,035**	388,035

(continued)

CONSOLIDATED STATEMENTS OF CAPITALIZATION—NEVADA POWER COMPANY (continued)

December 31,	**2002**	2001
(dollars in thousands)		
Pollution control revenue bonds		
6.38% due 2036	**20,000**	20,000
5.80% Series 1997B due 2032	**20,000**	20,000
5.30% Series 1995D due 2011	**14,000**	14,000
5.45% Series 1995D due 2023	**6,300**	6,300
5.35% Series 1995E due 2022	**13,000**	13,000
Subtotal	**73,300**	73,300
Variable rate notes		
Floating rate notes due 2003	**140,000**	140,000
IDRB Series 2000A due 2020	**100,000**	100,000
PCRB Series 2000B due 2009	**15,000**	15,000
Subtotal	**255,000**	255,000
Debt secured by General and Refunding Bonds		
8.25% Series A due 2011	**350,000**	350,000
10.88% Series E due 2009	**250,000**	—
	600,000	350,000
Other notes		
6.0% Series B notes due 2003	**210,000**	210,000
Obligation under capital leases	**73,259**	78,313
Current maturities and sinking fund requirements	**(354,677)**	(19,380)
Other, excluding current portion	**86**	197
Total Long-Term Debt	**1,488,597**	1,607,967
TOTAL CAPITALIZATION	**$2,826,600**	$3,190,422

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED BALANCE SHEETS—SIERRA PACIFIC POWER COMPANY

December 31,	**2002**	2001
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$2,447,401**	$2,387,457
Less accumulated provision for depreciation	**926,857**	854,834
	1,520,544	1,532,623
Construction work-in-progress	**90,157**	68,750
	1,610,701	1,601,373
Investments in subsidiaries and other property, net	**874**	1,866
Current Assets:		
Cash and cash equivalents	**88,910**	11,772
Restricted cash (Note 1)	**9,605**	—
Accounts receivable less provision for uncollectible accounts: 2002—$10,343; 2001—$8,474	**154,821**	175,771
Accounts receivable, affiliated companies	**58,680**	18,927
Deferred energy costs—electric	**55,786**	51,507
Deferred energy costs—gas	**17,045**	19,805
Materials, supplies and fuel, at average cost	**41,727**	42,607
Income tax receivable	**—**	62,109
Risk management assets (Note 19)	**1,397**	85,680
Other	**12,955**	5,935
	440,926	474,113
Deferred Charges and Other Assets:		
Deferred energy costs—electric	**161,530**	156,268
Deferred energy costs—gas	**—**	23,248
Regulatory tax asset	**57,818**	59,879
Other regulatory assets	**64,149**	49,356
Risk management assets (Note 19)	**—**	11,565
Risk management regulatory assets—net (Note 19)	**43,479**	313,119
Other	**19,013**	16,189
	345,989	629,624
	$2,398,490	$2,706,976

(continued)

CONSOLIDATED BALANCE SHEETS—SIERRA PACIFIC POWER COMPANY (continued)

December 31,	**2002**	2001
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholder's equity	**$ 639,295**	$ 692,901
Preferred stock	**50,000**	50,000
Long-term debt	**914,788**	923,070
	1,604,083	1,665,971
Current Liabilities:		
Short-term borrowings	**—**	46,500
Current maturities of long-term debt	**101,400**	2,630
Accounts payable	**71,247**	95,555
Accrued interest	**12,136**	8,408
Dividends declared	**968**	974
Accrued salaries and benefits	**10,812**	15,466
Deferred taxes	**35,612**	28,659
Risk management liabilities (Note 19)	**40,045**	332,793
Other current liabilities	**10,864**	3,387
	283,084	534,372
Commitments and Contingencies (Note 17)		
Deferred Credits and Other Liabilities:		
Deferred federal income taxes	**248,766**	258,733
Deferred investment tax credit	**26,590**	28,414
Regulatory tax liability	**25,418**	28,098
Customer advances for construction	**49,598**	46,725
Accrued retirement benefits	**44,856**	43,028
Risk management liabilities (Note 19)	**3,917**	77,324
Contract termination reserves (Note 17)	**86,778**	—
Other	**25,400**	24,311
	511,323	506,633
	$2,398,490	$2,706,976

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF OPERATIONS—SIERRA PACIFIC POWER COMPANY

Year ended December 31,	**2002**	2001	2000
(dollars in thousands, except per share amounts)			
OPERATING REVENUES:			
Electric	**$ 931,251**	$1,401,778	$894,919
Gas	**149,783**	145,652	100,803
	1,081,034	1,547,430	995,722
OPERATING EXPENSES:			
Operation:			
Purchased power	**545,040**	1,025,741	444,979
Fuel for power generation	**144,143**	286,719	233,748
Gas purchased for resale	**91,961**	136,534	83,199
Deferred energy costs disallowed	**56,958**	—	—
Deferral of energy costs—electric—net	**(54,632)**	(198,826)	—
Deferral of energy costs—gas—net	**24,785**	(23,170)	(16,164)
Other	**106,122**	118,526	97,021
Maintenance	**23,240**	24,363	18,420
Depreciation and amortization	**76,373**	72,103	71,630
Taxes:			
Income taxes	**(6,922)**	8,507	(672)
Other than income	**18,674**	17,965	18,152
	1,025,742	1,468,462	950,313
OPERATING INCOME	**55,292**	78,968	45,409
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**117**	856	357
Interest accrued on deferred energy	**10,644**	12,461	205
Other income	**4,266**	2,113	3,405
Other expense	**(6,577)**	(6,176)	(5,003)
Income taxes	**(2,431)**	91	690
	6,019	9,345	(346)
Total Income Before Interest Charges	**61,311**	88,313	45,063
INTEREST CHARGES:			
Long-term debt	**66,474**	55,199	36,865
Other	**10,663**	7,433	11,312
Allowance for borrowed funds used during construction and capitalized interest	**(1,858)**	(660)	(2,779)
	75,279	61,972	45,398
Dividend requirements of obligated mandatorily redeemable preferred trust securities	**—**	3,598	3,742
INCOME (LOSS) FROM CONTINUING OPERATIONS	**(13,968)**	22,743	(4,077)
DISCONTINUED OPERATIONS:			
Income from operations of water business disposed of (net of income taxes of $888 and $3,426 in 2001 and 2000, respectively)	**—**	1,022	9,634
Gain on disposal of water business (net of income taxes of $18,237)	**—**	25,845	—
NET INCOME (LOSS)	**(13,968)**	49,610	5,557
Preferred Dividend Requirements	**3,900**	3,700	3,499
Earnings (loss) applicable to common stock	**$ (17,868)**	$ 45,910	$ 2,058

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)— SIERRA PACIFIC POWER COMPANY

Year ended December 31,	**2002**	2001	2000
(dollars in thousands)			
NET INCOME (LOSS)	**$(13,968)**	$49,610	$(5,557)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of taxes of $114)	**—**	211	—
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $102 and $19 in 2002 and 2001, respectively)	**(189)**	36	—
Minimum pension liability adjustment (net of taxes of $350)	**(649)**	—	—
OTHER COMPREHENSIVE INCOME (LOSS)	**(838)**	247	—
COMPREHENSIVE INCOME (LOSS)	**$(14,806)**	$49,857	$(5,557)

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY— SIERRA PACIFIC POWER COMPANY

Year ended December 31,	**2002**	2001	2000
(dollars in thousands)			
COMMON STOCK:			
Balance at Beginning of Year and End of Year	**$ 4**	$ 4	$ 4
OTHER PAID-IN CAPITAL:			
Balance at Beginning of Year	**703,633**	598,684	584,684
Additional investment by parent company	**10,000**	104,949	14,000
Balance at End of Year	**713,633**	703,633	598,684
RETAINED EARNINGS (ACCUMULATED DEFICIT):			
Balance at Beginning of Year	**(10,983)**	6,107	89,049
Income (loss) from continuing operations before preferred dividends	**(13,968)**	22,743	(4,077)
Income from discontinued operations (before preferred dividend allocation of $200 and $401 in 2001 and 2000, respectively)	**—**	1,222	10,035
Gain on disposal of water business	**—**	25,845	—
Preferred stock dividends declared	**(3,900)**	(3,900)	(3,900)
Common stock dividends declared	**(44,900)**	(63,000)	(85,000)
Balance at End of Year	**(73,751)**	(10,983)	6,107
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**247**	—	—
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities:			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of taxes of $114)	**—**	211	—
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $102 and $19 in 2002 and 2001, respectively)	**(189)**	36	—
Minimum pension liability adjustment (net of taxes of $350)	**(649)**	—	—
Balance at End of Year	**(591)**	247	—
TOTAL COMMON SHAREHOLDER'S EQUITY AT END OF YEAR	**$639,295**	$692,901	$604,795

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS—SIERRA PACIFIC POWER COMPANY

Year ended December 31,	**2002**	2001	2000
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	**$ (13,968)**	$ 49,610	$ 5,557
Preferred dividends included in discontinued operations	**—**	200	401
Noncash items included in income:			
Depreciation and amortization	**76,373**	75,584	78,451
Deferred taxes and deferred investment tax credit	**(5,107)**	57,382	7,935
AFUDC and capitalized interest	**(1,975)**	(1,526)	(3,547)
Amortization of deferred energy costs—electric	**30,164**	—	—
Amortization of deferred energy costs—gas	**13,231**	3,562	—
Deferred energy costs disallowed (net of taxes)	**38,303**	—	—
Early retirement and severance amortization	**2,706**	3,121	4,196
Gain on disposal of water business	**—**	(44,081)	—
Other noncash	**(5,291)**	(300)	11,449
Changes in certain assets and liabilities:			
Accounts receivable	**(18,803)**	(36,835)	(41,604)
Deferral of energy costs—electric	**(75,502)**	(207,775)	—
Deferral of energy costs—gas	**10,270**	(30,245)	(16,370)
Materials, supplies and fuel	**880**	(12,700)	514
Other current assets	**(16,625)**	1,836	(26,749)
Accounts payable	**(24,308)**	(70,579)	87,643
Income tax receivable	**62,109**	—	—
Other current liabilities	**6,551**	2,380	1,231
Other assets	**(856)**	—	8,467
Other liabilities	**85,843**	(1,333)	(3,214)
Net Cash from Operating Activities	**163,995**	(211,699)	114,360
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	**(105,327)**	(132,754)	(155,625)
AFUDC and other charges to utility plant	**1,975**	1,526	3,605
Customer advances (refunds) for construction	**2,872**	4,949	2,864
Contributions in aid of construction	**7,447**	21,150	16,446
Net cash used for utility plant	**(93,033)**	(105,129)	(132,710)
Proceeds from sale of assets of water business	**—**	318,882	—
Disposal of subsidiaries and other property—net	**993**	17	298
Net Cash from Investing Activities	**(92,040)**	213,770	(132,412)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Decrease in short-term borrowings	**(46,500)**	(62,462)	(5,915)
Proceeds from issuance of long-term debt	**100,000**	400,000	200,000
Retirement of long-term debt	**(9,512)**	(299,732)	(102,797)
Redemption of preferred stock	**—**	(48,500)	—
Investment by parent company	**10,000**	104,948	14,000
Dividends paid	**(48,805)**	(89,901)	(84,899)
Net Cash from Financing Activities	**5,183**	4,353	20,389
NET INCREASE IN CASH AND CASH EQUIVALENTS	**77,138**	6,424	2,337
Beginning Balance in Cash and Cash Equivalents	**11,772**	5,348	3,011
Ending Balance in Cash and Cash Equivalents	**$ 88,910**	$ 11,772	$ 5,348
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid (received) during period for:			
Interest	**$ 73,409**	$ 66,597	$ 57,331
Income taxes	**$ (62,109)**	$ (25,632)	$ 9,644

The accompanying notes are an integral part of the financial statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION—SIERRA PACIFIC POWER COMPANY

December 31,	**2002**	2001
(dollars in thousands)		
COMMON SHAREHOLDER'S EQUITY:		
Common stock, $3.75 par value, 1,000 shares authorized, issued and outstanding	**$ 4**	$ 4
Other paid-in capital	**713,633**	703,633
Retained deficit	**(73,751)**	(10,983)
Accumulated other comprehensive income	**(591)**	247
Total Common Shareholder's Equity	**639,295**	692,901
CUMULATIVE PREFERRED STOCK:		
Not subject to mandatory redemption $25 stated value		
Class A Series 1; $1.95 dividend	**50,000**	50,000
LONG-TERM DEBT:		
Unamortized bond premium and discount, net	**(4,062)**	(961)
Debt secured by First Mortgage Bonds		
2.00% Series Z due 2004	**—**	56
2.00% Series O due 2011	**—**	1,281
6.35% Series FF due 2012	**1,000**	1,000
6.55% Series AA due 2013	**39,500**	39,500
6.30% Series DD due 2014	**45,000**	45,000
6.65% Series HH due 2017	**75,000**	75,000
6.65% Series BB due 2017	**17,500**	17,500
6.55% Series GG due 2020	**20,000**	20,000
6.30% Series EE due 2022	**10,250**	10,250
6.95% to 8.61% Series A MTN due 2022	**110,000**	110,000
7.10% and 7.14% Series B MTN due 2023	**58,000**	58,000
6.62% to 6.83% Series C MTN due 2006	**50,000**	50,000
5.90% Series JJ due 2023	**9,800**	9,800
5.90% Series KK due 2023	**30,000**	30,000
5.00% Series Y due 2024	**—**	3,072
6.70% Series II due 2032	**21,200**	21,200
5.50% Series D MTN due 2003	**5,000**	5,000
5.59% Series D MTN due 2003	**13,000**	13,000
Subtotal	**501,188**	508,698
Debt secured by General and Refunding Bonds		
8.00% Series A due 2008	**320,000**	320,000
10.50% (Variable) Series C due 2005	**100,000**	—
	420,000	320,000
Other notes		
5.75% Series 2001 due 2036	**80,000**	80,000
Other	**15,000**	17,002
Current maturities and sinking fund requirements	**(101,400)**	(2,630)
Total Long-Term Debt	**914,788**	923,070
TOTAL CAPITALIZATION	**$1,604,083**	$1,665,971

The accompanying notes are an integral part of the financial statements.

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies for both utility and non-utility operations are as follows:

General

The consolidated financial statements include the accounts of Sierra Pacific Resources (SPR) and its wholly owned subsidiaries, Nevada Power Company (NPC), Sierra Pacific Power Company (SPPC), Tuscarora Gas Pipeline Company (TGPC), Sierra Pacific Communications (SPC), Lands of Sierra, Inc. (LOS), Sierra Energy Company dba e·three (e·three), Sierra Pacific Energy Company (SPE), Sierra Water Development Company (SWDC), and Sierra Gas Holding Company (SGHC). NPC and SPPC are referred to together in this report as the Utilities. All significant intercompany balances and intercompany transactions have been eliminated in consolidation.

NPC is an operating public utility that provides electric service in Clark County in southern Nevada. The assets of NPC represent approximately 59% of the consolidated assets of SPR at December 31, 2002. NPC provides electricity to approximately 669,000 customers in the communities of Las Vegas, North Las Vegas, Henderson, Searchlight, Laughlin and adjoining areas, including Nellis Air Force Base. Service is also provided to the Department of Energy's Nevada Test Site in Nye County. The consolidated financial statements of SPR include the accounts of NPC's wholly owned subsidiaries, Nevada Electric Investment Company (NEICO), NVP Capital I, and NVP Capital III.

SPPC is an operating public utility that provides electric service in northern Nevada and northeastern California. SPPC also provides natural gas service in the Reno/Sparks area of Nevada. The assets of SPPC represent approximately 35% of the consolidated assets of SPR at December 31, 2002. SPPC provides electricity to approximately 318,000 customers in a 50,000 square mile service area including western, central, and northeastern Nevada, including the cities of Reno, Sparks, Carson City, and Elko, and a portion of eastern California, including the Lake Tahoe area. The consolidated financial statements of SPR include the accounts of SPPC's wholly owned subsidiaries, Piñon Pine Corporation, Piñon Pine Investment Company, GPSF-B, SPPC Funding LLC, and Sierra Pacific Power Capital I.

The Utilities' accounts for electric operations and SPPC's accounts for gas operations are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

TGPC is a partner in a joint venture that developed, constructed, and operates a natural gas pipeline serving the expanding gas market in the Reno area and certain northeastern California markets. TGPC accounts for its joint venture interest under the equity method. e·three provides comprehensive energy services in commercial and industrial markets on a regional basis. SPE markets a package of telecommunication products and services. SPC was formed in 1999 to provide telecommunications services using fiber-optic cable technology in both northern and southern Nevada.

Certain reclassifications of prior year information have been made for comparative purposes but have not affected previously reported net income or common shareholders' equity.

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

Management's Statement

Sierra Pacific Resources

SPR, on a stand-alone basis, had cash and cash equivalents of approximately $7.4 million at December 31, 2002, and approximately $179.3 million at February 28, 2003.

Currently, SPR has a substantial amount of debt and other obligations including, but not limited to: $133 million of its unsecured Floating Rate Notes due April 20, 2003; $300 million of its unsecured 8.75% Senior Notes due 2005; $240 million of its unsecured 7.93% Senior Notes due 2007; and $300 million of its 7.25% Convertible Notes due 2010. SPR intends to pay off the remaining principal balance of its Floating Rate Notes due April 20, 2003 with cash currently on hand.

SPR's future liquidity and its ability to pay the principal of and interest on its indebtedness depend on SPPC's ability to continue to pay dividends to SPR, on NPC's financial stability and a restoration of its ability to pay dividends to SPR, and on SPR's ability to access the capital markets or otherwise refinance maturing debt. On October 29, 2002, SPPC paid a common stock dividend of $25 million to its parent, SPR. Further adverse developments at NPC or SPPC, including a material disallowance of deferred energy costs in current and future rate cases or an adverse decision in the pending lawsuit by Enron, could make it difficult to continue to operate outside of bankruptcy. See Note 13, Dividend Restrictions for information regarding the dividend restrictions applicable to NPC and SPPC and Note 17, Commitments and Contingencies for additional information regarding uncertainties that could impact the SPR's liquidity and financial condition.

The provisions that currently restrict dividends payable by NPC or SPPC have adversely affected SPR's liquidity and will continue to negatively impact SPR's liquidity until those provisions are no longer in effect. Management intends to seek a modification of the financial covenant, contained in NPC's first mortgage indenture, in the near future. The regulatory limitation contained in the PUCN's Compliance Order, Docket No. 02-4037, dated June 19, 2002, expires on December 31, 2003. Prior to the expiration date of the Compliance Order, management may seek PUCN approval for a payment of dividends by NPC or may seek a waiver from the PUCN of the dividend restriction.

NOTES TO FINANCIAL STATEMENTS (continued)

Financing Transactions. On February 14, 2003, SPR issued and sold $300 million of its 7.25% Convertible Notes due 2010. Approximately $53.4 million of the net proceeds from the sale of the notes were used to purchase U.S. government securities that were pledged to the trustee for the first five interest payments on the notes payable during the first two and one-half years. A portion of the remaining net proceeds of the notes have been used to repurchase approximately $58.5 million of SPR's Floating Rate Notes due April 20, 2003. Of the remaining net proceeds, approximately $133 million will be used to repay the remainder of SPR's Floating Rate Notes due April 20, 2003, at maturity, and the remaining approximately $65 million will be available for general corporate purposes, including the payment of interest on SPR's other outstanding indebtedness.

The Convertible Notes will not be convertible prior to August 14, 2003. At any time on or after August 14, 2003, through the close of business February 14, 2010, holders of the Convertible Notes may convert each $1,000 principal amount of their notes into 219.1637 shares of SPR's common stock, subject to adjustment upon the occurrence of certain dilution events. Until SPR has obtained shareholder approval to fully convert the Convertible Notes into shares of common stock, holders of the Convertible Notes will be entitled to receive 76.7073 shares of common stock and a remaining portion in cash based on the average closing price of SPR's common stock over five consecutive trading days for each $1,000 principal amount of notes surrendered for conversion. At an assumed five-day average closing price of $3.20 (the last reported sale price of SPR's common stock on March 17, 2003), the total amount of the cash payable on conversion of the Convertible Notes would be approximately $137 million. If SPR does not obtain shareholder approval, SPR will be required to pay the cash portion of any Convertible Notes as to which the holders request conversion on or after August 14, 2003. Although management does not believe it is likely that a significant amount of the Convertible Notes will be converted in the foreseeable future, in the event that SPR does not have available funds to pay the cash portion of the Convertible Notes upon the requested conversion, SPR may have to issue additional debt to raise the necessary funds. There can be no assurance that SPR will be able to access the capital markets to issue such additional debt.

If SPR does obtain shareholder approval, it may elect to satisfy the cash payment component of the conversion price of the Convertible Notes solely with shares of common stock. SPR has agreed to use reasonable efforts to obtain shareholder approval, not later than 180 days after the date of issuance of the Convertible Notes, for approval to issue and deliver shares of SPR's common stock in lieu of the cash payment component of the conversion price of the Convertible Notes. For further information regarding the terms of the Convertible Notes, see Note 9, Long-Term Debt.

Effect of Holding Company Structure. Due to the holding company structure, SPR's right as a common shareholder to receive assets of any of its direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiary by its creditors. Therefore, SPR's debt obligations are effectively subordinated to all existing and future claims of its subsidiaries' creditors, particularly those of NPC and SPPC, including trade creditors, debt holders, secured creditors, taxing authorities, guarantee holders, and NPC's and SPPC's preferred security holders. As of December 31, 2002, NPC, SPPC, and their subsidiaries had approximately $2.86 billion of debt and other obligations outstanding and approximately $238.9 million of outstanding preferred securities. Although the Utilities are parties to agreements that limit the amount of additional indebtedness they may incur, the Utilities retain the ability to incur substantial additional indebtedness and other liabilities.

The accompanying financial statements do not include any adjustments that might result from the outcome of the uncertainties discussed above.

Nevada Power Company

NPC had cash and cash equivalents of approximately $95 million at December 31, 2002, and approximately $96 million at February 28, 2003.

In addition to anticipated capital requirements for construction NPC has approximately $355 million, of debt maturing in 2003. NPC expects to finance these requirements with internally generated funds, including the recovery of deferred energy and the issuance of debt.

NPC's liquidity would be significantly affected by an adverse decision in the lawsuit by Enron or by unfavorable rulings by the PUCN in pending or future NPC or SPPC rate cases. S&P and Moody's have NPC's credit ratings on "negative" and "stable," respectively. Future downgrades by either S&P or Moody's could preclude NPC's access to the capital markets. Furthermore, if NPC continues to experience financial difficulty or if its credit ratings are further downgraded, NPC may experience considerable difficulty entering into new power supply contracts, particularly under traditional payment terms. If suppliers will not sell power to NPC under traditional payment terms, NPC may have to pre-pay its power requirements. If it does not have sufficient funds or access to liquidity to pre-pay its power requirements, particularly at the onset of the summer months, and is unable to obtain power through other means, NPC's business, operations, and financial condition will be adversely affected. Adverse developments with respect to any one or a combination of the foregoing could make it difficult to continue to operate outside of bankruptcy.

NPC's General and Refunding Mortgage Indenture creates a lien on substantially all of NPC's properties in Nevada that is junior to the lien of the first mortgage indenture. As of December 31, 2002, $870 million of NPC's General and Refunding Mortgage Securities were outstanding. Additional securities may be issued under the General and Refunding Mortgage Indenture on the basis of (1) 70% of net utility property additions, (2) the principal amount of retired General and Refunding Mortgage Bonds, and/or (3) the principal amount of first mortgage bonds retired after delivery to the indenture trustee of the initial expert's certificate under the General and Refunding Mortgage Indenture.

As of December 31, 2002, NPC had the capacity to issue approximately $1.04 billion of additional General and Refunding Mortgage Securities. However, the financial covenants contained in NPC's Series E Notes limit NPC's ability to issue additional General and Refunding Mortgage Bonds or other debt. See Note 9, Long-Term Debt for information regarding NPC's Series E Notes. NPC has reserved $125 million of General and Refunding Mortgage Bonds for issuance upon the initial funding of NPC's receivables facility. See Note 12, Short-Term Borrowings, for information regarding NPC's accounts receivable facility. NPC intends to use its accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. NPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $125 million General and Refunding Mortgage Bonds.

The accompanying financial statements do not include any adjustments that might result from the outcome of the uncertainties discussed above.

Sierra Pacific Power Company

SPPC had cash and cash equivalents of approximately $88.9 million at December 31, 2002, and approximately $104.2 million at February 28, 2003.

In addition to anticipated capital requirements for construction, SPPC has approximately $101 million of debt maturing in 2003. SPPC expects to finance these requirements with internally generated funds, including the recovery of deferred energy and the issuance of debt.

SPPC's future liquidity could be significantly affected by unfavorable rulings by the PUCN in pending or future SPPC or NPC rate cases. S&P and Moody's have SPPC's credit ratings on "negative outlook" and "stable," respectively. Future downgrades by either S&P or Moody's could preclude SPPC's access to the capital markets. Furthermore, if SPPC continues to experience financial difficulty or if its credit ratings are further downgraded, SPPC may experience considerable difficulty entering into power supply contracts, particularly under traditional payment terms. If suppliers will not sell power to SPPC under traditional payment terms, SPPC may have to pre-pay its power requirements. If it does not have sufficient funds or access to liquidity to pre-pay its power requirements, and is unable to obtain power through other means, SPPC's business, operations, and financial condition will be adversely affected. Adverse developments with respect to any one or a combination of the factors and contingencies set forth above could make it difficult to continue to operate outside of bankruptcy.

SPPC's General and Refunding Mortgage Indenture creates a lien on substantially all of SPPC's properties in Nevada that is junior to the lien of the first mortgage indenture. As of December 31, 2002, $420 million of SPPC's General and Refunding Mortgage Bonds were outstanding. Additional securities may be issued under the General and Refunding Mortgage Indenture on the basis of (i) 70% of net utility property additions, (ii) the principal amount of retired General and Refunding Mortgage Bonds, and/or (iii) the principal amount of first mortgage bonds retired after delivery to the indenture trustee of the initial expert's certificate under the General and Refunding Mortgage Indenture.

At December 31, 2002, SPPC had the capacity to issue approximately $427 million of additional General and Refunding Mortgage Securities. However, the financial covenants contained in SPPC's Term Loan Agreement and Receivable Purchase Facility Agreements limit SPPC's ability to issue additional General and Refunding Mortgage Securities or other debt. SPPC has reserved $75 million of General and Refunding Mortgage Bonds for issuance upon the initial funding of its receivables purchase facility. See Note 9, Long-Term Debt, for information regarding SPPC's Term Loan Agreement, and Note 12, Short-Term Borrowings for information regarding SPPC's accounts receivable facility. SPPC intends to use its accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. SPPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $75 million General and Refunding Mortgage Bonds.

The accompanying financial statements do not include any adjustments that might result from the outcome of the uncertainties discussed above.

Regulatory Accounting and Other Regulatory Assets

The Utilities' rates are currently subject to the approval of the PUCN and, in the case of SPPC, rates are also subject to the approval of the California Public Utility Commission (CPUC), and are designed to recover the cost of providing generation, transmission, and distribution services. As a result, the Utilities qualify for the application of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," issued by the Financial Accounting Standards Board (FASB). This statement recognizes that the rate actions of a regulator can provide reasonable assurance of the existence of an asset and requires the capitalization of incurred costs that would otherwise be charged to expense where it is probable that future revenue will be provided to recover these costs. SFAS No. 71 prescribes the method to be used to record the financial transactions of a regulated entity. The criteria for applying SFAS No. 71 include the following: (i) rates are set by an independent third-party regulator, (ii) approved rates are intended to recover the specific costs of the regulated products or services, and (iii) rates that are set at levels that will recover costs can be charged to and collected from customers.

In addition to the deferral of energy costs discussed below, significant items to which SPR and the Utilities apply regulatory accounting include goodwill and other merger costs resulting from the 1999 merger of SPR and NPC, generation divestiture costs, and the loss on reacquired debt.

NOTES TO FINANCIAL STATEMENTS (continued)

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management regularly assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and the status of any pending or potential deregulation legislation.

Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced, and the Utilities might be required to reduce their asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation would also require affected utilities to write off their associated regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Utilities' future financial position and results of operations.

Management periodically assesses whether the requirements for application of SFAS No. 71 are satisfied. The provisions of Assembly Bill 369 (AB 369), signed into law in April 2001, include the repeal of all statutes authorizing retail competition in Nevada's electric utility industry. Accordingly, the Utilities continue to apply regulatory accounting to the generation, transmission, and distribution portions of their businesses.

The following Other regulatory assets were included in the consolidated balance sheets of SPR as of December 31 (dollars in thousands):

DESCRIPTION	Remaining Amortization Period	Receiving Regulatory Treatment: Earning a Return	Receiving Regulatory Treatment: Not Earning a Return	Waiting for Regulatory Treatment	**2002 Total**	2001 Total
Early retirement and severance offers	Various thru 2004	$ —	$4,995	$ —	**$ 4,995**	$ 7,701
Loss on reacquired debt	Term of related debt	31,812	—	—	**31,812**	32,882
Plant assets	Various thru 2031	3,558	—	—	**3,558**	3,783
Nevada divestiture costs		—	—	32,313	**32,313**	—
Merger transition costs[(a)]		—	—	12,601	**12,601**	10,543
Merger severance/relocation[(a)]		—	—	21,747	**21,747**	21,851
Merger goodwill[(a)]		—	—	19,675	**19,675**	19,675
California restructure costs		—	—	4,318	**4,318**	3,631
Conservation programs		—	—	3,374	**3,374**	1,798
Variable rate mechanism deferral		—	—	721	**721**	454
Other costs		—	—	1,819	**1,819**	(5,593)
Total Regulatory Assets		$35,370	$4,995	$96,568	**$136,933**	$96,725

(a) See Note 2, Sierra Pacific Resources and Nevada Power Merger, for additional information about the accounting treatment and regulatory recovery of merger costs. Merger goodwill above represents the portion of total goodwill that has been reclassified to a regulatory asset.

Deferral of Energy Costs

Nevada and California statutes permit regulated utilities to, from time to time, adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect of fluctuations in the cost of purchased gas, fuel, and purchased power.

On April 18, 2001, the Governor of Nevada signed into law AB 369. The provisions of AB 369, which are described in greater detail in Note 3, Regulatory Actions, include, among others, a reinstatement of deferred energy accounting for fuel and purchased power costs incurred by electric utilities. In accordance with the provisions of SFAS No. 71, the Utilities implemented deferred energy accounting on March 1, 2001, for their respective electric operations. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates, that excess is not recorded as a current expense on the statement of operations but rather is deferred and recorded as an asset on the balance sheet. Conversely, a liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to PUCN review.

AB 369 requires the Utilities to file applications to clear their respective deferred energy account balances at least every 12 months and provides that the PUCN may not allow the recovery of any costs for purchased fuel or purchased power "that were the result of any practice or transaction that was undertaken, managed or performed imprudently by the electric utility." In reference to deferred energy accounting, AB 369 specifies that fuel and purchased power costs include all costs incurred to purchase fuel, to purchase capacity, and to purchase energy. The Utilities also record and are eligible under the statute to recover a carrying charge on such deferred balances.

NPC utilized deferred energy accounting procedures until August 1, 2000, and resumed those procedures on March 1, 2001. SPPC resumed deferred energy accounting procedures for its natural gas operations as of January 1, 2000, and for its electric operations on March 1, 2001.

The following deferred energy costs were included in the consolidated balance sheets as of the dates shown (dollars in thousands):

	December 31, 2002			
DESCRIPTION	**NPC Electric**	**SPPC Electric**	**SPPC Gas**	**SPR Total**
Unamortized balances approved for collection in current rates	**$331,159**	**$120,183**	**$18,957**	**$ 470,299**
Balances pending PUCN approval	**195,670**	**15,380**	**—**	**211,050**
Balances accrued since end of periods submitted for PUCN approval(1)	**(17,750)**	**(148)**	**(1,912)**	**(19,810)**
Terminated suppliers(2)	**228,459**	**81,901**	**—**	**310,360**
Total	**$737,538**	**$217,316**	**$17,045**	**$ 971,899**
Current assets				
Deferred energy costs—electric	**$213,193**	**$ 55,786**	**$ —**	**$ 268,979**
Deferred energy costs—gas	**—**	**—**	**17,045**	**17,045**
Deferred assets				
Deferred energy costs—electric	**524,345**	**161,530**	**—**	**685,875**
Total	**$737,538**	**$217,316**	**$17,045**	**$ 971,899**

	December 31, 2001			
DESCRIPTION	NPC Electric	SPPC Electric	SPPC Gas	SPR Total
Unamortized balances approved for collection in current rates	$ —	$ —	$37,956	$ 37,956
Balances pending PUCN approval	921,917	205,418	—	1,127,335
Balances accrued since end of periods submitted for PUCN approval	58,148	2,357	5,097	65,602
Total	$980,065	$207,775	$43,053	$1,230,893
Current assets				
Deferred energy costs—electric	$281,555	$ 51,507	$ —	$ 333,062
Deferred energy costs—gas	—	—	19,805	19,805
Deferred assets				
Deferred energy costs—electric	698,510	156,268	—	854,778
Deferred energy costs—gas	—	—	23,248	23,248
Total	$980,065	$207,775	$43,053	$1,230,893

(1) Credits represent over-collections; that is, the extent to which gas or fuel and purchased power costs recovered through rates exceed actual gas or fuel and purchased power costs.
(2) Amounts related to terminated suppliers are discussed in Note 17, Commitments and Contingencies.

Utility Plant

The cost of additions, including betterments and replacements of units of property, is charged to utility plant. When units of property are replaced, renewed, or retired, their cost plus removal or disposal costs, less salvage, is charged to accumulated depreciation. The cost of current repairs and minor replacements is charged to operating expenses when incurred.

In addition to direct labor and material costs, certain direct and indirect costs are capitalized, including the cost of debt and equity capital associated with construction and retirement activity. The indirect construction overhead costs capitalized are based upon the following cost components: the cost of time spent by administrative employees in planning and directing construction; property taxes; employee benefits including such costs as pensions, postretirement and postemployment benefits, vacations and payroll taxes; and an allowance for funds used during construction (AFUDC).

Allowance for Funds Used During Construction and Capitalized Interest

As part of the cost of constructing utility plant, the Utilities capitalize AFUDC. AFUDC represents the cost of borrowed funds and, where appropriate, the cost of equity funds used for construction purposes in accordance with rules prescribed by the FERC and the PUCN. AFUDC is capitalized in the same manner as construction labor and material costs, with an offsetting credit to "other income" for the portion representing the cost of equity funds and as a reduction of interest charges for the portion representing borrowed funds. Recognition of this item as a cost of utility plant is in accordance with established regulatory ratemaking practices. Such practices are intended to permit the Utility to earn a fair return on, and recover in rates charged for utility services, all capital costs. This is accomplished by including such costs in the rate base and in the provision for depreciation. NPC's AFUDC rates used during 2002, 2001 and 2000 were 4.72%, 8.32%, and 8.34%, respectively. SPPC's AFUDC rates used during 2002, 2001, and 2000 were 5.54%, 7.97%, and 7.17%, respectively. As specified by the PUCN, certain projects were assigned a lower AFUDC rate due to specific low-interest-rate financings directly associated with those projects.

Depreciation

Substantially all of the Utilities' plant is subject to the ratemaking jurisdiction of the PUCN or the FERC, and, in the case of SPPC, the CPUC, which also approves any changes the Utilities may make to depreciation rates utilized for this property. Depreciation is calculated using the straight-line composite method over the estimated remaining service lives of the related properties, which approximates the anticipated physical lives of these assets in most cases. NPC's depreciation provision for 2002, 2001 and 2000, as authorized by the PUCN and stated as a percentage of the original cost of depreciable property, was approximately 3.0%, 2.94%, and 2.76%. SPPC's depreciation

NOTES TO FINANCIAL STATEMENTS (continued)

provision for 2002, 2001 and 2000, as authorized by the PUCN and stated as a percentage of the original cost of depreciable property, was approximately 3.33%, 3.29%, and 3.25%, respectively.

Impairment of Long-Lived Assets

SPR and the Utilities evaluate their Utility Plant and definite-lived tangible assets for impairment whenever indicators of impairment exist.

Cash and Cash Equivalents

Cash is comprised of cash on hand and working funds. Cash equivalents consist of high quality investments in money market funds.

Federal Income Taxes and Investment Tax Credits

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiary's respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return. Deferred taxes are provided on temporary differences at the statutory income tax rate in effect as of the most recent balance sheet date.

SPR accounts for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes." SFAS No. 109 requires recognition of deferred tax liabilities and assets for the future tax consequences of events that have been included in the consolidated financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference between the financial statement and tax bases of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

For regulatory purposes, the Utilities are authorized to provide for deferred taxes on the difference between straight-line and accelerated tax depreciation on post-1969 utility plant expansion property, deferred energy, and certain other differences between financial reporting and taxable income, including those added by the Tax Reform Act of 1986 (TRA). In 1981, the Utilities began providing for deferred taxes on the benefits of using the Accelerated Cost Recovery System for all post-1980 property. In 1987, the TRA required the Utilities to begin providing deferred taxes on the benefits derived from using the Modified Accelerated Cost Recovery System.

Investment tax credits are no longer available to the Utilities. The deferred investment tax credits are being amortized over the estimated service lives of the related properties.

Revenues

Operating revenues include billed and unbilled utility revenues. The accrual for unbilled revenues represents amounts owed to the Utilities for service provided to customers for which the customers have not yet been billed. These unbilled amounts are also included in accounts receivable.

Revenues related to the sale of energy are recorded based on meter reads, which occur on a systematic basis throughout a month, rather than when the service is rendered or energy is delivered. At the end of each month, the energy delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of energy procured and generated during that month, historical customer class usage patterns and the Utilities' current tariffs.

Stock Compensation Plans

In December 2002, the FASB released SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure," as an amendment to SFAS No. 123, "Accounting for Stock-Based Compensation." SPR has previously adopted the disclosure-only provisions of SFAS No. 123, and as of December 31, 2002 has adopted the updated disclosure requirements set forth in SFAS No. 148. At December 31, 2002, SPR had several stock-based compensation plans which are described more fully in Note 15, Stock Compensation Plans. SPR applies Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," in accounting for its stock option plans. Accordingly, no compensation cost has been recognized for nonqualified stock options and the employee stock purchase plan. Had compensation cost for SPR's nonqualified stock options and the employee stock purchase plan been determined based on the fair value at the grant dates for awards under those plans consistent with the provisions of SFAS No. 123, SPR's income applicable to common stock would have been decreased to the pro forma amounts indicated below (dollars in thousands, except per share amounts):

		2002	2001	2000
Stock compensation cost included in net income as reported, net of related tax effects	As reported	**$ (1,567)**	$ 346	$ (152)
Earnings (deficit) applicable to common stock	As reported	**$(307,521)**	$56,733	$(39,780)
Less: Stock compensation cost, net of related tax effects	Pro forma	**2,047**	1,209	695
Earnings (deficit) applicable to common stock	Pro forma	**$(309,568)**	$55,524	$(40,475)
Basic earnings per share	As reported	**$ (3.01)**	$ 0.65	$ (0.51)
	Pro forma	**$ (3.03)**	$ 0.63	$ (0.52)
Diluted earnings per share	As reported	**$ (3.01)**	$ 0.65	$ (0.51)
	Pro forma	**$ (3.03)**	$ 0.63	$ (0.52)

Recent Pronouncements

See Note 20, Change in Accounting for Goodwill, for a discussion of SPR's implementation of SFAS No. 142.

SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities will be recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities due to the passage of time will be an operating expense. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. The Utilities adopted SFAS No. 143 on January 1, 2003.

Prior to adopting SFAS No. 143, costs for removal of most utility assets were accrued as an additional component of depreciation expense. Under SFAS No. 143, only the costs to remove an asset with legally binding retirement obligations will be accrued over time through accretion of the asset retirement obligation and depreciation of the capitalized asset retirement cost.

Management's methodology to assess its legal obligation included an inventory of assets by system and components, and a review of right of ways and easements, regulatory orders, leases and federal, state, and local environmental laws. Management assumed in determining its Asset Retirement Obligations that transmission, distribution and communications systems will be operated in perpetuity and would continue to be used or sold without land remediation; and, mass asset properties that are replaced or retired frequently would be considered normal maintenance.

Management has identified a legal obligation to retire generation plant assets specified in land leases for NPC's jointly-owned Navajo generating station. The land on which the Navajo generating station resides is leased from the Navajo Nation. The provisions of the leases require the lessees to remove the facilities upon request of the Navajo Nation at the expiration of the leases. Management has determined that the present value of NPC's Navajo Asset Retirement Obligation will not have a material effect on the financial position or results of operations of SPR or NPC. SPPC has no significant asset retirement obligations.

The Utilities have various transmission and distribution lines as well as substations that operate under various rights of way that contain end dates and restorative clauses. Management operates the transmission and distribution system as though they will be operated in perpetuity and will continue to be used or sold without land remediation. As a result, the Utilities have not recorded any costs associated with the removal of the transmission and distribution systems.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This standard provides guidance on the impairment of long-lived assets and for long-lived assets to be disposed of. The standard supersedes the current authoritative literature on impairments as well as disposal of a segment of a business and was adopted January 1, 2002.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." Among other things, this statement rescinds SFAS No. 4, "Reporting Gains and Losses from Extinguishment of Debt" which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. As a result, the criteria in Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," will now be used to classify those gains and losses. Adoption of this statement did not have an impact on the financial position or results of operations of SPR, NPC, or SPPC.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the liability is incurred. A fundamental conclusion reached by the FASB in this statement is that an entity's commitment to a plan by itself does not create a present obligation to others that meets the definition of a liability. Adoption of this statement did not have an impact on the financial position or results of operations of SPR, NPC, or SPPC.

On January 22, 2003, the FASB directed its staff to prepare a draft of SFAS No. 149, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity." The final draft is expected to be issued in March 2003. The statement will establish standards for accounting for financial instruments with characteristics of liabilities, equity, or both. As such, the NPC obligated mandatorily redeemable preferred trust securities may be classified as a liability once SFAS No. 149 goes into effect. The proposed effective date of SFAS No. 149 is July 1, 2003.

In November 2002, the FASB issued Interpretation 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees," which elaborates on the disclosures to be made in interim and annual financial statements of a guarantor about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing a guarantee. Initial recognition and measurement provisions of the Interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements are effective for financial statements of interim or annual periods ending after December 15, 2002. As of December 31, 2002, any guarantees of SPR and its subsidiaries were intercompany, whereby the parent issues the guarantees on behalf of its consolidated subsidiaries to a third party.

NOTE 2. SIERRA PACIFIC RESOURCES AND NEVADA POWER MERGER

On July 28, 1999, the merger between SPR and NPC was consummated. The merger was accounted for as a reverse purchase under generally accepted accounting principles, with NPC considered the acquiring entity even though SPR is the surviving legal entity. As a result of the acquisition, goodwill of $331.2 million was recognized, which represented the total consideration paid to SPR common shareholders less the fair value of SPR's net assets.

The order issued by the PUCN in Docket No. 98-7023 on December 31, 1998, approving the merger of SPR and NPC directed both SPPC and NPC to defer three categories of merger costs to be reviewed for recovery through future rates. That order instructed both utilities to defer merger transaction costs, transition costs, and goodwill costs for a three-year period. The deferral of these costs was intended to allow adequate time for the anticipated savings from the merger to develop. At the end of the three-year period, the order instructs the Utilities to propose an amortization

NOTES TO FINANCIAL STATEMENTS (continued)

period for the merger costs and allows the Utilities to recover the costs to the extent they are offset by merger savings. Accordingly, goodwill amortization associated with the regulated Utilities has been reclassified to a regulatory asset.

Also deferred as a result of the PUCN order is $62.2 million in other merger costs as of December 31, 2002. These deferred costs consist of $40.5 million of transaction and transition costs and $21.7 million of employee separation costs. Employee separation costs were comprised of $17.2 million of employee severance, relocation, and related costs, and $4.5 million of pension and postretirement benefits, net of plan curtailment gains.

On October 1, 2001, and November 30, 2001, NPC and SPPC, respectively, filed applications with the PUCN for general rate increases that included, among other items, a request to recover deferred merger costs, including goodwill. The PUCN in its decisions on March 27, 2002, and May 28, 2002, for NPC and SPPC, respectively, decided not to make any determination on the recovery of merger costs until a general rate case is filed with a test year ending on or after December 31, 2002. However, the PUCN did instruct NPC and SPPC to continue to recognize these costs as deferred costs without carrying charges.

The extent to which goodwill and merger costs will be recovered in future revenues and the timing of those recoveries is expected to be determined in general rate cases that are required to be filed in 2003. To the extent that the Utilities are not permitted to recover any portion of goodwill in future rates, the amount not recoverable will be reviewed for impairment and accounted for under the provisions of SFAS No. 142. A significant disallowance of goodwill or merger costs by the PUCN could have a material adverse affect on the future financial condition, results of operations, and cash flows of SPR, NPC, and SPPC and could make it difficult for one or more of SPR, NPC, or SPPC to continue to operate outside of bankruptcy.

NOTE 3. REGULATORY ACTIONS

The Utilities are subject to the jurisdiction of the PUCN and, in the case of SPPC, the CPUC, with respect to rates, standards of service, siting of and necessity for generation and certain transmission facilities, accounting, issuance of securities, and other matters with respect to electric distribution and transmission operations. NPC and SPPC submit integrated resource plans to the PUCN for approval.

Under federal law, the Utilities and Tuscarora Gas Pipeline Company (TGPC) are subject to certain jurisdictional regulation, primarily by the FERC. The FERC has jurisdiction under the Federal Power Act with respect to rates, service, interconnection, accounting, and other matters in connection with the Utilities' sale of electricity for resale and interstate transmission. The FERC also has jurisdiction over the natural gas pipeline companies from which the Utilities take service.

As a result of regulation, many of the fundamental business decisions of the Utilities, as well as the rate of return they are permitted to earn on their utility assets, are subject to the approval of governmental agencies.

As with other utilities, NPC and SPPC are subject to federal, state, and local regulations governing air and water quality, hazardous and solid waste, land use, and other environmental considerations. Nevada's Utility Environmental Protection Act requires approval of the PUCN prior to construction of major utility, generation, or transmission facilities. The United States Environmental Protection Agency (EPA), Nevada Division of Environmental Protection (NDEP), and Clark County Health District (CCHD) administer regulations involving air quality, water pollution, and solid, hazardous and toxic waste. SPR's Board of Directors has a comprehensive environmental policy and separate board committee that oversees NPC's, SPPC's, and SPR's corporate performance and achievements related to the environment.

Deferred Energy Accounting

On April 18, 2001, the governor of Nevada signed into law AB 369. AB 369 required the Utilities to use deferred energy accounting for their respective electric operations beginning on March 1, 2001. The intent of deferred energy accounting is to ease the effect of fluctuations in the cost of purchased power and fuel.

Nevada Matters

Nevada Power Company 2001 General Rate Case

On October 1, 2001, NPC filed an application with the PUCN, as required by law, seeking an electric general rate increase. On December 21, 2001, NPC filed a certification to its general rate filing updating costs and revenues pursuant to Nevada regulations. In the certification filing, NPC requested an increase in its general rates charged to all classes of electric customers designed to produce an increase in annual electric revenues of $22.7 million, or an overall 1.7% rate increase. The application also sought a return on common equity (ROE) for NPC's total electric operations of 12.25% and an overall rate of return (ROR) of 9.30%.

On March 27, 2002, the PUCN issued its decision on the general rate application, ordering a $43 million revenue decrease with an ROE of 10.1% and ROR of 8.37%. The effective date for the decision was April 1, 2002. The decision also resulted in adjustments increasing accumulated depreciation by $6.7 million, and the inclusion of approximately $5 million of revenues related to SO_2 allowances. The PUCN delayed consideration of recovery of SPR/NPC merger costs until a future rate case. NPC was not granted a carrying charge on these deferred costs. NPC plans to renew its request to recover these costs in its next general rate case, which will be filed by the fourth quarter 2003. Recovery of costs related to the generation divestiture project, which supported Nevada's now-abandoned utility restructuring policy, were delayed until the plants are sold or some other mechanism is proposed to allow recovery of the costs. A carrying charge was allowed by the PUCN for the delayed recovery of divestiture costs.

On April 15, 2002, NPC filed a petition for reconsideration with the PUCN. On May 24, 2002, the PUCN issued an order on the petition for reconsideration. The PUCN modified its original order reversing the adjustment to accumulated depreciation of $6.7 million and decreased the SO2 allowance revenue amortization to $3.2 million per year. Revised rates for these changes went into effect on June 1, 2002.

Nevada Power Company 2001 Deferred Energy Case

On November 30, 2001, NPC filed an application with the PUCN seeking to clear deferred balances for purchased fuel and power costs accumulated between March 1, 2001, and September 30, 2001, as required by law. The application sought to establish a Deferred Energy Accounting Adjustment (DEAA) rate to clear accumulated purchased fuel and power costs of $922 million and spread the recovery of the deferred costs, together with a carrying charge, over a period of not more than three years.

On March 29, 2002, the PUCN issued its decision on the deferred energy application, allowing NPC to recover $478 million over a three-year period, but disallowing $434 million of deferred purchased fuel and power costs and $30.9 million in carrying charges, consisting of $10.1 million in carrying charges accrued through September 2001 and $20.8 million in carrying charges accrued from October 2001 through February 2002. The order stated that the disallowance was based on alleged imprudence in incurring the disallowed costs. On April 11, 2002, NPC filed a lawsuit in the First District Court of Nevada seeking to reverse portions of the PUCN's decision.

Nevada Power Company 2002 Deferred Energy Case

On November 14, 2002, NPC filed an application with the PUCN seeking to clear deferred balances for purchased fuel and power costs accumulated between October 1, 2001, and September 30, 2002, as required by law. The application seeks to establish a rate to repay accumulated purchased fuel and power costs of $195.7 million, together with a carrying charge, over a period of not more than three years. The application also requests a reduction to the going-forward rate for energy, reflecting reduced wholesale energy costs. The combined effect of these two adjustments results in an overall rate reduction of 5.3%. A hearing is scheduled to begin on April 7, 2003 and a ruling is required by May 15, 2003.

Sierra Pacific Power Company 2001 General Rate Case

On November 30, 2001, as required by law, SPPC filed an application with the PUCN seeking an electric general rate increase. On February 28, 2002, SPPC filed a certification to its general rate filing, updating costs and revenues pursuant to Nevada regulations. In the certification filing, SPPC requested an increase in its general rates charged to all classes of electric customers, which were designed to produce an increase in annual electric revenues of $15.9 million representing an overall 2.4% rate increase. The application also sought an ROE for SPPC's total electric operations of 12.25% and an overall ROR of 9.42%.

On May 28, 2002, the PUCN issued its decision on the general rate application, ordering a $15.3 million revenue decrease with an ROE of 10.17% and ROR of 8.61%. The effective date of the decision was June 1, 2002. The PUCN delayed consideration of recovery of SPR/NPC merger costs until a future rate case, and SPPC was not granted a carrying charge on these deferred costs. SPPC is currently planning to renew its request to recover these costs in a general rate case to be filed by the fourth quarter of 2003. Recovery of costs related to the generation divestiture project, which supported Nevada's now-abandoned utility restructuring policy, were delayed until the plants are sold or some other mechanism is proposed to allow recovery of the costs. A carrying charge was allowed by the PUCN for the delayed recovery of divestiture costs.

Sierra Pacific Power Company 2002 Deferred Energy Case

On February 1, 2002, SPPC filed an application with the PUCN, as required by law, seeking to clear deferred balances for purchased fuel and power costs accumulated between March 1, 2001 and November 30, 2001. The application sought to establish a DEAA rate to clear accumulated purchased fuel and power costs of $205 million and spread the cost recovery over a period of not more than three years. It also sought to recalculate the Base Tariff Energy Rate to reflect anticipated ongoing purchased fuel and power costs.

On May 28, 2002, the PUCN issued its decision on the deferred energy application, allowing SPPC three years to collect $150 million but disallowing $53 million of deferred purchased fuel and power costs and $2 million in carrying charges.

On August 22, 2002, SPPC filed a lawsuit in the First District Court of Nevada seeking to reverse portions of the decision of the PUCN denying the recovery of deferred energy costs incurred by SPPC on behalf of its customers in 2001 on the grounds that such power costs were not prudently incurred. SPPC's lawsuit requests that the District Court reverse portions of the order of the PUCN and remand the matter to the PUCN with direction that the PUCN authorize SPPC to immediately establish rates that would allow SPPC to recover its entire deferred energy balance of $205 million, with a carrying charge, over three years. A hearing date has been scheduled for October 2003.

Sierra Pacific Power Company 2003 Deferred Energy Case

On January 14, 2003, SPPC filed an application with the PUCN, as required by law, seeking to clear deferred balances for purchased fuel and power costs accumulated between December 1, 2001 and November 30, 2002. The application seeks to establish a DEAA rate to clear accumulated purchased fuel and power costs of $15.4 million and spread the cost recovery over a period of not more than three years. It also seeks to recalculate the Base Tariff Energy Rate to reflect anticipated ongoing purchased fuel and power costs. The total rate increase resulting from the requested DEAA would amount to 0.01%. A hearing is scheduled to begin on May 12, 2003, and a ruling is required before July 13, 2003.

Annual Purchased Gas Cost Adjustment (SPPC)

On July 1, 2002, SPPC filed a Purchased Gas Cost Adjustment application for its natural gas local distribution company. In the application, SPPC has asked for a reduction of $0.05421 to its Base Purchased Gas Rate and an increase in its Balancing Account Adjustment charge by the same amount. This request would result in no change to revenues or customer rates. This docket was consolidated for hearing purposes with the Liquid Petroleum Gas Cost Adjustment below.

NOTES TO FINANCIAL STATEMENTS (continued)

On December 23, 2002, the PUCN voted to decrease rates for SPPC's natural gas customers by approximately 3% ($3.2 million plus applicable carrying charges). The PUCN noted that the decrease was due primarily to lower gas costs for SPPC and to a disallowance for imprudent hedging practices. The PUCN adjusted SPPC's costs related to fixed floating hedging contracts. The PUCN also disallowed an alleged $0.7 million customer subsidy under an SPPC optional gas tariff. The new rates were implemented January 1, 2003.

SPPC has filed a petition for reconsideration of the decisions to disallow the $3.2 million hedging costs and the $0.7 million alleged customer subsidy. On February 6, 2003, the PUCN granted the petition for reconsideration and a decision is expected by the end of the first quarter 2003.

NOTE 4. EARNINGS PER SHARE

The following table outlines the calculation for earnings per share (EPS). The difference between Basic EPS and Diluted EPS is due to common stock equivalent shares resulting from stock options, the employee stock purchase plan, performance shares, and a non-employee director stock plan. Common stock equivalents were determined using the treasury stock method. Also see Note 7, Common Stock and Other Paid-In Capital.

	2002	2001	2000
BASIC EPS			
NUMERATOR ($000)			
Income (loss) from continuing operations	**$ (305,955)**	$ 29,866	$ (49,414)
Income from discontinued operations	**—**	1,022	9,634
Gain on disposal of water business	**—**	25,845	—
Cumulative effect of change in accounting principle	**(1,566)**	—	—
Earnings (deficit) applicable to common stock	**$ (307,521)**	$ 56,733	$ (39,780)
DENOMINATOR			
Weighted average number of shares outstanding	**102,126,079**	87,542,441	78,435,405
EARNINGS (DEFICIT) PER SHARE:			
From continuing operations	**$ (3.00)**	$ 0.34	$ (0.63)
From discontinued operations	**—**	0.01	0.12
Gain on disposal of water business	**—**	0.30	—
Cumulative effect of change in accounting principle	**(0.01)**	—	—
Applicable to common stock	**$ (3.01)**	$ 0.65	$ (0.51)
DILUTED EPS			
NUMERATOR ($000)			
Income (loss) from continuing operations	**$ (305,955)**	$ 29,866	$ (49,414)
Income from discontinued operations	**—**	1,022	9,634
Gain on disposal of water business	**—**	25,845	—
Cumulative effect of change in accounting principle	**(1,566)**	—	—
Earnings (deficit) applicable to common stock	**$ (307,521)**	$ 56,733	$ (39,780)
DENOMINATOR(1)			
Weighted average number of shares outstanding before dilution	**102,126,079**	87,542,441	78,435,405
Stock options	**8,154**	14,021	5,645
Executive long-term incentive plan—performance shares	**8,918**	43,693	35,393
Non-Employee stock plan	**13,861**	9,355	5,885
Employee stock purchase plan	**1,163**	2,862	2,807
	102,158,175	87,612,372	78,485,135
EARNINGS (DEFICIT) PER SHARE(2)			
From continuing operations	**$ (3.00)**	$ 0.34	$ (0.63)
From discontinued operations	**—**	0.01	0.12
Gain on disposal of water business	**—**	0.30	—
Cumulative effect of change in accounting principle	**(0.01)**	—	—
Applicable to common stock	**$ (3.01)**	$ 0.65	$ (0.51)

(1) The denominator does not include anti-dilutive stock equivalents for the Stock Option Plan and Corporate PIES due to conversion prices being higher than market prices at December 31, 2002.

(2) Because of net losses for the years ended December 31, 2000 and 2002, stock equivalents would be anti-dilutive. Accordingly, Diluted EPS for those periods are computed using weighted average number of shares outstanding before dilution.

NOTE 5. INVESTMENTS IN SUBSIDIARIES AND OTHER PROPERTY

Investments in subsidiaries and other property consisted of (dollars in thousands):

Sierra Pacific Resources

December 31,	**2002**	2001
Investment in Tuscarora Gas Transmission Company	**$ 26,912**	$18,799
Non-utility property of SPC and investment in Sierra Touch America	**68,353**	15,340
Cash value-life insurance	**12,560**	12,580
Non-utility property of NEICO	**6,555**	6,445
Non-utility property of e·three	**9,050**	9,561
Other non-utility property	**10,638**	10,848
	$134,068	$73,573

Nevada Power

December 31,	**2002**	2001
Cash value-life insurance	**$12,560**	$12,580
Non-utility property of NEICO	**6,555**	—
Non-utility property	**1,180**	141
	$20,295	$12,721

Sierra Pacific Power

December 31,	**2002**	2001
Non-utility property	**$874**	$1,866

NOTE 6. JOINTLY OWNED FACILITIES

At December 31, 2002, SPR owned the following undivided interests in jointly owned electric utility facilities:

Generating Facility	% Owned by Subsidiary	Plant in Service	Accumulated Depreciation	Net Plant in Service	Construction Work in Progress	Subsidiary
Navajo Station	11.3	$228,133	$104,198	$123,935	$1,572	NPC
Mohave Facility	14.0	84,914	39,230	45,684	3,038	NPC
Reid-Gardner No. 4	32.2	124,321	56,435	67,886	198	NPC
Valmy Station	50.0	282,807	133,038	149,769	—	SPPC
TOTAL		$720,175	$332,901	$387,274	$4,808	

The amounts for Navajo and Mohave include NPC's share of transmission systems and general plant equipment and, in the case of Navajo, NPC's share of the jointly owned railroad which delivers coal to the plant. Each participant provides its own financing for all of these jointly owned facilities. NPC's share of operating expenses for these facilities is included in the corresponding operating expenses in its Consolidated Statements of Operations.

NPC's ownership interest in Mohave comprises approximately 10% of NPC's peak generation capacity. Southern California Edison (SCE) is the operating partner of Mohave. On May 17, 2002, SCE filed with the CPUC an application to address the future disposition of SCE's share of Mohave. Mohave obtains all of its coal supply from a mine in northeast Arizona on lands of the Navajo Nation and the Hopi Tribe (the Tribes). This coal is delivered from the mine to Mohave by means of a coal slurry pipeline which requires water that is obtained from groundwater wells located on lands of the Tribes in the mine vicinity.

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application states that it appears that it probably will not be possible for SCE to extend Mohave's operations beyond 2005. Due to the uncertainty over a post-2005 coal supply, SCE and the other Mohave co-owners have been prevented from commencing the installation of extensive pollution control equipment that must be put in place if Mohave's operations are extended past 2005.

NPC is currently evaluating and analyzing all of its options with regard to the Mohave project.

SPPC and Idaho Power Company each own an undivided 50% interest in the Valmy generating station, with each company being responsible for financing its share of capital and operating costs. SPPC is the operator of the plant for both parties. SPPC's share of direct operation and maintenance expenses for Valmy is included in its accompanying Consolidated Statements of Operations.

NOTE 7. COMMON STOCK AND OTHER PAID-IN CAPITAL

On September 21, 1999, the Board of Directors of SPR (the SPR Board) declared a dividend distribution of one right (an SPR Right) for each outstanding share of SPR common stock to shareholders of record at the close of business on October 31, 1999. By issuing the new SPR Rights, the SPR Board extended the benefits and protections afforded to shareholders under the Rights Agreement, dated as of October 31, 1989, which expired on October 31, 1999. Each SPR Right, initially evidenced by and traded with the shares of SPR Common Stock, entitles the registered holder (other than an "Acquiring Person" as defined in the Rights Agreement) to purchase, at an exercise price of $75.00, $150.00 worth of common stock at its then-market value, subject to certain conditions and approvals set forth in the Rights Agreement. If, at any time while there is an Acquiring Person, SPR engages in a merger or other business combination transaction or series of related transactions in which the Common Stock is changed or exchanged or 50% or more of its assets or earning power is transferred, each SPR Right (not previously voided by the occurrence of a Flip-in Event, as described in the Rights Agreement) will entitle its holder to purchase, at the SPR Right's then-current Exercise Price, common stock of such

NOTES TO FINANCIAL STATEMENTS (continued)

Acquiring Person having a calculated value of twice the SPR Right's then-current Exercise Price. The SPR Rights are not exercisable until the Distribution Date and expire on October 31, 2009, unless previously redeemed by SPR. Following an SPR Distribution Date, the SPR Rights will trade separately from the SPR common stock and will be evidenced by separate certificates. Until an SPR Right is exercised, the holder thereof will have no rights as a shareholder of SPR, including, without limitation, the right to receive dividends. The purpose of the plan is to help ensure that SPR's shareholders receive fair and equal treatment in the event of any proposed hostile takeover of SPR.

On August 15, 2001, SPR completed a public offering of 23,575,000 shares of its common stock, yielding net proceeds of approximately $340 million, all of which were contributed to NPC as an additional equity investment.

On November 16 and 21, 2001, SPR issued an aggregate of $345 million senior unsecured notes in connection with the public offering of 6,900,000 of its Corporate Premium Income Equity Securities (PIES). Each Corporate PIES unit consists of a forward stock purchase contract and a senior unsecured note issued by SPR with a face amount of $50. The senior notes are pledged as collateral to secure each holder's obligation to purchase shares of SPR common stock under the stock purchase contract. The senior note may be released from the pledge arrangement if a holder opts to create Treasury PIES by delivering a like principal amount of U.S. Treasury securities to the Securities Intermediary in substitution for the senior notes pledged as collateral.

Each stock purchase contract obligates the holder to purchase SPR common stock on or before November 15, 2005, the Purchase Contract Settlement Date. The number of shares each investor is entitled to receive will depend on the average closing price of SPR common stock over a 20-day trading period prior to the settlement. Prior to the Purchase Contract Settlement Date, holders of Corporate PIES have the option to pay $50 per Corporate PIES to settle their purchase contract obligations. If the holders do not elect to make a cash payment, the proceeds from the remarketing of the senior notes will be used to satisfy their purchase contract obligations.

The purchase contracts are forward transactions in SPR common stock. Upon issuance, a liability for the present value of the purchase contract adjustment payments, approximately $13.7 million, was recorded in Other deferred credits, with a corresponding reduction to Other paid-in capital. See further discussion regarding these senior notes and the purchase contract adjustment payments in Note 9, Long-Term Debt. Upon settlement of a purchase contract, SPR will receive the stated amount of $50 on the purchase contract and will issue the required number of shares of common stock. The stated amount received will be credited to stockholders' equity and allocated between the Common stock and Other paid-in capital accounts.

Prior to the issuance of common stock upon settlement of the purchase contracts, SPR expects that the PIES will be reflected in SPR's earnings per share calculations using the treasury stock method. Under this method, the number of shares of common stock used in calculating earnings per share is deemed to be increased by the excess, if any, of the number of shares of common stock issuable upon settlement of the purchase contracts over the number of shares that could be purchased by SPR in the market at the average closing price during the relevant period using the proceeds receivable upon settlement.

As of December 31, 2002, 3,441,166 shares of common stock were reserved for issuance under the Common Stock Investment Plan (CSIP), Employees' Stock Purchase Plan (ESPP), and Executive Long-Term Incentive Plan (ELTIP). The ELTIP for key management employees allows for the issuance of SPR's common shares to key employees through December 31, 2003, which can be earned and issued after December 31, 2003. This Plan permits the following types of grants, separately or in combination: nonqualified and qualified stock options; stock appreciation rights; restricted stock; performance units; performance shares; and bonus stock. SPR also provides an ESPP to all of its employees meeting minimum service requirements. Employees can choose twice each year (offering date) to have up to 15% of their base earnings withheld to purchase SPR common stock. The purchase price of the stock is 90% of the market value on the offering date or 100% of the market price on the execution date, if less. The Non-employee Director Stock Plan provides that a portion of SPR's outside directors' annual retainer be paid in SPR common stock. SPR records the costs of these plans in accordance with Accounting Principles Board Opinion No. 25 (APB No. 25). In addition, in 1996 the Company eliminated its outside director retirement plan and converted the present value of each director's vested retirement benefit to phantom stock based on the stock price at the time of conversion. Phantom stock earns dividends, also payable in phantom stock, which are recorded in each Director's phantom account. The value of these accounts is issued in stock or cash, at the election of the Board, at the time the director leaves the Board.

The changes in common stock and additional paid-in capital for 2002, 2001, and 2000, are as follows (dollars in thousands):

	Shares Issued			Amount		
	2002	2001	2000	**2002**	2001	2000
Public Offering	**—**	23,575,000	—	**$ —**	$340,364	$ —
Merger Exchange	**—**	—	—	**—**	—	—
CSIP/DRP	**—**	—	5,389	**—**	—	237
ESPP and Other	**66,873**	60,319	55,268	**455**	361	1,055
	66,873	23,635,319	60,657	**$455**	$340,725	$1,292

Subsequent Events

In January 2003, SPR acquired $8.75 million aggregate principal amount of its Floating Rate Notes due April 20, 2003 in exchange for 1,295,211 shares of its common stock in two privately negotiated transactions exempt from the registration requirements of the Securities Act of 1933.

On February 5, 2003, SPR acquired 2,095,650 of its PIES, including approximately $104.8 million of 7.93% Senior Notes due 2007 that are a component of the PIES, in exchange for 13,662,393 shares of its common stock in five privately negotiated transactions exempt from the registration requirements of the Securities Act of 1933. Of the shares issued in these transactions, 7,565,506 shares represented the then-current conversion value of the PIES.

On February 14, 2003, SPR issued $300 million of its 7.25% Convertible Notes due 2010. Interest on the notes is payable semi-annually in arrears. SPR may redeem some or all of the notes for cash at any time on or after February 14, 2008. SPR used approximately $53.4 million of the proceeds to acquire U.S. Government securities that are pledged to the trustee as security for the notes for the first two and one-half years and which SPR expects to use to pay the first five interest payments on the notes. The proceeds will be used to redeem approximately $133 million of its Floating Rate Notes due April 20, 2003, and for general corporate purposes.

The Convertible Notes will not be convertible prior to August 14, 2003. At any time on or after August 14, 2003 through the close of business February 14, 2010, holders of the Convertible Notes may convert each $1,000 principal amount of their notes into 219.1637 shares of SPR's common stock, subject to adjustment upon the occurrence of certain dilution events. Until SPR has obtained shareholder approval to fully convert the Convertible Notes in shares of common stock, holders of the Convertible Notes will be entitled to receive 76.7073 shares of common stock and a remaining portion in cash based on the trading price of SPR's common stock for a certain period prior to conversion. If SPR does obtain shareholder approval, it may elect to satisfy the cash payment component of the conversion price of the Convertible Notes solely with shares of common stock. SPR has agreed to use reasonable efforts to obtain shareholder approval not later than 180 days after the date of issuance of the Convertible Notes for approval to issue and deliver shares of SPR's common stock in lieu of the cash payment component of the conversion price of the Convertible Notes.

NOTE 8. PREFERRED STOCK AND PREFERRED TRUST SECURITIES

Sierra Pacific Power Company

Preferred Stock

SPPC's Restated Articles of Incorporation, as amended on August 19, 1992, authorize an aggregate amount of 11,780,500 shares of preferred stock at any given time.

SPPC's preferred stock is superior to SPPC's common stock with respect to dividend payments (which are cumulative) and liquidation rights.

On January 30, 2003, a dividend of $975,000 ($0.4875 per share) was declared on SPPC's preferred stock. The dividend is payable on March 1, 2003, to holders of record as of February 14, 2003.

The following table indicates the dollar amount and number of shares of SPPC preferred stock outstanding at December 31 of each year:

	Amount		Shares Outstanding	
(dollars in thousands)	**2002**	2001	**2002**	2001
PREFERRED STOCK				
Not subject to mandatory redemption				
SPPC Class A Series I	**$50,000**	$50,000	**2,000,000**	2,000,000
Total preferred stock	**$50,000**	$50,000	**2,000,000**	2,000,000

Nevada Power Company

Preferred Trust Securities

On April 2, 1997, NVP Capital I (Trust), a wholly owned subsidiary of NPC, issued 4,754,860, 8.2% preferred trust securities (QUIPS) at $25 per security. NPC owns all of the Series A common securities, 147,058 shares issued by the Trust for $3.7 million. The QUIPS and the common securities represent undivided beneficial ownership interests in the assets of the Trust, a statutory business trust formed under the laws of the state of Delaware. The existence of the Trust is for the sole purpose of issuing the QUIPS and the common securities and using the proceeds thereof to purchase from NPC its 8.2% Junior Subordinated Deferrable Interest Debentures (QUIDS) due March 31, 2037, extendible to March 31, 2046, under certain conditions, in a principal amount of $122.6 million. The sole asset of the Trust is the QUIDS. Holders of the Series A QUIPS are entitled to receive preferential cumulative cash distributions accruing from the date of original issuance and payable quarterly on the last day of March, June, September, and December of each year. Interest payments made by NPC in respect of the QUIPS are sufficient to provide the trust with funds to pay the required cash distribution on the QUIPS and the common securities of the trust. The Series A QUIPS are subject to mandatory redemption, in whole or in part, upon repayment of the Series A QUIDS at maturity or their earlier redemption in an amount equal to the amount of related Series A QUIDS maturing or being redeemed. The QUIPS are redeemable at $25 per preferred security plus accumulated and unpaid distributions thereon to the date of redemption. NPC's obligations provide a full and unconditional guarantee of the Trust's obligations under the QUIPS. Financial statements of the Trust are consolidated with NPC's. Separate financial statements are not filed because the Trust is wholly owned by NPC and essentially has no independent operations and NPC's guarantee of the Trust's obligations is full and unconditional. The $118.9 million in net proceeds was used for general corporate utility purposes and the repayment of short-term debt.

NOTES TO FINANCIAL STATEMENTS (continued)

In October 1998, NVP Capital III (Trust), a wholly owned subsidiary of Nevada Power Company, issued 2,800,000, 7.75% Cumulative Trust Issued Preferred Securities (TIPS) at $25 per security. NPC owns the entire common securities, 86,598 shares issued by the Trust for $2.2 million. The TIPS and the common securities represent undivided beneficial ownership interests in the assets of the Trust, a statutory business trust formed under the laws of the state of Delaware. The existence of the Trust is for the sole purpose of issuing the TIPS and the common securities and using the proceeds thereof to purchase from NPC its 7.75% Junior Subordinated Deferrable Interest Debentures due September 30, 2038, extendible to September 30, 2047, under certain conditions, in a principal amount of $72.2 million. The sole asset of the Trust is the deferrable interest debentures. Holders of the TIPS are entitled to receive preferential cumulative cash distributions accruing from the date of original issuance and payable quarterly on the last day of March, June, September and December of each year. Interest payments by NPC in respect of the Junior Subordinated Deferrable Interest Debentures are sufficient to provide the trust with funds to pay the required cash distributions on the TIPS and the common securities of the trust. The TIPS are subject to mandatory redemption, in whole or in part, upon repayment of the deferrable interest debentures at maturity or their earlier redemption in an amount equal to the amount of related deferrable interest debentures maturing or being redeemed. The TIPS are redeemable at $25 per preferred security plus accumulated and unpaid distributions thereon to the date of redemption. NPC's obligations provide a full and unconditional guarantee of the Trust's obligations under the TIPS. Financial statements of the Trust are consolidated with NPC's. Separate financial statements are not filed because the Trust is wholly owned by NPC and essentially has no independent operations and NPC's guarantee of the Trust's obligations is full and unconditional. The $70 million in net proceeds was used for general corporate utility purposes, including the repayment of short-term debt.

The following table indicates the principal amount and number of shares of NPC preferred trust securities outstanding at December 31 of each year:

	Amount		Shares Outstanding	
(dollars in thousands)	**2002**	2001	**2002**	2001
PREFERRED TRUST SECURITIES				
Subject to mandatory redemption				
Preferred securities of Nevada Power Co Capital I	**$118,872**	$118,872	**147,058**	147,058
Preferred securities of Nevada Power Co Capital III	**70,000**	70,000	**86,598**	86,598
Total preferred Trust securities	**$188,872**	$188,872	**233,656**	233,656

Sierra Pacific Resources

SPR has issued neither preferred stock nor preferred trust securities.

NOTE 9. LONG-TERM DEBT

Substantially all utility plant is subject to the liens of NPC's and SPPC's indentures under which their First Mortgage Bonds and General and Refunding Mortgage Bonds are issued.

Nevada Power Company

On May 24, 2001, NPC issued $350 million of its 8.25% General and Refunding Mortgage Bonds, Series A, due June 1, 2011. The bonds were issued with registration rights under and secured by a General and Refunding Mortgage Indenture dated as of May 1, 2001 that is subject to the prior lien of NPC's Indenture of Mortgage dated as of October 1, 1953. On January 29, 2002, NPC exchanged these bonds for identical bonds registered under the Securities Act of 1933.

On June 12, 2001, $150 million of NPC's Floating Rate Notes matured and were paid in full.

On August 20, 2001, $100 million of NPC's Floating Rate Notes matured and were paid in full.

On September 20, 2001, and October 15, 2001, NPC issued an aggregate total of $210 million of 6% Unsecured Notes due September 15, 2003. Interest on the notes is payable on March 15 and September 15 of each year. These notes are not entitled to any sinking fund and are noncallable.

On October 18, 2001, NPC issued $140 million of its General and Refunding Mortgage Notes, Floating Rate, Series B, due October 15, 2003.

On May 13, 2000, NPC issued a General and Refunding Mortgage Bond, Series D, due April 15, 2004, in the principal amount of $130 million, for the benefit of the holders of NPC's 6.20% Senior Unsecured Notes, Series B, due April 15, 2004. The Senior Unsecured Notes Indenture required that in the event that NPC issued debt secured by liens on NPC's operating property in excess of 15% of its Net Tangible Assets or Capitalization (as both terms are defined in the Senior Unsecured Notes Indenture), NPC would equally and ratably secure the Senior Unsecured Notes. NPC triggered this negative pledge covenant on April 23, 2002, when it borrowed certain amounts under its secured credit facility.

On October 25, 2002 NPC redeemed its 7⅝% Series L, First Mortgage Bonds in the aggregate principal amount of $15 million.

On October 29, 2002, NPC issued and sold $250 million of its 10⅞% General and Refunding Mortgage Notes, Series E, due 2009 for net proceeds of $235.6 million. The Series E Notes, which were issued with registration rights, were exchanged for registered notes in January 2003. The proceeds of the issuance were used to pay off NPC's $200 million credit facility and for general corporate purposes. The Series E Notes will mature October 15, 2009.

As discussed in Note 13, Dividend Restrictions, NPC's Series E Notes limit the amount of dividends that NPC may pay to SPR. The terms of the Series E Notes also restrict NPC from incurring any additional indebtedness unless (i) at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for NPC's most recently ended four-quarter period on a pro forma basis is at least 2 to 1, or (ii) the debt incurred is specifically permitted, which includes certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, and certain letters of credit issued to support NPC's obligations with respect to energy suppliers.

If NPC's Series E Notes are upgraded to investment grade by both Moody's and S&P, the dividend restrictions and the restrictions on indebtedness applicable to the Series E Notes will be suspended and will no longer be in effect so long as the Series E Notes remain investment grade.

Among other things, the Series E Notes also contain restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. In the event of a change of control of NPC, the holders of Series E Notes are entitled to require that NPC repurchase the Series E Notes for a cash payment equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

Sierra Pacific Power Company

On April 27, 2001, Washoe County, Nevada, issued for SPPC's benefit $80 million of Water Facilities Refunding Revenue Bonds, Series 2001, due March 1, 2036. The bonds bear interest at a term rate of 5.75% per annum from their date of issuance to April 30, 2003. Beginning May 1, 2003, the method of determining the interest rate on the bonds may be converted from time to time in accordance with the related Indenture so that such bonds would, thereafter, bear interest at a daily, weekly, flexible, term or auction rate. The bonds were issued to refund $80 million of Washoe County variable rate Water Facilities Revenue Bonds (Sierra Pacific Power Company Project) Series 1990 on April 30, 2001. On June 11, 2001, SPPC completed the sale of its water business assets including the Project financed by the sale of the bonds. Although SPPC no longer owns the Project, SPPC will continue to bear the obligations and payments for the bonds under the terms of the Financing Agreement dated as of March 1, 2001, between SPPC and Washoe County, Nevada. These bonds will be subject to remarketing on May 1, 2003. In the event that these bonds cannot be successfully remarketed, SPPC will be required to purchase the outstanding bonds at a price of 100% of the principal amount, plus accrued interest.

On May 24, 2001, SPPC issued $320 million of its 8.00% General and Refunding Mortgage Bonds, Series A, due June 1, 2008. The bonds were issued with registration rights under and secured by a General and Refunding Mortgage Indenture dated as of May 1, 2001 that is subject to the prior lien of SPPC's Indenture of Mortgage dated as of December 1, 1940. On January 29, 2002, SPPC exchanged these bonds for identical bonds, registered under the Securities Act of 1933.

On June 12, 2001, $200 million of SPPC's Floating Rate Notes matured and were paid in full. The Floating Rate Notes were issued on June 9, 2000, and the net proceeds of the $200 million issue were used to redeem $100 million of Floating Rate Notes on July 14, and the remaining proceeds were used to reduce the amount of SPPC's commercial paper outstanding under the program established in July 1999.

On December 17, 2001, $17 million of SPPC's MTN Series D matured and were paid in full.

On May 23, 2002, SPPC satisfied its obligations with respect to its 2% First Mortgage Bonds due 2011, 5% Series Y First Mortgage Bonds due 2024, and 2% Series Z First Mortgage Bonds due 2004 by depositing $1.2 million, $3.1 million, and $45,000, respectively, with its First Mortgage Trustee. These First Mortgage Bonds were issued to secure loans made to SPPC by the United States under the Rural Electrification Act of 1936, as amended.

On October 30, 2002, SPPC entered into a $100 million Term Loan Agreement with several lenders and Lehman Commercial Paper Inc., as Administrative Agent. The net proceeds of $97 million from the Term Loan Facility, along with available cash, were used to pay off SPPC's $150 million credit facility, which was secured by a $150 million Series B General and Refunding Mortgage Bond.

As discussed in Note 13, Dividend Restrictions, SPPC's Term Loan Agreement limits the amount of dividends that SPPC may pay to SPR. SPPC's Term Loan Agreement also requires that SPPC maintain a ratio of consolidated total debt to consolidated total capitalization at all times during each of the following quarters in an amount not to exceed (i) .650 to 1.0 for the fiscal quarters ended December 31, 2002 through December 31, 2003, (ii) .625 to 1.0 for the fiscal quarters ended March 31, 2004, through December 31, 2004, and (iii) .600 to 1.0 for the fiscal quarter ended March 31, 2005, and for each fiscal quarter thereafter. SPPC's Term Loan Agreement also requires that SPPC maintain a consolidated interest coverage ratio for any four consecutive fiscal quarters ending with the fiscal quarter set forth below of not less than (i) 1.75 to 1.00 for the fiscal quarters ended December 31, 2002, and March 31, 2003, (ii) 2.50 to 1.0 for the fiscal quarters ended June 30, 2003, through December 31, 2003, (iii) 2.75 to 1.0 for the fiscal quarters ended March 31, 2004 through September 30, 2004, and (iv) 3.00 to 1.0 for the fiscal quarter ended December 31, 2004 and for each fiscal quarter thereafter. As of December 31, 2002, SPPC was in compliance with these financial covenants. The Term Loan Facility, which is secured by a $100 million Series C General and Refunding Mortgage Bond, will expire October 31, 2005.

NOTES TO FINANCIAL STATEMENTS (continued)

Sierra Pacific Resources

On November 16 and 21, 2001, SPR issued an aggregate of $345 million senior unsecured notes in connection with the public offering of 6,900,000 of its Corporate PIES. Each Corporate PIES unit consists of a forward stock purchase contract and a senior unsecured note issued by SPR with a face amount of $50. The senior notes are pledged as collateral to secure each holder's obligation to purchase shares of SPR common stock under the stock purchase contract. The senior note may be released from the pledge arrangement if a holder opts to create Treasury PIES by delivering a like principal amount of U.S. Treasury securities to the Securities Intermediary in substitution for the senior notes.

Each stock purchase contract obligates the holder to purchase SPR common stock on or before November 15, 2005, the Purchase Contract Settlement Date. The number of shares each investor is entitled to receive will depend on the average closing price of SPR common stock over a 20-day trading period prior to the settlement. See further discussion regarding the forward stock purchase contract at Note 7, Common Stock And Other Paid-In Capital.

Each holder of Corporate PIES is entitled to receive quarterly payments consisting of purchase contract adjustment payments and interest on the senior unsecured notes. The Corporate PIES have a combined rate of 9.0%, which is comprised of the coupon on the senior note of 7.93% and the stated rate of the purchase contract adjustment payments of 1.07%. Interest on the senior unsecured notes began to accrue on November 16, 2001, and quarterly interest payments will be made each quarter beginning with the first payment, which was made on February 15, 2002. All senior unsecured notes will be remarketed beginning on August 10, 2005, up to and including November 1, 2005, and, if necessary, on November 9, 2005, unless holders of senior notes that are not part of a Corporate PIES elect not to have their senior notes remarketed. Upon remarketing, the interest rate will be reset and the senior notes will accrue interest at the reset rate after the remarketing settlement date. Prior to the Purchase Contract Settlement Date, holders of Corporate PIES have the option to pay $50 per Corporate PIES to settle their purchase contract obligations. If the holders do not elect to make a cash payment, the proceeds from the remarketing of the senior notes will be used to satisfy their purchase contract obligations. If any senior notes remain outstanding after the Purchase Contract Settlement Date, SPR will pay interest payments on those senior notes until their maturity on November 15, 2007.

Purchase contract adjustment payments will accrue from November 16, 2001. Holders received the first quarterly purchase contract adjustment payments of $0.1323 per unit ($913,000 in aggregate) on February 15, 2002, and will receive payments of $0.1338 per unit ($923,000 in aggregate) for each subsequent quarter. Upon issuance, a liability for the present value of the purchase contract adjustment payments, approximately $13.7 million, was recorded in Other Deferred Credits, with a corresponding reduction to Other Paid-In Capital. As of December 31, 2002, the purchase contract adjustment payment liability was $10.5 million.

On April 20, 2002, $100 million of SPR's Floating Rate Notes matured and were paid in full.

In January 2003, SPR acquired $8,750,000 aggregate principal amount of its Floating Rate Notes due April 20, 2003 in exchange for 1,295,211 shares of its common stock in two privately negotiated transactions exempt from the registration requirements of the Securities Act.

On February 5, 2003, SPR acquired 2,095,650 of PIES including approximately $104.8 million of 7.93% Senior Notes due 2007 that are a component of the PIES, in exchange for 13,662,393 shares of its common stock in five privately negotiated transactions exempt from the registration requirements of the Securities Act.

On February 14, 2003, SPR issued $300 million of its 7.25% Convertible Notes due 2010. Interest on the notes is payable semi-annually. SPR may redeem some or all of the notes at any time on or after February 14, 2008. SPR used approximately $53.4 million of the proceeds to acquire U.S. Government securities that are pledged to the trustee as security for the notes for the first two and one-half years and which SPR expects to use to pay the first five interest payments on the notes. The proceeds will be used to redeem approximately $133 million of its Floating Rate Notes due April 20, 2003 and for general corporate purposes. See Note 7, Common Stock and Other Paid-In Capital for additional information regarding the terms of the Convertible Notes.

The indenture under which the Convertible Notes were issued does not contain any financial covenants or any restrictions on the payment of dividends, the repurchase of SPR's securities or the incurrence of indebtedness. The indenture does allow the holders of the Convertible Notes to require SPR to repurchase all or a portion of the holders' Convertible Notes upon a change of control. The indenture also provides for an event of default if SPR or any of its significant subsidiaries, including NPC and SPPC, fails to pay any indebtedness in excess of $10 million or has any indebtedness of $10 million or more accelerated and declared due and payable.

Sierra Pacific Communications

Sierra Touch America LLC (STA), a partnership between SPC and Touch America, formerly Montana Power Company, was formed to construct a fiber-optic line between Salt Lake City, Utah and Sacramento, CA.

On September 9, 2002, SPC entered into an agreement to purchase and lease certain telecommunications and fiber-optic assets from Touch America, subject to successful completion of the construction, in exchange for SPC's partnership units in Sierra Touch America and the execution of a $35 million promissory note for a total purchase price of $48.5 million. The promissory note accrues interest at 8% per annum. The first of twelve monthly payments of $3.3 million will commence on July 31, 2003 and continue until June 30, 2004, at which time all outstanding amounts will be due and payable. The promissory note is secured by all of SPC's assets, and prepayments will shorten the length of the loan but not reduce the installment payments.

As of December 31, 2002, NPC's, SPPC's, and SPR's aggregate annual amount of maturities for long-term debt (including obligations related to capital leases) for the next five years is shown below (in thousands of dollars):

	NPC	SPPC	SPR Holding Co. and Other Subs	SPR Consolidated
2003	$ 354,677	$ 101,400	$216,886	$ 672,963
2004	135,570	3,400	14,498	153,468
2005	6,091	100,400	300,000	406,491
2006	6,509	52,400	—	58,909
2007	5,949	2,400	345,000	353,349
	508,796	260,000	876,384	1,645,180
Thereafter	1,348,384	760,250	0	2,108,634
	1,857,180	1,020,250	876,384	3,753,814
Unamortized (Disc.)/Prem.	(13,906)	(4,062)	—	(17,968)
Total	$1,843,274	$1,016,188	$876,384	$3,735,846

The preceding table includes obligations related to the following capital lease obligations.

In 1984, NPC sold its administrative headquarters facility, less furniture and fixtures, for $27 million and entered into a 30-year capital lease of that facility with five-year renewal options beginning in year 31. The fixed rental obligation for the first 30 years is $5.1 million per year. Also, NPC has a purchase power contract with Nevada Sun-Peak Limited Partnership. The contract contains a buyout provision for the facility at the end of the contract term in 2016. The facility is situated on NPC property.

Future cash payments for these leases, combined, as of December 31, 2002, were as follows (dollars in thousands):

2003	$ 4,664
2004	5,557
2005	6,076
2006	6,494
2007	5,932
Thereafter	44,536

NOTE 10. TAXES

Sierra Pacific Resources

The following reflects the composition of taxes on income (in thousands of dollars):

	2002	2001	2000
As Reflected in Statement of Income			
Federal income taxes	**$(168,498)**	$ 1,934	$(31,468)
State income taxes	**—**	(3,164)	446
Federal income taxes on operating income	**(168,498)**	(1,230)	(31,022)
Other income—net	**4,058**	14,870	511
Total	**$(164,440)**	$13,640	$(30,511)

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons (in thousands of dollars):

	2002	2001	2000
Income (loss) from continuing operations	**$(302,055)**	$33,566	$(45,915)
Total income tax expense (benefit)	**(164,440)**	13,640	(30,511)
	(466,495)	47,206	(76,426)
Statutory tax rate	**35%**	35%	35%
Expected income tax expense (benefit)	**(163,273)**	16,522	(26,749)
Depreciation related to difference in costs basis for tax purposes	**3,081**	2,944	2,962
Allowance for funds used during construction—equity	**112**	85	151
Tax benefit from the disposition of assets	**(48)**	(111)	(175)
ITC amortization	**(3,454)**	(3,454)	(1,824)
State taxes (net of federal benefit)	**—**	(2,057)	(1,170)
Pension benefit plan	**1,400**	697	887
Other—net	**(2,258)**	(986)	(4,593)
	$(164,440)	$13,640	$(30,511)
Effective tax rate	**35.3%**	28.9%	39.9%

The net accumulated deferred federal income tax liability consists of accumulated deferred federal income tax liabilities less related accumulated deferred federal income tax assets, as shown (in thousands of dollars):

	2002	2001
Deferred Federal Income Tax Liabilities:		
Allowance for funds used during construction—debt	**$ 16,281**	$ 12,496
Bond redemptions	**11,132**	11,508
Excess of tax depreciation over book depreciation	**555,811**	401,358
Severance programs	**5,019**	5,299
Tax benefits flowed through to customer	**163,889**	169,738
Deferred energy	**339,640**	430,812
Ad Valorem taxes	**3,336**	172
Other	**18,289**	23,706
	1,113,397	1,055,089
Deferred Federal Income Tax Assets:		
Net operating loss carryforward	**281,866**	189,238
Avoided interest capitalized	**32,319**	23,661
Employee benefit plans	**13,421**	12,006
Reserve for bad debt	**15,121**	13,761
Contributions in aid of construction and customer advances	**109,877**	104,395
Gross-ups received on contribution in aid of construction and customer advances	**16,665**	11,976
Excess deferred income taxes	**16,460**	18,656
Unamortized investment tax credit	**26,258**	28,046
Other accumulated comprehensive income—additional minimum pension liability	**24,905**	—
Contract termination reserve	**109,408**	—
Other	**7,446**	(882)
	653,746	400,857
Total	**$ 459,651**	$ 654,232

NOTES TO FINANCIAL STATEMENTS (continued)

SPR's balance sheets contain a net regulatory asset of $121.3 million at year-end 2002 and $123.0 million at year-end 2001. The net regulatory asset consists of future revenue to be received from customers (a regulatory asset) of $163.9 million at year-end 2002 and $169.7 million at year-end 2001, due to flow-through of the tax benefits of temporary differences. Offset against these amounts are future revenues to be refunded to customers (a regulatory liability), consisting of $16.5 million at year-end 2002 and $18.7 million at year-end 2001, due to temporary differences for liberalized depreciation at rates in excess of current tax rates, and $26.2 million at year-end 2002 and $28.0 million at year-end 2001 due to unamortized investment tax credits. The regulatory liability for temporary differences related to liberalized depreciation will continue to be amortized using the average rate assumption method required by the Tax Reform Act of 1986. The regulatory liability for temporary differences caused by the investment tax credit will be amortized ratably in the same fashion as the accumulated deferred investment credit. In addition, certain items of deferred taxes represent positive cash flows to SPR. These items reduce rate base and, therefore, are benefits passed through to customers. However, because SPR had a net operating loss for tax purposes in 2001 and 2002, some of this benefit could not be utilized (i.e., deferred energy).

In March 2002, NPC received a federal income tax refund of $79.3 million. Additionally, SPR and the Utilities received $105.7 million of refunds in the second quarter of 2002. These refunds were the result of income tax losses generated in 2001. Federal legislation passed in March 2002 changed the allowed carryback of these losses from two years to five years. This change permitted SPR and the Utilities to accelerate the receipt of a portion of their income tax receivables sooner than expected. The remaining income tax losses of $281.9 million as of December 31, 2002, may be utilized in future periods to reduce taxes payable to the extent that SPR and the Utilities recognize taxable income. The carryforward period for net operating losses incurred is 20 years, and as such the losses incurred in the years ended December 31, 2000, 2001, and 2002 will expire in 2020, 2021, and 2022 respectively.

For the year 2000, all inter-company income tax-related payables and receivables due to/from affiliates were paid in full as of December 31, 2000. For the year 2001, SPR owed the following income tax-related balances to affiliates: SPPC, $62.1 million and NPC, $18.6 million. For the year 2001, SPR had a receivable from all other subsidiaries of $8.5 million. There were no income tax-related inter-company payables and receivables due to/from affiliates for the year ended December 31, 2002.

The consolidated amount of current and deferred tax expense is allocated among SPR and its subsidiaries on a pro-rata based on separate company taxable income. Any benefit or detriments associated with the consolidation of the income tax return are also allocated pro-rata basis on separate company taxable income.

As a large corporate taxpayer, the SPR consolidated group's tax returns are examined by the Internal Revenue Service on a regular basis. The IRS began an audit of the company's consolidated income tax returns in the third quarter of 2002. The years under examination include the separate company returns for NPC and its subsidiaries for 1997 and 1998 and the consolidated returns for SPR and its subsidiaries for 1997 through 2001. The focus of the examination is the net operating losses generated in 2000 and 2001 and carried back to earlier years. The losses reported in 2000 and 2001 are mainly due to the deductions claimed for purchased fuel and purchase power.

The losses claimed on the tax returns are mainly timing differences, and as such are not expected to cause a material impact on SPR's, NPC's, or SPPC's future income statements if it is determined they are allowable in a subsequent period. No Notices of Proposed Adjustment have been received to date.

Nevada Power Company

The following reflects the composition of taxes on income (in thousands of dollars):

	2002	2001	2000
As Reflected in Statement of Income			
Federal income taxes	**$(133,411)**	$18,715	$(12,162)
State income taxes	**—**	(940)	—
Federal income tax on operating income	**(133,411)**	17,775	(12,162)
Other income (expense)	**1,627**	14,962	1,201
Total	**$(131,784)**	$32,737	$(10,961)

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons (in thousands of dollars):

	2002	2001	2000
Income (loss) from continuing operations	**$(235,070)**	$63,405	$ (7,928)
Total income tax expense	**(131,784)**	32,737	(10,961)
	(366,854)	96,142	(18,889)
Statutory tax rate	**35%**	35%	35%
Expected income tax expense	**(128,399)**	33,650	(6,611)
Depreciation related to difference in costs basis for tax purposes	**1,431**	1,431	1,431
Allowance for funds used during construction—equity	**153**	383	300
Tax benefit from the disposition of assets	**—**	—	—
State taxes (net of federal benefit)	**—**	(611)	—
ITC amortization	**(1,630)**	(1,630)	(1,460)
Other—net	**(3,339)**	(486)	(4,621)
	$(131,784)	$32,737	$(10,961)
Effective tax rate	**35.9%**	34.1%	58.0%

The net accumulated deferred federal income tax liability consists of accumulated deferred federal income tax liabilities less related accumulated deferred federal income tax assets, as shown (in thousands of dollars):

	2002	2001
Deferred Federal Income Tax Liabilities:		
Allowance for funds used during construction—debt	**$ 9,238**	$ 7,659
Bond redemptions	**5,170**	5,460
Excess of tax depreciation over book depreciation	**304,002**	212,969
Severance programs	**2,606**	1,982
Tax benefits flowed through to customer	**106,070**	109,859
Deferred energy	**257,614**	343,023
Ad Valorem taxes	**3,336**	172
Other—net	**5,969**	5,559
	694,005	686,683
Deferred Federal Income Tax Assets:		
Net operating loss carryforward	**250,054**	211,504
Avoided interest capitalized	**15,202**	11,217
Employee benefit plans	**9,025**	8,555
Reserve for bad debt	**11,501**	10,801
Contributions in aid of construction and customer advances	**72,018**	69,232
Gross-ups received on contribution in aid of construction and customer advances	**11,054**	6,514
Excess deferred income taxes	**5,360**	5,859
Unamortized investment tax credit	**11,940**	12,745
Other accumulated comprehensive income—additional minimum pension liability	**4,838**	—
Contract termination reserve	**79,036**	—
Other—net	**3,674**	(4,904)
	473,702	331,523
Total	**$220,303**	$355,160

NPC's balance sheets contain a net regulatory asset of $88.8 million at year-end 2002 and $91.3 million at year-end 2001. The net regulatory asset consists of future revenue to be received from customers (a regulatory asset) of $106.1 million at year-end 2002 and $109.9 million at year-end 2001 due to flow-through of the tax benefits of temporary differences. Offset against this amount are future revenues to be refunded to customers (a regulatory liability), consisting of $5.4 million at year-end 2002 and $5.9 million at year-end 2001 due to temporary differences for liberalized depreciation at rates in excess of current tax rates, and $11.9 million at year-end 2002 and $12.7 million at year-end 2001 due to unamortized investment tax credits. The regulatory liability for temporary differences related to liberalized depreciation will continue to be amortized using the average rate assumption method required by the Tax Reform Act of 1986. The regulatory liability for temporary differences caused by the investment tax credit will be amortized ratably in the same fashion as the accumulated deferred investment credit. In addition, certain items of deferred taxes represent positive cash flows to NPC. These items reduce rate base and therefore are benefits passed through to customers. However, because NPC had a net tax operating loss in 2002, some of this benefit could not be utilized (i.e., deferred energy).

Sierra Pacific Power Company

The following reflects the composition of taxes on income (in thousands of dollars):

	2002	2001	2000
As Reflected in Statement of Income			
Federal income taxes	**$(6,922)**	$10,731	$(1,118)
State income taxes	**—**	(2,224)	446
Federal Income Tax on Operating Income:	**(6,922)**	8,507	(672)
Other income—net	**2,431**	(91)	(690)
Total	**$(4,491)**	$ 8,416	$(1,362)

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons (in thousands of dollars):

	2002	2001	2000
Income (loss) from continuing operations before preferred dividend requirements	**$(13,968)**	$22,743	$(4,077)
Total income tax expense	**(4,491)**	8,416	(1,362)
	(18,459)	31,159	(5,439)
Statutory tax rate	**35%**	35%	35%
Expected income tax expense	**(6,461)**	10,906	(1,904)
Depreciation related to difference in costs basis for tax purposes	**1,650**	1,513	1,531
Allowance for funds used during construction—equity	**(40)**	(298)	(149)
Tax benefit from the disposition of assets	**(48)**	(111)	(175)
ITC amortization	**(1,824)**	(1,824)	(1,824)
State taxes (net of federal benefit)	**—**	(1,446)	290
Pension benefit plan	**1,400**	697	887
Other—net	**832**	(1,021)	(18)
	$ (4,491)	$ 8,416	$(1,362)
Effective tax rate	**24.3%**	27.0%	25.0%

NOTES TO FINANCIAL STATEMENTS (continued)

The net accumulated deferred federal income tax liability consists of accumulated deferred federal income tax liabilities less related accumulated deferred federal income tax assets, as shown (in thousands of dollars):

	2002	2001
Deferred Federal Income Tax Liabilities:		
Allowance for funds used during construction—debt	**$ 7,043**	$ 4,837
Bond redemptions	**5,962**	6,048
Excess of tax depreciation over book depreciation	**251,809**	188,389
Severance programs	**2,413**	3,317
Tax benefits flowed through to customer	**57,818**	59,879
Deferred energy	**82,026**	87,790
Other	**5,801**	28,732
	412,872	378,992
Deferred Federal Income Tax Assets:		
Net operating loss carryforward	**237**	—
Avoided interest capitalized	**17,117**	12,444
Employee benefit plans	**4,396**	3,451
Reserve for bad debt	**3,620**	2,960
Contributions in aid of construction and customer advances	**37,859**	35,163
Gross-ups received on contribution in aid of construction and customer advances	**5,611**	5,462
Excess deferred income taxes	**11,100**	12,797
Unamortized investment tax credit	**14,318**	15,301
Other accumulated comprehensive income—additional minimum pension liability	**350**	—
Contract termination reserve	**30,372**	—
Other	**3,514**	4,022
	128,494	91,600
Accumulated deferred federal income taxes	**$284,378**	$287,392

SPPC's balance sheets contain a net regulatory asset of $32.4 million at year-end 2002 and $31.8 million at year-end 2001. The net regulatory asset consists of future revenue to be received from customers (a regulatory asset) of $57.8 million at year-end 2002 and $59.9 million at year-end 2001 due to flow-through of the tax benefits of temporary differences. Offset against this amount are future revenues to be refunded to customers (a regulatory liability) consisting of $11.1 million at year-end 2002 and $12.8 million at year-end 2001 due to temporary differences for liberalized depreciation at rates in excess of current tax rates, and $14.3 million at year-end 2002 and $15.3 million at year-end 2001 due to unamortized investment tax credits. The regulatory liability for temporary differences related to liberalized depreciation will continue to be amortized using the average rate assumption method required by the Tax Reform Act of 1986. The regulatory liability for temporary differences caused by the investment tax credit will be amortized ratably in the same fashion as the accumulated deferred investment credit. In addition, certain items of deferred taxes represent positive cash flows to SPPC. These items reduce rate base and therefore are benefits passed through to customers. However, because SPPC had a net operating loss for tax purposes in 2001 and 2002, some of this benefit could not be utilized (i.e., deferred energy).

NOTE 11. FAIR VALUE OF FINANCIAL INSTRUMENTS

The December 31, 2002, carrying amount for cash and cash equivalents, current assets, accounts receivable, accounts payable, and current liabilities approximates fair value due to the short-term nature of these instruments.

The total fair value of NPC's consolidated long-term debt at December 31, 2002, is estimated to be $1.298 billion (excluding current portion) based on quoted market prices for the same or similar issues or on the current rates offered to NPC for debt of the same remaining maturities. The total fair value (excluding current portion) was estimated to be $1.56 billion at December 31, 2001. The estimated fair value of NPC's preferred trust securities is $139.8 million at December 31, 2002. The fair value of NPC's preferred securities was estimated to be $181.5 million at December 31, 2001.

The total fair value of SPPC's consolidated long-term debt at December 31, 2002, is estimated to be $851.5 million (excluding current portion) based on quoted market prices for the same or similar issues or on the current rates offered to SPPC for debt of the same remaining maturities. The total fair value (excluding current portion) was estimated to be $946.5 million as of December 31, 2001. SPPC's preferred trust securities were redeemed on November 29, 2001.

The total fair value of SPR's consolidated long-term debt at December 31, 2002, is estimated to be $2.66 billion (excluding current portion) based on quoted market prices for the same or similar issues or on the current rates offered to SPR for debt of the same remaining maturities. The total fair value (excluding current portion) was estimated to be $3.386 billion as of December 31, 2001. The estimated fair value of SPR's consolidated preferred trust securities is $139.8 million at December 31, 2002. The fair value of SPR's consolidated preferred trust securities was estimated to be $181.5 million at December 31, 2001.

NOTE 12. SHORT-TERM BORROWINGS

Sierra Pacific Resources

On April 3, 2002, SPR terminated its $75 million unsecured revolving credit facility in connection with the amendment of NPC's $200 million unsecured revolving credit facility, discussed below.

Nevada Power Company

On November 29, 2001, NPC put into place a $200 million unsecured revolving credit facility for working capital and general corporate purposes, including commercial paper back-up. As a result of NPC's rate case decisions (discussed in Note 3, Regulatory Events) and the credit downgrades by S&P and Moody's, which occurred on March 29 and April 1, 2002, respectively, the banks participating in NPC's credit facility determined that a material adverse event had occurred with respect to NPC, thereby precluding NPC from borrowing funds under its credit facility. The banks agreed to waive the consequences of the material adverse event in a waiver letter and amendment that was executed on April 3, 2002. As required under the waiver letter and amendment, NPC issued and delivered its General and Refunding Mortgage Bond, Series C, due November 28, 2002, in the principal amount of $200 million, to the Administrative Agent for the credit facility.

As of September 30, 2002, NPC had borrowed the entire $200 million of funds available under its credit facility at an average interest rate of 3.72%.

On October 30, 2002, NPC paid in full and terminated its $200 million credit facility and retired its Series C General and Refunding Mortgage Bond, which secured the credit facility, with the proceeds from the issuance of NPC's $250 million aggregate principal amount of 10⅞% General and Refunding Notes, Series E, due 2009.

On October 29, 2002, NPC established an accounts receivable purchase facility of up to $125 million, which was arranged by Lehman Brothers. If NPC elects to activate the receivables purchase facility, NPC will sell all of its accounts receivable generated from the sale of electricity to customers to its newly created bankruptcy remote special purchase subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of the sale. The subsidiary will, in turn, sell the receivables to a bankruptcy remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables. Lehman Brothers Holding, Inc. will be the sole initial committed purchaser of all of the variable rate revolving notes. The agreements relating to the receivables purchase facility contain various conditions to purchase, covenants and trigger events, termination events, and other provisions customary in receivables transactions. In connection with NPC's receivables facility, SPR has agreed to guaranty NPC's performance of certain obligations as a seller and servicer under the facility.

NPC has agreed to issue $125 million principal amount of its General and Refunding Mortgage Bond upon activation of the accounts receivables purchase facility. The full principal amount of the Bond would secure certain of NPC's obligations as seller and servicer, plus certain interest, fees, and expenses thereon to the extent not paid when due, regardless of the actual amounts owing with respect to the secured obligations. As a result, in the event of an NPC bankruptcy or liquidation, the holder of the Bond securing the receivables facility may recover more on a pro rata basis than the holders of other General and Refunding Mortgage Securities, who could recover less on a pro rata basis than they otherwise would recover. However, in no event will the holder of the Bond recover more than the amount of obligations secured by the Bond.

NPC intends to use the accounts receivables purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. NPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $125 million General and Refunding Mortgage Bond. As of December 31, 2002, this facility has not been activated. NPC does not expect to activate this facility in the foreseeable future.

Sierra Pacific Power Company

On November 29, 2001, SPPC put into place a $150 million unsecured revolving credit facility for working capital and general corporate purposes, including commercial paper back-up. Under this credit facility, SPPC was required, in the event of a ratings downgrade of its senior unsecured debt, to secure the facility with General and Refunding Mortgage Bonds. In satisfaction of its obligation to secure the credit facility, on April 8, 2002, SPPC issued and delivered its General and Refunding Mortgage Bond, Series B, due November 28, 2002, in the principal amount of $150 million, to the Administrative Agent for the credit facility.

As of September 30, 2002, SPPC had borrowed the entire $150 million of funds available under its credit facility to, in part, pay off maturing commercial paper and to maintain a cash balance at SPPC at an average interest rate of 3.69%.

On October 31, 2002, SPPC paid off and terminated its $150 million credit facility and retired its Series B General and Refunding Mortgage Bond which secured the credit facility, with a combination of cash on hand and proceeds from its $100 million Term Loan Facility.

NOTES TO FINANCIAL STATEMENTS (continued)

On October 29, 2002, SPPC established an accounts receivable purchase facility of up to $75 million, which was arranged by Lehman Brothers. If SPPC elects to activate the receivables purchase facility, SPPC will sell all of its accounts receivable generated from the sale of electricity to customers to its newly created bankruptcy-remote special purpose subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiary will, in turn, sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables. Lehman Brothers Holdings, Inc., will be the sole initial committed purchaser of all of the variable rate revolving notes. The agreements relating to the receivables purchase facility contain various conditions to purchase, covenants and trigger events, termination events, and other provisions customary in receivables transactions. In connection with SPPC's receivables facility, SPR has agreed to guaranty SPPC's performance of certain obligations as a seller and servicer under the facility.

SPPC has agreed to issue $75 million principal amount of its General and Refunding Mortgage Bonds upon activation of the accounts receivables purchase facility. The full principal amount of the Bond would secure certain of SPPC's obligations as seller and servicer, plus certain interest, fees, and expenses thereon to the extent not paid when due, regardless of the actual amounts owing with respect to the secured obligations. As a result, in the event of an SPPC bankruptcy or liquidation, the holder of the Bond securing the receivables facility may recover more on a pro rata basis than the holders of other General and Refunding Mortgage Securities, who could recover less on a pro rata basis than they otherwise would recover. However, in no event will the holder of the Bond recover more than the amount of obligations secured by the Bond.

SPPC intends to use the accounts receivables purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. SPPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $75 million General and Refunding Mortgage Bond. As of December 31, 2002, this facility has not been activated.

NOTE 13. DIVIDEND RESTRICTIONS

Since SPR is a holding company, substantially all of its cash flow is provided by dividends paid to SPR by NPC and SPPC on their common stock, all of which is owned by SPR. Since NPC and SPPC are public utilities, they are subject to regulation by state utility commissions which may impose limits on investment returns or otherwise impact the amount of dividends that the Utilities may declare and pay, and to federal statutory limitation on the payment of dividends. In addition, certain agreements entered into by the Utilities set restrictions on the amount of dividends they may declare and pay and restrict the circumstances under which such dividends may be declared and paid. The specific restrictions on dividends contained in agreements to which NPC and SPPC are party, as well as specific regulatory limitations on dividends, are summarized below.

Nevada Power Company

First Mortgage Indenture. NPC's first mortgage indenture limits the cumulative amount of dividends and other distributions that NPC may pay on its capital stock to the cumulative net earnings of NPC since 1953, subject to adjustments for the net proceeds of sales of capital stock since 1953. At the present time, this restriction precludes NPC from making further payments of dividends on NPC's common stock and will continue to bar dividends until NPC, over time, generates sufficient earnings to eliminate the deficit under this provision (which was approximately $237 million as of December 31, 2002), unless the restriction is earlier waived, amended, or removed by the consent of the first mortgage bondholders, or the first mortgage bonds are redeemed or defeased. Under this provision, NPC continues to have capacity to repurchase or redeem shares of its capital stock.

Series E Notes. NPC's 10⅞% General and Refunding Mortgage Notes, Series E, due 2009, which were issued on October 29, 2002, limit the amount of payments in respect of common stock that NPC may pay to SPR. However, that limitation does not apply to payments by NPC to enable SPR to pay its reasonable fees and expenses (including, but not limited to, interest on SPR's indebtedness and payment obligations on account of SPR's Premium Income Equity Securities (PIES)) provided that:

- those payments do not exceed $60 million for any one calendar year,
- those payments comply with any regulatory restrictions then applicable to NPC, and
- the ratio of consolidated cash flow to fixed charges for NPC's most recently ended four full fiscal quarters immediately preceding the date of payment is at least 1.75 to 1.

The terms of the Series E Notes also permit NPC to make payments to SPR in an aggregate amount not to exceed $15 million from the date of the issuance of the Series E Notes. In addition, NPC may make dividend payments to SPR in excess of the amounts described above so long as, at the time of payment and after giving effect to the payment:

- there are no defaults or events of default with respect to the Series E Notes,
- NPC can meet a fixed charge coverage ratio test, and
- the total amount of such dividends is less than:
  - the sum of 50% of NPC's consolidated net income measured on a quarterly basis cumulative of all quarters from the date of issuance of the Series E Notes, plus
  - 100% of NPC's aggregate net cash proceeds from the issuance or sale of certain equity or convertible debt securities of NPC, plus
  - the lesser of cash return of capital or the initial amount of certain restricted investments, plus
  - the fair market value of NPC's investment in certain subsidiaries.

If NPC's Series E Notes are upgraded to investment grade by both Moody's Investors Service, Inc. (Moody's) and Standard & Poor's Rating Group, Inc. (S&P), these dividend restrictions will be suspended and will no longer be in effect so long as the Series E Notes remain investment grade.

Accounts Receivable Facility. On October 29, 2002, NPC established an accounts receivable purchase facility. The agreements relating to the receivables purchase facility contain various conditions, including a limitation on the payment of dividends by NPC to SPR that is identical to the limitation contained in NPC's General and Refunding Mortgage Notes, Series E, described above.

Preferred Trust Securities. The terms of NPC's preferred trust securities provide that no dividends may be paid on NPC's common stock if NPC has elected to defer payments on the junior subordinated debentures issued in conjunction with the preferred trust securities. At this time, NPC has not elected to defer payments on the junior subordinated debentures.

PUCN Order. The PUCN issued a Compliance Order, Docket No. 02-4037, on June 19, 2002, relating to NPC's request for authority to issue long-term debt. The PUCN order requires that, until such time as the order's authorization expires (December 31, 2003), NPC must either receive the prior approval of the PUCN or reach an equity ratio of 42% before paying any dividends to SPR. If NPC achieves a 42% equity ratio prior to December 31, 2003, the dividend restriction ceases to have effect. As of December 31, 2002, NPC's equity ratio was 36.1%.

Federal Power Act. NPC is subject to the provisions of the Federal Power Act that state that dividends cannot be paid out of funds that are properly included in capital account. Although the meaning of this provision is not clear, it could be interpreted to impose an additional material limitation on a utility's ability, in the absence of retained earnings, to pay dividends.

Sierra Pacific Power Company

Term Loan Agreement. SPPC's Term Loan Agreement dated October 30, 2002, which expires October 31, 2005, limits the amount of dividends that SPPC may pay to SPR. However, that limitation does not apply to payments by SPPC to enable SPR to pay its reasonable fees and expenses (including, but not limited to, interest on SPR's indebtedness and payment obligations on account of SPR's PIES) provided that those payments do not exceed $90 million, $80 million and $60 million in the aggregate for the twelve-month periods ending on October 30, 2003, 2004, and 2005, respectively. The Term Loan Agreement also permits SPPC to make dividend payments to SPR in an aggregate amount not to exceed $10 million during the term of the Term Loan Agreement. In addition, SPPC may make dividend payments to SPR in excess of the amounts described above so long as, at the time of the payment and after giving effect to the payment there are no defaults or events of default under the Term Loan Agreement, and such amounts, when aggregated with the amount of dividends paid to SPR by SPPC since the date of execution of the Term Loan Agreement, do not exceed the sum of:

- (i) 50% of SPPC's Consolidated Net Income for the period commencing January 1, 2003, and ending with last day of fiscal quarter most recently completed prior to the date of the contemplated dividend payment, plus
- (ii) the aggregate amount of cash received by SPPC from SPR as equity contributions on its common stock during such period.

Accounts Receivable Facility. On October 29, 2002, SPPC established an accounts receivable purchase facility. The agreements relating to the receivables purchase facility contain various conditions, including a limitation on the payment of dividends by SPPC to SPR that is identical to the limitation contained in SPPC's Term Loan Agreement, described above.

Articles of Incorporation. SPPC's Articles of Incorporation contain restrictions on the payment of dividends on SPPC's common stock in the event of a default in the payment of dividends on SPPC's preferred stock. SPPC's Articles also prohibit SPPC from declaring or paying any dividends on any shares of common stock (other than dividends payable in shares of common stock), or making any other distribution on any shares of common stock or any expenditures for the purchase, redemption, or other retirement for a consideration of shares of common stock (other than in exchange for or from the proceeds of the sale of common stock) except from the net income of SPPC, and its predecessor, available for dividends on common stock accumulated subsequent to December 31, 1955, less preferred stock dividends, plus the sum of $500,000. At the present time, SPPC believes that these restrictions do not materially limit its ability to pay dividends and/or to purchase or redeem shares of its common stock.

Federal Power Act. SPPC is subject to the provisions of the Federal Power Act that state that dividends cannot be paid out of funds that are properly included in capital account. Although the meaning of this provision is not clear, it could be interpreted to impose an additional material limitation on a utility's ability, in the absence of retained earnings, to pay dividends.

NOTES TO FINANCIAL STATEMENTS (continued)

NOTE 14. RETIREMENT PLAN AND POSTRETIREMENT BENEFITS

SPR has pension plans covering substantially all employees. Benefits are based on years of service and the employee's highest compensation for a period prior to retirement. SPR also has other postretirement plans which provide medical and life insurance benefits for certain retired employees. The following table provides a reconciliation of benefit obligations, plan assets, and the funded status of the plans; the market-related value of the plan assets equals fair value. This reconciliation is based on a September 30 measurement date (dollars in thousands).

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	**2002**	2001
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligation, beginning of year	**$ 360,677**	$348,135	**$ 75,443**	$ 77,790
Service cost	**11,954**	13,494	**1,287**	1,922
Interest cost	**27,733**	27,742	**5,599**	6,358
Participant contributions	**—**	—	**590**	466
Plan amendment & special termination	**7,938**	476	**—**	—
Actuarial loss (gain)	**50,670**	6,864	**56,189**	(5,201)
Special termination benefits	**—**	394	**—**	—
Acquisitions and divestiture	**—**	—	**—**	(1,231)
Benefits paid	**(29,997)**	(36,428)	**(6,938)**	(4,661)
Benefit obligation, end of year	**$428,975**	$360,677	**$132,170**	$ 75,443
CHANGE IN PLAN ASSETS				
Fair value of plan assets, beginning of year	**$ 275,305**	$349,153	**$ 61,407**	$ 81,900
Actual return (loss) on plan assets	**(23,090)**	(39,320)	**(6,817)**	(15,797)
Company contributions	**16,616**	1,900	**183**	730
Participant contributions	**—**	—	**590**	466
Acquisition and divestiture	**—**	—	**—**	(1,231)
Benefits paid	**(29,997)**	(36,428)	**(6,937)**	(4,661)
Fair value of plan assets, end of year	**$ 238,834**	$275,305	**$ 48,426**	$ 61,407
Funded status, end of year	**$(190,142)**	$ (85,373)	**$(83,744)**	$(14,036)
Unrecognized net actuarial (gains) losses	**154,222**	61,750	**61,553**	(5,365)
Unrecognized prior service cost	**17,001**	10,366	**724**	—
Unrecognized net transition obligation	**—**	—	**9,311**	10,280
Contributions made in 4th quarter	**24,495**	11,917	**—**	—
Prepaid (accrued) pension and postretirement benefit obligations	**$ 5,576**	$ (1,340)	**$(12,156)**	$ (9,121)

Amounts for pension and postretirement benefits recognized in the Consolidated Balance Sheets consist of the following:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	**2002**	2001
Prepaid pension asset	**$ 19,813**	$ 14,051	**N/A**	N/A
Accrued benefit liability	**(14,237)**	(15,391)	**$(12,156)**	$(9,121)
Intangible asset	**17,001**	—	**N/A**	N/A
Accumulated other comprehensive income	**72,550**	1,395	**N/A**	N/A
Additional minimum liability	**(89,551)**	(1,395)	**N/A**	N/A
Net amount recognized	**$ 5,576**	$ (1,340)	**$(12,156)**	$(9,121)

The weighted average actuarial assumptions as of the measurement date were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2002	2001	2000	**2002**	2001	2000
Discount rate	**6.75%**	7.50%	8.00%	**6.75%**	7.50%	8.00%
Expected return on plan assets	**8.50%**	8.50%	8.50%	**8.50%**	8.50%	8.50%
Rate of compensation increase	**4.50%**	4.50%	4.50%	**N/A**	N/A	N/A

SPR has assumed a health care cost trend rate of 6% for 2002 and all future years.

Net periodic pension and other postretirement benefit costs include the following components:

	Pension Benefits		
	2002	2001	2000
Service cost	**$ 11,954**	$ 13,494	$ 11,907
Interest cost	**27,733**	27,742	26,469
Expected return on assets	**(22,768)**	(28,806)	(27,186)
Amortization of:			
Transition asset	**—**	—	—
Prior service costs	**1,676**	1,195	1,201
Actuarial losses	**2,252**	200	159
Net periodic benefit cost	**20,847**	13,825	12,550
Special termination charges	**1,646**	394	—
Total net benefit cost	**$ 22,493**	$ 14,219	$ 12,550

	Other Postretirement Benefits		
	2002	2001	2000
Service cost	**$ 1,287**	$ 1,922	$ 1,775
Interest cost	**5,599**	6,358	5,829
Expected return on assets	**(5,044)**	(6,774)	(5,327)
Amortization of:			
Prior service costs	**187**	—	—
Transition obligation	**969**	969	968
Actuarial gains	**—**	—	(598)
Net periodic benefit cost	**2,998**	2,475	2,647
Special termination charges	**58**	—	—
Total net benefit cost	**$ 3,056**	$ 2,475	$ 2,647

The assumed health care cost trend rate has a significant effect on the amounts reported. A one percentage point change in the assumed health care cost trend rate would have had the following effects on 2002 service and interest costs and the accumulated postretirement benefit obligation at year end:

One Percentage Point Change	Increase	Decrease
Effect on service and interest components of net periodic cost	$ 1,491	$ (1,206)
Effect on accumulated postretirement benefit obligation	$14,886	$(12,324)

NOTE 15. STOCK COMPENSATION PLANS

At December 31, 2002, Sierra Pacific Resources had several stock-based compensation plans which are described below.

SPR's executive long-term incentive plan for key management employees, which was approved by shareholders on May 16, 1994, provides for the issuance of up to 750,000 of SPR's common shares to key employees through December 31, 2003. On June 19, 2000, shareholders approved an increase of 1,000,000 shares for the executive long-term incentive plan. The plan permits the following types of grants, separately or in combination: nonqualified and qualified stock options, stock appreciation rights, restricted stock, performance units, performance shares, and bonus stock. During 2002, SPR issued nonqualified stock options, performance shares, and restricted stock under the long-term incentive plan.

Nonqualified Stock Options

Nonqualified stock options granted during 2002 were issued at an option price not less than market value at the date of the grants. The grants awarded in January and December vest to the participants 33% per year over a three-year period from the grant date; the remaining grants awarded in 2002 vest to the participants 100% one year from the grant date. All grants may be exercised for a period not exceeding ten years from the grant date. The options may be exercised using either cash or previously acquired shares valued at the current market price or a combination of both.

A summary of the status of SPR's nonqualified stock option plan as of December 31, 2002, 2001, and 2000, and changes during the year is presented below:

	2002		2001		2000	
Nonqualified Stock Options	**Shares**	**Weighted Average Exercise Price**	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	**1,213,958**	**$18.28**	799,428	$19.94	839,442	$24.33
Granted	**502,380**	**$14.05**	414,530	$15.08	400,000	$16.00
Exercised	**—**	**—**	—	—	14,107	$14.28
Forfeited	**197,232**	**$18.07**	—	—	425,907	$25.07
Outstanding at end of year	**1,519,106**	**$16.91**	1,213,958	$18.28	799,428	$19.94
Options exercisable at year-end	**601,371**	**$19.52**	262,533	$23.03	202,394	$22.66
Weighted average grant date fair value of options granted:(1)						
Average of all grants for:						
2002	**$4.56**					
2001			$3.83			
2000					$4.10	

(1) The fair value of each nonqualified option has been estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for grants issued in 2002, 2001, and 2000:

Year of Option Grant	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Average Expected Life
2002	0.00%	38.23%	5.03%	10 years
2001	4.99%	32.31%	5.32%	10 years
2000	4.81%	30.49%	6.14%	9.6 years

NOTES TO FINANCIAL STATEMENTS (continued)

The following table summarizes information about nonqualified stock options outstanding at December 31, 2002:

		Options Outstanding		Options Exercisable	
Year of Grant	Average Exercise Price	Number Outstanding at 12/31/02	Remaining Contractual Life	Average Exercise Price	Number Exercisable at 12/31/02
1994	$14.24	8,003	1 year	$14.24	8,003
1995	$13.02	9,010	2 years	$13.02	9,010
1996	$16.23	7,485	3 years	$16.23	7,485
1997	$19.97	33,428	4 years	$19.97	33,428
1998	$24.93	56,160	5 years	$24.93	56,160
1999	$25.11	222,120	6-6.6 years	$25.11	179,124
2000	$16.00	400,000	7 years	$16.00	200,000
2001	$15.95	338,010	8-8.6 years	$15.95	108,161
2002	$ 7.75	444,890	9-9.9 years	$ 7.75	—
Weighted Average Remaining Contractual Life			7.54 years		

Each participant was granted dividend equivalents for all 1996 and prior nonqualified option grants. Each dividend equivalent entitles the participant to receive a contingent right to be paid an amount equal to dividends declared on shares originally granted from the date of grant through the exercise date. Dividend equivalents will be forfeited if options expire unexercised.

Performance Shares

In 2002, 2001, and 2000, SPR granted performance shares in the following numbers and initial values:

	1/1/02	1/1/01	8/4/00	1/1/00
Shares granted	96,772	144,271	4,798	31,707
Value per share	$15.58	$14.80	$16.00	$26.00

The actual number of shares earned by each participant is dependent upon SPR achieving certain financial goals over three-year performance periods. However, 66,100 shares included in the number granted on January 1, 2001, had a one-year performance period, from January 1 through December 31, 2001. The value of all performance share grants, if earned, will be equal to the market value of SPR's common shares as of the end of the performance periods. SPR, at its sole discretion, may pay earned performance shares in the form of cash or in shares or a combination thereof. The grant of 66,100 shares on January 1, 2001, would have been paid in SPR stock only; however, this grant has not been approved for payment by SPR Board of Directors.

Simultaneous with the grant of the performance shares above, each participant was granted dividend equivalents. Each dividend equivalent entitles the participant to receive a contingent right to be paid an amount equal to dividends declared on shares originally granted throughout the performance period. Additionally, in order for dividend equivalents to be paid on the performance shares, certain financial targets must be met. Dividend equivalents will be forfeited if options expire unexercised.

Restricted Stock Shares

In 2002, SPR granted 4,500 restricted stock shares at an average grant price of $6.88 per share. The grants vest over 4 years at 25% per year.

During 2001, SPR granted 13,200 shares of restricted stock at an average grant price of $15.67 per share. The grants vest to the participants over 4 years at 25% per year. In 2002, according to the vesting schedule for each grant, 1,750 shares were issued under these grants.

In 2000, SPR granted 16,000 restricted stock shares at a grant price of $16.00 per share. The grant vests over 4 years with 4,000 shares becoming available in 2002, 4,000 shares in 2003, and 8,000 shares in 2004. In 2002, 4,000 shares were issued under this grant, in accordance with the vesting schedule. There is no performance criteria associated with the restricted stock grants except for continued employment with SPR or its subsidiaries, and all grants were issued with an entitlement to dividend equivalents.

Employee Stock Purchase Plan

Upon the inception of SPR's employee stock purchase plan, SPR was authorized to issue up to 400,162 shares of common stock to all of its employees with minimum service requirements. On June 19, 2000, shareholders approved an additional 700,000 shares for distribution under the plan. According to the terms of the plan, employees can choose twice each year to have up to 15% of their base earnings withheld to purchase SPR's common stock. The purchase price of the stock is 90% of the market value on the offering commencement date. Employees can withdraw from the plan at any time prior to the exercise date. Under the plan SPR sold 73,321, 33,830, and 46,773 shares to employees in 2002, 2001, and 2000, respectively. For purposes of determining the pro forma disclosure, compensation cost has been estimated for the employees' purchase rights on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for 2002, 2001, and 2000:

Year	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Weighted Average Fair Value
2002	0.00%	38.00%	3.12%	$1.45
2001	5.01%	32.43%	2.82%	$2.72
2000	4.72%	30.97%	5.86%	$3.03

Non-Employee Director Stock

The annual retainer for non-employee directors is $30,000, and the minimum amount to be paid in SPR stock is $20,000 per director. During 2002, 2001, and 2000, SPR granted the following total shares and related compensation to directors in SPR stock, respectively: 18,540, 14,573, and 16,915 shares, and $160,000, $210,000, and $250,000.

NOTE 16. DISCONTINUED OPERATIONS AND DISPOSAL OF LONG-LIVED ASSETS

Sale of Water Business

In June 2001, SPPC closed the sale of its water business to the Truckee Meadows Water Authority (TMWA) for $341 million. SPPC recorded a $25.8 million gain on the sale, net of the refund described below and net of income taxes of $18.2 million. Included in the sale were facilities for water storage, supply, transmission, treatment, and distribution, as well as accounts receivable and regulatory assets. Accounts receivable consisted of amounts due from developers for distribution facilities. Regulatory assets consisted primarily of costs incurred in connection with the Truckee River negotiated water settlement. Transfer of hydroelectric facilities included in the contract of sale for an additional $8 million will require action by the CPUC. The sale agreement contemplates a second closing for the hydroelectric facilities to accommodate the CPUC's review of the transaction. See Note 3, Regulatory Actions, for a discussion of California legislative and regulatory developments involving the hydroelectric facilities.

Pursuant to a stipulation entered into in connection with the sale and approved by the PUCN, SPPC was required to hold in trust for refund to customers $21.5 million of the proceeds from the sale. The refund was credited on the electric bills of SPPC's former water customers over a fifteen-month period ending November 2002. Under a service contract with TMWA, SPPC provided customer service and billing services to TMWA until August 2002. SPPC continues to provide meter-reading services under a one-year contract renewable in one-year increments by TMWA through 2008.

Revenues from operations of the water business for the years ended December 31, 2001 and 2000, were $23 million and $57 million, respectively. The net income from operations of the water business, as shown in the Consolidated Statements of Operations of both SPR and SPPC, includes preferred dividends of $200,000 and $401,000 for the years ended December 31, 2001 and 2000, respectively. These amounts are not included in the revenues and income (loss) from continuing operations shown in the accompanying Consolidated Statements of Operations.

Asset Sales

During 2002, the Utilities began pursuing the sale of several non-essential properties. As a result, on January 15, 2003, NPC sold a parcel of land located on Flamingo Road near the Barbary Coast Casino in Las Vegas, Nevada. NPC received cash proceeds of approximately $18 million for the property and retained an easement and other rights necessary to maintain aerial power lines that cross the property. Also, it was agreed that NPC will receive an additional $2.6 million from the sale if the power lines that cross the property are removed and the other rights are relinquished within a five-year period from the date of the sale. The property had been originally transferred to NPC at no cost. The transaction resulted in a gain of $17.7 million, which will be recognized into revenue over a period of three years consistent with the accounting treatment directed by the PUCN.

On November 11, 2002, SPPC agreed to sell land located in Nevada County and Sierra County, California, commonly referred to as Independence Lake. The sale remains subject to review by a third party who retains certain rights, including water rights, after the sale is completed. Also, the sales agreement includes a due diligence review period of 180 days which allows the buyer to review and accept a variety of matters agreed to by both parties. The buyer may terminate the agreement during the review period by providing written notice or by allowing the review period to expire. The agreed-upon sales price is $22 million and the transaction is expected to close, subject to the conditions described, in the second quarter of 2003. The carrying value of the property is approximately $108,000.

NOTE 17. COMMITMENTS AND CONTINGENCIES

Purchased Power

At December 31, 2002, NPC has six long-term contracts for the purchase of electric energy. Expiration of these contracts ranges from 2016 to 2024. SPPC has one long-term contract with an expiration date of 2009. Estimated future commitments under non-cancelable agreements including agreements with Qualifying Facilities (QF's) as of December 31, 2002, were as follows (dollars in thousands):

Purchased Power

	NPC	SPPC	Total
2003	$ 408,656	$138,803	$ 547,459
2004	241,957	42,968	284,925
2005	220,343	28,874	249,217
2006	204,666	29,406	234,072
2007	189,434	30,957	220,391
Thereafter	3,456,297	38,351	3,494,648

NOTES TO FINANCIAL STATEMENTS (continued)

According to the regulations under the Public Utility Regulatory Policies Act, the Utilities are obligated, under certain conditions, to purchase the generation produced by small power producers and cogeneration facilities at costs determined by the appropriate state utility commission. Generation facilities that meet the specifications of the regulations are known as qualifying facilities. As of December 31, 2002, NPC had a total of 305 MWs of contractual firm capacity under contract with four QFs. The contracts terminate between 2022 and 2024. As of December 31, 2002, SPPC had a total of 109 MWs of maximum contractual firm capacity under 15 contracts with QFs. SPPC also has contracts with three projects at variable short-term avoided cost rates. SPPC's long-term QF contracts terminate between 2006 and 2039.

Coal and Natural Gas

The Utilities have several long-term contracts for the purchase and transportation of coal and natural gas. These contracts expire in years ranging from 2003 to 2027. Estimated future commitments under noncancelable agreements were as follows (dollars in thousands):

	Coal and Gas			Transportation		
	NPC	SPPC	Total	NPC	SPPC	Total
2003	$37,818	$31,699	$69,517	$ 36,606	$ 61,733	$ 98,339
2004	27,040	15,364	42,404	42,285	60,651	102,936
2005	9,605	15,830	25,435	28,946	56,001	84,947
2006	2,829	16,302	19,131	28,946	53,174	82,120
2007	1,007	0	1,007	28,946	50,270	79,216
Thereafter	4,029	0	4,029	337,312	318,493	655,805

Leases

SPPC has an operating lease for its corporate headquarters building. The primary term of the lease is 25 years, ending 2010. The current annual rental is $5.4 million, which amount remains constant until the end of the primary term. The lease has renewal options for an additional 50 years.

SPR's estimated future minimum cash payments, including SPPC's headquarters building, under noncancelable operating leases as of December 31, 2002, were as follows (dollars in thousands):

	Operating Leases			
	NPC	SPPC	Other Subs	Total
2003	$2,263	$ 8,357	$ 479	$11,099
2004	1,170	7,080	476	8,726
2005	869	6,425	380	7,674
2006	181	6,177	147	6,505
2007	119	6,173	147	6,439
Thereafter	459	55,153	2,086	57,698

Sale of Generation Assets

As a condition to its approval of the merger between SPR and NPC, the PUCN required the Utilities to file a Divestiture Plan for the sale of their electric generation assets. The PUCN approved a revised Divestiture Plan stipulation in February 2000. In May 2000, an agreement was announced for the sale of NPC's 14% undivided interest in the Mohave Generating Station ("Mohave"). In the fourth quarter of 2000, the Utilities announced agreements to sell six additional bundles of generation assets described in the approved Divestiture Plan. The sales were subject to approval and review by various regulatory agencies.

AB 369, which was signed into law on April 18, 2001, prohibits until July 2003 the sale of generation assets and directs the PUCN to vacate any of its orders that had previously approved generation divestiture transactions. In January 2001, California enacted a law that prohibits until 2006 any further divestiture of generation properties by California utilities, including SPPC, and could also affect any sale of NPC's interest in Mohave after July 2003 since the majority owner of that project is Southern California Edison.

In addition, SPPC's request for an exemption from the requirements of a separate California law requiring approval of the CPUC to divest its plants was denied. In September 2002, the California Legislature approved an amendment, AB1235, to AB 6 that would allow SPPC to complete the sale of the four hydroelectric units to TMWA. Section 851 of the Public Utilities Code requires review and approval of the sale by the CPUC. The sale of the Farad Hydroelectric Unit is conditioned on the completion of the reconstruction of the Farad dam and flume or assignment of SPPC insurance claim for reconstruction of the dam. The Farad Reconstruction Project is currently in the permitting phase with permits expected by mid-2003.

The sales agreements for the six bundles provided that they terminate eighteen months after their execution unless the parties agreed to an earlier termination. The parties could have extended the termination another six months to obtain additional regulatory approvals. As a result of the legislative and regulatory developments which rendered the contracts impossible to perform, the Utilities engaged in discussions with the buyers of the generation assets regarding the formal termination of the sales agreements and the related energy buyback contracts and interconnection agreements. Those discussions ended without agreement to mutually terminate; however, all the contracts have now terminated in accordance with the contract provisions. As of December 31, 2002, the Utilities had incurred costs of approximately $20.1 million at NPC and $12.2 million at SPPC in order to prepare for the sale of generation assets. The Utilities requested recovery of these costs in each Utility's respective general rate case filings with the PUCN. The PUCN delayed recovery of the divestiture costs to a future rate case request but did grant a carrying charge on the costs until such time as recovery is allowed.

Environmental

Nevada Power Company

The Grand Canyon Trust and Sierra Club filed a lawsuit in the U.S. District Court, District of Nevada, in February 1998 against the owners (including NPC) of the Mohave Generation Station ("Mohave"), alleging violations of the Clean Air Act regarding emissions of sulfur dioxide and particulates. An additional plaintiff, National Parks and Conservation Association, later joined the suit. The plant owners and plaintiffs have had numerous settlement discussions and filed a proposed settlement with the court in October 1999. The consent decree, approved by the court in November 1999, established emission limits for sulfur dioxide and opacity and required installation of air pollution controls for sulfur dioxide, nitrogen oxides, and particulate matter. The new emission limits must be met by January 1, 2006, and April 1, 2006 for the first and second units respectively. The estimated cost of new controls is $1.1 billion. As a 14% owner in Mohave, NPC's cost could be $154 million.

NPC's ownership interest in Mohave comprises approximately 10% of NPC's peak generation capacity. Southern California Edison (SCE) is the operating partner of Mohave. On May 17, 2002, SCE filed with the CPUC an application to address the future disposition of SCE's share of Mohave. Mohave obtains all of its coal supply from a mine in northeast Arizona on lands of the Navajo Nation and the Hopi Tribe (the Tribes). This coal is delivered from the mine to Mohave by means of a coal slurry pipeline which requires water that is obtained from groundwater wells located on lands of the Tribes in the mine vicinity.

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application states that it appears that it probably will not be possible for SCE to extend Mohave's operations beyond 2005. Due to the uncertainty over a post-2005 coal supply, SCE and the other Mohave co-owners have been prevented from commencing the installation of extensive pollution control equipment that must be put in place if Mohave's operations are extended past 2005.

NPC is currently evaluating and analyzing all of its options with regard to the Mohave project.

In May 1997, the Nevada Division of Environmental Protection (NDEP) ordered NPC to submit a plan to eliminate the discharge of Reid-Gardner Station wastewater to groundwater. The NDEP order also required a hydrological assessment of groundwater impacts in the area. In June 1999, NDEP determined that wastewater ponds had degraded groundwater quality. In August 1999, NDEP issued a discharge permit to Reid-Gardner Station and an order that requires all wastewater ponds to be closed or lined with impermeable liners over the next 10 years. This order also required NPC to submit a Site Characterization Plan to NDEP to ascertain impacts. This plan has been approved by NDEP. NDEP is expected to identify remediation requirements of contaminated groundwater resulting from these evaporation ponds by July 2003. New pond construction and lining costs are estimated at $15 million.

At the Reid-Gardner Station, the NDEP has determined that there is additional groundwater contamination that resulted from oil spills at the facility. NDEP has required NPC to submit a corrective action plan. The extent of contamination has been determined and remediation is occurring at a modest rate. A hydro-geologic evaluation of the current remediation was completed and a dual phase extraction-remediation system, which has been approved by NDEP will be constructed beginning April 2003, at an estimated cost of $150,000.

In May 1999, NDEP issued an order to eliminate the discharge of NPC's Clark Station wastewater to groundwater. The order also required a hydrological assessment of groundwater impacts in the area. This assessment, submitted to NDEP in February 2001, warranted a Corrective Action Plan, which was approved in June 2002. Remediation costs are expected to be approximately $100,000. In addition to remediation, NPC will spend $789,000 to line existing ponds. This project was started in 2002 and is expected to be completed in the first quarter 2003.

In July 2000, NPC received a request from the EPA for information to determine the compliance of certain generation facilities at the Clark Station with the applicable State Implementation Plan. In November 2000, NPC and the Clark County Health District entered into a Corrective Action Order requiring, among other steps, capital expenditures at the Clark Station totaling approximately $3 million. In March 2001, the EPA issued an additional request for information that could result in remediation beyond that specified in the November 2000 Corrective Action Order. If the EPA prevails, capital expenditures and temporary outages of four of Clark Station's generation units could be required. Additionally, depending on the time of year that the compliance activity and corresponding generation outage would occur, the incremental cost to purchase replacement energy could be substantial. To date, the EPA has not issued additional requests for further information.

NEICO, a wholly owned subsidiary of NPC, owns property in Wellington, Utah, which was the site of a coal washing and load out facility. The site now has a reclamation estimate supported by a bond of $4.8 million with the Utah Division of Oil and Gas Mining. The property was under contract for sale and the contract required the purchaser to provide $1.3 million in escrow towards reclamation. However, the sales contract was terminated and NEICO took title to the escrow funds. The property is currently leased with the intention to reclaim coal fines with subsequent revenues and reduction to the reclamation bond.

NOTES TO FINANCIAL STATEMENTS (continued)

Sierra Pacific Power Company

In September 1994, Region VII of the EPA notified SPPC that it was being named as a potentially responsible party (PRP) regarding the past improper handling of Polychlorinated Biphenyls (PCB's) by PCB Treatment, Inc., in two buildings, one located in Kansas City, Kansas, and the other in Kansas City, Missouri (the Sites). Prior to 1994, SPPC sent PCB contaminated material to PCB Treatment, Inc. for disposal. Certificates of disposal were issued to SPPC by PCB Treatment, Inc. however, the contaminated material was not disposed of but remained on-site. A number of the largest PRPs formed a steering committee, which is chaired by SPPC. The steering committee has completed its site investigations and the EPA has determined that the Sites should be remediated by removing the buildings to the appropriate landfills. The EPA has issued an administrative order on consent requiring the steering committee to oversee the performance of the work. SPPC has recorded a preliminary liability for the Sites of $650,000, of which approximately $136,000 has been spent through December 31, 2002. The steering committee is obtaining cost estimates for removal of the buildings. Once these costs have been determined, SPPC will be in a better position to estimate and record the ultimate liabilities for the Sites.

Lands of Sierra

LOS, a wholly owned subsidiary of SPR, owns property in North Lake Tahoe, California, which is leased to independent condominium owners. The property has both soil and groundwater petroleum contamination resulting from an underground fuel tank that has been removed from the property. Additional contamination from a third-party fuel tank on the property has also been identified and is undergoing remediation. The Lahontan Regional Water Quality Control Board has approved closure without additional remediation pending a one-year monitoring period. Final closure is anticipated in December 2003.

Other Commitments and Contingencies

In 2000, Sierra Pacific Communications (SPC), a wholly owned subsidiary of SPR, and Touch America (formerly known as Montana Power), formed Sierra Touch America LLC (STA), a limited liability company whose primary purpose was to engage in communications and fiber-optics business projects, including construction of a fiber-optic line between Salt Lake City, Utah, and Sacramento, California. The conduits included in the line are to be sold to AT&T, PF Net Corporation, and STA. Construction is expected to be completed in the second quarter of 2003. The project sustained significant cost overruns, and several complaints and mechanics liens have been filed by several contractors and subcontractors, including Williams Communications LLC, Bayport Pipeline Company, and Mastec North America. In September 2002, SPC conveyed its membership interest in STA to Touch America and obtained an indemnity for any liabilities associated with STA, all in exchange for title to several fibers in the line and a $35 million promissory note. Several of the mechanics lienors have named SPC as the owner of the project and Bayport Pipeline has suggested it may amend its complaint to name SPC.

SPPC owns a 345 kV transmission line that connects SPPC to the facilities of the Bonneville Power Administration (BPA) near Alturas, California. The Transmission Agency of Northern California (TANC) initiated proceedings in the United States District Court for the Eastern District of California and the United States Court of Appeals for the Ninth Circuit, in each case alleging that BPA's construction of a small portion of the Alturas Intertie violated the Northwest Power Preference Act and is requesting an injunction prohibiting operation of the Alturas Intertie. The case before the Eastern District was dismissed for lack of jurisdiction. The case before the Ninth Circuit was dismissed for TANC's failure to prosecute. In December 1999, TANC filed suit in the Superior Court of the State of California, Sacramento County, seeking an injunction against operation of the Alturas Intertie based on numerous allegations under state law, including inverse condemnation, trespass, private nuisance, and conversion. That case was removed to Federal Court and dismissed by the trial court. The dismissal was affirmed by the Ninth Circuit Court of Appeals, and TANC has now filed a writ of certiorari with the United States Supreme Court. Management believes the final outcome of the appeal is not likely to have a material adverse effect on SPPC's financial position or results of operation.

Enron filed a complaint with the United States Bankruptcy Court for the Southern District of New York seeking to recover approximately $216 million and $93 million against NPC and SPPC, respectively, for liquidated damages for power supply contracts terminated by Enron in May 2002 and for power previously delivered to the Utilities. The Utilities have denied liability on numerous grounds, including deceit and misrepresentation in the inducement, (including, but not limited to, misrepresentation as to Enron's ability to perform), and for fraud, unfair trade practices, and market manipulation. The Utilities filed motions to dismiss for lack of jurisdiction and/or for a stay of all proceedings pending the actions of the Utilities' proceedings under Section 206 of the Federal Power Act at the FERC. The Utilities have also filed proofs of claims and counterclaims against Enron for the full amount of the approximately $300 million claimed to be owed and additional damages, as well as for unspecified damages to be determined during the case as a result of acts and omissions of Enron in manipulating the power markets.

On December 19, 2002, the bankruptcy judge granted Enron's motion for partial summary judgment on Enron's claim for $17.7 million and $6.7 million, respectively, for energy delivered by Enron in April 2002 for which NPC and SPPC did not pay. The court ordered this money to be deposited into an escrow account not subject to claims of Enron's creditors and subject to refund depending on the outcome of the Utilities' FERC cases on the merits. The Utilities made the deposit as required. The bankruptcy court denied the Utilities' motion to stay the proceeding pending the outcome of the Utilities' Section 206 case at the FERC and denied the Utilities' motion to dismiss for lack of jurisdiction as to Enron's claims for power previously delivered to the Utilities. The court stated that it would rule in due course on Enron's motion for partial summary judgment to require NPC and SPPC to post $200 million and $87 million, respectively pending the outcome of the case on the merits, and for judgment on the merits on Enron's liquidated damage claim (contract price less market price on the date of termination) relating to power it did not deliver under contracts terminated by Enron in May 2002. The court took under advisement the Utilities' motion to stay or dismiss Enron's claim for liquidated damages relating to the undelivered power and set a hearing on Enron's motion to dismiss the Utilities' counterclaims for April 3, 2003. The utilities are unable to predict the outcome of these motions. The United States District Court for the Southern District of New York also denied the Utilities' motion to withdraw reference of the matter to the bankruptcy court without prejudice.

The bankruptcy court currently has under submission (1) Enron's motion to dismiss the Utilities' counterclaims, (2) Enron's motion for partial summary judgment regarding the amounts alleged to be due for undelivered power and the posting of collateral for undelivered power, and (3) the Utilities' motion to dismiss or stay proceeding on Enron's claims relating to delivered power. Enron's motion to dismiss the Utilities' counterclaims is set for hearing on April 3, 2003. An decision adverse to the Utilities on Enron's motion for partial summary judgment, or an adverse decision in the lawsuit with respect to liability as to Enron's claims on the merits for undelivered power, would have a material adverse effect on SPR's and the Utilities' financial condition and liquidity and could make it difficult for one or more of SPR, NPC, or SPPC to continue to operate outside of bankruptcy.

On September 5, 2002, Morgan Stanley Capital Group (MSCG) initiated an arbitration pursuant to the arbitration provisions in various power supply contracts terminated by MSCG in April 2002. In the arbitration, MSCG is requesting that the arbitrator compel NPC to pay MSCG $25 million pending the outcome of any dispute regarding the amount owed under the contracts. NPC claims that nothing is owed under the contracts on various grounds, including breach by MSCG in terminating the contracts, and further, that the arbitrator does not have jurisdiction over NPC's contract claims and defenses.

On September 30, 2002, plaintiffs Stephen A. Gordon and Gail M. Gordon filed a lawsuit in the District Court for Clark County, Nevada, seeking class action status for themselves and all shareholders of SPR against SPR and all of its directors for an alleged breach of fiduciary duty in failing to meaningfully evaluate and consider an alleged offer from the Southern Nevada Water Authority (SNWA) to purchase NPC. The suit seeks extraordinary relief in the form of an injunction requiring the directors to carefully evaluate and consider such offer, formation of a special stockholders committee to ensure fair and adequate evaluation procedures, and for unspecified damages and/or punitive damages in the event the SNWA withdraws its alleged offer before it can be carefully evaluated. SPR intends to vigorously defend the suit. No answer or responsive pleading has yet been required nor have plaintiffs moved for class certification. On September 30, 2002, plaintiff John Anderson filed a virtually identical lawsuit seeking the same relief. On March 21, 2003, plaintiffs' counsel moved to consolidate the Gordon and Anderson cases with another virtually identical lawsuit filed by John Dedolph. SPR believes that the cases are completely without merit and plans to file motions to dismiss in the second quarter 2003.

On October 21, 2002, Bonneville Square and Union Plaza filed a complaint seeking class certification in the Eighth Judicial District Court for Clark County, Nevada, against NPC for fraud and misrepresentation for allegedly overcharging a certain class of customers for energy delivered over the past several years. Plaintiffs allege that NPC fraudulently placed its meters and measured energy delivered at a point prior to passing through transformers, during which process a certain amount of energy is dissipated as heat, instead of placing the meters after they pass through the transformer. NPC's motion to dismiss on jurisdictional grounds was denied and NPC is filing a writ before the Nevada Supreme Court and is being joined in by the PUCN, which agrees with NPC that it has exclusive jurisdiction over the suit. NPC denies that the placement of the meters was fraudulent and alleges that placement of the meters was mandated by either or both customer request or applicable tariff.

On April 22, 2002, Reliant Energy Services, Inc. (Reliant), filed and served a cross-complaint against NPC and SPPC in the wholesale electricity antitrust cases, which was consolidated in the Superior Court of the State of California. Plaintiffs in that case seek damages and restitution from the named defendants for alleged fraud, misrepresentation, and anticompetitive conduct in manipulating the energy markets in California, resulting in prices far in excess of what would otherwise have been a fair price to the plaintiff class in a competitive market. Reliant filed cross-complaints against all energy suppliers selling energy in California who were not named as original defendants in the complaint, denying liability but alleging that if there is liability, it should be spread among all energy suppliers. The trial court has held all answers to cross-claims in abeyance until such time as it decides demurrers filed by all the defendants.

On May 3, 2002, and July 3, 2002, respectively, Reliant Resources and IDACORP Energy, L.P. (Idaho) terminated their power deliveries to NPC. On May 20, 2002, and July 30, 2002, Reliant Resources and Idaho asserted claims for $25.6 million and $8.9 million, respectively, under the Western System Power Pool Agreement (WSPP) for liquidated damages under energy contracts that each company terminated before the delivery dates of the power. Such claims are subject to mandatory mediation and, in some cases, arbitration under the contracts. To date only Idaho has requested mediation of the contracts, which should be completed by the end of second quarter. NPC alleges that Idaho and Reliant Resources were participants in market manipulation in the West and therefore are not entitled to termination payments under the contract.

In August 2002, El Paso Merchant Energy (EPME) terminated contracts for energy it had delivered to NPC under a program that called for delayed payment of the full contract price. In October 2002, EPME asserted a claim against NPC for $19 million in damages representing the approximate amount unpaid under the contracts. NPC alleges that EPME's termination resulted in net payments due to NPC under the WSPP liquidated damages provision for liquidated damages measured by the difference between the contract price and market price of energy EPME was to deliver from 2004 to 2012. Both claims are subject to mandatory mediation under the WSPP, but neither party has requested mediation at the present time.

NOTES TO FINANCIAL STATEMENTS (continued)

In connection with claims by their terminated energy suppliers, the Utilities established reserves, included in their Consolidated Balance Sheets in "contract termination reserves," totaling approximately $313 million, and pursuant to the deferred energy accounting provisions of AB 369, NPC and SPPC added approximately $228 million and $82 million, respectively, to their deferred energy balances for recovery in rates in future periods.

SPR and its subsidiaries, through the course of their normal business operations, are currently involved in a number of other legal actions, none of which has had or, in the opinion of management, is expected to have a significant impact on their financial positions, results of operations, or cash flows.

See Notes 3, 5, 6, 7, 8, 9, 12, and 14 for additional commitments and contingencies.

NOTE 18. SEGMENT INFORMATION

SPR operates three business segments (as defined by FASB Statement No. 131, "Disclosure About Segments of an Enterprise and Related Information") providing regulated electric and natural gas service. Electric service is provided to Las Vegas and surrounding Clark County, northern Nevada, and the Lake Tahoe area of California. Natural gas services are provided in the Reno-Sparks area of Nevada. Other segment information includes segments below the quantitative threshold for separate disclosure.

The net assets and operating results of SPPC's water business, divested in 2001, has been reported as discontinued operations in the financial statements for 2001 and 2000.

Operational information of the different business segments is set forth below based on the nature of products and services offered. SPR evaluates performance based on several factors, of which the primary financial measure is business segment operating income. The accounting policies of the business segments are the same as those described in Note 1, Summary of Significant Accounting Policies. Inter-segment revenues are not material.

December 31, 2002	**NPC Electric**	**SPPC Electric**	**Total Electric**	**Gas**	**All Other**	**Reconciling Eliminations**	**Consolidated**
Operating revenues	**$1,901,034**	**$ 931,251**	**$2,832,285**	**$149,783**	**$ 9,635**		**$2,991,703**
Operating income (loss)	**(104,003)**	**49,944**	**(54,059)**	**5,348**	**15,655**	**—**	**(33,056)**
Operating income taxes	**(133,411)**	**(7,236)**	**(140,647)**	**314**	**(28,165)**		**(168,498)**
Depreciation	**98,198**	**70,190**	**168,388**	**6,183**	**1,211**		**175,782**
Interest expense on long-term debt	**98,886**	**62,004**	**160,890**	**4,470**	**69,182**		**234,542**
Assets	**4,068,522**	**2,064,749**	**6,133,271**	**208,752**	**429,232**	**124,989**	**6,896,244**
Capital expenditures	**294,480**	**90,343**	**384,823**	**14,984**		**—**	**399,807**

December 31, 2001	NPC Electric	SPPC Electric	Total Electric	Gas	All Other	Reconciling Eliminations	Consolidated
Operating revenues	$3,025,103	$1,401,778	$4,426,881	$145,652	$ 18,841		$4,591,374
Operating income (loss)	144,364	71,219	215,583	7,749	(463)	—	222,869
Operating income taxes	17,775	5,534	23,309	2,973	(27,512)		(1,230)
Depreciation	93,101	66,393	159,494	5,710	1,181		166,385
Interest expense on long-term debt	81,599	50,071	131,670	5,128	51,572		188,370
Assets	4,704,606	2,357,548	7,062,154	264,108	580,494	85,320	7,992,076
Capital expenditures	200,852	116,713	317,565	16,041		—	333,606

December 31, 2000	NPC Electric	SPPC Electric	Total Electric	Gas	All Other	Reconciling Eliminations	Consolidated
Operating revenues	$1,326,192	$ 894,919	$2,221,111	$100,803	$ 14,199		$2,336,113
Operating income	74,182	31,989	106,171	13,420	6,794		126,385
Operating income taxes	(12,162)	(3,944)	(16,106)	3,272	(18,188)		(31,022)
Depreciation	85,989	66,655	152,644	4,975	696		158,315
Interest expense on long-term debt	64,513	23,435	87,948	4,318	42,330		134,596
Assets	3,407,751	1,722,725	5,130,476	151,905	61,768	333,759	5,677,908
Capital expenditures	204,505	117,785	322,290	14,490		23,350	360,130

The reconciliation of capital expenditures for 2000 represents capital expenditures of the discontinued water business. The reconciliation of segment assets at December 31, 2002, 2001, and 2000 to the consolidated total includes the following unallocated amounts:

	2002	2001	2000
Other property	**$ —**	$ —	$ 1,998
Cash	**98,515**	11,772	5,348
Current assets—other	**—**	50,862	29,852
Other regulatory assets	**24,555**	22,626	33,315
Net assets—discontinued operations	**—**	—	261,479
Deferred charges—other	**1,919**	60	1,767
	$124,989	$85,320	$333,759

NOTE 19. DERIVATIVES AND HEDGING ACTIVITIES (SPR, NPC, SPPC)

Effective January 1, 2001, SPR, SPPC, and NPC adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, both issued by the Financial Accounting Standards Board. As amended, SFAS No. 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position, measure those instruments at fair value, and recognize changes in the fair value of the derivative instruments in earnings in the period of change unless the derivative qualifies as an effective hedge.

However, in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," regulatory assets and liabilities are established to the extent that such derivative gains and losses are recoverable or payable through future rates. Because of this accounting treatment, the Utilities will not apply hedge accounting to their electricity and natural gas derivatives. SPR and the Utilities have adopted cash flow hedge accounting for other derivative instruments not subject to regulatory treatment. The transition adjustments resulting from adoption of SFAS No. 133 related to the other derivative instruments not subject to regulatory treatment was reported as the cumulative effect of a change in accounting principle in Other Comprehensive Income of SPR and the Utilities.

SPR's and the Utilities' objective in using derivatives is to reduce exposure to energy price risk and interest rate risk. Energy price risks result from activities that include the generation, procurement, and marketing of power and the procurement and marketing of natural gas. Derivative instruments used to manage energy price risk include forwards, options, and swaps. These contracts allow the Utilities to reduce the risks associated with volatile electricity and natural gas markets.

Derivatives used to manage interest rate risk include interest rate swaps designed to moderate exposure to interest rate changes and lower the overall cost of borrowing. On April 1, 2002, SPR paid $9.5 million to terminate an interest rate swap related to $200 million of SPR Floating Rate Notes maturing April 20, 2003.

At December 31, 2002, the fair value of the derivatives resulted in the recording of $30 million, $29 million, and $1 million in risk management assets and $74 million, $30 million, and $44 million in risk management liabilities in the Consolidated Balance Sheets of SPR, NPC, and SPPC, respectively. Also, $45 million, $2 million, and $43 million in net risk management regulatory assets were recorded in the Consolidated Balance Sheets of SPR, NPC, and SPPC, respectively, at December 31, 2002. In addition, for the twelve months ended December 31, 2002, the unrealized gains and losses resulting from the change in the fair value of derivatives designated and qualifying as cash flow hedges for SPR, NPC, and SPPC were recorded in Other Comprehensive Income. Such amounts will be reclassified into earnings when the related transactions are settled or terminate. Accordingly, $7.3 million relating to SPR's terminated interest rate swap was reclassified into earnings during the twelve-month period ended December 31, 2002.

The effects of the adoption of SFAS No. 133 on comprehensive income have been reported in the consolidated statements of comprehensive income.

NOTE 20. CHANGE IN ACCOUNTING FOR GOODWILL (SPR, NPC, SPPC)

SFAS No. 142, adopted by SPR, NPC, and SPPC on January 1, 2002, changed the accounting for goodwill from an amortization method to one requiring at least an annual review for impairment. Upon adoption, SPR ceased amortizing goodwill.

SPR's Consolidated Balance Sheet as of December 31, 2002, includes approximately $306 million of goodwill pertaining to regulated operations resulting from the July 28, 1999, merger between SPR and NPC, net of approximately $19.7 million of amortization that has been deferred as a regulatory asset. The PUCN stipulation approving the merger allows for future recovery of this goodwill in rates charged to customers of SPR's regulated utility subsidiaries, NPC and SPPC, provided that NPC and SPPC demonstrate that merger savings exceed merger costs. The amount and timing of the recovery of this goodwill will be determined by the outcome of general rate cases expected to be filed by the Utilities with the PUCN in late 2003. For additional information, see Note 2, SPR and NPC Merger.

SPR's Consolidated Balance Sheet as of December 31, 2001, included approximately $6.2 million of goodwill related to unregulated operations that are reported under the "All Other" segment in Note 18. SFAS No. 142 provides that an impairment loss shall be recognized if the carrying value of each reporting unit's goodwill exceeds its fair value. For purposes of testing goodwill for impairment, a discounted cash flow model was used to determine the fair value of each reporting unit of SPR's unregulated operations. The reporting units included in SPR's unregulated operations evaluated for goodwill impairment were LOS, SPC, TGPC, and "Energy" (a reporting unit consisting of Sierra Energy Company dba e·three and Sierra Pacific Energy Company). As a result of the impairment testing, which included revenue forecasts and appraisal of assets, SPR recorded a transitional goodwill impairment charge of approximately $1.7 million ($1.6 million, net of applicable taxes) as a cumulative effect of a change in

NOTES TO FINANCIAL STATEMENTS (continued)

accounting principle on SPR's Consolidated Statements of Operations for the twelve months ended December 31, 2002. The goodwill impairment recognized by reporting unit was approximately $131,000, $40,000 and $1.5 million for LOS, SPC, and "Energy," respectively. Goodwill assigned to TGPC was determined not to be impaired.

The changes in the carrying amount of goodwill for the twelve-month period ended December 31, 2002, are as follows:

(dollars in thousands)	Regulated Operations	Unregulated Operations	Total
Balance as of January 1, 2002	$305,982	$ 6,163	$312,145
Impairment loss	—	(1,704)	(1,704)
Balance as of December 31, 2002	$305,982	$ 4,459	$310,441

A reconciliation of SPR's previously reported net income (loss) and earnings (loss) per share to the amounts adjusted for the adoption of SFAS No. 142 net of the related income tax effect follows:

Year ended December 31,	**2002**	2001	2000
(dollars in thousands, except per share amounts)			
EARNINGS (LOSS):			
Applicable to common stock	**$(307,521)**	$56,733	$(39,780)
Add back amortization of goodwill, net of tax	**—**	137	142
As adjusted	**(307,521)**	56,870	(39,638)
Add back cumulative effect of change in accounting principle, net of tax	**1,566**	—	—
As adjusted before cumulative effect of change in accounting principle	**$(305,955)**	$56,870	$(39,638)
BASIC AND DILUTED EARNINGS (LOSS) PER SHARE:			
As reported	**$ (3.01)**	$ 0.65	$ (0.51)
Add back amortization of goodwill, net of tax	**—**	—	—
As adjusted	**(3.01)**	0.65	(0.51)
Add back cumulative effect of change in accounting principle, net of tax	**0.01**	—	—
As adjusted before cumulative effect of change in accounting principle	**$ (3.00)**	$ 0.65	$ (0.51)

NOTE 21. PIÑON PINE (SPR, SPPC)

SPPC, through its wholly owned subsidiaries, Piñon Pine Corp., Piñon Pine Investment Co., and GPSF-B, owns Piñon Pine Company, L.L.C. (the LLC). The LLC was formed to take advantage of federal income tax credits associated with the alternative fuel (syngas) produced by the coal gasifier available under Section 29 of the Internal Revenue Code. The entire project, which includes an LLC-owned gasifier, an an SPPC-owned combined cycle generation facility and a post-gasification facility to partially cool and clean the syngas, is referred to collectively as the Piñon Pine Power Project (Piñon Pine). Construction of Piñon Pine was completed in June 1998.

Piñon Pine was co-funded by the Department of Energy (DOE) under an agreement between SPPC and DOE that expired December 31, 2000. The DOE funded approximately $167 million for construction, operation, and maintenance of the project. Included in the Consolidated Balance Sheets of SPR and SPPC is the net book value of the gasifier and related assets, which is approximately $100 million as of December 31, 2002.

To date, SPPC has not been successful in obtaining sustained operation of the gasifier. In 2001, SPPC retained an independent engineering consulting firm to complete a comprehensive study of the Piñon Pine gasification plant. The scope of the study included evaluation of the potential modifications required to make the facility operational and reliable using several technology scenarios. The evaluation of each scenario included an estimate of the additional capital expenditures necessary for reliable operation of the facility and the risks associated with that technology.

SPPC received a final report of the study in November 2002. The results of the study identified a number of potential modifications to the facility each with varying degrees of technical risk and cost. Modifications considered to provide the highest probability for successful operation of the facility generally were also estimated to be the highest cost options. SPPC is reviewing the various options outlined in the study. If after evaluating the options presented in the draft report SPPC decides not to pursue modifications intended to make the facility operational, SPPC intends to seek recovery, net of salvage, through regulated rates in its next general rate case based, in part, on the PUCN's approval of Piñon Pine as a demonstration project in an earlier resource plan. However, if SPPC is unsuccessful in obtaining recovery, there could be a material adverse effect on SPPC's and SPR's financial condition and results of operations.

NOTE 22. SUBSEQUENT EVENTS

See Notes 1, 3, 7, 8, 9, 16, and 17 for discussion of events occurring after December 31.

NOTE 23. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following figures are unaudited and include all adjustments necessary in the opinion of management for a fair presentation of the results of interim periods. Dollars are presented in thousands except per share amounts.

Quarter Ended	**March 31, 2002**	**June 30, 2002**	**September 30, 2002**	**December 31, 2002**
Operating revenues	**$ 638,864**	**$ 701,313**	**$1,020,716**	**$630,810**
Operating income (loss)	**$(230,751)**	**$ 19,899**	**$ 143,327**	**$ 34,469**
Earnings (deficit) applicable to common shareholders	**$(305,482)**	**$ (41,916)**	**$ 79,374**	**$ (39,497)**
Earnings (deficit) per share—basic	**$ (2.98)**	**$ (0.41)**	**$ 0.78**	**$ (0.39)**
Earnings (deficit) per share—diluted	**$ (2.98)**	**$ (0.41)**	**$ 0.78**	**$ (0.39)**

Quarter Ended	March 31, 2001	June 30, 2001	September 30, 2001	December 31, 2001
Operating revenues	$ 738,809	$1,156,178	$1,972,427	$723,960
Operating income	$ (30,487)	$ 78,294	$ 122,190	$ 52,872
Income (loss) from continuing operations	$ (83,860)	$ 27,549	$ 80,409	$ 5,768
Income from discontinued operations	381	641	—	—
Gain from disposal of water business	—	25,845	—	—
Earnings (deficit) applicable to common shareholders	$ (83,479)	$ 54,035	$ 80,409	$ 5,768
Earnings (deficit) per share—basic:				
From continuing operations	$ (1.07)	$ 0.35	$ 0.89	$ 0.06
From discontinued operations	$ 0.01	$ 0.01	$ —	$ —
From disposal of water business	$ —	$ 0.33	$ —	$ —
Earnings (deficit) applicable to common shareholders	$ (1.06)	$ 0.69	$ 0.89	$ 0.06
Earnings (deficit) per share—diluted:				
From continuing operations	$ (1.07)	$ 0.35	$ 0.89	$ 0.06
From discontinued operations	$ 0.01	$ 0.01	$ —	$ —
From disposal of water business	$ —	$ 0.33	$ —	$ —
Earnings (deficit) applicable to common shareholders	$ (1.06)	$ 0.69	$ 0.89	$ 0.06

SHAREHOLDER INFORMATION

CORPORATE DOCUMENTS

The SEC Annual Report on Form 10-K and 10-Year Statistical Report are available free of charge by written request to:

Shareholder Relations
Sierra Pacific Resources
P.O. Box 30150
Reno, Nevada 89520-3150

INDEPENDENT ACCOUNTANT

Deloitte & Touche LLP
Reno, Nevada

ANALYST CONTACT

Vicki Erickson
Sierra Pacific Resources
Investor Relations
P.O. Box 30150
Reno, Nevada 89520-3150
(775) 834-5646

NYSE SYMBOL

Sierra Pacific Resources' common stock is traded on the New York Stock Exchange under the symbol SRP.

SHAREHOLDER RELATIONS OFFICE

For shareholder records and dividend disbursement information, contact our Shareholder Relations Department:

Shareholder Relations
Sierra Pacific Resources
6100 Neil Rd.
Reno, Nevada 89511
(800) 662-7575 or (775) 834-3610
Fax: (775) 834-3614

Mailing Address:

P.O. Box 30150
Reno, Nevada 89520-3150

E-mail Address: sharerelations@sppc.com
Web Site: www.sierrapacificresources.com

COMMON STOCK INVESTMENT PLAN

Sierra Pacific Resources' Common Stock Investment Plan offers a simple and convenient method of investing common stock dividends and/or making optional cash investments to purchase additional shares of common stock directly from the company.

Please direct questions or requests for a prospectus to our Shareholder Relations Department.

STOCK TRANSFER AGENT AND REGISTRAR

Wells Fargo Shareowner Services
161 North Concord Exchange St.
South St. Paul, Minnesota 55075-1139

Our transfer agent is responsible for changes in certificate shares only. All other shareholder services are the responsibility of the Shareholder Relations Department in Reno, Nevada.

LOST OR STOLEN CERTIFICATES

If your stock certificates have been lost, stolen, or destroyed, please notify our Shareholder Relations Department in writing immediately.

ACCOUNT CONSOLIDATION

You may consolidate your accounts by contacting the Shareholder Relations Department. If your account registrations are different, it may be necessary to reissue stock certificates.

ANNUAL SHAREHOLDERS' MEETING

The annual shareholders' meeting is scheduled to be held in the convention center at The Orleans Hotel and Casino, 4500 W. Tropicana Avenue, Las Vegas, Nevada, at 10 a.m. (PDT) on Monday, May 12, 2003.

2002 ANNUAL REPORT

The Annual Report to Shareholders and the statements and statistics contained herein have been assembled for informative purposes and are not intended to induce, or for use in connection with, any sale or purchase of securities. Under no circumstances is this report or any part of its contents to be considered a prospectus, or as an offer to sell, or the solicitation of an offer to buy, any securities.

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SIERRA PACIFIC RESOURCES—SENIOR OFFICERS

( ) years of utility experience

Walter M. Higgins
Chairman, President and Chief Executive Officer, SPR; Chief Executive Officer, SPPC/NPC (26)

Jeffrey L. Ceccarelli
President, SPPC (31)

Donald L. “Pat” Shalmy
President, NPC (*)

Michael W. Yackira
Executive Vice President, Strategy and Policy, SPR/NPC/SPPC (16)

Richard K. Atkinson
Vice President and Chief Financial Officer, SPR/NPC/SPPC (23)

C. Stanley Hunterton
Senior Vice President, General Counsel and Corporate Secretary, SPR/NPC/SPPC (*)

Victor H. Peña
Senior Vice President and Chief Administrative Officer, SPR/NPC/SPPC (12)

SPR: Sierra Pacific Resources
NPC: Nevada Power Company
SPPC: Sierra Pacific Power Company

**Messrs. Shalmy and Hunterton joined the company in 2002. Mr. Shalmy has 35 years of administrative management experience; Mr. Hunterton has 29 years of legal experience.*

SIERRA PACIFIC RESOURCES—BOARD OF DIRECTORS

( ) years of board service

Edward P. Bliss
Consultant to Zurich Scudder Investments Company, an investment counsel firm in Boston, Massachusetts; retired partner, Loomis, Sayles & Company, Inc. (13)

Mary Lee Coleman
President of Coleman Enterprises, a developer of shopping centers and industrial parks. (23)

Krestine M. Corbin
President and Chief Executive Officer of Sierra Machinery, Inc., a manufacturer of roller burnishing heads and machines. (14)

Theodore J. Day
Senior Partner of Hale, Day, Gallagher Company, a Nevada-based real estate brokerage and investment firm. (16)

James R. Donnelley
Partner, Stet and Query, Ltd., a family-owned investment company; Director of Pacific Magazines & Printing, Ltd.; retired Vice Chairman of the Board, R.R. Donnelley & Sons. (16)

Jerry E. Herbst
Chief Executive Officer of Terrible Herbst, Inc., a large chain of family-owned service stations and related businesses; partner in Coast Resorts, a hotel-gaming company. (13)

Walter M. Higgins
Chairman, President and Chief Executive Officer, Sierra Pacific Resources; Director and Chief Executive Officer of Nevada Power and Sierra Pacific Power. (8)

John F. O’Reilly
Chairman and Chief Executive Officer of the law firm of O’Reilly and Ferrario; Chairman and Chief Executive Officer of the O’Reilly Gaming Group. (8)

Clyde T. Turner
Chairman and Chief Executive Officer of Turner Investments, a general purpose investment company, and Spectrum Companies, a special purpose real estate development company; retired Chairman and Chief Executive Officer of The Mandalay Bay group, a hotel-gaming company. (1)

Dennis E. Wheeler
Chairman and Chief Executive Officer of Coeur d’Alene Mines Corporation, an Idaho-based precious minerals mining company. (13)

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Sierra Pacific Resources
P.O. Box 30150
Reno, NV 89520-3150
www.sierrapacificresources.com